COPY

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Prefiled Testimony and Exhibits of Ohio Valley Gas Corporation in Cause No. 43209 upon the following by personal service or by depositing same in the U.S. Mail, first class, postage prepaid to the following addresses:

The Indiana Office of Utility Consumer Counselor
Indiana Government Center North
100 North Senate Avenue, Room N501
Indianapolis IN 46204-3215

FILED

MAR 3 0 2007

INDIANA UTILITY
REGULATORY COMMISSION

Dated this 30th day of March, 2007.

Ronald L. Loyd
Vice President & General Manager
OHIO VALLEY GAS CORPORATION
111 Energy Park Drive
P. O. Box 469
Winchester IN 47394-0469
Telephone: 765-584-6842
Fax: 765-584-0826

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS CORPORATION FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	CAUSE NO. 43209

PETITIONER'S EXHIBIT DJB

DIRECT TESTIMONY

OF

DAVID J. BEYNON

CHAIRMAN, PRESIDENT, CHIEF EXECUTIVE OFFICER

ON BEHALF OF

OHIO VALLEY GAS CORPORATION

MARCH 2007

PREPARED DIRECT TESTIMONY OF DAVID J. BEYNON

OHIO VALLEY GAS CORPORATION

1. Q. Will you please state your name and business address?

A. David J. Beynon, 111 Energy Park Drive, Winchester, Indiana.

2. Q. By whom are you employed?

A. The Petitioner in this proceeding, Ohio Valley Gas Corporation.

3. Q. What is your position with Petitioner?

A. Chairman, President, and Chief Executive Officer.

4. Q. When did you begin your employment with the Petitioner?

A. On September 1, 1953.

5. Q. Please summarize your educational background.

A. I graduated from the University of Nebraska in 1955 with a Bachelor of Science Degree in Electrical Engineering.

6. Q. Please summarize your professional experience and qualification

A. USNR Active Duty 1955-1957. Westinghouse Electric Corporation from 1958-1960. I am a member of the Institute of Electrical & Electronic Engineers. I have been a director of the Company since August 1953. In February 1990, I was elected Chairman, President, and Chief Executive Officer of the Petitioner. Since 1960, I have been involved in almost every aspect of the gas business, including the selection of our data processing and personal computer systems, rate design,

1 employee hiring and promotions, banking affiliations, insurance agents and
2 companies and establishing an electronic service department, including installation
3 and maintenance of our two-way radio system and numerous telemetry systems to
4 keep track of the flow of natural gas. I have spent many days at a time in the districts
5 observing various construction projects of the Petitioner. This has provided me with
6 the opportunity to know our employees, gas systems, and customers. I maintain
7 current personnel files and vehicle files, etc. in my office. I approve the expenditure
8 of funds for all significant projects via the Company's annual construction budget. I
9 was, for many years, a director of the Indiana Gas Association, Inc. Through this
10 association, I have been able to exchange ideas and assist with the resolution of
11 mutual problems with other natural gas utilities in the state.
12 7. Q. Have you previously testified before the Indiana Utility Regulatory Commission?
13 A. Yes, I have testified in proceedings on behalf of Petitioner and its wholly owned
14 subsidiary, Ohio Valley Gas, Inc.
15 8. Q. Is Petitioner a Corporation organized and existing under and by virtue of the laws of
16 the state of Indiana?
17 A. Yes, Petitioner was incorporated on December 14, 1943.
18 9. Q. Where is Petitioner's principal office?
19 A. Winchester, Randolph County, Indiana.
20 10. Q. Is Petitioner a public utility under the laws of the State of Indiana and is it subject to
21 the jurisdiction of the Indiana Utility Regulatory Commission?

A. Yes, we are a public utility and as such we are subject to the jurisdiction of the Indiana Utility Regulatory Commission.

11. Q. Please tell the Commission what areas are served by Petitioner.

A. We are authorized to, and do, operate a gas utility system which transports, distributes, and sells natural gas in the municipalities of Cannelton, Connersville, Ferdinand, Fountain City, Liberty, Lynn, Pennville (Jay County), Portland, Ridgeville, St. Leon, Saratoga, Sunman, Tell City, Troy, Union City, and Winchester, plus the unincorporated communities of Bluff Point, Bretzville, Brownsville, Center, Clinton Corners, College Corner (Jay County), Deerfield, Dover, Everton, Guilford, Harrisville, Haysville, Lawrenceville, Logan, Lyonsville, Maltersville, Negangard Corner, New Alsace, Penntown, Randolph, Springersville, St. Anthony, St. Marks (Dubois County), St. Marks (Perry County), St. Meinrad, Yorkville, and other rural areas, all located within Dearborn, Dubois, Fayette, Franklin, Jay, Perry, Randolph, Ripley, Spencer, Union, and Wayne Counties in Indiana.

12. Q. Is this an interconnected system?

A. No. Petitioner has multiple delivery points on both ANR Pipeline Company ("ANR") and Texas Gas Transmission Corporation ("TGT") pipelines, and operates numerous segregated distribution systems in its certificated service territories.

13. Q. From whom is the natural gas transported and distributed through Petitioner's distribution systems purchased?

A. Petitioner purchases nearly all of its system supply gas through a natural gas broker, BP Canada Energy Marketing, Inc. Such purchases are made on a periodic, on-

1 going basis as both fixed-price (futures) contracts and market-based (index)
2 purchases.
3 14. Q. Does Petitioner have any other source(s) of gas?
4 A. Yes. At Union City and Connersville we have propane-air peak-shaving plants. The
5 Union City facility has storage consisting of six (6) 30,000 gallon tanks. At
6 Connersville, there are three (3) 60,000 gallon tanks. The Union City facility can
7 produce 1,500 MCF of 1000 BTU/CF natural gas equivalent per 24-hour day (1,500
8 Dekatherms per day). At Connersville, the facility can produce 3,000 MCF of 1,000
9 BTU/CF natural gas equivalent per 24-hour day (3,000 Dekatherms per day).
10 Petitioner has, at several locations, installed pipeline connections to allow for the
11 purchase of locally produced, pipeline-quality natural gas as (when) available.
12 15. Q. Is Petitioner required to have a United States Department of Transportation ("DOT")
13 Drug Testing Program and Alcohol Testing Program?
14 A. Yes.
15 16. Q. Does Petitioner have its DOT Drug Testing Program and Alcohol Testing Program in
16 place and functioning, as required by DOT?
17 A. Yes. These programs were implemented in November 1990 and January 1995,
18 respectively. The drug testing program provides for monthly random screenings on a
19 randomly selected work day each month, as well as screenings under the categories
20 of post accident, pre-employment, and for reasonable cause as defined therein. The
21 alcohol testing program provides for screenings to be conducted for reasonable
22 cause as defined therein.

1 17. Q. Who is responsible for the management of the DOT Drug Program?

2 A. I am. The Medical Review officer (MRO) makes his reports directly to me. After my
3 review, these reports are sent to Ronald. L. Loyd, our Vice President and General
4 Manager, who maintains the required files. Mr. Loyd randomly selects the work day
5 of the month and randomly selects the employees to be tested through the use of a
6 computer-generated randomizing process, and then provides a listing to me each
7 month of employees selected for testing. He then advises those employees who
8 have been so selected to report for the required screening. I am also responsible for
9 the management of the DOT Alcohol Program as it currently applies to Petitioner.

10 18. Q. Are all of your employees covered under these programs?

11 A. All employees, considered by me to be employed in a safety-sensitive position, are
12 included in our pool of employees subject to the random monthly selection process
13 for drug screening. All employees, regardless of their position with the company are
14 subject to testing under the alcohol program.

15 19. Q. Please describe the document marked Petitioner's Exhibit DJB-1.

16 A. It is a copy of Petitioner's Verified Petition in this Cause, filed with the Commission on
17 January 8, 2007.

18 20. Q. Please describe the documents marked Petitioner's Exhibit DJB-2.

19 A. They are the required proofs of publication of the legal notice regarding the filing of
20 our petition in this cause as received from those newspapers in which said notice
21 was published.

22 21. Q. Please identify Petitioner's Exhibit DJB-3.

1 A. It is the certified resolution of Petitioner's Board of Directors ratifying and confirming
2 the actions of our officers in commencing proceedings in this cause.
3 22. Q. Please identify Petitioner's Exhibit DJB-4.
4 A. This exhibit contains a facsimile copy of the required first notice of filing for rate
5 increase as required by Commission rules. This notice was mailed to all residential
6 customers between February 19 and February 22, 2007.
7 Inasmuch as the impact of the request for increased rates on a typical residential
8 customer could not be determined at the time of the first notice, a second notice will
9 be mailed to all residential customers at some point prior to the evidentiary hearing in
10 this Cause. This second notice will provide additional general information regarding
11 the request for increased rates and what effect such an increase, if granted by the
12 Commission, would have on Petitioner's billings to a typical residential customer.
13 Petitioner warrants that such a second notice will, in fact, be mailed to all of its
14 residential customers and that a facsimile copy of such notice(s) will be entered into
15 the record of this Cause as a late-filed exhibit, as necessary and appropriate.
16 23. Q. What is the present dividend being paid to Petitioner's shareholders?
17 A. No dividend has been paid to Petitioner's shareholders since October 1, 2003. While
18 dividends had been regularly paid through 2001 at the rate of $0.20 per share
19 (approx. $74,000 per year in total), Petitioner's Board of Directors, at a special
20 meeting held in February 2002, determined that such dividends should be suspended
21 after reviewing the January 2002 financial report. In May of 2003, Petitioner's Board
22 of Directors determined that a dividend of $0.50 per share should be paid in equal

installments of $0.25 per share each to all shareholders of record on July 1 and October 1, 2003. Since the payment of the 2003 dividends, the Board of Directors has annually reviewed the financial position of the Company and determined that no dividend should be paid.

24. Q. What is the basis for the proposed schedules of rates and charges in Exhibit RLL-4?

A. These rates and charges are intended to recover Petitioner's cost of service as determined and allocated among customer rate classes by Kerry A. Heid (Exhibit KAH-1) and produce a fair return on the original cost and fair value of Petitioner's investment in utility property used and useful for service to the public. The proposed rates should provide for a uniform and equitable return among all rate classes based on the cost of service study.

25. Q. Then you propose that your new rates be based on a cost of service study?

A. Yes. The rates we propose reflect, to the best of our ability, our true costs of service and virtually eliminate any inter-rate class subsidies that exist under the present rates and rate structure.

26. Q. Why does Petitioner need an increase in its rates and charges for natural gas service?

A. In Cause No. 42239, approved by the Indiana Utility Regulatory Commission on January 2, 2003, Petitioner was authorized to earn utility operating income of $2,664,901. Exhibit SMK-3, Page 1, shows that Petitioner's unadjusted utility operating income per its books for the twelve months ended June 30, 2006 was $454,064, just 17% of the allowed amount. When Petitioner's utility operating income

for the twelve months ended June 30, 2006 is adjusted for various fixed, known, and measurable adjustments, including weather normalization and multiple customer changes, among other adjustments, Petitioner's adjusted utility operating income is a negative $154,066. These results are especially alarming when Petitioner's investment in rate base of $32,249,225 as of September 30, 2006 (Exhibit SMK-3, Page 25) is considered. Petitioner's present rates and charges clearly do not produce a fair return on its used and useful property and therefore are unjust and confiscatory.

27. Q. What increase in revenues will be required to produce a fair return on the original costs and fair value of Petitioner's used and useful utility property and cover its cost of service?

A. The Petitioner's rates should be adjusted to generate $5,539,794 in additional annual revenue to produce annual Utility Operating Income of $3,141,074, resulting in a fair return of 9.74% on the depreciated original costs (Exhibit SMK-3, Page 32), and a 3.55% return on the fair value of Petitioner's investment in used and useful utility plant in service.

28. Q. What rate of return on equity are the proposed rates calculated to produce?

A. The rates and charges developed by Kerry A. Heid (Exhibit KAH-1) should allow the Petitioner to earn a return on common equity of 11.75% if, and only if, Petitioner does not incur costs or expenses greater than those incurred in the test year, as adjusted, and proposed revenues based on those rates are actually realized. Based upon the testimony of Paul R. Moul (Exhibit PRM), who developed Petitioner's proposed cost

of equity capital, the management of Petitioner has determined that the proposed rates and charges should allow Petitioner to earn an acceptable and fair rate of return on the fair value of Petitioner's utility plant that is used and useful for providing natural gas service to Petitioner's customers.

29. Q. Does this conclude your direct testimony in this Cause 43209?

A. Yes, it does.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS CORPORATION FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLAN OR PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	FILED JAN 0 8 2007 INDIANA UTILITY REGULATORY COMMISSION CAUSE NO. 43209

PETITION

Ohio Valley Gas Corporation ("OVGC" or "Petitioner") respectfully requests authority to increase its rates and charges for gas utility service rendered by it; approval of new schedules of rates and charges applicable to such service; approval of various changes to its tariffs, rules and regulations for gas service, including increases in certain non-recurring charges; approval of a pipeline safety cost adjustment mechanism to recover costs of complying with federal law; approval to implement a normal temperature adjustment (NTA) mechanism in its tariffs; authority to use deferral accounting associated with the NTA and pipeline safety compliance

costs; approval of changes in depreciation rates; and for approval as necessary and appropriate of all such relief as a component or components of an alternative regulatory plan or plans pursuant to IND. CODE 8-1-2.5. In support of this request, Petitioner respectfully represents to the Commission that:

1. Petitioner's Corporate and Regulatory Standing. Petitioner is a corporation duly organized and existing under the laws of the State of Indiana with its principal office located at 111 Energy Park Drive, Winchester, Indiana. Petitioner is a public utility as defined by IND. CODE §8-1-2-1(a) and an energy utility as defined by IND. CODE §8-1-2.5-2, and is therefore subject to regulation by the Commission in the manner and to the extent provided by the laws of the State of Indiana.

2. Petitioner's Operation and Utility Properties. Petitioner is authorized to and does provide gas utility service to more than 24,400 customers in 11 counties in southern and east central Indiana. Petitioner provides such gas utility service by means of utility plant, property, equipment and related facilities owned, leased, operated, managed and controlled by it (collectively referred to as its "Utility Properties") used and useful for the convenience of the public in the production, treatment, transmission, transportation, distribution and sale of gas.

3. Petitioner's Operating Results Under Current Rates. Petitioner's existing basic rates and charges for gas utility service were established pursuant to the Commission's order dated January 2, 2003 in Cause No. 42239. Since its rates and charges for gas utility service were last established, Petitioner has continued to make significant capital expenditures for additions, replacements and improvements to its Utility Properties. Also, the fair value of Petitioner's Utility Properties and its utility service operating expenses and other costs have increased. As a result Petitioner's current rates and charges for gas utility service are unjust,

unreasonable, insufficient, discriminatory and confiscatory and should be increased. Petitioner's return on its Utility Properties is, and without relief as herein requested will continue to be below the level required to permit Petitioner to earn a fair return on the fair value of its Utility Properties, and to provide revenues to enable it to continue to attract capital for additions, make replacements and improvements to its Utility Properties at a reasonable cost, maintain and support its credit and assure confidence in its financial soundness. Petitioner therefore requests that new rates, charges, rules, regulations and regulatory proceedings be authorized that will enable it to realize a proper and adequate net operating income necessary and appropriate for the provision of safe, adequate and continuous gas utility service to the public.

4. Depreciation Rates. Rapid obsolescence of certain equipment requires changes to Petitioner's depreciation rates. Petitioner proposes that the annual depreciation rates for its office furniture and equipment (Account 391) and communications equipment (Account 397) be changed to 10.0% to reflect the much shorter useful lives of this equipment.

5. Normal Temperature Adjustment. To address the volatility of customer bills, send more accurate price signals and improve Petitioner's position with rating agencies and the financial community, Petitioner proposes adoption of a normal temperature, or "NTA" mechanism that will adjust current billings to Petitioner's residential and certain other customers on a real-time basis during certain heating periods to mitigate the effect of heating degree-day variations from the normal level of heating degree-days used to establish base rates. Petitioner proposes using deferred accounting for the effects of non-normal temperatures through the effective date of the approved NTA mechanism utilizing the same weather normalization methodology employed in this proceeding, and to recover from or refund to customers the effects

of non-normal temperatures through the interim use of a deferred "Type 2" NTA mechanism until such time as its "Type 1" mechanism is approved.

6. Pipeline Safety Compliance Cost Recovery Mechanism. Pursuant to provisions of the Federal Pipeline Safety Improvement Act of 2002, as re-authorized by Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the "Act"), Petitioner has incurred, and will continue to incur, incremental operating costs in order to assure compliance with the Act. The Federal Department of Transportation has adopted rules under the Act containing a compliance timeline requiring ongoing integrity management costs, and requiring Petitioner to adopt a comprehensive public education program. Significant resources are being devoted to meet the Act's requirements in a timely manner. This increase in operating expenses represents a significant new ongoing cost that needs to be reflected in Petitioner's rates. The magnitude and timing of these costs are uncertain and variable. Therefore, Petitioner proposes that these costs be recovered through a tracking mechanism authorized pursuant to IND. CODE §8-1-2-42(a). Petitioner also proposes to use deferral accounting for the costs incurred to comply with the Act through the effective date of the tracking mechanism, and to recover the deferred costs from customers in future periods through such tracking mechanism.

7. Tariffs, Rules and Regulations. Petitioner proposes and requests authority to revise its tariffs, rules and regulations for gas service, including, but not limited to, increases and adjustments to certain non-recurring charges and changes in its budget billing and alternative payment plans.

8. Test Year and Other Accounting and Procedural Matters. Petitioner proposes an adjusted test year of the twelve months ended June 30, 2006 and a cut-off date for determining the original cost and fair value of Petitioner's Utility Properties as of September 30, 2006 for

purposes of considering the relief hereby requested. Petitioner will cause notice of the filing of this Petition to be published in a newspaper of general circulation in Indiana and will provide its residential customers with a notice summarizing the nature and extent of the proposed rate changes affecting them as required by applicable statutes and Commission rules.

9. Applicable Statutory Provisions. Petitioner believes the provisions of IND. CODE §8-1-2-1 et seq., particularly §§8-1-2-4, 6, 7, 9, 24, 25, 38, 42, 61, 68 and 71, and IND. CODE §8-1-2-5-1 et seq., among others, are applicable to the subject matter of this Petition.

10. Attorneys for Petitioner and Service of Documents. Larry J. Wallace (1110-49), James A.L. Buddenbaum (14511-49) and Jerry R. Comeau (26310-53), Parr Richey Obremskey & Morton, 201 N. Illinois Street, Suite 300, Indianapolis, Indiana 46204, are counsel for Petitioner. Communications concerning this Petition should be addressed to:

Ronald L. Loyd
Vice President & General Manager
Ohio Valley Gas Corporation
111 Energy Park Drive
P. O. Box 469
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(765) 584-6842, ext. 102
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Larry J. Wallace (1110-49)
James A.L. Buddenbaum (14511-49)
Jeremy R. Comeau (26310-53)
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(317) 269-2500
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lwallace@parrlaw.com
jbuddenbaum@parrlaw.com
jcomeau@parrlaw.com

WHEREFORE, Petitioner respectfully prays that the Commission promptly conduct a pre-hearing conference and preliminary hearing and expeditiously make such investigation and hold such hearings as are necessary or advisable in this Cause, and thereafter issue an order:

a. finding that Petitioner's existing rates for gas utility service are unjust, unreasonable, insufficient, discriminatory, confiscatory and inadequate to provide a fair return on

the fair value of Petitioner's Utility Properties used and useful for the convenience of the public in rendering gas utility service;

b. determining, and by order fixing, increased rates and charges to be applicable in the future to Petitioner's gas utility service in lieu of its existing rates and charges therefor;

c. authorizing and approving the filing by Petitioner of new schedules of increased rates and charges applicable to its gas utility service as necessary to constitute just, reasonable, sufficient and non-discriminatory rates;

d. authorizing Petitioner to implement a normal temperature adjustment and to defer, for future recovery, the interim effects of a normal temperature adjustment as described above and by Petitioner's evidence submitted in support thereof;

e. authorizing Petitioner to use deferral accounting and to recover its pipeline safety compliance costs as described above and by Petitioner's evidence submitted in support thereof;

f. authorizing changes in depreciation rates;

g. approving various changes in terms, conditions and provisions of Petitioner's rate schedules, tariffs, rules and regulations applicable to gas utility service as described herein and by testimony in support thereof;

h. approving such alternative regulatory plan or plans necessary and appropriate to facilitate and implement the regulatory authority, approvals, processes and actions herein proposed and requested; and

i. granting such other further and related relief as may be appropriate and proper.

Respectfully submitted,

By _____

Larry J. Wallace (1110-49)
James A. L. Buddenbaum (14511049)
Jeremy R. Comeau (26310-53)
PARR RICHEY OBREMSKEY & MORTON
201 N. Illinois Street, Suite 300
Indianapolis, IN 46204

Attorneys for Petitioner Ohio Valley Gas Corporation

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing has been served this 8th day of January, 2007, via United States Mail, postage-prepaid, and addressed as follows:

Indiana Office of Utility Consumer Counselor
Indiana Government Center North
100 N. Senate Avenue, Room N501
Indianapolis, IN 46204

_____
Larry J. Wallace

PARR RICHEY OBREMSKEY & MORTON
201 N. Illinois Street, Suite 300
Indianapolis, IN 46204
Telephone: (317) 269-2500
Facsimile: (317) 269-2514

206721

PUBLISHER'S AFFIDAVIT PRINTER'S FEE $. 19/78

State of Indiana, Jay County, ss:

Legal Notice

Notice is hereby given that on the 5th day of January, 2007, Ohio Valley Gas Corporation, an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission, in Cause No. 43240, for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations applicable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism, for approval of new depreciation rates as applicable to certain structural portions of its gas utility plant in service, for deferral and future recovery of certain of the Normal Temperature Adjustment and pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to IC 8-1-2.5 as amended, including, and applicable to such authority, approvals and deferrals.

A copy of the petition is on file at the Indiana Utility Regulatory Commission, Room N306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2264.

Ohio Valley Gas Corporation
By: R.L. Loyd
Vice President &
General Manager
On February 1, 2007

Personally appeared before me the undersigned, a Notary Public in and for said County and State, the undersigned JULIE E. SWOVELAND who, being duly sworn, says that she is Business Manager of THE COMMERCIAL REVIEW, a public daily newspaper of general circulation, in said county, printed and published in Portland, in the county aforesaid, and that the Notice of which the attached is a true copy, was duly published in said paper for 1 insertion weeks successively.

The first publication was on the 1 day of February 20 07

The last on the ____ day of _____ 20 ____

Julie E. Swoveland

Julie E. Swoveland

Subscribed and sworn to before me, this 5 day of February 20 07

My commission expires December 11 2007

Joy E. Ballard

Joy E. Ballard, Jay Co. Notary Public

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LEGAL NOTICE

Notice is hereby given that on the 8th day of January, 2007, Ohio Valley Gas Corporation, an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission in Cause No. 43209 for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations applicable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and pipeline safety compliance tracking mechanism, for approval of a new depreciation rates as applicable to certain short lived portions of its gas utility plant in service, for general and future recovery of the cost of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to IC 8-1-2.5-5 as certified, necessary and applicable to such authority, approvals and orders.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2215.

Ohio Valley Gas Corporation
By: Eric Lloyd
Vice President &
General Manager

February 23, 2007

Printer's Fees $48.18

Proof of Publication Notice

STATE OF INDIANA, FAYETTE COUNTY, SS. _____

Before me Laura Gallimore a Notary Public, this day personally came Chris Foreman who, being duly sworn according to law, says that he is a Legal Clerk of THE CONNERSVILLE NEWS-EXAMINER, a daily newspaper published at Connersville, Indiana, in said County, and that the notice, of which the annexed is a true copy, was published in said paper on the 3rd day of February and _____ day of _____, 2007 being one day.

Chris Foreman

Subscribed and sworn to before me this 3rd day of February, 2007.

Laura Gallimore

Laura Gallimore, Notary Public
County of Residence: Fayette
My Commission expires July 11th, 2007

Form Prescribed by State Board of Accounts

February 6th, 2007

General Form No. 99P (Rev. 1995)

Ohio Valley Gas Corp

Federal ID #16-0980985

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A Division of Federated Publications, Inc.
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Wayne County, Indiana

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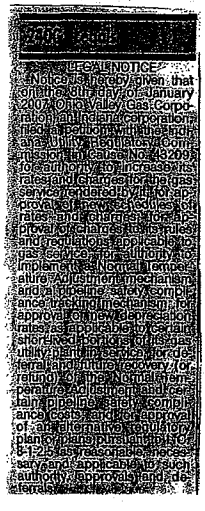
Jackie Cain

Date: February 6th, 2007

Title: Advertising Analyst



LEGAL NOTICE

Notice is hereby given that on the 1st day of January 2007 Ohio Valley Gas Corporation, an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission, Cause No. 43209, for authority to increase its rates and charges for the gas service rendered by it, for approval of increased rates for approval of charges, rules and regulations applicable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism, for approval of a new depreciation rate, as applicable to Cause and shareholder notice for this gas utility plant in service, for deferral and future recovery (or refund) of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to IC 8-1-2.5-5 as reasonable, necessary and applicable, or such authority, approvals and deferrals

PUBLISHER'S AFFIDAVIT

State of Indiana, Wayne County

Personally appeared before me, a notary public and for said county and state, the undersigned Jackie Cain who, being duly sworn, says that (s)he is Advertising Analyst of the Palladium-Item, a daily newspaper of general circulation printed and published in the English language in the city of Richmond in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for one time(s), the dates of publication being as follows:

2/2/2007

Renee A Sparks, Notary Public

Subscribed and sworn to before me this 6th day of February, 2007

My Commission expires January 11, 2008

THE HERALD - P.O. Box 31, Jasper, IN 47547-0031

Ohio Valley Gas Corp.

PUBLISHER'S CLAIM

Dubois
County, Indiana

COMPUTATION OF CHARGES

3¼ column inches at 10.85 per column inch

Charge per insertion $ 35.36

Charge for extra proofs of publication
($1.00 for each proof in excess of two) $ _____

Number of insertions _____

TOTAL AMOUNT OF CLAIM $ 35.36

I hereby certify that the foregoing account is just and correct, that the amount claimed is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Dan E. Rumbach
Co-publisher

Date: Feb. 1, 2007

LEGAL NOTICE

Notice is hereby given that on the 5th day of January 2007, Ohio Valley Gas Corporation, an Indiana Corporation, filed a petition with the Indiana Utility Regulatory Commission in Cause No. 43209, for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations applicable to gas service, for authority to implement a normal temperature adjustment mechanism, and to establish safety compliance tracking mechanism, for approval of new accounting rules as applicable to certain significant portions of its gas distribution system, for approval and future recovery of deferral of the normal temperature adjustment and safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to IC 8-1-2.5 as reasonable, necessary and applicable to such authority, approvals and deferrals.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E-306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2784.

Ohio Valley Gas Corporation
By: Ira L. Loyer
Vice President & General Manager
1-11

PUBLISHER'S AFFIDAVIT

State of Indiana)
Dubois County) ss

Personally appeared before me, a notary public in and for said county and state, the undersigned, Dan E. Rumbach, who, being duly sworn, says that he is co-publisher of THE HERALD, a daily newspaper of general circulation printed and published in the English language in the city of Jasper in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for 1 time, the dates of publication being as follows:

Feb. 1, 2007

Dan E. Rumbach

Subscribed and sworn to before me this 1 day of Feb, 2007

Notary Public

My commission expires MY COMMISSION EXPIRES AUGUST 30, 2013

PROOF OF PUBLICATION

ST TE OF INDIANA, }
UNION COUNTY, } SS:

Personally appeared before the undersigned,

John Estridge, Editor

OF THE LIBERTY HERALD

A newspaper of general circulation published n Liberty, in the county aforesaid, who being duly sworn upon his oath, saith that the notice, of which the attached is a true copy, was duly published in said paper ONE weeks successively, the first of which publications was on the 8th day of February 2007, and the last on the 8th day of February 2007.

John Estridge Editor.

Subscribed and sworn to before me this 8th day of Feb 2007.

Donna Schuler

Notary Public

My Commission expires February 4, 2015.

Printing and Publishing $ 19.13

Post Filed Feb date 8th 2007

Received Payment:

LEGAL NOTICE

Notice is hereby given that on the 8th day of January, 2007, Ohio Valley Gas Corporation, an Indiana Corporation, filed a petition with the Indiana Utility Regulatory Commission in Cause No. 43209, for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations applicable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism, for approval of new depreciation rates as applicable to certain short-lived portions of its gas utility plant in service (or retired) of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such requested approvals and relief.

Copies of the petitions are on file with the Indiana Utility Regulatory Commission, Room 1021, Indiana government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2788.

Ohio Valley Gas Corporation
By R. L. Boyd
Vice President & General Manager

Form prescribed by State Board of Accounts General Form No. 99P (Rev. 2002)

Legal Notice / Petition filed Jan. 8 To: Dearborn County Register Dr.
(Governmental Unit) Ohio Valley Gas Corp.

Dearborn County, Indiana Lawrenceburg, Indiana 47025

Fed. I.D. #35-1869520
Acct. #15001

LINE COUNT	PUBLISHER'S CLAIM
Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) - number of equivalent lines	25
Head - number of lines	
Body - number of lines	
Tail - number of lines	
Total number of lines in notice	25

COMPUTATION OF CHARGES

25 lines, 1 columns wide equals 25 equivalent lines at .800 cents per line	$ 20.00
Additional charge for notices containing rule or tabular work (50 percent of above amount)	$
Charge for extra proofs of publication ($1.00 for each proof in excess of two)	
TOTAL AMOUNT OF CLAIM	$ 20.00

DATA FOR COMPUTING COST

Width of single column 9.6 ems

Number of insertions 1

Size of type 6 point

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Joseph M. Awad

Date: Feb. 8, 2007 Title: Publisher

PROOF OF PUBLICATION/PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss:
Dearborn County)

Personally appeared before me, a notary public in and for said county the undersigned Joseph M. Awad who, said duly that he is Publisher of the Dearborn County Register newspaper of cculation printed and published in the English language in (town) of Lawrenceburg in the state and county afore- that the printed matter attached hereto is a true copy, duly published in said paper for 1 time, the ublication being as follows:

Feb. 8

Joseph M. Awad

and sworn to before me this 8th day of Feb, 2007

Yvonne D. Waters

Yvonne D. Waters, Notary Public

My commission expires: 5-30-13

NOTICE OF PUBLICATION
Notice is hereby given that on the 8th day of January, 2007, Ohio Valley Gas Corporation, an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission in Cause No. 43202 for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges for approval of changes to its filing and regulations applicable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism for approval of new depreciation rates as applicable to Gas in service, for approval of the gas utility plant in service for deferral and future recovery (Or refund) of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such authority, approval and relief.
A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2264.
Ohio Valley Gas Corporation
By: [illegible]
Vice President & General Manager
C-2-8-1

Form Prescribed by State Board of Accounts

General Form No. 99P (Revised 1998)

Atlas Valley Gas Corp.

To: News-Gazette 68001 Dr.

Randolph County, Indiana

Winchester, Indiana

PUBLISHER'S CLAIM

L. COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) number of equivalent lines .....

Head number of lines .....

Body number of lines 56

Tail number of lines .....

Total number of lines in notice 60

COMPUTATION OF CHARGES

30 lines, 2 columns wide equal 60 equivalent lines at 1 66 cents per line ..... $ 39.60

Additional charge for notices containing rule or tabular work (50 percent of above amount) X

Charge for extra proofs of publication ($1.00 for each proof) in excess of two) .....

TOTAL AMOUNT OF CLAIM ..... $ 39.60

DATA FOR COMPUTING COST

Width of single column 12 ems

Number of insertions 1

Siz type 6 point

I.D. 5237 (please put this ID number on your check)

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid:

Sam Shinn

Date February 6, 20 07 Title Legal Clerk

PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss
Randolph County)

Personally appeared before me, a notary public in and for said county and state, the undersigned Sam Shinn who, being duly sworn, says that he is Legal Clerk of the News-Gazette newspaper of general circulation printed and published in the English language in the city of Winchester in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for ____ time ____, the dates of publication being as follows:

2/6/2007

Subscribed and sworn to before me this 6 day of Feb, 20 07.

Notary Public

Notary Public (Name Printed)

My commission expires 1/08

County of Residence Randolph

CERTIFIED

PROOF OF PUBLICATION

AFFIDAVIT

Franklin County)
) ss:
State Of Indiana)

Personally appeared before me, a notary public in and for said county and state, the undersigned Bonnie Chaney, who being duly sworn says that (he or she) is of competent age and is Bookkeeper of The Brookville Democrat, a weekly newspaper which for at least five (5) consecutive years has been published in the town of Brookville, county of Franklin, state of Indiana, and which, during that time, has been a newspaper of general circulation, having a bona fide paid circulation, printed in the English language and entered, authorized and accepted by the post-office department of the United States of America as mailable matter of the second-class as defined by the Act of Congress of the United States of March 3, 1879, and that the printed matter attached hereto is a true copy, which was duly published in said newspaper 1 times, the dates of publication being as follows:

Feb. 7, 2007

Bonnie Chaney
Affiant

Subscribed and sworn to before me this 7th day of Feb., 2007

My commission expires 6-26-08

Donald P. Ang

Proof of Publication

Legal Notice

o Valley
s. Corp.

Fees . $ 19.65

..... $

..... $ 19.65

Filed:

LEGAL NOTICE

Notice is hereby given that on the h day of January, 2007, Ohio Valley as Corporation, an Indiana orporation, filed a petition with the Indiana Utility Regulatory ommission, in Cause No. 43209, for uthority to increase its rates and harges for the gas service rendered, vith for approval of new schedules of ates and charges, for approval of hanges to its rules and regulations pplicable to gas service, for authority o implement a Normal Temperature djustment mechanism and to pipeline afety compliance tracking mechanism, for approval of new depreciation rates as applicable to certain non-lived portions of its gas utility plant in service, for deferral and future recovery (or refund) of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such authority, approvals and deferrals.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2584.

Ohio Valley Gas Corporation
By: R. L. Loyd
Vice President &
General Manager

p6-1teD

Form Prescribed by State Board of Accounts General Form No. 99P (Revised 1995)

THE FERDINAND NEWS
Dubois County, Indiana

To: Ohio Valley Gas Dr.
Rate Increase

PUBLISHER'S CLAIM

'E COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) — Number of equivalent lines. .....

Head - number of lines .....

Body - number of lines .....

Tail - number of lines .....

Total number of lines in notice .....

COMPUTATION OF CHARGES

27 lines, 1 columns wide equals 27 equivalent lines at 51.7 cents per line $. 13.96

Additional charge for notices containing rule or tabular work (50 percent of above amount) $.....

Charge for extra proofs of publication ($1.00 for each proof in excess of two) $.

TOTAL AMOUNT OF CLAIM $. 13.96

DATA FOR COMPUTING COST

Width for single column: 12 ems size of type 6 point

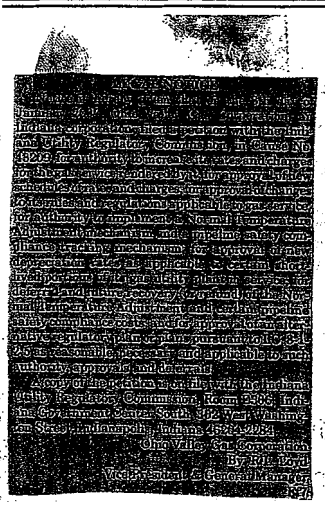
Number of insertions ..... Size of quad upon which type is cast .....

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Date: Feb 12, 20 07

Paul M Ash
Title: President



PUBLISHER'S AFFIDAVIT

State of Indiana
County of Dubois } SS:

Personally appeared before me, a notary public in and for said county and state, the undersigned **Paul Michael Ash** who, being duly sworn, says that he is **President of Dubois - Spencer Counties Publishing, Inc.**, publisher of THE FERDINAND NEWS, a newspaper of general circulation printed and published in the English language in the town of **FERDINAND** in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for 1 time(s) ....., the date(s) of publication being as follows:

February 7, 2007

Paul M Ash

Subscribed and sworn to me this 12 day of Feb 20 07.

Kathleen J. Tretter

Kathleen J. Tretter, Dubois County, Indiana, Notary Public
My commission expires: January 8, 2015

Form Prescribed by State Board of Accounts

General Form No. 99P (Revised 1995)

Ohio Valley Gas Corp.
(Governmental Unit)

_____ County, Indiana

To: The Perry County News

Tell City, Indiana

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) -- number of equivalent lines.....

Head -- number of lines.....

Body -- number of lines.....

Tail -- number of lines.....

TOTAL NUMBER OF LINES IN NOTICE.....

COMPUTATION OF CHARGES

31 lines, _____ columns wide equals _____ equivalent lines at .474 cents per line..... $ 14.69

Additional charge for notices containing rule or tabular work (50 percent of above amount).....

Charge for extra proofs of publication ($1.00 for each proof in excess of two).....

TOTAL AMOUNT OF CLAIM..... $14.69

DATA FOR COMPUTING COST

Width of single column 12 ems

Number of insertions 1

Size of type 6 point

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Teresa Rice

Date: February 5, 20 07 Title: Publisher

PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss
Perry County)

LEGAL NOTICE

Notice is hereby given that on the 5th day of January 2007, Ohio Valley Gas Corporation, an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission in Cause No. 43264, for an increase in rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations applicable to gas service, for a Safety Improvement & Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism for approval of accounting and ratemaking treatment of certain capital costs incurred on its gas utility plant in service, for deferral and future recovery (or gain) of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to IC 8-1-2.5 as reasonable, necessary and applicable to such authority, approvals and relief.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2264.

Ohio Valley Gas Corporation
By: R. L. Loyd, Vice President
& General Manager

Personally appeared before me, a notary public in and for said county and state, the undersigned Teresa Rice who, being duly sworn, says that she is Publisher of The Perry County News, a semi-weekly newspaper of general circulation printed and published in the English language in the (city) (town) of Tell City in state and county afore said, and that the printed matter attached hereto is a true copy, which was duly published in said paper for _____ time 1, the dates of publication being as follows:

February 5, 2007

Teresa Rice

Subscribed and sworn to before me this 5 day of February, 20 07

Nancy Ludwig
Notary Public

My commission expires: 6-30-09

Ohio Valley Gas
Legal Notice
Ripley County

Versailles

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of the type in which the body of the

Head - number of lines	3
Body - number of lines	35
Tail - number of lines	
TOTAL number of lines in notice	38

COMPUTATION OF CHARGES

1 column wide 38 equivalent 0.675

line	25.65
l charges notices containing rule or tabular work (50% of above amount)	
r extra proofs of publication ($1.00 for each proof in excess of two)	1.00
AMOUNT OF CLAIM	26.65

OR COMPUTING COST

single column 8 ems Size of type 6 point

of Insertions 1

to the provisions and penalties of Chapter 155, Acts 1953,

certify that the foregoing account is just and correct, that the amount claimed is legally r allowing all just credits, and that no part of the same has been paid.

y 2 ,2007

Publisher

Legal Notice

PUBLISHER'S AFFIDAVIT

Indiana}
ounty } ss:

Personally appeared before me, a notary public in and for said county and state, the undersigned Linda Chandler who, being duly sworn, says that she is publisher of The Versailles Republican, a weekly newspaper of general circulation printed and published in the English language in the (city)(town) of Versailles in state and county aforesaid, and paper for 1 times, the date of publication being as follows: 2/1/2007

Subscribed and sworn to before me this 2nd day of February 2007

Wanda R. Burnett
Notary Public
Resident of Ripley County

My commission expires July 30, 2014
Ripley Publishing Co., Inc., PO 158 Versailles, IN 470442

Ohio Valley Gas
Legal Notice
Ripley County

Versailles

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of the type in which the body of the

Head - number of lines	3
Body - number of lines	35
Tail - number of lines	
TOTAL number of lines in notice	38

COMPUTATION OF CHARGES

38 lines 1 column wide 38 equivalent 0.675

Cents per line	25.65
Additional charges notices containing rule or tabular work (50% of above amount)	
Charge for extra proofs of publication ($1.00 for each proof in excess of two)	1.00
TOTAL AMOUNT OF CLAIM	26.65

A FOR COMPUTING COST

th of single column 8 ems Size of type 6 point

ber of Insertions 1

uant to the provisions and penalties of Chapter 155, Acts 1953,

ereby certify that the foregoing account is just and correct, that the amount claimed is legally after allowing all just credits, and that no part of the same has been paid.

ruary 7 ,2007

Publisher

Legal Notice

Notice is hereby given that on the [illegible] day of January, 2007, Ohio Valley Gas Corporation, an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission in Cause No. [illegible] seeking an annual increase in rates and charges for the gas service rendered by it in its approved service areas, for approval of changes in rates and charges, rules and regulations applicable to gas service, for approval of an improvement [illegible] Temporarily adjusted mechanism and a [illegible] recovery mechanism, for approval of a [illegible] mechanism, for approval of an [illegible] and for approval of a [illegible] and for approval of an alternative regulatory plan pursuant to IC [illegible] as [illegible] reasonably [illegible] and [illegible] to state authority, approvals and [illegible]

[illegible] are parties to the [illegible] Indiana Utility Regulatory Commission, Room [illegible], Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana [illegible]

Ohio Valley Gas Corporation
[illegible] Lovell
Vice President & General Manager

PUBLISHER'S AFFIDAVIT

of Indiana}
y County } ss:

sonally appeared before me, a notary public in and for said county and state, the undersigned Linda dler who, being duly sworn, says that she is publisher of The Osgood Journal, a weekly newspaper neral circulation printed and published in the English language in the (city)(town) of Versailles in and county aforesaid, and paper for 1 times, the date of publication being as follows:
2/6/2007

Subscribed and sworn to before me this 7th day of February 2007

Wanda R. Burnett
Notary Public
Resident of Ripley County

My commission expires July 30, 2014
Ripley Publishing Co., Inc., PO 158 Versailles, IN 470442

Form Prescribed by State Board of Accounts

General Form No. 99P (Revised 1995)

Ohio Valley Gas Corporation
(Governmental Unit)

Spencer County, Indiana

To: The Spencer County Journal Democrat
Rockport, Indiana

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) -- number of equivalent lines.....

Head -- number of lines.....

Body -- number of lines.....

Tail -- number of lines.....

TOTAL NUMBER OF LINES IN NOTICE.....

COMPUTATION OF CHARGES

31 lines, _____ columns wide equals _____ equivalent lines at .474 cents per line..... $ 14.70

Additional charge for notices containing rule or tabular work (50 percent of above amount).....

Charge for extra proofs of publication ($1.00 for each proof in excess of two).....

TOTAL AMOUNT OF CLAIM..... 14.70

DATA FOR COMPUTING COST

Width of single column 11 ems

Number of insertions 1

Size of type 6 point

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Teresa Rice

Date: February 8, 20 07 Title: Publisher

PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss
Spencer County)

Personally appeared before me, a notary public in and for said county and state, the undersigned Teresa Rice who, being duly sworn, says that she is Publisher of The Spencer County Journal Democrat, weekly newspaper of general circulation printed and published in the English language in the (city) (town) of Rockport in state and county afore said, and that the printed matter attached hereto is a true copy, which was duly published in said paper for _____ time 1, the dates of publication being as follows:

February 8, 2007

Teresa Rice

Subscribed and sworn to before me this 8 day of February, 20 07.

Nancy Rudwig
Notary Public

My commission expires: 6-30-09

RESOLUTION OF THE BOARD OF DIRECTORS

OF

OHIO VALLEY GAS CORPORATION

BE IT RESOLVED, that the Officers of the Company be and are hereby authorized to file a petition with the Indiana Utility Regulatory Commission for an increase in its rates and charges for the sale and transportation of natural gas and other miscellaneous service revenues (collection, returned check charges, reconnection charges, etc.) on, or as soon as possible after, January 2, 2007.

I, the undersigned, Scott A. Miller, Assistant Secretary of Ohio Valley Gas Corporation, hereby certify that the above and foregoing is a true and exact copy of a resolution adopted by the Corporation's Board of Directors at its meeting on the 21st of May, 2005, pertaining to filing for increased rates and charges with the Indiana Utility Regulatory Commission.

IN ATTESTATION OF WHICH, I have hereunto set my hand and affixed the official seal of said Corporation, this 3rd day of January, 2007.

Scott A. Miller, Assistant Secretary

GENERAL SERVICE CUSTOMERS OF OHIO VALLEY GAS CORPORATION

FEBRUARY 19, 2007

ON JANUARY 8, 2007, OHIO VALLEY GAS FILED A PETITION WITH THE INDIANA UTILITY REGULATORY COMMISSION REQUESTING: AUTHORIZATION TO INCREASE ITS RATES AND CHARGES FOR GAS SERVICE AND APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES; APPROVAL OF CHANGES TO ITS GENERAL RULES AND REGULATIONS FOR GAS SERVICE; AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND A PIPELINE SAFETY COMPLIANCE TRACKING MECHANISM, AS WELL AS THE DEFERRAL OF RELATED COSTS FOR FUTURE RECOVERY; APPROVAL OF NEW DEPRECIATION RATES FOR CERTAIN SHORT-LIVED ITEMS IN ITS GAS UTILITY PLANT; APPROVAL OF AN ALTERNATIVE REGULATORY PLAN OR PLANS PURSUANT TO I.C. 8-1-2.5 AS REASONABLE, NECESSARY AND APPLICABLE TO SUCH APPROVALS AND DEFERRALS.

THE AMOUNT OF THE REQUESTED INCREASE, AS WELL AS THE EFFECT OF SAME AT VARYING USAGE LEVELS, WILL BE PROVIDED IN A SECOND NOTICE UPON OUR FILING OF OUR SUPPORTING EVIDENCE.

THE INDIANA UTILITY REGULATORY COMMISSION WILL CONDUCT A PUBLIC HEARING DURING WHICH OHIO VALLEY GAS WILL BE REQUIRED TO SHOW THAT THE REQUESTED ITEMS ARE JUSTIFIED. AN ORDER WILL THEN BE ISSUED BY THE COMMISSION BASED ON THE EVIDENCE PRESENTED.

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS CORPORATION FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST-TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	CAUSE NO. 43209

PETITIONER'S EXHIBIT RLL

DIRECT TESTIMONY

OF

RONALD L. LOYD

VICE PRESIDENT & GENERAL MANAGER

ON BEHALF OF

OHIO VALLEY GAS CORPORATION

MARCH 2007

PREPARED DIRECT TESTIMONY OF RONALD L. LOYD

OHIO VALLEY GAS CORPORATION

1. Q. Will you please state your name and business address?

A. My name is Ronald L. Loyd. My business address is 111 Energy Park Drive, Winchester, Indiana 47394.

2. Q. By whom are you employed?

A. The Petitioner in this Cause, Ohio Valley Gas Corporation.

3. Q. What is your position with Ohio Valley Gas Corporation?

A. My position is that of Vice President & General Manager.

4. Q. What is your educational background?

A. I hold a Bachelor of Science Degree in Chemical Engineering from Rose-Hulman Institute of Technology.

5. Q. What is your employment history?

A. I have been continuously employed by Ohio Valley Gas Corporation since my graduation from Rose-Hulman in 1972. From 1979 through September 2004, my primary responsibilities as Chief Engineer included all matters relating to the construction, installation, operation and maintenance of the gas transmission and distribution systems owned and operated by Petitioner. In 1990, I was named as a Vice President of the Company, and continued in my role as Chief Engineer until October 1, 2004, at which time I assumed my present position as General Manager.

6. Q. What are your industry affiliations?

A. I am a member of the Gas Executive Committee of the Indiana Energy Association (IEA), and previously served as a Director of the former Indiana Gas Association (IGA, now a part of the IEA) and Indiana Underground Plant Protection Service (IUPPS). I have also served on numerous IGA/IEA committees and sub-committees, including Distribution System Engineering & Design, Measurement, Safety & Industrial Hygiene, and Personnel & Industrial Relations.

7. Q. Will you please tell the Commission what the document marked as Petitioner's Exhibit RLL-1 is?

A. This exhibit represents a determination of the Fair Value of Petitioner's Utility Plant in Service as of September 30, 2006, wherein each item of Petitioner's Utility Plant In Service is assigned to one (1) of its two (2) Supplier Service Areas, which take their respective names from the name of the pipeline company which delivers gas to those areas, namely:

- ANR = ANR Pipeline Company
- TXG = Texas Gas Transmission Corporation

To effectively assign each of the items of Petitioner's plant to the appropriate service area, it was first necessary to separate that plant into four (4) primary groups, as follows:

- Shared OVGC General Office Plant
- Shared OVGC Tell City Plant
- OVGC Plant in ANR Supplier Service Area
- OVGC Plant in TXG Supplier Service Area

The General Office Plant and the Tell City Plant are shared by, and used in support of, both the ANR and TXG service areas. It should be noted, however, that nearly 83% of Petitioner's Utility Plant in Service is directly related to one or the other of Petitioner's two (2) service areas, with the remaining 17% being found in the first two groups above. In the final analysis, each item of Petitioner's total Utility Plant in Service has been appropriately assigned to only one of the two service areas.

8. Q. Will you please discuss the scope of Exhibit RLL-1?

A. For each of Petitioner's service areas, this exhibit sets forth, by primary plant categories, the original cost, the current cost new, the percent condition and the resulting current cost less depreciation (i.e. fair value) of all gas utility property which Petitioner had in service as of September 30, 2006. The Shared General Office Plant and the Shared Tell City Plant, as shown on pages 1.a. and 1.b., respectively, have each been allocated to the Petitioner's two (2) supplier service areas based on the percentage of total gas bills rendered to customers in each area during the test year.

9. Q. Can you explain the basis and methods used in making the valuations set forth in Exhibit RLL-1?

A. The numbered plant account categories set forth in Column (1) on pages 1.a.(1), 1.b.(1), 1.c.(1) and 1.d.(1), are in accordance with the "Uniform System of Accounts for Class A and B Gas Utilities," as established by the National Association of Regulatory Utility Commissioners. Original Cost balances for each of these accounts were determined from our plant account records. These

balances reflect the cumulative cost of surviving plant property (i.e. year-by-year acquisitions less all subsequent retirements) and, in the final analysis, lead to a reasonable estimation of the Fair Value of Petitioner's Utility Plant in Service as of July 30, 2006. Pages 1.a., 1.b., 1.c. and 1.d. update said balances through September 30, 2006.

10. Q. How were the "Current Cost New" figures shown in Column (4) of pages 1.a. (1), 1.b. (1). 1. c. (1) and 1.d. (1) derived?

A. Most of these figures were determined using cost-trending factors (see pages 2-39) taken from the January 1, 2006, issue of the "Handy-Whitman Index of Public Utility Construction Costs" (Bulletin No. 163). However, for Accounts 391 through 398, which contain General Plant items such as office furniture and equipment, laboratory equipment, tools, shop and garage equipment, transportation equipment, etc., the Column (4) figures were determined using cost-trending factors based on the Urban Consumer Price Index (CPI-U), which relates the relative cost of all items for urban consumers. This index is based on a reference period of 1982-1985, during which period the "average" of the monthly indices is set equal to 100. The cost-trending factor for utility plant added between July 1, 2006 and September 30, 2006 was assumed to be 1.00, thus making the "Current Cost New" figures equal to the "Original Cost" figures for such additions.

11. Q. What is the "Handy-Whitman Index," and how is it used?

A. The "Handy-Whitman Index" is a standard reference on public utility construction costs which has been published continuously since 1924, and is comprised of index numbers for various utility plant accounts and for a number of sub-account

categories of property which commonly occur in building construction, in general, and gas utility plant construction, in particular. It addresses six (6) geographic divisions of the United States, with Indiana being one of twelve states located in the North Central Division. The tabulated index numbers are an indication of the relative cost of materials, labor and equipment, by year, when compared to a certain base year (1973). The indices are based on studies (by others) of numerous statistical items pertaining to such things as wage rates, costs of living, material and equipment costs, etc. These indices are then used to approximate the replacement cost of a utility's total plant.

12. Q. Can you explain the term "cost-trending factor"?

A. A cost-trending factor is a conversion factor which represents the ratio of the acquisition cost of a given item of property between two dates. For example, if an item of property costs $10.00 in 1960, and the same item costs $40.00 in 2006, the cost-trending factor between these two dates would be 4.00 ($40.00 divided by $10.00). Conversely, if the original cost of a given item of property is $10.00 and the cost-trending factor is known to be 4.00, the Current Cost New of that same item would be $40.00 ($10.00 times 4.00).

13. Q. Are you convinced that the use of the "Handy-Whitman Index," as well as, the Consumer Price Index where necessary, and the cost indices contained therein, is an appropriate means of estimating current (i.e. replacement) costs for Petitioner's existing gas utility plant?

A. Yes. It is my personal belief, and the contention of the Petitioner herein, that the use of these particular indices offers a reasonable, and appropriate method of

estimating the reproduction cost of Petitioner's plant in service. With the subsequent application of a "percent condition" factor to each area of the plant account, Petitioner contends that it has taken into account both inflation, and the approximate current condition of its plant, in arriving at an estimate on the Fair Value of its existing Utility Plant in Service.

14. Q. What do you mean by "percent condition"?

A. Each element of Petitioner's plant has been assigned a Predicted Useful Life (PUL), in years, in order to arrive at an estimate of that element's remaining useful life. These predictions of "useful life" are based on Petitioner's knowledge of its system and the various components thereof, as well as, the methods used to install, protect, and maintain same. The PUL is not considered as an absolute length of time after which a given unit of plant account is automatically no longer used or useful. Rather, it is intended to represent an estimate of the "average" useful life of such plant account unit. The "percent condition" is simply the ratio of remaining useful life (i.e. the PUL less the age of the plant account unit in question) to the PUL itself. For example, if a surviving unit of plant account has a PUL of twenty years, and was originally acquired in 1991, its "percent condition" in 2006, is estimated to be twenty-five percent (25%), since its remaining useful life of five years (2011 minus 2006), when divided by its PUL of twenty (20) years equals 0.25.

15. Q. What do the figures found on Line 6, Column (4), of pages 1.c. and 1.d. represent?

A. These figures represent the total, cumulative current cost of the gas plant properties located in (or allocated to) Petitioner's two supplier service areas as of

September, 30, 2006. They represent actual original costs of all such surviving properties, grouped and adjusted (via cost-trending and percent condition factors) by vintage years to current procurement prices. They represent what it would cost to acquire those properties in new condition as of September 30, 2006.

16. Q. Do these figures include amounts for construction work-in-progress, materials and supplies, or working capital?

A. No. Allowances for these allowable items of rate base have not been included in this exhibit.

17. Q. Will you please summarize your findings?

A. Line 6 of pages 1.c. and 1.d. reflect the following with regard to Petitioner's Total Utility Plant in Service for its two Supplier Service Areas at September 30, 2006:

- Net Original Acquisition Costs of:

  $19,610,506.09 for its ANR Supplier Service Area

  $32,965,308.17 for its TXG Supplier Service Area

  $52,575,814.26 Total

- Current (09/30/06) Replacement Costs of approximately:

  $ 52,430,723.00 for its ANR Supplier Service Area

  $ 72,955,219.00for its TXG Supplier Service Area

  $125,385,942.00 Total

- Approximate Percent Condition (based on Predicted Useful Life) of:

  68% for its ANR Supplier Service Area

  72% for its TXG Supplier Service Area

- Estimated Fair Value, as of September 30, 2006, of at least:

  $35,864,004.00 for its ANR Supplier Service Area

  $52,676,299.00 for its TXG Supplier Service Area

  $88,540,303.00 Total

18. Q. Are you saying that the Fair Value of Petitioner's Total Utility Plant in Service at September 30, 2006, was at least $88,540,303?

A. Yes, I am.

19. Q. Does this conclude your testimony with regard to Petitioner's Exhibit RLL-1 and the fair value of Petitioner's plant in service as of September 30, 2006?

A. Yes, it does.

20. Q. Does Petitioner have any "transmission" pipelines as defined by Title 49, Part 192, "Transportation of Natural or Other Gas by Pipeline – Minimum Federal Safety Standards" promulgated by the U.S. Department of Transportation (U.S. D.O.T.)?

A. Yes, Petitioner has approximately fifty-seven (57) miles of "transmission" pipelines, all located in its existing Texas Gas service area.

21. Q. Are these pipelines subject to the requirement for a written Integrity Management Plan (IMP)?

A. Yes.

22. Q. What is required to be included in such a plan?

A. As an operator of a gas transmission pipeline facility, Petitioner must develop an IMP that provides for the following:

- Identification of all "High Consequence Areas" (HCAs).
- A baseline assessment plan to ensure the integrity of all identified HCAs.

- A framework document that contains all required elements of the Integrity Management Program as adopted by D.O.T. and incorporated into the pipeline safety code, including a process for continual evaluation and assessment, provisions for the remediation of conditions found during integrity assessments, specified recordkeeping provisions, a communication plan, etc.
- A process to ensure continual improvement to the IMP.
- Provisions to implement industry standards invoked by reference.
- A process to document (and notify the Office of Pipeline Safety, as required) of any change(s) to the IMP.
- An on-going process to identify and assess newly identified "High Consequence Areas" (HCAs).

23. Q. Does Petitioner have a written IMP for its transmission pipeline facilities?

A. Petitioner has purchased a "framework" document for its IMP which sets forth, generically, the considerations and methodologies by which Petitioner can determine the "integrity" of its transmission pipelines which are located within identified HCAs. Petitioner's written IMP is a work-in-progress which will, when completed, help to identify and prioritize the various risks (threats) to the integrity of Petitioner's transmission pipelines, and which will provide for the initial ("baseline") and required follow-up assessments of those segments of its transmission pipelines which are located within an identified HCA.

24. Q. How will Petitioner determine the HCAs, if any, along its transmission pipelines?

A. A "High Consequence Area" (HCA) for a natural gas transmission pipeline is determined by first estimating (via an accepted equation/formula) the distance

from a potential pipeline explosion at which death, injury or significant property damage could occur. Such a determination must be made for each point along the pipeline by considering the characteristics of the pipeline (diameter, wall thickness, maximum allowable operating pressure, etc.), and the population density within a so-called "potential impact circle," which is defined as that circular area centered on a point on the pipeline with a radius equal to the "potential impact radius" (PIR) determined by the aforesaid equation/formula.

If a potential impact circle contains twenty (20) or more structures intended for human occupancy, a building housing populations of limited mobility, a building that would be difficult to evacuate, or an identified building or outside area occupied by more than twenty (20) persons on a specified minimum number of days per year are, the area contained within that circle is, by definition, a High Consequence Area (HCA).

25. Q. What do you mean by "baseline assessment"?

A. A "baseline assessment," as it relates to the integrity of any given natural gas pipeline, is an exercise in which the various risks that a given transmission pipeline may be exposed to are determined and prioritized so as to minimize the likelihood of a pipeline incident. Such an assessment will also include a physical determination of the condition of said pipeline in any given HCA. The "baseline assessment" is intended to determine whether or not the pipeline has experienced, or is experiencing, external corrosion, internal corrosion, stress cracking, etc., each of which could jeopardize the integrity and continued safe operation of the pipeline segment being assessed. Such assessments may be completed using a

combination of electrical and/or ultrasonic surveys to determine potential areas of external and/or internal corrosion and the resultant reduction of the pipe's wall thickness as an indication of poor or defective pipe coatings, corrosive soil and or other conditions which surround the pipeline, third-party damage to the pipeline, etc. The results of such an assessment will determine whether or not there is any need for remedial maintenance on, or possibly replacement of, a given transmission pipeline segment.

26. Q. Has Petitioner identified any HCAs along its transmission pipeline?

A. Yes, Petitioner has identified at least two (2) and possibly three (3) such areas as HCAs.

27. Q. Has Petitioner completed its baseline assessments of these identified HCAs?

A. No. However, Petitioner is obligated, per the D.O.T. Code, to complete a baseline assessment on at least fifty percent (50%) of its identified HCAs on or before December 17, 2007, and one hundred percent (100%) by December 17, 2012.

28. Q. Does Petitioner have a plan as to how these required "baseline assessments" will be completed by the required deadline?

A. Petitioner has determined that completion of the "baseline assessments" will require outside (contractor) assistance to provide for the specialized equipment needed for the electrical and/or ultrasonic surveys of its pipelines which are located within an identified HCA.

29. Q. Can an area which is not initially categorized as an HCA become, at some point in the future, an HCA?

A. Yes. On-going and continuous monitoring of construction activity and other changes along the route of a transmission pipeline will be required to determine if new HCAs have been created. Development of new housing sub-divisions, building of schools, churches, nursing homes, etc. could all cause a non-HCA to become an HCA, and thereby require additional baseline assessments, and result in the potential need for remedial pipeline maintenance or replacement.

30. Q. Are the pipeline safety requirements relative to Pipeline Integrity Management "new"?

A. The rule which sets forth the requirements relative to Pipeline Integrity Management became effective February 14, 2004. Implementation of the provisions of the rule, including the development of applicable protocols to allow for reasonable and appropriate oversight review/inspection of operator efforts to comply with the rule have been on-going since. To date, Petitioner has not been subjected to inspection of its progress toward meeting the provisions of the rule, but such inspections are inevitable.

31. Q. Has Petitioner determined or estimated what the financial impact of compliance with the Pipeline Integrity Management rule may be?

A. In the test year, Petitioner expended approximately $35,000, primarily for the solicitation, review and purchase of a framework document designed to allow for Petitioner's eventual development of its own written IMP. Based on its own research, and on discussions with other transmission pipeline operators, Petitioner estimates that its total cost of compliance with this rule, not including potential remedial costs which may be required, will be in the range of $350,000 to

$600,000 through 2012. Further, it is specifically anticipated that the incremental costs of compliance for calendar year 2007 will be $125,000 to $200,000, and that the incremental costs for subsequent years (i.e. through 2012) will average between $35,000 and $75,000 per year, again not including potential remedial costs which may be required.

32. Q. Please expand on the nature of the anticipated costs.

A. For calendar year 2007, Petitioner's cost of compliance will include:

- Development and review of our written IMP.
- Pipeline locating, marking, surveying and staking costs.
- Completion of a required Close Interval Potential Survey (CIPS), an electrical survey designed to assess the overall effectiveness of the pipeline's cathodic protection.
- Completion of a Direct Current Voltage Gradient (DCVG) survey, an electrical survey aimed at locating the faults in the protective coating on buried pipelines.
- Completion of Direct Assessment excavations, as needed, to investigate and confirm the results of the electrical surveys.

Petitioner believes that all reasonable and documented costs required to ensure compliance with the Pipeline Integrity Management rule, and with any and all other pipeline safety rules, including those applicable to distribution facilities, with which Petitioner may be required to comply, whether now existing or promulgated in the future, should be borne by those ratepayers to which such costs are reasonably applicable, and not by Petitioner's shareholders. Petitioner is proposing that such

incremental costs be recoverable via an approved Pipeline Safety Act cost compliance tracking mechanism, and that the deferred recovery of all such incremental costs incurred by Petitioner beginning July 1, 2005, including remedial costs, if any, be authorized by the Commission to begin with the implementation of such tracking mechanism following the issuance of an Order in this Cause.

33. Q. Is Petitioner aware of other pipeline safety rules which may be promulgated and which may require additional expenditures by Petitioner to ensure compliance with same?

A. Yes. The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act of 2006), as passed by both houses of Congress will, if enacted, reauthorize the provisions of the Pipeline Safety Act of 2002 through 2010. Further, the PIPES Act of 2006 includes provisions which expand the philosophy of pipeline integrity management to the distribution systems of Petitioner and all other local distribution companies (LDCs) by requiring the Pipeline and Hazardous Materials Safety Administration (PHMSA) to pass a final Distribution Integrity Management Program (DIMP) rule on or before December 31, 2007. The DIMP rule must, among other things, require that LDCs provide for the installation of an excess flow valve (EFV) on all new and replaced residential natural gas services lines which operate continuously at a pressure in excess of 10 psig. The installation of such EFVs is, under current law, an option which must be offered to Petitioner's customers (at customer's expense) at the time of installation of new or replacement residential natural gas service lines.

34. Q. Does this conclude your testimony relative to Petitioner's specific request for approval of a Pipeline Safety Act cost compliance tracking mechanism?

A. Yes, it does.

35. Q. Please identify Petitioner's Exhibit RLL-2 and explain its relevance to these proceedings.

A. Exhibit RLL-2 contains Petitioner's proposed General Rules and Regulations Applicable to Gas Service ("Rules and Regulations") which, together with Petitioner's various rate schedules, and the terms and conditions of service applicable thereto, comprise Petitioner's gas tariff. Collectively, these items form the basis and parameters for the utility services available to customers of Petitioner and set forth the rights and obligations of both the Petitioner and its customers with respect to such services.

Q. Are the Rules and Regulations presented in Petitioner's Exhibit RLL-2 in this Cause different from the existing Rules and Regulations under which Petitioner currently provides utility service to customers?

A. Yes. Petitioner is proposing numerous verbiage and grammatical changes to its existing, approved Rules and Regulations in some cases simply to clarify the intent of a rule, and in others to set forth Petitioner's desire to actually change, or add to, an existing rule, as follows:

- In Rule 3, Petitioner proposes to require customers to provide additional information relative to the level and type of service desired.
- In Rule 7, Petitioner proposes to strengthen the language regarding customer responsibility relative to providing access to premises.

- In Rule 14, Petitioner proposes to update the guidelines relative to the adjustment of bills due to meter error to comply with the existing Commission rule in subject regard.
- In Rule 15, Petitioner proposes to strengthen and clarify the question of warranty of title to the natural gas delivered to customers.
- In Rule 17, Petitioner proposes to strengthen and clarify the question of liability and responsibility for the natural gas delivered to customers.
- In Rule 18, Petitioner proposes to strengthen and clarify its responsibilities relative to continuity of service.
- In Rule 19, Petitioner proposes to update the rate of interest payable on customer deposits in accordance with the current Commission-approved rate.
- In Rule 20, Petitioner proposes to update and clarify various aspects of the monthly bills rendered to its customers.
- In Rule 24, Petitioner proposes to clarify that late payment charges will be applied to all accounts not paid on or before the due date.
- In Rule 29, Petitioner proposes to revise its existing Budget (Level) Payment Plan to allow for semi-annual review of account balances, and adjustment, as necessary, to a customer's required Monthly Payment Amount due under the Plan in order to avoid unnecessarily large annual "true-up" adjustments to a Budget Plan customer's account balance.

Petitioner also proposes to revise the manner in which it handles the annual "true-up" of account balances under the Plan so that both debit and credit balances are appropriately spread over the ensuing twelve-month period,

thereby prospectively increasing or decreasing the Monthly Payment Amount due under the Plan from any individual customer in smaller increments from one Plan year to the next.

- In Rule 31, Petitioner proposes to strengthen and clarify its statement with regard to "force majeure".
- Rules 2, 4, 5, 6, 8, 9, 10, 11, 12, 13, 16, 21, 22, 23, 25, 26, 27, 28, 30, 32 and 34 all contain minor verbiage and/or grammatical changes to more clearly and appropriately present the intent of each respective rule.

37. Q. Does this complete your testimony with regard to Petitioner's Exhibit RLL-2?

A. Yes, it does.

38. Q. Please explain why Petitioner is proposing to implement a Normal Temperature Adjustment ("NTA") mechanism.

A. This proposal is being made as an integral part of Petitioner's efforts to stabilize recovery of its fixed costs; essentially all costs (except purchased gas costs) which are associated with providing service to its customers. Such costs, for purposes of a NTA mechanism, include operation expense (excluding purchased gas costs), maintenance expense, depreciation expense, taxes other than income, income taxes and capital costs.

Petitioner's existing rates, and the rates proposed in the instant Cause, have been designed on the basis of expected volumes of gas to be sold to its heat sensitive (i.e. heating) customers under "normal" weather conditions. Thus, Petitioner can recover its annual fixed cost of providing service <u>only</u> when (if) the weather-normalized level of sales volumes upon which Petitioner's rates are designed is

actually achieved. Without such a mechanism, Petitioner will almost always either over-collect or under-collect its annual fixed costs and, conversely, its customers will almost always pay too much or too little for the service being rendered to them. Petitioner and its customers are, without a NTA mechanism, subject to the vagaries of Indiana's unpredictable winter weather. The NTA also helps to address the ever-increasing issue of volatility in Petitioner's billings to its customers. Such a mechanism will help to provide more stable annual bill amounts and mitigate the undesirable volatility in monthly billings during the heating season.

Finally, it is important to recognize that the NTA mechanism will help to send more accurate and timely price signals to Petitioner's customers compared to the current ratemaking methodology because it will stabilize that portion of the customers' bills related to the recovery of fixed costs while still recovering the actual variable costs of the gas itself on a metered/volumetric basis.

39. Q. What do you mean by "normal" weather (temperatures)?

A. Daily weather (specifically temperature) data which is compiled and maintained by weather stations operated under the auspices of the National Oceanic and Atmospheric Administration (NOAA), and located at various geographical sites around the U.S., relates heating degree day information on a running 30-year average. The current basis for these 30-year averages is the time period from 1971 through 2000. These 30-year average heating degree day numbers then are considered to be "normal" and are compared to current, actual heating degrees days for a given billing cycle to determine whether said cycle was "colder than

normal" or "warmer than normal". Because Petitioner's NTA mechanism will require immediately available weather data on a daily basis, Petitioner must use data reported by those NOAA weather stations known as Class A stations.

40. Q. Has Petitioner determined which of these Class A NOAA weather stations are best suited for use in the implementation of its proposed NTA mechanism?

A. Yes. Based on the geographical spread of its customers, Petitioner is proposing to use weather data from the following Class A NOAA weather stations:

- For all customers to which the NTA will apply located in Petitioner's "northern" service areas (i.e. Petitioner's Portland, Winchester, Union City and Connersville districts), the NOAA Class A station located at Indianapolis, IN, and
- For all customers to which the NTA will apply located in Petitioner's "southern" service area (i.e. Petitioner's Tell City district), the NOAA Class A station located at Evansville, IN.

41. Q. Please explain why temperature is such an important and appropriate factor to be considered in the gas utility ratemaking process.

A. As a part of the ratemaking process, both test-year costs (expenses) and test-year revenues have, historically, been weather-normalized. A weather-normalized test year used by the utility is recognized as the most representative "picture" of the operating conditions which may reasonably be expected to occur during the period in which the utility's approved rates and charges are to be in effect.

Since weather (specifically ambient air temperature) directly impacts the volume of natural gas used by heat-sensitive (i.e. heating) customers, a process whereby the

effects of colder, or warmer, than normal temperatures on a gas utility's ability to recover its fixed costs can be mitigated is, in Petitioner's view, appropriate. The proposed NTA mechanism, as has been previously approved for other gas utilities in the state of Indiana, is such a process.

42. Q. Please explain how fluctuations in temperature impact, over time, a gas utility's heat-sensitive (heating) customers.

A. Since, under current and proposed rate design, Petitioner's billings to its customers are based primarily on the metered volume of gas consumed, billings to heating customers can, and do, vary widely depending on the number of heating degree days in any given billing cycle. These types of fluctuations can be particularly burdensome on people who operate on a fixed income basis. If actual temperatures are colder than normal, the typical gas customer will use more gas, and thus pay more than appropriate for service by virtue of his/her "overpayment" of fixed costs because such costs are currently being recovered primarily on a volumetric basis based on normal temperatures. Because Petitioner's level of "fixed" costs does not change with temperature, the greater gas volumes consumed, when applied against the same unit rate, generate greater non-gas revenues than the level established and approved by the Commission, thereby negatively affecting Petitioner's heating customers. Conversely, if actual temperatures are warmer than normal, the typical gas customer will use less gas, and thus pay less than appropriate for service by virtue of his/her "underpayment" of fixed costs because such costs are currently being recovered primarily on a volumetric basis based on normal temperatures. Because Petitioner's level of

"fixed" costs does not change with temperature, the lower gas volumes, when applied against the same unit rate, generate lower non-gas revenues than the level established and approved by the Commission, thereby precluding Petitioner's from being able to appropriately recover its fixed costs.

43. Q. How will the proposed NTA mechanism help to alleviate the conditions to which you just referred?

A. The proposed NTA mechanism will help to mitigate the detrimental financial impact to Petitioner's heating customers which occurs when it is colder than normal. During such times, gas consumption is typically greater (for heating customers) and commodity prices are typically higher). This compounded effects of increased consumption and higher gas costs result in greater fixed cost recovery which is problematic for customers, regulators and utilities. The proposed NTA mechanism combats this compounded effect by ensuring that in periods of abnormally cold temperature customers only pay for the level of fixed costs appropriately allocated to them, and no more.

44. Q. Is there more than one way to implement a NTA mechanism?

A. Yes. There are two (2) basic approaches that have been utilized by other natural gas utilities in this regard. Petitioner's witness, Mr. Kerry Heid, addresses these methods in detail in Petitioner's Exhibit KAH.

45. Q. Which approach is Petitioner proposing for approval in this proceeding?

A. Petitioner is proposing to use the real-time, individual customer NTA mechanism (i.e. the Type 1 methodology described by Mr. Heid.)

46. Q. Why is Petitioner proposing to use a real-time, individual customer (Type 1) NTA mechanism?

A. By doing so, Petitioner will be adjusting its billings to customers on a real-time basis, tailored to the individual customer's consumption characteristics based on historical data, thereby allowing the customer to more readily link the resultant billing adjustments with the events (weather) which cause the adjustments. Additionally, Petitioner will benefit from the cash flow effect of the mechanism in a timelier manner than that provided by the Type 2 (deferred) mechanism.

47. Q. What are the most important characteristics/benefits of Petitioner's proposed NTA mechanism?

A. Consistent with previously approved NTA mechanisms, Petitioner believes that the most important characteristics/benefits of the proposed NTA mechanism include:

- The mechanism will be applicable to all heating customers served under Petitioner's general service rates (i.e. Rate 11 on its ANR system and Rate 41 on its Texas Gas system).
- The mechanism adjusts Petitioner's billings to its customers only during the designated heating months set forth in Petitioner's witness Kerry Heid's testimony (Exhibit KAH) regarding the mechanics of the adjustment.
- The mechanism adjusts the volume of gas billed to each applicable customer to reverse the effect of abnormally warm or cold temperatures (low or high degree-day levels) for each applicable billing cycle.

- The mechanism is structured on a customer-specific basis (i.e. each customer will receive billing adjustments supported by the specific, historical gas consumption characteristics for that customer.

48. Q. How will Petitioner's proposed NTA mechanism "work"?

A. The proposed NTA mechanism will effectively adjust the metered heat-sensitive volume of natural gas consumed by each applicable customer during a given billing cycle to effectively weather-normalize the metered consumption utilized for the recovery of the fixed cost component of the customer's bill. The gas cost component of the bill would not be adjusted and would reflect actual metered consumption. Mr. Heid discusses the mechanics of the calculations used to make the appropriate adjustment(s), as well as other technical details of the NTA mechanism in Petitioner's Exhibits KAH.

49. Q. Does this complete your testimony with regard to Petitioner's proposed NTA mechanism?

A. Yes, it does.

50. Q. How are customer complaints handled?

A. Generally speaking, customer complaints, whether received directly from the customer or referred to Petitioner by the Commission, are assigned to the appropriate District Manager for resolution. Any complaint that may be filed with the Commission is initially referred to me (as General Manager) for response. Upon completion of the requisite "investigation" into the merits or validity of such a complaint and, as necessary and appropriate, discussing the nature of the complaint with the customer, a formal response is made to the Commission

indicating whether or not the complaint has been resolved. We respond to each known complaint in a courteous and forthright manner, listening to the customer's position and reviewing the facts, and then attempt to resolve the matter to the satisfaction of all concerned parties.

51. Q. Does Petitioner maintain an internal fund to assist customers with the payment of natural gas billings?

A. Yes. Petitioner's internal fund has been entitled Gas Help Fund and has been in existence since 1982. Each of Petitioner's operating districts maintains a separate Gas Help Fund which is administered by a third party. Contributions are received from various community service organizations, churches, customers and Petitioner's employees. Such contributions are then matched on a "dollar for dollar" basis by Petitioner's shareholders. Funds are maintained in FDIC-insured accounts in local financial institutions.

52. Q. Does Petitioner participate in the Help Thy Neighbor program, established by the state of Indiana, the Lilly Foundation and the large Indiana utilities, to assist certain customers who are not eligible for assistance with payment of their gas bill through federal or other programs?

A. Yes. While Petitioner has not contributed financially to the Help Thy Neighbor program, it does assist in the administration of the program by processing applications for assistance thereunder for its qualified customers. This process is initiated when a customer provides indication of an inability to pay and it is determined that their annual household income falls within the established limits of the program (i.e. 150-200% of the established federal poverty level).

53. Q. Does Petitioner promote energy conservation efforts to its customers? If so, what methods are used?

A. Yes. Petitioner uses its internet website, bill inserts/messages, radio spots, brochures, etc. to impress upon its customers various conservation techniques and the benefits of same. Also, Petitioner has for several years promoted energy efficiency through a rebate plan which offers cash incentives to customers upon installation of high-efficiency gas-fired equipment.

54. Q. Does Petitioner offer a Budget (Level) Payment Plan ("Budget Plan") to its residential customers?

A. Yes. Such a plan is not only offered, but is promoted by Petitioner as one way to assist its customers in the management of their natural gas bills. The particulars of Petitioner's Budget Plan are contained in Rule 29 of our proposed Rules and Regulations Applicable to Gas Service (see Exhibit RLL-2).

At December 31, 2006, 4,680 of Petitioner's residential heating customers (21.22% of Petitioner's 22,054 residential heating customers) were participating in the offered Budget Plan. The level (%) of participation has steadily increased from 17.22% since Petitioner's June 30, 2002 evaluation.

Petitioner also offers its Budget Plan to customers in certain other revenue classifications. As of December 31, 2006, 150 such non-residential heating customers were also participants in the Plan.

55. Q. How does Petitioner promote its Budget Plan and other available assistance programs?

A. Petitioner specifically promotes its Budget Plan via its internet website, radio spots, bill inserts, and through "Important Messages" printed directly on its monthly billing statements to customers. Such "Important Messages" also periodically discuss the existence of various assistance programs such as the federally-funded LIHEAP (Low Income Home Energy Assistance Program, generally known as EAP) and the aforementioned Help Thy Neighbor (HTN) program.

56. Q. Is Petitioner satisfied with the functionality and results of its Budget Plan?

A. No. Petitioner believes that certain changes to our existing Budget Plan, as discussed in my response to Q.36., should be made to enhance the review process, and where necessary and appropriate, the adjustment of monthly payments due under the Plan.

57. Q. Does Petitioner provide its customers with options relative to the payment of natural gas billings?

A. Yes. Petitioner continues to maintain local customer service offices in many of its service areas. Customers may, at their convenience, thus pay their monthly billings from Petitioner either by U.S. mail, or in person at any of said customer service offices.

Additionally, customers are offered the opportunity to have their natural gas billings paid via direct debit of a specified financial institution (bank) account. Participation in this Debit Payment Plan (DPP) is available to all customers and can be initiated by completion of an appropriate application which is included on the reverse side of Petitioner's monthly billing statements.

1 Finally, Customers can also pay their monthly billings via credit or debit card
2 transaction through a third-party administrator of card payment plans.
3 58. Q. Has Petitioner made any recent changes in its customer billing process?
4 A. Yes. In October 2005, Petitioner installed new bill printing software to enable the
5 issuance of full-page, statement-type billings to its customers, and subsequently
6 installed mailing software to enable the use of the carrier route, bar-coded
7 customer address to achieve the lowest cost post rate available. Prior to October
8 2005, Petitioner's billings to customers were printed on postcard stock. While the
9 billings issued in this manner contained the minimal requisite information relative
10 to metered consumption, amount billed (gross and net), due date, etc., the small
11 size of the bill prevented Petitioner from providing additional information regarding
12 consumption history, details of charges, comparative weather and other data, as
13 well as the opportunity to include informative and flexible bill messages to its
14 customers. in a timely and efficient manner.
15 59. Q. Please summarize Petitioner's Exhibit RLL-3.
16 A. This exhibit contains actual examples of Petitioner's statement-type bills, including
17 a regular bill, a Budget Plan bill, a Final Bill and a Disconnect Notice, which
18 provide Petitioner's customers with the following:
19 - A complete summary of the customers account activity since the previous
20 statement, including account-specific information relative to the customer name,
21 account number, mailing address, service address, service type (i.e. revenue
22 class), previous balance due, payments received, if any, previous balance carried
23 forward, current charges for services rendered in the current billing cycle and

current account balance. Note: For those customers participating in Petitioner's Budget Plan, this portion of the statement also includes a Budget Payment Plan Summary, including previous budget payment due, budget payments received, if any, budget payments carried forward, if any, and the current budget payment due. For those customers participating in the direct debit payment plan, the date and amount of the bank transfer of funds is also reflected.

With regard to the amount of natural gas consumed during the current billing cycle, the billing statement provides previous and current meter readings and the dates of said readings, the number of days in the billing cycle, the metered volume of gas (in ccfs) and the thermal volume of gas (in therms). The statement also provides a bar chart which reflects the customer's usage for each of the last 13 months, the total consumption for the previous 12 months, and the average consumption per month for the previous 12 months. Additionally, there is a clear indication of the comparative degree day information provided as a percent warmer or colder than 1) the previous billing cycle, and 2) the same period from the prior year.

The bottom section of the front side of the statement billing provides information relative to Petitioner's address, telephone number(s), office hours, emergency contact number(s), and its website. It also provides space for Petitioner to relate general information in the form of various "Important Messages" to its customers. Topics periodically covered in this section include Energy Assistance Program information, Budget Plan information, Direct Debit Payment Plan information, Call

1 Before You Dig information and contact numbers and various other information
2 which may be of interest to Petitioner's customers.
3 In addition to the enrollment form for the Direct Debit Payment Plan, the reverse
4 side of the statement bill contains expanded information on general payment
5 terms, definitions and general information about estimated bills, final bills, etc. It
6 also contains contact information for customers who may have billing questions,
7 including information relative to contacting either the Indiana Utility Regulatory
8 Commission or the Indiana Office of Consumer Counselor at their respective toll-
9 free telephone numbers and websites.
10 Based on undocumented feedback from numerous customers, the additional
11 information provided on the new statement bill has proven to be generally helpful
12 to, and well-received by Petitioner's customers.
13 60. Q. Does this complete your pre-filed, direct testimony in this Cause?
14 A. Yes, it does.

I.U.R.C. No. 43209
INDEX OF EXHIBIT
EXHIBIT RLL-1

OHIO VALLEY GAS CORPORATION

Page	Description of Page
1.a. - 1.d.(1)	Original Cost of Utility Plant in Service at September 30, 2006 and the Corresponding Current Cost Less Depreciation Valuations
2 – 8	Current Cost of General Office Plant in Service
9 – 12	Current Cost of Tell City District Plant in Service
13 – 27	Current Cost of OVGC's ANR Pipeline Plant in Service
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OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
9-30-06 AND THEIR 9-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

SHARED GENERAL OFFICE PLANT

(1)	(2)		(3)	(4)	(5)	(6)
Line No			Original Cost	Current Cost New	Approx Percent Condition	Cost Less Depreciation
1	Net Plant in Service at 6-30-06 per Plant Ledger		$7,712,821.73	$11,086,088	69%	$7,666,256
2	Net Plant Placed in Service 7-1-06 through 9-30-06		10,181.54	10,182	100%	10,182
3	Net Plant in Service at 9-30-06		$7,723,003.27	$11,096,270	69%	$7,676,438
	Allocation to:					
4	ANR Pipeline System	41.07%	$3,171,837.44	$4,557,238	69%	$3,152,713
5	Texas Gas Pipeline System	58.93%	$4,551,165.83	$6,539,032	69%	$4,523,725

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
6-30-06 AND THEIR 6-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

- SHARED GENERAL OFFICE PLANT -

LINE NO.	(1) ACCT NO.	(2) PLANT ACCOUNT DESCRIPTION	(3) ORIGINAL COST	(4) 6-30-06 CURRENT COST NEW	(5) APPROX. PERCENT CONDITION	(6) 6-30-06 COST LESS DEPRECIATION
		INTANGIBLE PLANT				
1	301	Organization				
2	302	Franchises & Consents				
3	303	Miscellaneous				
		MFG. GAS PRODUCTION PLANT				
4	304	Land & Land Rights				
5	305	Structures & Improvements				
6	311	Liquif. Petrol. Gas Equip.				
		TRANSMISSION PLANT				
7	365.1	Land & Land Rights				
8	365.2	Rights of Way				
9	366	Structures & Improvements				
10	367	Mains				
11	369	Measure. & Reg. Sta. Equip.				
		DISTRIBUTION PLANT				
12	374	Land & Land Rights				
13	375	Structures & Improvements				
14	376	Mains				
15	378	Meas.&Reg.Sta.Equip.-Gen.				
16	379	Meas.&Reg.Sta.Equip.-CtyGate				
17	380	Services				
18	381	Meters	$2,052,091.10	$2,942,351	55	$1,612,266
19	383	House Regulators	$957,375.69	$1,551,285	63	$978,149
20	385	Indus.Meas.&Reg.Sta.Equip.				
		GENERAL PLANT				
21	389	Land & Land Rights	$120,268.22	$120,269	100	$120,269
22	390	Structures & Improvements	$3,233,077.66	$4,466,195	90	$4,018,401
23	391	Office Furniture & Equip.	$582,403.76	$730,731	69	$503,301
24	392	Transportation Equip.	$318,133.32	$449,645	35	$158,823
25	394	Tools, Shop, & Garage Equip.	$89,855.47	$159,056	32	$51,076
26	395	Laboratory Equip.	$46,361.41	$90,489	21	$19,013
27	397	Communications Equip.	$303,444.27	$563,484	35	$197,371
28	398	Miscellaneous Equipment	$9,810.83	$12,583	60	$7,587
29		NET PLANT IN SERVICE	$7,712,821.73	$11,086,088	69	$7,666,256
		ALLOCATION TO:				
30		ANR Pipe.Syst. (41.07%)	$3,167,655.88	$4,553,056	69	$3,148,531
31		Texas Gas Syst. (58.93%)	$4,545,165.85	$6,533,032	69	$4,517,725

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
9-30-06 AND THEIR 9-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

SHARED TELL CITY PLANT

(1) Line No	(2)		(3) Original Cost	(4) Current Cost New	(5) Approx Percent Condition	(6) Cost Less Depreciation
1	Net Plant in Service at 6-30-06 per Plant Ledger		$1,229,514.24	$1,922,722	56%	$1,070,965
2	Net Plant Placed in Service 7-1-06 through 9-30-06					
3	Net Plant in Service at 9-30-06		$1,229,514.24	$1,922,722	56%	$1,070,965
	Allocation to:					
4	ANR Pipeline System	23.99%	$294,960.47	$461,261	56%	$256,925
5	Texas Gas Pipeline System	76.01%	$934,553.77	$1,461,461	56%	$814,040

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
6-30-06 AND THEIR 6-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

- SHARED TELL CITY PLANT -

LINE NO.	(1) ACCT NO.	(2) PLANT ACCOUNT DESCRIPTION	(3) ORIGINAL COST	(4) 6-30-06 CURRENT COST NEW	(5) APPROX. PERCENT CONDITION	(6) 6-30-06 COST LESS DEPRECIATION
		INTANGIBLE PLANT				
1	301	Organization				
2	302	Franchises & Consents				
3	303	Miscellaneous				
		MFG. GAS PRODUCTION PLANT				
4	304	Land & Land Rights				
5	305	Structures & Improvements				
6	311	Liquif. Petrol. Gas Equip.				
		TRANSMISSION PLANT				
7	365.1	Land & Land Rights				
8	365.2	Rights of Way				
9	366	Structures & Improvements				
10	367	Mains				
11	369	Measure. & Reg. Sta. Equip.				
		DISTRIBUTION PLANT				
12	374	Land & Land Rights				
13	375	Structures & Improvements				
14	376	Mains				
15	378	Meas.&Reg.Sta.Equip.-Gen.				
16	379	Meas.&Reg.Sta.Equip.-CtyGate				
17	380	Services				
18	381	Meters				
19	383	House Regulators				
20	385	Indus.Meas.&Reg.Sta.Equip.				
		GENERAL PLANT				
21	389	Land & Land Rights	$63,933.20	$63,933	100	$63,933
22	390	Structures & Improvements	$146,754.55	$530,045	57	$301,894
23	391	Office Furniture & Equip.	$35,118.50	$61,648	44	$26,962
24	392	Transportation Equip.	$462,973.55	$533,381	65	$344,049
25	394	Tools, Shop, & Garage Equip.	$461,702.87	$644,409	45	$289,970
26	395	Laboratory Equip.	$1,882.56	$3,715	26	$970
27	397	Communications Equip.	$55,989.66	$79,776	54	$43,187
28	398	Miscellaneous Equipment	$1,159.35	$5,815		
29		NET PLANT IN SERVICE	$1,229,514.24	$1,922,722	56	$1,070,965
		ALLOCATION TO:				
30		ANR Pipe.Syst. (23.99%)	$294,960.47	$461,261	56	$256,925
31		Texas Gas Syst. (76.01%)	$934,553.77	$1,461,461	56	$814,040

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
9-30-06 AND THEIR 9-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

ANR DISTRIBUTION SYSTEM

(1) Line No	(2)	(3) Original Cost	(4) Current Cost New	(5) Approx Percent Condition	(6) Cost Less Depreciation
1	Net Plant in Service at 6-30-06 per Plant Ledger	$16,093,449.16	$47,361,965	68%	$32,404,107
2	Net Plant Placed in Service 7-1-06 through 9-30-06	50,259.02	50,259	100%	50,259
3	Net Plant in Service at 9-30-06	$16,143,708.18	$47,412,224	68%	$32,454,366
	Allocation From:				
4	General Office Plant	$3,171,837.44	$4,557,238	69%	$3,152,713
5	Tell City Plant	$294,960.47	$461,261	56%	$256,925
6	Gross Plant in Service at 9-30-06	$19,610,506.09	$52,430,723	68%	$35,864,004

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
6-30-06 AND THEIR 6-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

- OVGC(ANR) DISTRIBUTION SYSTEM -

LINE NO.	(1) ACCT NO.	(2) PLANT ACCOUNT DESCRIPTION	(3) ORIGINAL COST	(4) 6-30-06 CURRENT COST NEW	(5) APPROX. PERCENT CONDITION	(6) 6-30-06 COST LESS DEPRECIATION
		INTANGIBLE PLANT				
1	301	Organization				
2	302	Franchises & Consents	$185.60	$186	100	$186
3	303	Miscellaneous				
		MFG. GAS PRODUCTION PLANT				
4	304	Land & Land Rights	$23,005.62	$23,006	100	$23,006
5	305	Structures & Improvements	$90,594.64	$248,110	64	$159,686
6	311	Liquif. Petrol. Gas Equip.	$255,802.32	$938,122	36	$341,714
		TRANSMISSION PLANT				
7	365.1	Land & Land Rights	$4,165.19	$4,166	100	$4,166
8	365.2	Rights of Way	$19,417.70	$19,418	100	$19,418
9	366	Structures & Improvements	$4,913.91	$24,033	47	$11,209
10	367	Mains	$1,581,648.82	$6,662,320	61	$4,048,339
11	369	Measure. & Reg. Sta. Equip.	$495,440.54	$932,465	71	$662,648
		DISTRIBUTION PLANT				
12	374	Land & Land Rights	$133,417.12	$133,419	100	$133,419
13	375	Structures & Improvements	$8,203.63	$29,015	58	$16,710
14	376	Mains	$7,837,459.03	$24,733,051	75	$18,469,543
15	378	Meas.&Reg.Sta.Equip.-Gen.	$171,255.16	$487,913	54	$261,584
16	379	Meas.&Reg.Sta.Equip.-CtyGate	$329,856.84	$589,090	70	$410,633
17	380	Services	$2,921,720.44	$7,234,871	78	$5,627,599
18	381	Meters				
19	383	House Regulators				
20	385	Indus.Meas.&Reg.Sta.Equip.	$47,260.09	$193,215	41	$78,749
		GENERAL PLANT				
21	389	Land & Land Rights	$60,506.50	$60,507	100	$60,507
22	390	Structures & Improvements	$483,936.06	$2,470,755	47	$1,163,803
23	391	Office Furniture & Equip.	$86,876.75	$184,559	31	$58,089
24	392	Transportation Equip.	$697,983.56	$884,278	46	$404,968
25	394	Tools, Shop, & Garage Equip.	$684,677.96	$1,246,167	27	$335,408
26	395	Laboratory Equip.	$5,713.68	$33,610	2	$533
27	397	Communications Equip.	$145,374.20	$210,524	53	$111,507
28	398	Miscellaneous Equipment	$4,033.80	$19,165	4	$683
29		NET PLANT IN SERVICE	$16,093,449.16	$47,361,965	68	$32,404,107
		ALLOCATION FROM:				
30		General Office Plant	$3,167,655.88	$4,553,056	69	$3,148,531
31		Tell City Plant	$294,960.47	$461,261	56	$256,925
32		GROSS PLANT IN SERVICE	$19,556,065.51	$52,376,282	68	$35,809,563

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
9-30-06 AND THEIR 9-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

TXGAS DISTRIBUTION SYSTEM

(1) Line No	(2)	(3) Original Cost	(4) Current Cost New	(5) Approx Percent Condition	(6) Cost Less Depreciation
1	Net Plant in Service at 6-30-06 per Plant Ledger	$27,331,538.19	$64,806,676	73%	$47,190,483
2	Net Plant Placed in Service 7-1-06 through 9-30-06	148,050.38	148,050	100%	148,050
3	Net Plant in Service at 9-30-06	$27,479,588.57	$64,954,726	73%	$47,338,533
	Allocation From:				
4	General Office Plant	$4,551,165.83	$6,539,032	69%	$4,523,725
5	Tell City Plant	$934,553.77	$1,461,461	56%	$814,040
6	Gross Plant in Service at 9-30-06	$32,965,308.17	$72,955,219	72%	$52,676,299

OHIO VALLEY GAS CORPORATION
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
6-30-06 AND THEIR 6-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

- OVGC(TXG) DISTRIBUTION SYSTEM -

LINE NO.	(1) ACCT NO.	(2) PLANT ACCOUNT DESCRIPTION	(3) ORIGINAL COST	(4) 6-30-06 CURRENT COST NEW	(5) APPROX. PERCENT CONDITION	(6) 6-30-06 COST LESS DEPRECIATION
		INTANGIBLE PLANT				
1	301	Organization	$9,502.84	$9,503	100	$9,503
2	302	Franchises & Consents	$2,046.28	$2,046	100	$2,046
3	303	Miscellaneous	$15,480.51	$15,481	100	$15,481
		MFG. GAS PRODUCTION PLANT				
4	304	Land & Land Rights	$69,957.47	$69,957	100	$69,957
5	305	Structures & Improvements	$69,057.39	$151,731	69	$105,424
6	311	Liquif. Petrol. Gas Equip.	$355,962.12	$919,492	47	$430,668
		TRANSMISSION PLANT				
7	365.1	Land & Land Rights				
8	365.2	Rights of Way	$364,550.83	$364,551	100	$364,551
9	366	Structures & Improvements	$7,275.54	$14,727	72	$10,670
10	367	Mains	$6,484,972.25	$17,683,439	70	$12,353,060
11	369	Measure. & Reg. Sta. Equip.	$299,667.63	$493,787	78	$384,989
		DISTRIBUTION PLANT				
12	374	Land & Land Rights	$439,559.64	$439,561	100	$439,561
13	375	Structures & Improvements	$20,258.35	$34,684	80	$27,720
14	376	Mains	$12,448,482.45	$30,972,879	76	$23,548,057
15	378	Meas.&Reg.Sta.Equip.-Gen.	$308,154.98	$712,958	58	$413,933
16	379	Meas.&Reg.Sta.Equip.-CtyGate	$114,138.04	$272,285	62	$169,194
17	380	Services	$3,886,801.44	$8,468,264	79	$6,669,992
18	381	Meters				
19	383	House Regulators				
20	385	Indus.Meas.&Reg.Sta.Equip.	$33,299.89	$251,901	29	$72,956
		GENERAL PLANT				
21	389	Land & Land Rights	$184,307.64	$184,309	100	$184,309
22	390	Structures & Improvements	$783,477.10	$1,779,305	60	$1,068,917
23	391	Office Furniture & Equip.	$76,140.79	$104,339	57	$59,223
24	392	Transportation Equip.	$578,627.64	$727,681	43	$313,675
25	394	Tools, Shop, & Garage Equip.	$636,572.19	$915,568	40	$367,792
26	395	Laboratory Equip.	$3,088.85	$12,115	10	$1,213
27	397	Communications Equip.	$136,745.57	$190,409	56	$106,997
28	398	Miscellaneous Equipment	$3,410.76	$15,704	4	$595
29		NET PLANT IN SERVICE	$27,331,538.19	$64,806,676	73	$47,190,483
		ALLOCATION FROM:				
30		General Office Plant	$4,545,165.85	$6,533,032	69	$4,517,725
31		Tell City Plant	$934,553.77	$1,461,461	56	$814,040
32		GROSS PLANT IN SERVICE	$32,811,257.81	$72,801,169	72	$52,522,248

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
381	1927 & PR	$ 9,598.14	6.962963	$ 66,831
381	1928-1932	75.58	6.962963	526
381	1933-1937	3,396.61	7.520000	25,543
381	1938-1942	1,130.65	7.230769	8,175
381	1943-1947	4,968.56	7.230769	35,927
381	1948-1949	11,480.27	4.476190	51,388
381	1950	75.03	3.916667	294
381	1951	513.02	3.418182	1,754
381	1952	73.36	3.418182	251
381	1953	1,096.21	3.418182	3,747
381	1954	4,313.63	3.418182	14,745
381	1955	15,425.65	3.357143	51,786
381	1956	16,214.36	2.984127	48,386
381	1957	20,580.31	2.848485	58,623
381	1958	17,460.17	2.647887	46,233
381	1959	14,151.53	2.647887	37,472
381	1960	13,320.59	2.647887	35,271
381	1961	8,206.81	2.575342	21,135
381	1962	16,737.13	2.379747	39,830
381	1963	26,157.23	2.379747	62,248
381	1964	25,276.11	2.379747	60,151
381	1965	27,006.43	2.379747	64,268
381	1966	24,379.82	2.186047	53,295
381	1967	35,084.79	2.136364	74,954
381	1968	30,885.77	2.136364	65,983
381	1969	44,201.87	2.112360	93,370
381	1970	24,411.15	2.000000	48,822
381	1971	61,023.88	1.880000	114,725
381	1972	34,407.54	1.880000	64,686
381	1973	57,376.92	1.880000	107,869
381	1974	19,169.76	1.693694	32,468
381	1975	5,279.93	1.468750	7,755
381	1976	8,951.38	1.435115	12,846
381	1977	456.78	1.382353	631
381	1978	17,421.41	1.352518	23,563
381	1979	5,719.70	1.314685	7,520
381	1980	55,571.89	1.261745	70,118
381	1981	35,002.22	1.189873	41,648
381	1982	13,353.16	1.189873	15,889
381	1983	7,631.44	1.287671	9,827
381	1984	39,536.85	1.278912	50,564
381	1985	19,161.98	1.189873	22,800
381	1986	86,901.57	1.132530	98,419
381	1987	33,563.10	1.139394	38,242

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
381	1988	$ 60,037.53	1.105882	$ 66,394
381	1989	83,154.45	1.062147	88,322
381	1990	44,771.03	1.016216	45,497
381	1991	35,441.46	.989474	35,068
381	1992	43,045.12	.979167	42,148
381	1993	61,562.12	.984293	60,595
381	1994	85,400.79	.994709	84,949
381	1995	110,804.82	.989474	109,638
381	1996	111,469.47	.979167	109,147
381	1997	41,857.76	.959184	40,149
381	1998	62,301.81	.949495	59,155
381	1999	50,571.08	.969072	49,007
381	2000	15,620.78	.935323	14,610
381	2001	17,452.99	.930693	16,243
381	2002	15,818.03	.874419	13,832
381	2003	95,290.70	.954315	90,937
381	2004	103,114.17	1.044444	107,697
381	2005	46,774.40	1.016216	47,533
381	2006	70,852.30	1.000000	70,852
	TOTAL ACCT.	$ 2,052,091.10		$ 2,942,351
383	1927 & PR	$ 368.75	9.052632	$ 3,338
383	1943-1947	384.17	7.166667	2,753
383	1950	87.53	4.985507	436
383	1951	678.58	4.648649	3,154
383	1952	94.82	4.648649	441
383	1953	2,561.64	4.648649	11,908
383	1954	772.21	4.648649	3,590
383	1955	977.57	4.648649	4,544
383	1956	2,971.83	4.648649	13,815
383	1957	3,683.26	4.526316	16,672
383	1958	6,768.86	4.300000	29,106
383	1959	6,304.45	4.300000	27,109
383	1960	3,416.68	4.300000	14,692
383	1961	2,660.15	4.246914	11,297
383	1962	5,183.64	4.195122	21,746
383	1963	5,978.93	4.195122	25,082
383	1964	4,353.60	4.195122	18,264
383	1965	5,306.81	4.300000	22,819
383	1966	12,062.17	4.300000	51,867
383	1967	8,421.50	4.300000	36,212
383	1968	5,317.41	4.246914	22,583
383	1969	10,126.60	4.144578	41,970

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
383	1970	$ 6,011.64	3.739130	$ 22,478
383	1971	9,499.65	3.510204	33,346
383	1972	10,514.49	3.440000	36,170
383	1973	9,130.96	3.440000	31,411
383	1974	7,249.50	3.245283	23,527
383	1975	1,042.81	2.752000	2,870
383	1976	11,623.40	2.606061	30,291
383	1977	2,972.84	2.529412	7,520
383	1978	5,538.73	2.388889	13,231
383	1979	13,611.10	2.011696	27,381
383	1980	15,730.42	1.711443	26,922
383	1981	5,522.24	1.638095	9,046
383	1982	5,200.30	1.585253	8,244
383	1983	11,768.57	1.556561	18,318
383	1984	10,297.30	1.495652	15,401
383	1985	11,640.51	1.451477	16,896
383	1986	9,527.73	1.457627	13,888
383	1987	16,024.44	1.415638	22,685
383	1988	15,007.62	1.392713	20,901
383	1989	35,058.37	1.359684	47,668
383	1990	39,632.10	1.278810	50,682
383	1991	39,890.39	1.215548	48,489
383	1992	44,942.24	1.170068	52,585
383	1993	43,170.47	1.158249	50,002
383	1994	32,230.34	1.135314	36,592
383	1995	42,814.69	1.139073	48,769
383	1996	56,800.07	1.135314	64,486
383	1997	56,451.30	1.135314	64,090
383	1998	31,320.39	1.127869	35,325
383	1999	27,097.26	1.116883	30,264
383	2000	24,510.85	1.124183	27,555
383	2001	21,317.58	1.142857	24,363
383	2002	29,545.76	1.075000	31,762
383	2003	46,473.64	1.081761	50,273
383	2004	37,210.76	1.106109	41,159
383	2005	32,881.55	1.023810	33,664
383	2006	49,632.52	1.000000	49,633
	TOTAL ACCT.	$ 957,375.69		$ 1,551,285
389	1970	$ 2,594.50	7.818182	$ 2,595
389	1996	19,771.02		19,771
389	1998	97,902.70		97,903
	TOTAL ACCT.	$ 120,268.22		$ 120,269

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
390	1970	$ 29,340.78	5.329114	$ 156,360
390	1971	189.25	4.784091	905
390	1997	142.32	1.375817	196
390	1999	3,203,405.31	1.345048	4,308,734
	TOTAL ACCT.	$ 3,233,077.66		$ 4,466,195
391	1949	$ 1,056.26	8.250000	$ 8,714
391	1955	28.60	7.333333	210
391	1957	79.42	7.071429	562
391	1958	49.94	6.827586	341
391	1961	49.73	6.600000	328
391	1962	402.68	6.600000	2,658
391	1963	103.40	6.600000	682
391	1964	63.90	6.387097	408
391	1967	427.45	6.000000	2,565
391	1968	3,075.27	5.823529	17,909
391	1969	632.10	5.500000	3,477
391	1970	434.46	5.210526	2,264
391	1971	792.75	4.950000	3,924
391	1972	350.32	4.829268	1,692
391	1973	341.07	4.604651	1,571
391	1974	227.23	4.212766	957
391	1975	993.66	3.807692	3,784
391	1977	212.76	3.355932	714
391	1978	2,065.34	3.142857	6,491
391	1979	588.36	2.911765	1,713
391	1981	102.65	2.275862	234
391	1982	356.81	2.106383	752
391	1983	7,762.20	2.020408	15,683
391	1985	1,359.18	1.867925	2,539
391	1986	19,453.85	1.800000	35,017
391	1987	998.08	1.783784	1,780
391	1988	1,139.95	1.706897	1,946
391	1989	6,953.01	1.636364	11,378
391	1990	311.11	1.559055	485
391	1991	1,278.11	1.466667	1,875
391	1992	3,317.47	1.434783	4,760
391	1993	1,683.70	1.384615	2,331
391	1994	17,931.08	1.356164	24,317
391	1995	3,292.83	1.320000	4,347
391	1996	5,701.38	1.285714	7,330
391	1997	5,740.69	1.245283	7,149
391	1998	4,893.09	1.222222	5,980

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
391	1999	$	126,943.29	1.207317	$	153,261
391	2000		5,962.73	1.171598		6,986
391	2001		90,086.33	1.131429		101,926
391	2002		26,838.78	1.118644		30,023
391	2003		36,868.16	1.087912		40,109
391	2004		59,709.03	1.070270		63,905
391	2005		106,646.27	1.036649		110,555
391	2006		35,099.28	1.000000		35,099
	TOTAL ACCT.	$	582,403.76		$	730,731
392	1971	$	14,485.28	4.950000	$	71,702
392	1972		281.90	4.829268		1,361
392	1991		51,861.86	1.466667		76,064
392	1994		1,474.52	1.356164		2,000
392	1995		67,846.09	1.320000		89,557
392	1997		21,334.35	1.245283		26,567
392	1998		22,551.73	1.222222		27,563
392	2000		51,882.66	1.171598		60,786
392	2001		22,712.82	1.131429		25,698
392	2002		23,508.50	1.118644		26,298
392	2003		7,469.47	1.087912		8,126
392	2005		32,724.14	1.036649		33,923
	TOTAL ACCT.	$	318,133.32		$	449,645
394	1960	$	33.30	6.827586	$	227
394	1961		820.00	6.600000		5,412
394	1966		131.88	6.187500		816
394	1967		360.00	6.000000		2,160
394	1968		81.50	5.823529		475
394	1969		2,241.79	5.500000		12,330
394	1970		299.99	5.210526		1,563
394	1971		1,194.93	4.950000		5,915
394	1972		2,826.99	4.829268		13,652
394	1974		2,002.41	4.212766		8,436
394	1975		421.20	3.807692		1,604
394	1976		18.05	3.535714		64
394	1978		327.69	3.142857		1,030
394	1979		409.71	2.911765		1,193
394	1980		1,790.26	2.538462		4,545
394	1981		676.48	2.275862		1,540
394	1982		398.95	2.106383		840
394	1984		300.29	1.941176		583

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
394	1985	$	142.41	1.867925	$	266
394	1986		1,290.00	1.800000		2,322
394	1987		1,590.39	1.783784		2,837
394	1988		5,411.50	1.706897		9,237
394	1989		671.01	1.636364		1,098
394	1990		1,075.46	1.559055		1,677
394	1991		2,803.02	1.466667		4,111
394	1992		168.06	1.434783		241
394	1993		771.24	1.384615		1,068
394	1994		9,713.58	1.356164		13,173
394	1995		1,025.73	1.320000		1,354
394	1996		212.18	1.285714		273
394	1997		4,220.17	1.245283		5,255
394	1999		24,009.08	1.207317		28,987
394	2000		7,493.00	1.171598		8,779
394	2001		1,885.69	1.131429		2,134
394	2002		243.06	1.118644		272
394	2003		1,866.53	1.087912		2,031
394	2004		8,945.57	1.070270		9,574
394	2006		1,982.37	1.000000		1,982
	TOTAL ACCT.	$	89,855.47		$	159,056
395	1949	$	515.00	8.250000	$	4,249
395	1959		824.75	6.827586		5,631
395	1964		523.55	6.387097		3,344
395	1965		1,339.62	6.387097		8,556
395	1966		343.98	6.187500		2,128
395	1982		14,395.34	2.106383		30,322
395	1985		1,248.00	1.867925		2,331
395	1986		1,243.95	1.800000		2,239
395	1998		25,927.22	1.222222		31,689
	TOTAL ACCT.	$	46,361.41		$	90,489
397	1966	$	2,091.00	6.187500	$	12,938
397	1967		2,431.15	6.000000		14,587
397	1968		3,087.94	5.823529		17,983
397	1970		2,127.74	5.210526		11,087
397	1971		45.30	4.950000		224
397	1972		1,384.67	4.829268		6,687
397	1975		2,423.09	3.807692		9,226
397	1976		132.55	3.535714		469
397	1977		1,387.44	3.355932		4,656

OHIO VALLEY GAS CORPORATION
CURRENT COST OF GENERAL OFFICE PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
397	1978	$ 1,192.12	3.142857	$ 3,747
397	1979	16,726.36	2.911765	48,703
397	1980	25,073.72	2.538462	63,649
397	1981	1,625.93	2.275862	3,700
397	1982	5,647.84	2.106383	11,897
397	1984	11,133.41	1.941176	21,612
397	1985	11,750.45	1.867925	21,949
397	1986	5,290.72	1.800000	9,523
397	1987	14,791.99	1.783784	26,386
397	1988	6,059.48	1.706897	10,343
397	1989	8,071.81	1.636364	13,208
397	1990	25,096.60	1.559055	39,127
397	1991	552.60	1.466667	810
397	1992	84,620.18	1.434783	121,412
397	1994	25,898.69	1.356164	35,123
397	1995	3,926.23	1.320000	5,183
397	1996	2,209.05	1.285714	2,840
397	1998	909.47	1.222222	1,112
397	1999	34,785.30	1.207317	41,997
397	2000	1,073.26	1.171598	1,257
397	2002	982.10	1.118644	1,099
397	2005	916.08	1.036649	950
	TOTAL ACCT.	$ 303,444.27		$ 563,484
398	1970	$ 192.27	5.210526	$ 1,002
398	1982	78.52	2.106383	165
398	1999	6,686.78	1.207317	8,073
398	2000	2,853.26	1.171598	3,343
	TOTAL ACCT.	$ 9,810.83		$ 12,583
	TOTAL SYSTEM	$ 7,712,821.73		$11,086,088

ALLOCATION OF GENERAL OFFICE PLANT TO OVGC SUPPLIER SYSTEMS

ANR PIPELINE	$ 3,167,655.88	$ 4,553,056
TEXAS GAS	$ 4,545,165.85	$ 6,533,032
	$ 7,712,821.73	$11,086,088

OHIO VALLEY GAS CORPORATION
CURRENT COST OF TELL CITY DISTRICT GENERAL PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
389	1959	$	2,535.00		$	2,535
389	1981		28,063.92			28,064
389	1992		4,109.73			4,110
389	1994		19,643.09			19,643
389	1995		9,581.46			9,581
	TOTAL ACCT.	$	63,933.20		$	63,933
390	1963	$	41,082.02	7.517857	$	308,849
390	1964		192.68	7.385965		1,423
390	1965		59.44	7.135593		424
390	1969		8,020.00	5.767123		46,252
390	1971		488.12	4.784091		2,335
390	1972		3,432.08	4.526882		15,537
390	1981		34,910.84	2.239362		78,178
390	1985		5,413.52	1.913636		10,360
390	1988		368.56	1.746888		644
390	1989		378.72	1.711382		648
390	1992		8,272.43	1.664032		13,766
390	1998		4,884.34	1.366883		6,676
390	2001		6,273.01	1.264264		7,931
390	2002		267.97	1.209770		324
390	2003		15,484.06	1.156593		17,909
390	2004		17,226.76	1.090674		18,789
	TOTAL ACCT.	$	146,754.55		$	530,045
391	1949	$	667.66	8.250000	$	5,508
391	1952		350.54	7.333333		2,571
391	1953		22.50	7.333333		165
391	1956		582.21	7.333333		4,270
391	1957		281.17	7.071429		1,988
391	1959		300.70	6.827586		2,053
391	1960		10.00	6.827586		68
391	1963		200.20	6.600000		1,321
391	1964		392.96	6.387097		2,510
391	1966		25.75	6.187500		159
391	1974		262.74	4.212766		1,107
391	1977		739.35	3.355932		2,481
391	1978		107.57	3.142857		338
391	1980		41.88	2.538462		106
391	1982		183.21	2.106383		386
391	1984		128.43	1.941176		249
391	1986		285.39	1.800000		514

OHIO VALLEY GAS CORPORATION
CURRENT COST OF TELL CITY DISTRICT GENERAL PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
391	1989	$	126.79	1.636364	$	207
391	1990		302.72	1.559055		472
391	1991		681.24	1.466667		999
391	1992		115.21	1.434783		165
391	1993		793.80	1.384615		1,099
391	1996		960.89	1.285714		1,235
391	1997		3,313.61	1.245283		4,126
391	1998		6,315.98	1.222222		7,720
391	1999		2,919.27	1.207317		3,524
391	2000		1,109.85	1.171598		1,300
391	2001		602.50	1.131429		682
391	2002		1,114.92	1.118644		1,247
391	2003		6,710.76	1.087912		7,301
391	2004		4,383.02	1.070270		4,691
391	2006		1,085.68	1.000000		1,086
	TOTAL ACCT.	$	35,118.50		$	61,648
392	1989	$	27,009.53	1.636364	$	44,197
392	1990		14,982.98	1.559055		23,359
392	1995		13,983.51	1.320000		18,458
392	1997		52,752.28	1.245283		65,692
392	1998		18,525.09	1.222222		22,642
392	2000		24,859.63	1.171598		29,125
392	2001		30,224.32	1.131429		34,197
392	2002		24,592.50	1.118644		27,510
392	2003		51,550.22	1.087912		56,082
392	2004		75,418.45	1.070270		80,718
392	2005		63,468.78	1.036649		65,795
392	2006		65,606.26	1.000000		65,606
	TOTAL ACCT.	$	462,973.55		$	533,381
394	1949	$	166.64	8.250000	$	1,375
394	1951		240.28	7.920000		1,903
394	1963		458.59	6.600000		3,027
394	1965		36.99	6.387097		236
394	1966		73.46	6.187500		455
394	1967		500.09	6.000000		3,001
394	1969		520.91	5.500000		2,865
394	1970		456.85	5.210526		2,380
394	1971		683.48	4.950000		3,383
394	1972		697.60	4.829268		3,369
394	1976		2,841.05	3.535714		10,045

OHIO VALLEY GAS CORPORATION
CURRENT COST OF TELL CITY DISTRICT GENERAL PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
394	1977	$	3,872.15	3.355932	$	12,995
394	1978		855.31	3.142857		2,688
394	1980		6,656.53	2.538462		16,897
394	1981		10,047.12	2.275862		22,866
394	1982		733.13	2.106383		1,544
394	1983		4,046.67	2.020408		8,176
394	1984		168.86	1.941176		328
394	1985		378.12	1.867925		706
394	1986		5,448.03	1.800000		9,806
394	1987		45,031.87	1.783784		80,327
394	1988		2,041.80	1.706897		3,485
394	1989		4,362.12	1.636364		7,138
394	1990		11,845.44	1.559055		18,468
394	1991		9,708.98	1.466667		14,240
394	1992		67,179.87	1.434783		96,389
394	1993		11,180.36	1.384615		15,480
394	1994		4,107.61	1.356164		5,571
394	1995		2,898.66	1.320000		3,826
394	1996		631.75	1.285714		812
394	1997		4,384.15	1.245283		5,460
394	1998		10,172.56	1.222222		12,433
394	1999		2,342.72	1.207317		2,828
394	2000		46,382.82	1.171598		54,342
394	2001		25,499.01	1.131429		28,850
394	2002		7,997.36	1.118644		8,946
394	2003		75,367.95	1.087912		81,994
394	2004		30,753.57	1.070270		32,915
394	2005		52,575.73	1.036649		54,503
394	2006		8,356.68	1.000000		8,357
	TOTAL ACCT.	$	461,702.87		$	644,409
395	1963	$	100.00	6.600000	$	660
395	1967		150.00	6.000000		900
395	1995		1,632.56	1.320000		2,155
	TOTAL ACCT.	$	1,882.56		$	3,715
397	1992	$	54,153.03	1.434783	$	77,698
397	1994		153.27	1.356164		208
397	1995		169.11	1.320000		223
397	2003		1,514.25	1.087912		1,647
	TOTAL ACCT.	$	55,989.66		$	79,776

OHIO VALLEY GAS CORPORATION
CURRENT COST OF TELL CITY DISTRICT GENERAL PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
398	1963	$ 220.00	6.600000	$ 1,452
398	1964	228.69	6.387097	1,461
398	1965	239.55	6.387097	1,530
398	1979	471.11	2.911765	1,372
	TOTAL ACCT.	$ 1,159.35		$ 5,815
	TOTAL SYSTEM	$ 1,229,514.24		$ 1,922,722

ALLOCATION OF TELL CITY GENERAL PLANT TO OVGC SUPPLIER SYSTEMS

ANR PIPELINE	$ 294,960.47	$ 461,261
TEXAS GAS	$ 934,553.77	$ 1,461,461
	$ 1,229,514.24	$ 1,922,722

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
302	1914	$	185.60		$	186
	TOTAL ACCT.	$	185.60		$	186
304	1963	$	2,000.00		$	2,000
304	1980		21,005.62			21,006
	TOTAL ACCT.	$	23,005.62		$	23,006
305	1966	$	1,156.47	6.901639	$	7,982
305	1968		601.41	6.283582		3,779
305	1975		24,490.83	3.289063		80,552
305	1976		8,211.24	3.213740		26,389
305	1980		51,703.34	2.338889		120,928
305	1985		4,431.35	1.913636		8,480
	TOTAL ACCT.	$	90,594.64		$	248,110
311	1961	$	7,857.30	7.854545	$	61,716
311	1963		159.81	7.578947		1,211
311	1967		86.45	6.750000		584
311	1975		241,114.28	3.570248		860,838
311	1976		2,624.19	3.401575		8,926
311	2003		3,960.29	1.223796		4,847
	TOTAL ACCT.	$	255,802.32		$	938,122
365.1	1957	$	483.65		$	484
365.1	1971		430.42			430
365.1	1985		521.58			522
365.1	1992		2,729.54			2,730
	TOTAL ACCT.	$	4,165.19		$	4,166
365.2	1927 & PR	$	337.70		$	338
365.2	1953		87.17			87
365.2	1956		4.00			4
365.2	1958		6.00			6
365.2	1960		2.00			2
365.2	1965		756.00			756
365.2	1968		350.00			350
365.2	1988		7.00			7
365.2	1991		1,383.95			1,384
365.2	1992		12,692.88			12,693

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
365.2	1997	$	1,585.00		$ 1,585
365.2	2002		2,206.00		2,206
	TOTAL ACCT.	$	19,417.70		$ 19,418
366	1957	$	2,186.34	8.420000	$ 18,409
366	1979		1,065.49	2.536145	2,702
366	1986		984.00	1.871111	1,841
366	1993		678.08	1.594697	1,081
	TOTAL ACCT.	$	4,913.91		$ 24,033
367	1927 & PR	S $	2,082.13	19.727273	$ 41,075
367	1938-1942	S	1,209.92	20.666667	25,005
367	1943-1947	S	14,400.54	19.727273	284,083
367	1954	S	6,999.60	10.093023	70,647
367	1955	S	4,058.10	9.863636	40,028
367	1956	S	17,828.25	9.234043	164,627
367	1957	S	75,498.17	8.680000	655,324
367	1958	S	123,119.29	8.346154	1,027,573
367	1959	S	4,027.01	8.037037	32,365
367	1960	S	18,580.37	7.890909	146,616
367	1961	S	4,626.79	7.614035	35,229
367	1962	S	21,141.13	7.482759	158,194
367	1964	S	99,448.45	7.000000	696,139
367	1965	S	26,035.28	6.888889	179,354
367	1966	S	106,060.44	6.781250	719,222
367	1967	S	82,320.74	6.676923	549,649
367	1968	S	27,423.19	6.382353	175,024
367	1969	S	1,962.85	5.864865	11,512
367	1972	S	31,837.53	4.520833	143,932
367	1974	S	656.67	3.773913	2,478
367	1978	S	4,839.43	2.480000	12,002
367	1982	S	18,538.24	1.715415	31,801
367	1988	S	3,641.89	1.613383	5,876
367	1989	S	20,960.19	1.601476	33,567
367	1991	S	72,411.70	1.688716	122,283
367	1992	S	627,640.36	1.695313	1,064,047
367	1993	S	17,166.68	1.675676	28,766
367	1997	S	31,119.25	1.471186	45,782
367	2002	S	112,752.70	1.382166	155,843
367	2004	S	3,261.93	1.311178	4,277
	TOTAL ACCT.	$	1,581,648.82		$ 6,662,320

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
369	1957	$	2,482.51	10.075472	$	25,012
369	1967		2,651.79	8.090909		21,455
369	1968		11,089.77	7.739130		85,825
369	1969		365.36	7.216216		2,637
369	1972		2,448.40	5.562500		13,619
369	1981		13,328.86	2.394619		31,918
369	1984		5,859.03	2.197531		12,875
369	1985		6,477.94	2.170732		14,062
369	1986		2,197.64	2.136000		4,694
369	1992		239,643.79	1.679245		402,421
369	1993		137,576.30	1.638037		225,355
369	2000		3,106.70	1.358779		4,221
369	2002		19,381.96	1.302439		25,244
369	2003		13,537.66	1.348485		18,255
369	2004		35,292.83	1.271429		44,872
	TOTAL ACCT.	$	495,440.54		$	932,465
374	1914	$	50.00		$	50
374	1949		65.00			65
374	1952		29.69			30
374	1954		17.00			17
374	1962		250.00			250
374	1964		10.00			10
374	1965		14.00			14
374	1967		801.00			801
374	1968		2,137.00			2,137
374	1970		3.00			3
374	1972		5.00			5
374	1975		402.67			403
374	1976		5.50			6
374	1977		105.00			105
374	1978		828.00			828
374	1980		10.00			10
374	1981		15.00			15
374	1982		45.50			46
374	1983		8.00			8
374	1984		9.00			9
374	1985		5,547.80			5,548
374	1986		8.00			8
374	1987		38.50			39
374	1988		265.00			265
374	1989		130.08			130
374	1990		174.00			174

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
374	1991	$	1,815.77		$	1,816
374	1992		598.87			599
374	1993		141.00			141
374	1994		150.48			150
374	1995		5,554.99			5,555
374	1996		59.06			59
374	1997		2,466.15			2,466
374	1998		5,120.90			5,121
374	1999		508.00			508
374	2000		39,063.06			39,063
374	2001		29,089.35			29,089
374	2002		18,998.41			18,998
374	2003		9,896.83			9,897
374	2004		4,065.51			4,066
374	2005		4,915.00			4,915
	TOTAL ACCT.	$	133,417.12		$	133,419
375	1957	$	419.35	8.420000	$	3,531
375	1962		696.00	7.654545		5,328
375	1964		150.00	7.385965		1,108
375	1967		821.46	6.682540		5,489
375	1970		656.40	5.329114		3,498
375	1979		1,959.04	2.536145		4,968
375	1985		844.90	1.913636		1,617
375	1998		680.00	1.366883		929
375	1999		900.00	1.345048		1,211
375	2000		400.00	1.295385		518
375	2002		676.48	1.209770		818
	TOTAL ACCT.	$	8,203.63		$	29,015
376	1927 & PR S	$	1,101.91	36.117647	$	39,798
376	1933-1937 S		219.04	40.933333		8,966
376	1938-1942 S		3,411.56	34.111111		116,372
376	1943-1947 S		1,890.43	32.315789		61,091
376	1948-1949 S		6,315.67	21.172414		133,718
376	1950 S		2,621.79	19.187500		50,306
376	1951 S		8,600.20	17.542857		150,872
376	1952 S		6,712.81	16.594595		111,396
376	1954 S		6,854.12	14.619048		100,201
376	1955 S		8,860.02	14.279070		126,513
376	1956 S		4,709.52	13.347826		62,862
376	1957 S		16,205.11	12.530612		203,060

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
376	1958	S	$ 31,679.65	12.039216	$ 381,398
376	1959	S	35,108.15	11.584906	406,725
376	1960	S	33,979.13	11.163636	379,331
376	1961	S	9,425.07	10.771930	101,526
376	1962	S	34,994.43	10.586207	370,458
376	1963	S	27,320.82	10.233333	279,583
376	1964	S	69,456.64	9.903226	687,845
376	1965	S	46,550.93	9.593750	446,598
376	1966	S	155,185.49	9.446154	1,465,906
376	1967	S	127,780.77	8.898551	1,137,064
376	1968	S	180,350.26	8.527778	1,537,987
376	1969	S	165,861.98	7.871795	1,305,632
376	1970	P	47.61	4.918605	234
376	1970	S	131,490.77	7.397590	972,715
376	1971	P	4,922.82	4.597826	22,634
376	1971	S	128,446.59	6.747253	866,662
376	1972	P	35,276.95	4.406250	155,439
376	1972	S	53,839.54	6.395833	344,349
376	1973	P	52,862.44	4.230000	223,608
376	1973	S	54,695.90	6.140000	335,833
376	1974	P	3,632.62	3.776786	13,720
376	1974	S	31,536.23	5.339130	168,376
376	1975	P	1,439.22	3.330709	4,794
376	1975	S	80,751.47	4.834646	390,405
376	1976	P	530.79	3.133333	1,663
376	1976	S	42,260.68	4.514706	190,795
376	1977	P	2,125.82	2.937500	6,245
376	1977	S	44,189.11	4.205479	185,836
376	1978	P	1,280.07	2.729032	3,493
376	1978	S	78,176.58	3.813665	298,139
376	1979	P	2,801.78	2.502959	7,013
376	1979	S	88,191.09	3.528736	311,203
376	1980	P	3,082.63	2.262032	6,973
376	1980	S	253,263.74	3.283422	831,572
376	1981	S	129,033.22	2.966184	382,736
376	1982	P	10,581.51	1.922727	20,345
376	1982	S	75,636.71	2.716814	205,491
376	1983	P	3,854.51	1.855263	7,151
376	1983	S	66,394.37	2.623932	174,214
376	1984	P	1,634.28	1.815451	2,967
376	1984	S	115,807.54	2.526749	292,617
376	1985	P	11,267.54	1.800000	20,282
376	1985	S	296,499.97	2.526749	749,181
376	1986	P	5,433.90	1.769874	9,617

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
376	1986	S	$ 113,293.64	2.623932	$ 297,275
376	1987	P	10,211.96	1.719512	17,560
376	1987	S	110,872.85	2.526749	280,148
376	1988	P	87,635.60	1.633205	143,127
376	1988	S	81,805.42	2.352490	192,446
376	1989	P	81,624.87	1.538182	125,554
376	1989	S	79,291.77	2.240876	177,683
376	1990	P	113,350.55	1.494700	169,425
376	1990	S	66,552.16	2.192857	145,939
376	1991	P	176,222.99	1.463668	257,932
376	1991	S	104,899.13	2.154386	225,993
376	1992	P	101,950.55	1.443686	147,185
376	1992	S	186,897.66	2.109966	394,348
376	1993	P	224,637.89	1.410000	316,739
376	1993	S	113,152.33	2.060403	233,139
376	1994	P	170,517.19	1.377850	234,947
376	1994	S	119,844.76	1.912773	229,236
376	1995	P	151,098.60	1.351438	204,200
376	1995	S	40,381.65	1.860606	75,134
376	1996	P	29,465.71	1.317757	38,829
376	1996	S	45,328.03	1.843844	83,578
376	1997	P	94,359.85	1.293578	122,062
376	1997	S	173,109.37	1.790087	309,881
376	1998	P	235,730.93	1.277946	301,251
376	1998	S	53,579.44	1.774566	95,080
376	1999	P	51,581.20	1.255193	64,744
376	1999	S	185,630.75	1.739377	322,882
376	2000	P	105,778.20	1.229651	130,070
376	2000	S	26,301.20	1.641711	43,179
376	2001	P	106,686.36	1.198300	127,842
376	2001	S	412,861.16	1.607330	663,604
376	2002	P	229,182.51	1.181564	270,794
376	2002	S	223,886.14	1.582474	354,294
376	2003	P	61,360.05	1.146341	70,340
376	2003	S	7,123.33	1.535000	10,934
376	2004	P	241,746.58	1.119048	270,526
376	2004	S	212,943.62	1.376682	293,156
376	2005	P	140,951.56	1.057500	149,056
376	2005	S	37,606.89	1.053173	39,607
376	2006	P	195,312.53	1.000000	195,313
376	2006	S	36,508.55	1.000000	36,509
	TOTAL ACCT.		$ 7,837,459.03		$24,733,051

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
378	1946	$ 365.26	19.111111	$ 6,981
378	1947	17.31	16.125000	279
378	1949	35.65	14.333333	511
378	1951	294.10	12.585366	3,701
378	1952	853.22	12.285714	10,482
378	1953	583.82	12.285714	7,173
378	1954	1,119.65	11.727273	13,130
378	1955	144.90	11.217391	1,625
378	1956	176.94	10.320000	1,826
378	1957	666.98	9.555556	6,373
378	1958	1,707.97	9.214286	15,738
378	1959	1,161.55	8.896552	10,334
378	1961	317.06	8.600000	2,727
378	1963	41.85	8.322581	348
378	1964	283.23	8.190476	2,320
378	1965	493.34	8.062500	3,978
378	1966	1,544.51	7.818182	12,075
378	1967	1,628.73	7.701493	12,544
378	1968	5,171.85	7.478261	38,676
378	1970	5,780.58	6.370370	36,824
378	1971	3,547.47	5.797753	20,567
378	1972	3,782.21	5.375000	20,329
378	1973	1,209.67	5.160000	6,242
378	1975	7,480.73	4.031250	30,157
378	1976	2,008.65	3.685714	7,403
378	1977	58.37	3.463087	202
378	1978	995.49	3.165644	3,151
378	1979	2,190.28	2.948571	6,458
378	1980	3,754.15	2.701571	10,142
378	1981	1,566.21	2.422535	3,794
378	1983	1,236.43	2.233766	2,762
378	1984	432.47	2.168067	938
378	1985	1,573.92	2.150000	3,384
378	1986	1,311.87	2.123457	2,786
378	1987	1,607.01	2.055777	3,304
378	1988	1,397.34	1.918216	2,680
378	1989	1,422.42	1.849462	2,631
378	1990	1,809.80	1.842857	3,335
378	1991	4,790.50	1.829787	8,766
378	1992	16,232.53	1.755102	28,490
378	1993	6,544.94	1.702970	11,146
378	1994	19,261.48	1.627760	31,353
378	1995	1,001.90	1.587692	1,591
378	1996	2,125.50	1.544910	3,284

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
378	1997	$	8,984.16	1.495652	$ 13,437
378	1998		10,734.90	1.482759	15,917
378	1999		6,535.36	1.465909	9,580
378	2000		2,845.63	1.413699	4,023
378	2001		3,520.27	1.390836	4,896
378	2002		6,919.01	1.354331	9,371
378	2003		10,931.85	1.357895	14,844
378	2004		8,118.19	1.277228	10,369
378	2006		2,935.95	1.000000	2,936
	TOTAL ACCT.	$	171,255.16		$ 487,913
379	1961	$	119.70	8.982759	$ 1,075
379	1962		54.03	8.830508	477
379	1964		3,645.27	8.540984	31,134
379	1965		4,275.06	8.403226	35,924
379	1966		537.82	8.140625	4,378
379	1967		6,678.41	7.893939	52,719
379	1968		9,990.19	7.550725	75,433
379	1969		4,785.99	7.040541	33,696
379	1975		3,990.49	4.038760	16,117
379	1981		1,436.03	2.434579	3,496
379	1985		5,655.63	2.152893	12,176
379	1986		7,231.98	2.144033	15,506
379	1992		3,485.79	1.778157	6,198
379	1997		3,946.40	1.514535	5,977
379	2000		5,321.88	1.431319	7,617
379	2003		12,526.96	1.378307	17,266
379	2004		47,394.36	1.289604	61,120
379	2006		208,780.85	1.000000	208,781
	TOTAL ACCT.	$	329,856.84		$ 589,090
380	1927 & PR	S $	592.44	35.571429	$ 21,074
380	1933-1937	S	148.13	38.307692	5,675
380	1938-1942	S	22.93	33.200000	761
380	1943-1947	S	89.52	31.125000	2,786
380	1948-1949	S	612.33	19.153846	11,728
380	1950	S	277.22	17.172414	4,761
380	1951	S	290.43	16.064516	4,666
380	1952	S	539.26	15.090909	8,138
380	1953	S	1,504.84	14.228571	21,412
380	1954	S	1,444.65	13.459459	19,444
380	1955	S	3,086.31	12.769231	39,410

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
380	1956	S	$ 6,746.13	11.857143	$ 79,990
380	1957	S	5,998.65	11.066667	66,385
380	1958	S	7,393.20	10.826087	80,039
380	1959	S	7,881.19	10.163265	80,099
380	1960	S	7,415.77	9.764706	72,413
380	1961	S	6,039.94	9.576923	57,844
380	1962	S	5,799.79	9.222222	53,487
380	1963	S	5,968.78	9.054545	54,045
380	1964	S	4,827.84	8.736842	42,180
380	1965	S	5,615.83	8.440678	47,401
380	1966	S	23,348.98	8.163934	190,620
380	1967	S	66,483.97	7.781250	517,328
380	1968	S	13,069.45	7.432836	97,143
380	1969	S	38,584.98	6.821918	263,224
380	1970	S	33,169.33	6.148148	203,930
380	1971	P	1,438.20	4.865169	6,997
380	1971	S	29,340.04	5.533333	162,348
380	1972	P	11,881.98	4.557895	54,157
380	1972	S	15,645.71	5.242105	82,016
380	1973	P	8,002.74	4.330000	34,652
380	1973	S	24,244.12	4.980000	120,736
380	1974	P	1,732.77	3.972477	6,883
380	1974	S	18,149.85	4.486486	81,429
380	1975	P	6,816.74	3.578512	24,394
380	1975	S	14,988.61	4.048780	60,686
380	1976	P	11,831.53	3.409449	40,339
380	1976	S	20,055.48	3.801527	76,241
380	1977	P	7,345.63	3.207407	23,560
380	1977	S	21,596.37	3.557143	76,821
380	1978	P	5,126.09	3.006944	15,414
380	1978	S	50,248.55	3.276316	164,630
380	1979	P	4,725.03	2.775641	13,115
380	1979	S	67,141.73	3.036585	203,882
380	1980	P	6,782.23	2.547059	17,275
380	1980	S	107,362.43	2.797753	300,374
380	1981	P	2,201.21	2.340541	5,152
380	1981	S	55,225.02	2.540816	140,317
380	1982	P	6,193.94	2.101942	13,019
380	1982	S	62,087.00	2.305556	143,145
380	1983	P	8,869.32	2.013953	17,862
380	1983	S	51,867.29	2.203540	114,292
380	1984	P	9,383.42	1.959276	18,385
380	1984	S	46,638.36	2.128205	99,256
380	1985	P	14,194.65	1.915929	27,196

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
380	1985	S	$ 48,840.64	2.110169	$ 103,062
380	1986	P	13,220.94	1.874459	24,782
380	1986	S	39,375.41	2.110169	83,089
380	1987	P	17,723.30	1.819328	32,244
380	1987	S	46,105.64	2.049383	94,488
380	1988	P	33,005.18	1.760163	58,094
380	1988	S	48,125.01	1.960630	94,355
380	1989	P	39,458.81	1.704724	67,266
380	1989	S	43,536.94	1.908046	83,070
380	1990	P	26,902.40	1.652672	44,461
380	1990	S	65,403.15	1.858209	121,533
380	1991	P	94,606.69	1.615672	152,853
380	1991	S	92,212.89	1.817518	167,599
380	1992	P	38,059.23	1.568841	59,709
380	1992	S	50,949.17	1.759717	89,656
380	1993	P	69,258.79	1.530035	105,968
380	1993	S	85,800.96	1.711340	146,835
380	1994	P	70,138.60	1.472789	103,299
380	1994	S	50,171.17	1.627451	81,651
380	1995	P	30,020.25	1.438538	43,185
380	1995	S	39,434.20	1.585987	62,542
380	1996	P	26,786.04	1.401294	37,535
380	1996	S	31,675.76	1.556250	49,295
380	1997	P	35,193.24	1.365931	48,072
380	1997	S	86,524.46	1.518293	131,369
380	1998	P	45,251.71	1.348910	61,040
380	1998	S	77,433.80	1.500000	116,151
380	1999	P	55,124.26	1.316109	72,550
380	1999	S	28,892.70	1.464706	42,319
380	2000	P	46,173.23	1.277286	58,976
380	2000	S	46,078.92	1.406780	64,823
380	2001	P	33,035.56	1.233618	40,753
380	2001	S	30,836.07	1.368132	42,188
380	2002	P	75,452.18	1.196133	90,251
380	2002	S	33,751.50	1.335121	45,062
380	2003	P	19,587.70	1.145503	22,438
380	2003	S	31,907.31	1.280206	40,848
380	2004	P	83,041.78	1.101781	91,494
380	2004	S	61,961.25	1.200000	74,354
380	2005	P	19,364.61	1.053528	20,401
380	2005	S	29,411.15	1.048421	30,835
380	2006	P	35,517.99	1.000000	35,518
380	2006	S	8,301.92	1.000000	8,302
	TOTAL ACCT.		$ 2,921,720.44		$ 7,234,871

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
385	1957	$	5,000.10	9.555556	$	47,779
385	1958		1,913.88	9.214286		17,635
385	1964		177.97	8.190476		1,458
385	1965		2,013.15	8.062500		16,231
385	1967		2,444.08	7.701493		18,823
385	1968		3,380.69	7.478261		25,282
385	1971		468.11	5.797753		2,714
385	1972		287.11	5.375000		1,543
385	1973		503.64	5.160000		2,599
385	1977		936.01	3.463087		3,241
385	1979		1,880.96	2.948571		5,546
385	1981		1,096.75	2.422535		2,657
385	1984		10,218.32	2.168067		22,154
385	1996		13,109.18	1.544910		20,253
385	2001		3,068.45	1.390836		4,268
385	2002		761.69	1.354331		1,032
	TOTAL ACCT.	$	47,260.09		$	193,215
389	1927 & PR	$	5,262.81		$	5,263
389	1958		2,083.80			2,084
389	1965		4,000.00			4,000
389	1967		10,000.00			10,000
389	1969		2,512.00			2,512
389	1980		12,626.66			12,627
389	1986		10,419.00			10,419
389	1987		2,528.89			2,529
389	1990		11,073.34			11,073
	TOTAL ACCT.	$	60,506.50		$	60,507
390	1927 & PR	$	15,282.16	26.312500	$	402,112
390	1942		192.50	21.050000		4,052
390	1958		3,063.86	8.096154		24,805
390	1963		300.36	7.517857		2,258
390	1964		131.97	7.385965		975
390	1965		26,105.60	7.135593		186,279
390	1967		156,992.23	6.682540		1,049,107
390	1968		44,775.75	6.283582		281,352
390	1969		13,392.26	5.767123		77,235
390	1971		2,078.77	4.784091		9,945
390	1972		3,468.10	4.526882		15,700
390	1974		21,152.11	3.598291		76,111
390	1977		115.98	3.072993		356

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
390	1980	$	5,000.00	2.338889	$ 11,694
390	1981		381.53	2.239362	854
390	1982		37,192.81	2.137056	79,483
390	1986		7,896.00	1.871111	14,774
390	1987		25,532.50	1.814655	46,333
390	1988		146.96	1.746888	257
390	1989		2,845.37	1.711382	4,870
390	1990		33,034.93	1.690763	55,854
390	1991		127.30	1.711382	218
390	1992		45,939.53	1.664032	76,445
390	1993		406.95	1.594697	649
390	1994		5,955.36	1.508961	8,986
390	1995		144.36	1.461806	211
390	1999		618.35	1.345048	832
390	2000		17,292.94	1.295385	22,401
390	2003		14,268.85	1.156593	16,503
390	2005		100.67	1.029340	104
	TOTAL ACCT.	$	483,936.06		$ 2,470,755
391	1949	$	1,754.61	8.250000	$ 14,476
391	1950		247.05	8.250000	2,038
391	1951		3.07	7.920000	24
391	1952		390.05	7.333333	2,860
391	1954		87.00	7.333333	638
391	1955		1,088.54	7.333333	7,983
391	1956		299.47	7.333333	2,196
391	1957		1,104.22	7.071429	7,808
391	1958		53.75	6.827586	367
391	1959		465.22	6.827586	3,176
391	1960		499.13	6.827586	3,408
391	1961		410.98	6.600000	2,712
391	1962		1,423.00	6.600000	9,392
391	1963		45.00	6.600000	297
391	1964		178.10	6.387097	1,138
391	1965		897.00	6.387097	5,729
391	1966		459.17	6.187500	2,841
391	1967		2,256.26	6.000000	13,538
391	1968		978.52	5.823529	5,698
391	1969		270.48	5.500000	1,488
391	1971		37.78	4.950000	187
391	1974		568.97	4.212766	2,397
391	1975		165.65	3.807692	631
391	1976		182.41	3.535714	645

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
391	1977	$	206.12	3.355932	$	692
391	1978		225.85	3.142857		710
391	1979		67.60	2.911765		197
391	1980		85.85	2.538462		218
391	1982		666.44	2.106383		1,404
391	1983		136.91	2.020408		277
391	1984		478.83	1.941176		929
391	1986		634.20	1.800000		1,142
391	1987		917.40	1.783784		1,636
391	1988		1,273.69	1.706897		2,174
391	1989		306.18	1.636364		501
391	1990		281.56	1.559055		439
391	1991		1,827.35	1.466667		2,680
391	1992		1,927.98	1.434783		2,766
391	1993		1,785.43	1.384615		2,472
391	1994		3,257.29	1.356164		4,417
391	1995		2,936.88	1.320000		3,877
391	1996		10,434.95	1.285714		13,416
391	1997		15,017.97	1.245283		18,702
391	1998		3,673.93	1.222222		4,490
391	1999		4,659.63	1.207317		5,626
391	2000		4,371.35	1.171598		5,121
391	2001		252.63	1.131429		286
391	2002		553.89	1.118644		620
391	2003		6,616.50	1.087912		7,198
391	2004		6,725.74	1.070270		7,198
391	2005		417.97	1.036649		433
391	2006		3,271.20	1.000000		3,271
	TOTAL ACCT.	$	86,876.75		$	184,559
392	1980	$	22,242.90	2.538462	$	56,463
392	1986		11,458.50	1.800000		20,625
392	1988		27,413.38	1.706897		46,792
392	1991		30,124.04	1.466667		44,182
392	1992		26,432.39	1.434783		37,925
392	1993		38,865.36	1.384615		53,814
392	1994		56,712.29	1.356164		76,911
392	1996		21,034.06	1.285714		27,044
392	1998		60,405.25	1.222222		73,829
392	1999		62,278.45	1.207317		75,190
392	2000		27,480.88	1.171598		32,197
392	2001		55,215.78	1.131429		62,473
392	2002		22,603.77	1.118644		25,286

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
392	2003	$	67,171.33	1.087912	$	73,076
392	2004		138,530.94	1.070270		148,266
392	2005		5,205.15	1.036649		5,396
392	2006		24,809.09	1.000000		24,809
	TOTAL ACCT.	$	697,983.56		$	884,278
394	1949	$	490.44	8.250000	$	4,046
394	1951		146.95	7.920000		1,164
394	1955		167.95	7.333333		1,232
394	1956		3,134.25	7.333333		22,984
394	1957		208.64	7.071429		1,475
394	1958		499.94	6.827586		3,413
394	1960		696.67	6.827586		4,757
394	1961		2,386.54	6.600000		15,751
394	1963		686.59	6.600000		4,531
394	1965		819.24	6.387097		5,233
394	1966		21,230.01	6.187500		131,361
394	1967		549.60	6.000000		3,298
394	1968		4,914.77	5.823529		28,621
394	1969		9,394.70	5.500000		51,671
394	1970		66.44	5.210526		346
394	1971		3,824.23	4.950000		18,930
394	1972		808.77	4.829268		3,906
394	1973		2,075.36	4.604651		9,556
394	1974		1,127.71	4.212766		4,751
394	1975		1,924.54	3.807692		7,328
394	1976		217.48	3.535714		769
394	1977		3,215.85	3.355932		10,792
394	1978		18,762.06	3.142857		58,966
394	1979		3,848.50	2.911765		11,206
394	1980		5,389.08	2.538462		13,680
394	1981		14,451.41	2.275862		32,889
394	1982		1,856.21	2.106383		3,910
394	1983		5,241.50	2.020408		10,590
394	1984		44,972.89	1.941176		87,300
394	1985		6,085.50	1.867925		11,367
394	1986		3,596.67	1.800000		6,474
394	1987		23,074.47	1.783784		41,160
394	1988		1,318.51	1.706897		2,251
394	1989		7,472.43	1.636364		12,228
394	1990		25,634.18	1.559055		39,965
394	1991		23,065.69	1.466667		33,830
394	1992		44,825.17	1.434783		64,314

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC ANR PIPELINE SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
394	1993	$	57,790.98	1.384615	$	80,018
394	1994		39,879.17	1.356164		54,083
394	1995		57,300.10	1.320000		75,636
394	1996		42,021.93	1.285714		54,028
394	1997		7,173.39	1.245283		8,933
394	1998		15,480.17	1.222222		18,920
394	1999		4,830.59	1.207317		5,832
394	2000		2,521.87	1.171598		2,955
394	2001		5,021.75	1.131429		5,682
394	2002		4,109.05	1.118644		4,597
394	2003		28,848.63	1.087912		31,385
394	2004		91,346.89	1.070270		97,766
394	2005		3,101.94	1.036649		3,216
394	2006		37,070.56	1.000000		37,071
	TOTAL ACCT.	$	684,677.96		$	1,246,167
395	1949	$	113.03	8.250000	$	932
395	1952		103.00	7.333333		755
395	1956		151.54	7.333333		1,111
395	1957		256.69	7.071429		1,815
395	1959		526.83	6.827586		3,597
395	1960		206.75	6.827586		1,412
395	1964		3,419.66	6.387097		21,842
395	1967		209.73	6.000000		1,258
395	1998		726.45	1.222222		888
	TOTAL ACCT.	$	5,713.68		$	33,610
397	1988	$	17,429.38	1.706897	$	29,750
397	1990		385.81	1.559055		601
397	1992		92,474.49	1.434783		132,681
397	1993		3,314.38	1.384615		4,589
397	1994		29,177.92	1.356164		39,570
397	1996		2,592.22	1.285714		3,333
	TOTAL ACCT.	$	145,374.20		$	210,524
398	1957	$	280.00	7.071429	$	1,980
398	1967		2,435.66	6.000000		14,614
398	1968		161.08	5.823529		938
398	1983		334.86	2.020408		677
398	1994		151.00	1.356164		205
398	2002		671.20	1.118644		751
	TOTAL ACCT.	$	4,033.80		$	19,165
	TOTAL SYSTEM	$	16,093,449.16		$	47,361,965

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
301	1927 & PR	$	600.00		$	600
301	1930		8,902.84			8,903
	TOTAL ACCT.	$	9,502.84		$	9,503
302	1930	$	1,402.39		$	1,402
302	1931		10.00			10
302	1934		199.96			200
302	1940		317.99			318
302	1944		115.94			116
	TOTAL ACCT.	$	2,046.28		$	2,046
303	1930	$	15,480.51		$	15,481
	TOTAL ACCT.	$	15,480.51		$	15,481
304	1993	$	69,957.47		$	69,957
	TOTAL ACCT.	$	69,957.47		$	69,957
305	1963	$	8,916.00	7.517857	$	67,029
305	1982		2,156.26	2.137056		4,608
305	1995		120.85	1.461806		177
305	1996		9,894.53	1.422297		14,073
305	1997		30,758.68	1.375817		42,318
305	1998		17,211.07	1.366883		23,526
	TOTAL ACCT.	$	69,057.39		$	151,731
311	1963	$	25,559.00	7.578947	$	193,710
311	1967		28,297.47	6.750000		191,008
311	1974		42,448.06	3.857143		163,728
311	1991		8,624.95	1.661538		14,331
311	1997		249,390.05	1.421053		354,396
311	1998		1,642.59	1.411765		2,319
	TOTAL ACCT.	$	355,962.12		$	919,492
365.2	1942	$	10.14		$	10
365.2	1953		17,106.77			17,107
365.2	1965		1,791.83			1,792
365.2	1966		407.82			408
365.2	1986		1,510.00			1,510

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
365.2	1989		$ 15,300.50		$ 15,301
365.2	1995		79,423.39		79,423
365.2	1996		935.00		935
365.2	2000		229,059.10		229,059
365.2	2001		19,006.28		19,006
	TOTAL ACCT.		$ 364,550.83		$ 364,551
366	1963		$ 675.54	7.517857	$ 5,079
366	1995		6,600.00	1.461806	9,648
	TOTAL ACCT.		$ 7,275.54		$ 14,727
367	1953	S	$ 404,902.47	10.585366	$ 4,286,041
367	1961	S	8,437.36	7.614035	64,242
367	1963	S	478,433.27	7.355932	3,519,323
367	1965	S	45,858.24	6.888889	315,912
367	1966	S	242,406.49	6.781250	1,643,819
367	1968	S	733.90	6.382353	4,684
367	1983	S	11,289.76	1.815900	20,501
367	1986	S	46,371.30	1.764228	81,810
367	1989	S	617,143.79	1.601476	988,341
367	1995	S	1,313,525.88	1.595588	2,095,846
367	1997	S	92,154.61	1.471186	135,577
367	2001	S	3,216,078.59	1.404531	4,517,082
367	2003	S	7,636.59	1.343653	10,261
	TOTAL ACCT.		$ 6,484,972.25		$17,683,439
369	1963		$ 4,406.55	8.754098	$ 38,575
369	1965		1,868.84	8.476190	15,841
369	1968		926.49	7.739130	7,170
369	1978		4,165.00	3.178571	13,239
369	1987		21,252.05	2.053846	43,648
369	1989		14,278.42	1.816327	25,934
369	1992		240.09	1.679245	403
369	1993		909.03	1.638037	1,489
369	1994		562.53	1.570588	884
369	1995		57,905.64	1.530086	88,601
369	1996		1,483.28	1.487465	2,206
369	2001		190,383.89	1.335000	254,162
369	2004		1,285.82	1.271429	1,635
	TOTAL ACCT.		$ 299,667.63		$ 493,787

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
374	1950	$ 814.75		$ 815
374	1953	272.00		272
374	1954	79.54		80
374	1966	660.50		661
374	1968	508.20		508
374	1969	110.14		110
374	1970	28.00		28
374	1972	10.00		10
374	1978	150.00		150
374	1979	7,976.73		7,977
374	1980	7,980.24		7,980
374	1981	637.28		637
374	1982	14,209.64		14,210
374	1985	557.00		557
374	1986	2,273.56		2,274
374	1987	1,650.70		1,651
374	1988	6,491.62		6,492
374	1989	2,403.13		2,403
374	1990	4,492.72		4,493
374	1991	2,478.07		2,478
374	1992	3,053.78		3,054
374	1993	1,705.17		1,705
374	1994	577.80		578
374	1995	5,088.48		5,088
374	1996	88,182.21		88,182
374	1997	25,885.09		25,885
374	1998	7,359.42		7,359
374	1999	119,210.27		119,210
374	2000	941.27		941
374	2001	37,700.00		37,700
374	2002	7,430.99		7,431
374	2003	220.52		221
374	2004	81,733.20		81,733
374	2005	6,673.62		6,674
374	2006	14.00		14
	TOTAL ACCT.	$ 439,559.64		$ 439,561
375	1967	$ 766.92	6.682540	$ 5,125
375	1979	1,376.96	2.536145	3,492
375	1986	349.50	1.871111	654
375	1990	934.97	1.690763	1,581
375	1991	400.87	1.711382	686
375	1992	2,280.39	1.664032	3,795

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
375	1995	$	2,736.12	1.461806	$ 4,000
375	1996		2,750.00	1.422297	3,911
375	1998		5,062.05	1.366883	6,919
375	2000		1,250.55	1.295385	1,620
375	2001		1,705.54	1.264264	2,156
375	2003		644.48	1.156593	745
	TOTAL ACCT.	$	20,258.35		$ 34,684
376	1928-1932	S $	4,316.03	36.117647	$ 155,885
376	1933-1937	S	550.00	40.933333	22,513
376	1938-1942	S	128.47	34.111111	4,382
376	1943-1947	S	1,939.73	32.315789	62,684
376	1948-1949	S	1,079.87	21.172414	22,863
376	1951	S	444.96	17.542857	7,806
376	1952	S	347.44	16.594595	5,766
376	1953	S	68,945.14	15.350000	1,058,308
376	1954	S	16,300.17	14.619048	238,293
376	1955	S	37,817.31	14.279070	539,996
376	1956	S	35,450.34	13.347826	473,185
376	1957	S	28,205.55	12.530612	353,433
376	1958	S	54,294.73	12.039216	653,666
376	1959	S	33,478.53	11.584906	387,846
376	1960	P	45.30	6.409091	290
376	1960	S	36,104.40	11.163636	403,056
376	1961	S	17,801.96	10.771930	191,761
376	1962	S	24,224.89	10.586207	256,450
376	1963	S	47,119.66	10.233333	482,191
376	1964	S	107,249.06	9.903226	1,062,112
376	1965	S	70,024.16	9.593750	671,794
376	1966	S	234,178.61	9.446154	2,212,087
376	1967	S	19,561.64	8.898551	174,070
376	1968	S	97,795.40	8.527778	833,977
376	1969	S	163,690.31	7.871795	1,288,537
376	1970	P	465.77	4.918605	2,291
376	1970	S	92,163.29	7.397590	681,786
376	1971	P	4,976.56	4.597826	22,881
376	1971	S	56,317.98	6.747253	379,992
376	1972	P	24,702.51	4.406250	108,845
376	1972	S	55,153.43	6.395833	352,752
376	1973	P	2,932.82	4.230000	12,406
376	1973	S	46,676.44	6.140000	286,593
376	1974	P	1,883.03	3.776786	7,112
376	1974	S	13,872.88	5.339130	74,069

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
376	1975	P	$ 1,933.08	3.330709	$ 6,439
376	1975	S	23,230.74	4.834646	112,312
376	1976	P	1,027.11	3.133333	3,218
376	1976	S	39,213.34	4.514706	177,037
376	1977	S	18,588.71	4.205479	78,174
376	1978	P	8,461.75	2.729032	23,092
376	1978	S	55,151.66	3.813665	210,330
376	1979	P	946.89	2.502959	2,370
376	1979	S	146,943.30	3.528736	518,524
376	1980	P	1,576.39	2.262032	3,566
376	1980	S	96,392.14	3.283422	316,496
376	1981	P	38,256.14	2.073529	79,325
376	1981	S	85,711.86	2.966184	254,237
376	1982	P	3,272.50	1.922727	6,292
376	1982	S	66,716.24	2.716814	181,256
376	1983	P	2,956.56	1.855263	5,485
376	1983	S	77,483.97	2.623932	203,313
376	1984	P	2,135.34	1.815451	3,877
376	1984	S	31,109.34	2.526749	78,605
376	1985	P	21,611.37	1.800000	38,900
376	1985	S	12,374.78	2.526749	31,268
376	1986	P	116,370.74	1.769874	205,962
376	1986	S	29,199.85	2.623932	76,618
376	1987	P	79,610.75	1.719512	136,892
376	1987	S	40,285.47	2.526749	101,791
376	1988	P	126,128.67	1.633205	205,994
376	1988	S	196,724.27	2.352490	462,792
376	1989	P	532,361.43	1.538182	818,869
376	1989	S	34,776.86	2.240876	77,931
376	1990	P	168,340.65	1.494700	251,619
376	1990	S	47,811.15	2.192857	104,843
376	1991	P	361,115.94	1.463668	528,554
376	1991	S	104,249.47	2.154386	224,594
376	1992	P	326,062.92	1.443686	470,732
376	1992	S	15,507.20	2.109966	32,720
376	1993	P	325,124.38	1.410000	458,425
376	1993	S	150,526.20	2.060403	310,145
376	1994	P	326,403.65	1.377850	449,735
376	1994	S	50,700.63	1.912773	96,979
376	1995	P	144,989.94	1.351438	195,945
376	1995	S	63,254.98	1.860606	117,693
376	1996	P	505,550.31	1.317757	666,192
376	1996	S	1,209,238.74	1.843844	2,229,648
376	1997	P	292,262.95	1.293578	378,065

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
376	1997	S	$ 18,568.84	1.790087	$ 33,240
376	1998	P	560,753.95	1.277946	716,613
376	1998	S	463,277.56	1.774566	822,117
376	1999	P	387,464.41	1.255193	486,343
376	1999	S	367,744.68	1.739377	639,647
376	2000	P	415,038.72	1.229651	510,353
376	2000	S	103,632.65	1.641711	170,135
376	2001	P	322,284.77	1.198300	386,194
376	2001	S	21,129.00	1.607330	33,961
376	2002	P	376,933.40	1.181564	445,371
376	2002	S	31,091.43	1.582474	49,201
376	2003	P	577,941.45	1.146341	662,518
376	2003	S	20,746.73	1.535000	31,846
376	2004	P	548,221.52	1.119048	613,486
376	2004	S	172,981.83	1.376682	238,141
376	2005	P	414,193.27	1.057500	438,009
376	2005	S	49,326.39	1.053173	51,949
376	2006	P	212,869.81	1.000000	212,870
376	2006	S	2,353.31	1.000000	2,353
	TOTAL ACCT.		$12,448,482.45		$30,972,879
378	1930		$ 117.00	23.454545	$ 2,744
378	1949		567.78	14.333333	8,138
378	1950		238.30	13.945946	3,323
378	1952		295.07	12.285714	3,625
378	1953		14,712.50	12.285714	180,754
378	1954		25.69	11.727273	301
378	1955		180.09	11.217391	2,020
378	1958		103.77	9.214286	956
378	1959		77.59	8.896552	690
378	1961		40.91	8.600000	352
378	1962		329.18	8.322581	2,740
378	1964		4,318.23	8.190476	35,368
378	1965		607.86	8.062500	4,901
378	1966		1,797.28	7.818182	14,051
378	1967		250.00	7.701493	1,925
378	1968		479.45	7.478261	3,585
378	1969		1,114.46	7.068493	7,878
378	1970		2,757.14	6.370370	17,564
378	1971		761.58	5.797753	4,415
378	1972		699.36	5.375000	3,759
378	1975		608.61	4.031250	2,453
378	1979		1,696.64	2.948571	5,003

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
378	1980	$	614.15	2.701571	$	1,659
378	1982		680.00	2.233766		1,519
378	1983		3,925.94	2.233766		8,770
378	1986		641.11	2.123457		1,361
378	1988		1,986.25	1.918216		3,810
378	1989		3,467.42	1.849462		6,413
378	1991		3,573.79	1.829787		6,539
378	1992		1,413.10	1.755102		2,480
378	1993		7,766.79	1.702970		13,227
378	1994		2,653.51	1.627760		4,319
378	1995		735.63	1.587692		1,168
378	1996		56,376.62	1.544910		87,097
378	1997		4,366.25	1.495652		6,530
378	1998		22,254.11	1.482759		32,997
378	1999		14,289.50	1.465909		20,947
378	2000		2,897.83	1.413699		4,097
378	2001		118,107.96	1.390836		164,269
378	2002		2,578.56	1.354331		3,492
378	2003		14,059.41	1.357895		19,091
378	2004		8,761.12	1.277228		11,190
378	2005		5,227.44	1.040323		5,438
	TOTAL ACCT.	$	308,154.98		$	712,958
379	1957	$	676.77	10.019231	$	6,781
379	1964		1,583.96	8.540984		13,529
379	1965		664.00	8.403226		5,580
379	1967		3,191.88	7.893939		25,197
379	1973		6,681.63	5.210000		34,811
379	1980		14,329.86	2.713542		38,885
379	1981		8,924.14	2.434579		21,727
379	1989		19,737.03	1.860714		36,725
379	1991		1,763.38	1.840989		3,246
379	1992		332.79	1.778157		592
379	1994		3,473.21	1.643533		5,708
379	1995		14,728.87	1.603077		23,612
379	1996		722.05	1.564565		1,130
379	1999		31,239.03	1.484330		46,369
379	2003		6,089.44	1.378307		8,393
	TOTAL ACCT.	$	114,138.04		$	272,285
380	1927 & PR S	$	1,154.07	35.571429	$	41,052
380	1928-1932 S		302.44	35.571429		10,758

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
380	1933-1937	S	$ 18.81	38.307692	$ 721
380	1938-1942	S	229.00	33.200000	7,603
380	1943-1947	S	60.28	31.125000	1,876
380	1948-1949	S	920.91	19.153846	17,639
380	1950	S	912.17	17.172414	15,664
380	1951	S	386.32	16.064516	6,206
380	1952	S	104.80	15.090909	1,582
380	1953	S	10,247.00	14.228571	145,800
380	1954	S	2,967.42	13.459459	39,940
380	1955	S	4,871.55	12.769231	62,206
380	1956	S	6,898.84	11.857143	81,801
380	1957	S	9,304.43	11.066667	102,969
380	1958	S	13,872.87	10.826087	150,189
380	1959	S	8,148.29	10.163265	82,813
380	1960	S	7,912.57	9.764706	77,264
380	1961	S	7,671.38	9.576923	73,468
380	1962	S	8,344.18	9.222222	76,952
380	1963	S	13,289.99	9.054545	120,335
380	1964	S	12,735.21	8.736842	111,266
380	1965	S	19,680.34	8.440678	166,115
380	1966	S	11,978.01	8.163934	97,788
380	1967	S	8,246.66	7.781250	64,169
380	1968	S	11,212.37	7.432836	83,340
380	1969	S	56,116.10	6.821918	382,819
380	1970	S	36,889.10	6.148148	226,800
380	1971	P	176.09	4.865169	857
380	1971	S	41,125.44	5.533333	227,561
380	1972	P	64.26	4.557895	293
380	1972	S	42,648.18	5.242105	223,566
380	1973	P	104.23	4.330000	451
380	1973	S	32,758.37	4.980000	163,137
380	1974	P	638.53	3.972477	2,537
380	1974	S	11,665.44	4.486486	52,337
380	1975	P	1,191.76	3.578512	4,265
380	1975	S	7,872.27	4.048780	31,873
380	1976	P	802.52	3.409449	2,736
380	1976	S	13,625.37	3.801527	51,797
380	1977	P	331.09	3.207407	1,062
380	1977	S	22,487.93	3.557143	79,993
380	1978	P	1,576.87	3.006944	4,742
380	1978	S	45,080.98	3.276316	147,700
380	1979	P	12,996.27	2.775641	36,073
380	1979	S	87,746.85	3.036585	266,451
380	1980	P	1,648.40	2.547059	4,199

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
380	1980	S	$ 65,260.23	2.797753	$ 182,582
380	1981	P	4,560.34	2.340541	10,674
380	1981	S	59,298.33	2.540816	150,666
380	1982	P	2,553.93	2.101942	5,368
380	1982	S	42,315.70	2.305556	97,561
380	1983	P	3,758.64	2.013953	7,570
380	1983	S	32,290.44	2.203540	71,153
380	1984	P	4,893.98	1.959276	9,589
380	1984	S	33,694.37	2.128205	71,709
380	1985	P	7,263.68	1.915929	13,917
380	1985	S	29,865.37	2.110169	63,021
380	1986	P	13,473.97	1.874459	25,256
380	1986	S	41,926.24	2.110169	88,471
380	1987	P	18,157.78	1.819328	33,035
380	1987	S	41,862.96	2.049383	85,793
380	1988	P	18,150.94	1.760163	31,949
380	1988	S	41,968.02	1.960630	82,284
380	1989	P	68,984.05	1.704724	117,599
380	1989	S	40,716.90	1.908046	77,690
380	1990	P	42,561.76	1.652672	70,341
380	1990	S	52,521.78	1.858209	97,596
380	1991	P	68,019.38	1.615672	109,897
380	1991	S	43,427.90	1.817518	78,931
380	1992	P	59,694.83	1.568841	93,652
380	1992	S	35,003.66	1.759717	61,597
380	1993	P	121,566.10	1.530035	186,000
380	1993	S	37,122.36	1.711340	63,529
380	1994	P	109,257.25	1.472789	160,913
380	1994	S	33,001.97	1.627451	53,709
380	1995	P	61,249.59	1.438538	88,110
380	1995	S	70,573.78	1.585987	111,929
380	1996	P	148,117.43	1.401294	207,556
380	1996	S	85,334.08	1.556250	132,801
380	1997	P	126,592.93	1.365931	172,917
380	1997	S	65,434.45	1.518293	99,349
380	1998	P	174,188.82	1.348910	234,965
380	1998	S	36,783.09	1.500000	55,175
380	1999	P	114,580.76	1.316109	150,801
380	1999	S	35,045.02	1.464706	51,331
380	2000	P	124,613.87	1.277286	159,168
380	2000	S	18,762.33	1.406780	26,394
380	2001	P	108,968.72	1.233618	134,426
380	2001	S	27,347.78	1.368132	37,415
380	2002	P	92,946.04	1.196133	111,176

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
380	2002	S	$ 22,788.97	1.335121	$ 30,426
380	2003	P	312,616.16	1.145503	358,103
380	2003	S	27,783.43	1.280206	35,569
380	2004	P	184,698.82	1.101781	203,498
380	2004	S	41,685.40	1.200000	50,022
380	2005	P	163,625.07	1.053528	172,384
380	2005	S	21,817.61	1.048421	22,874
380	2006	P	61,062.47	1.000000	61,062
380	2006	S	7,996.00	1.000000	7,996
	TOTAL ACCT.		$ 3,886,801.44		$ 8,468,264
385	1954		$ 3,849.04	11.727273	$ 45,139
385	1956		4,810.10	10.320000	49,640
385	1958		259.87	9.214286	2,395
385	1965		714.00	8.062500	5,757
385	1967		15,306.32	7.701493	117,882
385	1968		500.71	7.478261	3,744
385	1969		1,043.45	7.068493	7,376
385	1975		1,608.61	4.031250	6,485
385	1976		910.48	3.685714	3,356
385	1977		403.14	3.463087	1,396
385	1981		173.41	2.422535	420
385	1983		3,720.76	2.233766	8,311
	TOTAL ACCT.		$ 33,299.89		$ 251,901
389	1927 & PR		$ 2,750.00	1.354331	$ 2,750
389	1929		97.00		97
389	1959		1,000.00		1,000
389	1967		17,136.51		17,137
389	1972		1,500.00		1,500
389	1993		50,781.80		50,782
389	2001		64,054.66		64,055
389	2003		46,987.67		46,988
	TOTAL ACCT.		$ 184,307.64		$ 184,309
390	1927 & PR		$ 89.56	26.312500	$ 2,357
390	1929		10,896.94	24.764706	269,860
390	1930		689.54	26.312500	18,144
390	1932		175.66	30.071429	5,282
390	1937		424.39	24.764706	10,510
390	1938		5,572.50	24.764706	138,001

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
390	1939	$ 73.48	24.764706	$ 1,820
390	1940	744.07	23.388889	17,403
390	1941	1,098.03	22.157895	24,330
390	1942	2,183.71	21.050000	45,967
390	1946	45.00	16.840000	758
390	1960	75.00	7.654545	574
390	1969	7,729.16	5.767123	44,575
390	1970	92.61	5.329114	494
390	1971	229.47	4.784091	1,098
390	1972	10,373.51	4.526882	46,960
390	1975	783.47	3.289063	2,577
390	1978	29,495.82	2.825503	83,341
390	1982	429.85	2.137056	919
390	1986	398.00	1.871111	745
390	1990	371.01	1.690763	627
390	1993	7,537.36	1.594697	12,020
390	1994	651,425.67	1.508961	982,976
390	1995	891.04	1.461806	1,303
390	1996	2,147.40	1.422297	3,054
390	1997	5,259.20	1.375817	7,236
390	1999	5,333.85	1.345048	7,174
390	2000	154.98	1.295385	201
390	2001	38,756.82	1.264264	48,999
	TOTAL ACCT.	$ 783,477.10		$ 1,779,305
391	1949	$ 373.76	8.250000	$ 3,084
391	1955	161.70	7.333333	1,186
391	1959	60.00	6.827586	410
391	1960	439.79	6.827586	3,003
391	1966	188.55	6.187500	1,167
391	1970	95.83	5.210526	499
391	1976	79.85	3.535714	282
391	1983	5,550.96	2.020408	11,215
391	1985	269.91	1.867925	504
391	1987	303.00	1.783784	540
391	1993	793.80	1.384615	1,099
391	1994	15,354.54	1.356164	20,823
391	1995	535.27	1.320000	707
391	1996	3,597.13	1.285714	4,625
391	1997	12,508.40	1.245283	15,576
391	1998	1,856.71	1.222222	2,269
391	1999	4,346.11	1.207317	5,247
391	2000	4,391.50	1.171598	5,145

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
391	2001	$	649.54	1.131429	$	735
391	2002		6,300.32	1.118644		7,048
391	2003		9,051.81	1.087912		9,848
391	2004		986.62	1.070270		1,056
391	2005		698.40	1.036649		724
391	2006		7,547.29	1.000000		7,547
	TOTAL ACCT.	$	76,140.79		$	104,339
392	1986	$	26,308.05	1.800000	$	47,354
392	1989		22,258.13	1.636364		36,422
392	1990		7,993.95	1.559055		12,463
392	1991		14,317.17	1.466667		20,999
392	1993		29,122.20	1.384615		40,323
392	1994		60,990.09	1.356164		82,713
392	1995		38,922.98	1.320000		51,378
392	1997		24,030.90	1.245283		29,925
392	1998		61,652.66	1.222222		75,353
392	1999		52,445.39	1.207317		63,318
392	2000		16,513.72	1.171598		19,347
392	2001		64,640.46	1.131429		73,136
392	2002		58,341.73	1.118644		65,264
392	2003		84,595.95	1.087912		92,033
392	2004		16,494.26	1.070270		17,653
	TOTAL ACCT.	$	578,627.64		$	727,681
394	1953	$	650.15	7.333333	$	4,768
394	1956		188.60	7.333333		1,383
394	1961		273.85	6.600000		1,807
394	1963		622.55	6.600000		4,109
394	1964		144.27	6.387097		921
394	1965		284.00	6.387097		1,814
394	1966		649.88	6.187500		4,021
394	1967		2,034.46	6.000000		12,207
394	1968		710.57	5.823529		4,138
394	1969		1,203.52	5.500000		6,619
394	1970		775.95	5.210526		4,043
394	1971		787.03	4.950000		3,896
394	1972		1,176.89	4.829268		5,684
394	1973		186.66	4.604651		860
394	1974		551.43	4.212766		2,323
394	1976		125.32	3.535714		443
394	1977		1,438.61	3.355932		4,828

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
394	1978	$ 799.53	3.142857	$ 2,513
394	1979	5,674.30	2.911765	16,522
394	1980	8,525.55	2.538462	21,642
394	1981	1,529.65	2.275862	3,481
394	1982	356.33	2.106383	751
394	1983	769.80	2.020408	1,555
394	1984	1,341.38	1.941176	2,604
394	1985	4,761.00	1.867925	8,893
394	1986	6,461.84	1.800000	11,631
394	1987	41,516.02	1.783784	74,056
394	1988	26,672.34	1.706897	45,527
394	1989	2,792.65	1.636364	4,570
394	1990	80,206.41	1.559055	125,046
394	1991	36,775.71	1.466667	53,938
394	1992	31,596.20	1.434783	45,334
394	1993	25,996.00	1.384615	35,994
394	1994	18,542.80	1.356164	25,147
394	1995	4,605.07	1.320000	6,079
394	1996	29,772.31	1.285714	38,279
394	1997	17,217.02	1.245283	21,440
394	1998	39,406.35	1.222222	48,163
394	1999	5,368.82	1.207317	6,482
394	2000	25,167.73	1.171598	29,486
394	2001	9,720.61	1.131429	10,998
394	2002	68,550.87	1.118644	76,684
394	2003	45,716.50	1.087912	49,736
394	2004	3,072.72	1.070270	3,289
394	2005	304.11	1.036649	315
394	2006	81,548.83	1.000000	81,549
	TOTAL ACCT.	$ 636,572.19		$ 915,568
395	1949	$ 435.34	8.250000	$ 3,592
395	1953	97.00	7.333333	711
395	1956	196.31	7.333333	1,440
395	1962	130.50	6.600000	861
395	1963	163.52	6.600000	1,079
395	1965	362.06	6.387097	2,313
395	1995	819.33	1.320000	1,082
395	2000	884.79	1.171598	1,037
	TOTAL ACCT.	$ 3,088.85		$ 12,115
397	1984	$ 3,153.60	1.941176	$ 6,122

OHIO VALLEY GAS CORPORATION
CURRENT COST OF OVGC TEXAS GAS SYSTEM PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
397	1993	$ 125,403.44	1.384615	$ 173,635
397	1994	5,659.99	1.356164	7,676
397	1999	382.03	1.207317	461
397	2000	2,146.51	1.171598	2,515
	TOTAL ACCT.	$ 136,745.57		$ 190,409
398	1967	$ 2,376.69	6.000000	$ 14,260
398	1984	398.49	1.941176	774
398	2001	264.24	1.131429	299
398	2006	371.34	1.000000	371
	TOTAL ACCT.	$ 3,410.76		$ 15,704
	TOTAL SYSTEM	$27,331,538.19		$64,806,676

IURC GAS TARIFF

ORIGINAL VOLUME NO. 8

(Supersedes IURC Gas Tariff Original Volume 7)

of

OHIO VALLEY GAS CORPORATION

Filed with

Indiana Utility Regulatory Commission

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OHIO VALLEY GAS CORPORATION
GENERAL RULES AND REGULATIONS APPLICABLE TO GAS SERVICE

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OHIO VALLEY GAS CORPORATION

GENERAL RULES AND REGULATIONS APPLICABLE TO GAS SERVICE

1. **RULES AND REGULATIONS ON FILE:**

A copy of all rates, as well as all rules and regulations under which gas service will be supplied, are posted or on file for the public's benefit in the offices of the Company and with the Indiana Utility Regulatory Commission ("IURC").

2. **WRITTEN APPLICATION OR CONTRACT REQUIRED:**

All applications for service will be made on the Company's standard application or contract form, which shall be signed by the Customer and accepted by the Company before service is supplied. A separate application or contract shall be made for service at each location/account. The Company may require up to two working days notice for all connections of existing natural gas service.

In any case where unusual construction or equipment expense is necessary to furnish the service, the Company may require a contract with reasonable guarantees as specified by the Company.

The Customer is also responsible for payment of all natural gas usage at a service location for up to three working days following notice to the Company to disconnect the natural gas service.

3. **DESCRIPTION OF DESIRED SERVICE:**

Upon request, the Customer shall furnish to the Company a list of the gas consuming equipment that is to be connected to the Company's gas supply on the premises. The Customer shall also advise the Company of their preference, if any, as to the pressure at which natural gas is to be delivered to Customer, and their preference, if any, regarding status as an "Off-System" customer, if applicable.

4. **COMPANY-OWNED PIPING AND EQUIPMENT:**

The Company shall furnish/install/maintain without charge to the Customer, as necessary and appropriate:

a. **Service Lines** consisting of gas piping extending from the Company's gas mains to the Customer's property line.

b. **Pressure Regulating Equipment,** as required by the Company to meet metering and delivery pressure requirements.

c. **Metering Equipment**, as required by the Company to determine the amount of natural gas consumed for billing purposes.

d. **Other Equipment**, if any, as required by the Company.

5. **LOCATION OF COMPANY REGULATORS, METERS AND APPURTENANCES:**

The Customer shall provide free of expense to the Company and at a location satisfactory to the Company a suitable place for necessary regulators, meter, or other equipment which may be furnished by the Company. Whenever possible, the meter setting shall be appropriately located outside and in a location which it is both readily accessible and reasonably protected from damage.

6. **EQUIPMENT LOCATION PERMIT OR EASEMENT:**

If the Customer is not the owner of the premises being served, or of any property between the premises to be served and the Company's main, the Customer shall obtain from the owner(s) of such properties certain permits or easements. These permits or easements shall be in a form satisfactory to the Company, and shall allow for the installation and maintenance of all piping and other gas equipment needed to supply gas to the Customer.

7. **ACCESS TO PREMISES:**

Employees and authorized agents of the Company shall have the right, at all reasonable times, to enter on the premises of the Customer. Such right of entry shall be used for inspecting, reading, testing, repairing, or replacing any Company-owned meters, regulators, or other equipment used to supply natural gas service, or for the removal of the aforesaid equipment upon termination of the contract or discontinuance of service.

The Customer shall take all necessary steps to appropriately restrain animals in order to prevent injury to Company employees or agents entering the Customer's property for the above reason(s). Any such injuries other damages (and all costs associated therewith) which are incurred by the Company, its employees or agents while legally engaged in the above shall be the responsibility of the Customer. The Company, its shareholders, directors, officers, employees and agents specifically reserve the right to seek full and complete restitution, from any court of competent jurisdiction, for any claims, cause of action, losses or damages resulting from animal bites. This reservation of rights to seek restitution shall include but not be limited to seeking an equitable claim of subrogation.

8. **PROTECTION OF THE COMPANY'S PROPERTY:**

The Customer shall protect the Company's property on the Customer's premises from loss or damage and shall not permit anyone who is not an employee or agent of the Company to remove or tamper with the Company's property. If the Company's equipment is damaged or destroyed through the neglect of the Customer, the cost of repairs or replacement shall be paid by the Customer.

9. **CUSTOMER FURNISHED PIPING AND EQUIPMENT:**

The Customer shall furnish, install and maintain, at their expense, and in full compliance with Company prescribed standards, applicable Federal and state laws, rules and regulations, and local ordinances and codes the following:

a. **Yard Line** consisting of gas piping from the Customer's property line to the Company's meter setting. The Yard Line shall not be run under or through any portion of any building.

b. **Fuel Lines** consisting of all gas piping downstream of the Company's meter setting.

c. **Pressure Regulating Equipment,** as necessary to regulate the pressure of the gas after delivery to Customer.

d. **Metering Equipment,** as may be desired by the Customer to confirm the measurement of natural gas consumption. Such equipment shall be installed so as not to interfere with the operation of the Company's metering equipment.

The Company shall be under no obligation to inspect the piping and equipment of the Customer. Inspecting, reading, calibrating and adjusting any Customer-owned equipment shall be the responsibility of the Customer. Any future changes, repairs, replacements or relocations of the Customer's yard or fuel line(s), for whatever reason(s), shall be completed at the Customer's expense.

10. **POINT OF DELIVERY:**

The point of delivery of gas supplied by the Company shall be at the outlet of the meter. The Company will make the necessary connection at the point of delivery. Neither the Customer, nor anyone other than the Company, may lawfully alter or interfere with this connection, or with any of the equipment owned and maintained by the Company in any way.

11. **METERING:**

All natural gas used by the Customer will be measured by the meter(s) to be furnished and installed by the Company. Monthly bills shall be calculated upon the registration of said meter(s). Meters shall conform to the Rules, Regulations and Standards of Service for Gas Public Utilities in Indiana established by the IURC. If more than one meter is installed on the same premises, gas service to each meter shall be billed separately; however, if multiple meters are installed to serve the same rate classification strictly for the convenience of the Company, then only one monthly service charge for that rate class will be applied.

Customers receiving service under all Rate Schedules other than 11 and 41 shall, at the request of the Company, provide; 1) electricity (nominal 115 volts with the line fused at 15 amperes), and 2) access to a direct telephone line that is capable of allowing the Company to contact the metering location to obtain billing and flow information for the purposes of tracking daily and monthly usage at the Company's metering location.

12. **MEASUREMENTS:**

a. **Sales Unit** - The sales unit of the natural gas delivered by the Company to Customer shall be the Therm (Th). By definition, a therm is the amount of thermal energy equal to 100,000 British Thermal Units (BTUs). For example, where the heating value of the gas is 1000 BTU per standard cubic foot (SCF):

1 Therm (Th) = 100,000 BTU / 1,000 BTU/SCF = 100 SCF

b. **A Standard Cubic Foot (SCF)** of natural gas is that volume which occupies one (1) cubic foot of space when measured at sixty (60) degrees Fahrenheit and a pressure of 14.73 psia.

c. **Assumed Atmospheric Pressure** - The average absolute atmospheric pressure shall be assumed to be fourteen and four tenths (14.4) pounds per square inch. This standard shall be irrespective of the

actual elevation of the point of delivery above sea level or variations in such atmospheric pressu from time to time.

d. **Flowing Temperature of Delivered Natural Gas** - At points of delivery where the installation of a recording thermometer or other temperature correcting device is provided, the indicated temperature of the gas flowing through the meter(s) shall be used in computing gas volumes. When such a device is not provided, the temperature of the gas shall be assumed to be sixty (60) degrees Fahrenheit.

13. **FAILURE OF METER:**

Whenever it is discovered that a meter is not recording correctly, adjustments shall be made correcting such inaccuracy in accordance with the Rules, Regulations and Standards of Service for Gas Public Utilities in Indiana. The volume of gas delivered by the Company to the Customer may be estimated, if necessary:

a. by using the registration of any Customer-owned meter or meters if installed and accurately registering, or,

b. by correcting the error if the percentage of error is ascertainable by calibration, test, or mathematical calculation, or,

c. by estimating the quantity of natural gas delivered based on deliveries made during periods under similar conditions when the meter was registering accurately.

14. **ADJUSTMENT OF BILLS DUE TO METER ERROR:**

If, upon test at thirty five (35) percent and eighty (80) percent of rated capacity, any measuring equipment is found to be, on average, not more than two (2) percent fast or slow, previous recordings of such equipment shall be considered commercially accurate in computing deliveries of natural gas; but such equipment shall be adjusted at once to record accurately.

If, upon test at thirty five (35) percent and eight (80) percent of rated capacity any measuring equipment shall be found to be, on average, more than two (2) percent fast or slow, previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon between the Company and the Customer. Such correction shall be for a period extending over one-half of the time elapsed since the date of last test, or one (1) year, whichever period is shorter, and the Customer's account shall be either credited or debited, as appropriate.

15. **WARRANTY OF TITLE TO GAS:**

The Company warrants title to and the lawful right to sell its system supply natural gas to Customer. Specifically, Company asserts that such natural gas shall be free from any and all claims, liens or other encumbrances. However, no such warranty shall attach to any natural gas received by Company for transportation to any "Off-System End User".

Off System End User shall be defined as a Customer for whom Company has no contractual obligation to provide natural gas from its system supply, and for whose natural gas requirements Company is no contractually committed to pay interstate pipeline charges of any kind.

16. **RESALE OF GAS:**

The Customer shall not pipe natural gas delivered by the Company off the premises being served, nor sell same to any other Customer or person.

17. **RESPONSIBILITY AFTER GAS IS DELIVERED BY COMPANY:**

Customer assumes liability and accepts responsibility for natural gas service on or about Customer's premises. Specifically, Customer premises shall include, but shall not be limited to, all pipe and equipment that is used and useful in connection with Customer's natural gas service and which is located downstream of the "Point of Delivery".

Customer shall hold Company harmless for all demands, claims, suits, judgments and executions, and for any personal injury or death, or damages to property (real, personal or mixed), due to Customer's use of natural gas on or about Customer's premises. Customer's duty to hold Company harmless shall not attach to injury or death, or for damages to property (real, personal or mixed) that may occur due to the sole negligence of the Company, its employees or agents.

18. **CONTINUITY OF SERVICE:**

Company shall employ natural gas industry best practices in its efforts to assure a continuous and adequate supply of natural gas for its Customers. Company does not, however, warrant or guarantee either a sufficient supply of natural gas or an adequate pressure for the natural gas delivered to Customer, and shall not be liable for damages due to interruptions in the supply of natural gas when such failure(s) are not due to the negligence of the Company.

19. **DEPOSIT TO ENSURE PAYMENT OF BILLS:**

a. **Residential Customers.** As set forth in the Rules, Regulations and Standards of Service for Gas Public Utilities in Indiana, the Company may require a cash deposit from an applicant for service or an existing Customer whenever standards of credit worthiness are not satisfied.

b. **Non-Residential Customers.** The Company shall require a cash deposit from an applicant for service or from an existing Customer as described in the Non-Residential Customer Security Requirements (See Rule No. 22 below).

c. **Interest.** Cash deposits of both residential and non-residential Customers which are held more than twelve (12) months shall earn interest from the date of deposit at an annual rate as prescribed, from time to time, by the IURC.

20. **MONTHLY BILLS:**

a. Bills for natural gas service will be rendered monthly unless otherwise specified. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled readings of the meter(s) by the Company. Meter readings are to be taken as nearly as practicable every thirty (30) days.

b. When the Company is unable to read a meter after reasonable effort, the Customer will be billed based on an estimated consumption.

c. Failure to receive a bill in no way exempts the Customer from the provisions of these General Rules and Regulations Applicable to Gas Service, or the obligation to pay for the service(s) provided by Company.

d. The monthly billing for natural gas service will be considered paid when payment has been received by the Company at its designated address. The Company will not consider the payments as being made based on a postmark on the mailing envelope. Payments received after the due date printed on the monthly natural gas billings will be subject to the addition of a Late Payment Charge (Rule No. 24 below).

e. The Company may, at its sole discretion, require any Customer with monthly billings aggregating $25,000.00 or more to make payment to the Company in the form of a wire transfer directed to a bank account designated by the Company. Wire transferred funds shall be available to the Company on or before the due date printed on the monthly natural gas billings. The Customer may also be required to make a facsimile transmission to the Company, at a designated telephone (fax) number, setting forth the pertinent details of the wire transfer.

21. **DISCONNECTION OF RESIDENTIAL SERVICE:**

a. The Company may disconnect a residential service without request by the Customer and without prior notice only:

(1) if a condition dangerous or hazardous to life or property exists; or,

(2) upon receipt of an order by any Court, the Commission or other duly authorized public authority; or,

(3) if fraudulent or unauthorized use of gas is detected and the Company has reasonable grounds to believe the affected Customer is responsible for such use; or,

(4) if the Company's regulating or metering equipment has been tampered with and the Company has reasonable grounds to believe that the affected Customer is responsible for such tampering.

b. In all other instances the Company, upon providing a residential Customer with fourteen (14) days prior written notice, may disconnect service subject to the following:

(1) The Company shall postpone the disconnection of service for ten (10) days if, prior to the disconnect date specified in the disconnect notice, the Customer provides the Company with a medical statement from a licensed physician or public health official which must affirm that disconnection would be a serious and immediate threat to the health or safety of a designated person in the household of the Customer. The postponement of disconnection shall be continued for one additional ten (10) day period upon the providing of an additional, and similar, medical statement from a licensed physician.

(2) The Company will not disconnect a residential service if the Customer shows cause, including financial hardship, for his inability to pay the full amount due and said Customer satisfies all of the following:

(a) Pays a reasonable portion (not to exceed the lesser of $10 or one-tenth (1/10) of the billed amount), unless the Customer agrees to pay a greater portion of the billed amount.

(b) Agrees to pay the remainder of the outstanding bill within three (3) months.

(c) Agrees to pay all undisputed future bills for service as they become due.

(d) Has not breached any similar agreement with the Company made pursuant to this rule within the past twelve (12) months.

Provided however, that the Company may add to the outstanding bill a Late Payment Charge not to exceed the amount set forth in Rule No. 24., and provided further, that the above terms of agreement shall be in writing and signed by the Customer and by a representative of the Company.

(3) The Company will not disconnect a residential service if a Customer is unable to pay a bill which is unusually large due to prior incorrect reading of the meter, incorrect application of the rate schedule, incorrect connection or functioning of the meter, prior estimates where no actual reading was taken for over two months, stopped or slow meters, or any human or mechanical error attributable to the Company, provided that the Customer satisfies all of the following:

(a) Pays a portion of the bill not to exceed an amount equal to the Customer's average bill for the twelve (12) bills immediately preceding the bill in question,

(b) Agrees to pay the remainder of the outstanding bill on a reasonable payment schedule.

(c) Agrees to pay all undisputed future bills for service as they become due.

Provided however, that the Company may not add to the unpaid balance of such a bill any Late Payment Charge or any other fee for the privilege of paying such a bill over the agreed period of time, and provided further, that the above terms of agreement shall be in writing and signed by the Customer and a representative of the Company.

c. Normally, the Company will disconnect service only between the hours of 8:00 a.m. and 3:00 p.m., prevailing local time. However, disconnections pursuant to Rule No. 21.a. are not subject to this limitation.

d. The Company will not disconnect service for non-payment on any day on which the Company office is closed to the public, or after twelve (12:00) noon of the day immediately preceding any day on which the Company office is not open to the public. However, disconnections pursuant to Rule No. 21.a. are not subject to this limitation.

22. **NON-RESIDENTIAL CUSTOMER SECURITY REQUIREMENTS:**

The Company may require a cash deposit from an applicant for service or from an existing Customer as set forth below:

a. **Cash Deposit Requirement.** The amount of the cash deposit shall be calculated based on the highest estimated monthly consumption multiplied by twice the rate in effect on the date of the application for service, or upon an existing Customer's receipt of a notice requiring a deposit.

The deposit calculation for a new Customer shall be based on reasonable estimated usage/consumption which shall include, but not be limited to, historical consumption on the property, any increased or decreased heating, processing load, etc., or an applicant's declaration of its projected usage and load.

The deposit calculation for an existing Customer shall be based on the highest monthly consumption during the previous five (5) years or, if a Customer less than five (5) years, the highest monthly consumption recorded since becoming a Customer, taking into consideration, without limitation, changes in the physical size of premises served, changes in usage or process application, removal or installation of different heating and processing equipment, etc.

b. **Exception To The Cash Deposit Requirement.** The Company shall have the discretion to waive the cash deposit requirement for both new applicants and existing Customers upon receipt of adequate assurance that the non-residential Customer is creditworthy. Adequate assurance of creditworthiness shall be demonstrated by the Customer by presenting all of the following to the Company, as requested/required:

(1) Their Dun & Bradstreet D-U-N-S No. and payment index which reflects a prompt payment history.

(2) A copy of their most recent audited financial report that includes a balance sheet showing assets exceeding liabilities, an income statement, and a cash flow statement; OR a verified or sworn financial report of the business entity that includes a balance sheet showing assets exceeding liabilities, an income statement, and a cash flow statement. Additionally, all owners of a business entity (Customer) may, upon a facts and circumstances determination made by Company, be required to provide a personal guaranty and personal financial statements to further ensure the payment of all natural gas bills rendered to the Customer by Company.

(3) Credit reference(s) from other public utilities stating that the entity has or had a prompt payment history on their utility bills and that no delinquency on such bills currently exists.

c. **Deferred Payment.**

(1) **New Customer.** Non-residential customers shall have their cash deposit, if not waived, paid prior to the establishment of natural gas service. The Company will, on request, consider allowing payment of the cash deposit on an installment basis contingent on the planned usage pattern of the new Customer and other factors which may affect the Customer's ability

to pay. Provided that the Customer makes the initial installment payment in a prompt and timely manner, the Company shall initiate natural gas service. Should the Customer fail thereafter to tender payments on their installment payment plan, the Company shall be entitled to terminate natural gas service until the Customer has tendered the total amount of the deposit and paid, in full, all consumption billed to the Customer prior to termination of the service. A reconnect charge (See Rule No. 25 below) shall also apply to any Customer whose service is interrupted due to non-payment of a deposit installment.

(2) **Existing Customer.** The Company will, on request, consider allowing the payment of an existing Customer's cash deposit on an installment basis conditioned on all of the following:

(a) Terms mutually agreeable to both the Company and the Customer.

(b) The planned usage pattern of the Customer.

(c) Other factors which may affect the Customer's ability to pay.

Should the Customer fail to tender the initial installment or any installments thereafter, in a prompt and timely manner, the Company shall be entitled to terminate natural gas service until the Customer has tendered the total amount of the deposit and paid, in full, all consumption billed to the Customer prior to termination of the service. A reconnect charge (See Rule No. 25 below) shall also apply to any Customer whose service is interrupted due to non-payment of a deposit installment.

(3) **Applicability To Existing Non-Residential Customers.** The Company may require an existing non-residential customer to make an initial or additional cash deposit, if they are delinquent twice in a twelve (12) consecutive month period subsequent to the effective date of these General Rules And Regulations Applicable To Gas Service.

d. **Refunds.** The Company will not refund any cash deposit from a non-residential Customer until service is disconnected at the premises for which the deposit was collected. At the request of the Customer, but not more frequently than once during any given twelve month period, accrued interest will be transferred to the Customer's account.

e. **Public Authority Customers.** All Customers properly classified as public authority users shall be exempt from the requirement to provide a cash deposit until and unless an unexplained pattern of late (delinquent) payments develops.

23. **DISCONNECTION/NON-CONNECTION OF NON-RESIDENTIAL SERVICE FOR FAILURE TO SUPPLY CASH DEPOSIT:**

a. A new non-residential Customer shall not be entitled to natural gas service from the Company until an application for natural gas service is submitted, and accepted by the Company, and the required cash deposit is tendered to, or a waiver is granted by, the Company as described in Rule No. 22.

b. An existing non-residential Customer who fails within ten (10) calendar days of receiving written notice from the Company, to tender the required cash deposit as described in Rule No. 22., may have their natural gas service disconnected unless and until said Customer provides such deposit or obtains a

waiver from the Company. A reconnection charge (See Rule No. 25 below) shall also apply to a Customer whose service is disconnected due to non-payment of the required deposit.

24. **LATE PAYMENT CHARGE:**

A Late Payment Charge, as shown on the applicable rate sheet will be applied to all accounts, including those enrolled in the Company's Budget (Level) Payment Plan, not paid on or before the due date as printed on the monthly natural gas billing

25. **RECONNECTION CHARGE:**

To cover the cost of disconnecting and reconnecting service for the same Customer at the same service address, a Reconnection Charge will be made in the amount shown on the applicable rate sheet. The Reconnection Charge shall be paid in full prior to the reconnection of natural gas service. If the disconnection period exceeds one year, the Company may waive the Reconnection Charge, provided the disconnection was not for a violation of any of the Company's Rules and Regulations.

26. **COLLECTION CHARGE:**

A collection charge, in the amount shown on the applicable rate sheet, may be made when it becomes necessary to send an employee or other authorized agent to a Customer's premises to collect a past due account. If the employee or other authorized agent is unable to make physical contact with the Customer, the hanging of a door card requesting the Customer to contact the Company shall constitute a basis for charging the Customer a Collection Charge. Customers enrolled in the Company's Budget (Level) Payment Plan will not be exempted from a Collection Charge for a collection trip to the Customer's premises for the purpose of collecting a past due Monthly Payment Amount.

27. **RETURNED CHECK CHARGE:**

A returned check charge, in the amount shown on the applicable rate sheet, will be levied on all checks received and on all authorized direct debits processed through the Automated Clearing House ("ACH") as payment of gas bills which are not honored, for whatever reason, by the Customer's bank. Additionally, any charges assessed by the Company's bank or the ACH processing system due to non-sufficient funds or a closed account will be added to the Customer's account with the Company and will be in addition to the Company's Returned Check Charge.

28. **THEFT OR UNAUTHORIZED USE OF GAS (A Class C infraction per IC 35-43-3-6):**

When theft or unauthorized use of gas (actual or attempted) is discovered, the Customer shall be charged a minimum fee of One Hundred Dollars ($100.00). Further, the Customer shall be charged for the estimated volume of natural gas, as determined by the Company to have been so used. The Customer shall also pay any costs incurred by the Company to repair damaged or altered Company equipment, and/or to pursue legal remedy due to Customer's theft or unauthorized use.

29. **BUDGET (LEVEL) PAYMENT PLAN:**

The Company shall offer a Budget (Level) Payment Plan ("Plan") under which an eligible Customer may have their monthly billing amounts pre-determined (based on projected/estimated consumption), and equalized, for the duration of any given Plan year, as follows:

a. **Eligible Customer:** Residential, small commercial (including small farming operations, except for grain drying), public authority (including school corporations) and not-for-profit (including churches) system sales customers whose account(s) with the Company are, at the time of application, paid in full, shall be eligible to participate in the Plan. Eligible customers are generally limited to those served via a meter size of 800 scfh or less.

b. **Plan Year:** The Plan Year shall be defined as the twelve consecutive months beginning July 1 of one year and continuing through June 30 of the following year.

c. **Enrollment:** Any eligible Customer may enroll in the Plan at any time by contacting the local office of the Company, completing the prescribed Enrollment Form. The Customer will be enrolled in the Plan for the next billing cycle following receipt and acceptance, by the Company, of the completed Enrollment Form.

d. **Monthly Payment Amount.** The Monthly Payment Amount under the Plan shall be determined, by the Company, as follows:

(1) **For existing accounts with a minimum twelve-month usage history**, by weather normalizing the most recent twelve months' usage for the account and pricing said normalized usage at the estimated rates for the ensuing Plan Year, or remaining portion of the current Plan Year, as appropriate.

(2) **For new accounts or existing accounts with less than twelve months of usage history**, by establishing a weather normalized annual usage level (utilizing connected load and other information as may be available), and pricing said normalized usage at the estimated rates for the ensuing Plan Year, or remaining portion of the current Plan Year, as appropriate.

e. **Semi-Annual Review of Monthly Payment Amount:** Upon completion of the Company's billing cycles for June and December of each calendar year, the Monthly Payment Amount for each customer enrolled in the Plan shall be reviewed, and adjusted as necessary, based on account balance, usage history and updated pricing estimates for the new Plan Year or remaining portion of the current Plan Year, as applicable. Revised Monthly Payment Amounts will be appropriately communicated, in writing, to the applicable customers, and will become effective with the July, or January, billing cycle, as appropriate. If the semi-annual review determines that no change in the Monthly Payment Amount is required, the existing Monthly Payment Amount shall continue to be utilized until the next such semi-annual review and determination is completed.

f. **Annual "True-Up" of Plan Balance:** Coincident with the semi-annual review following the June billing cycle, each enrolled Customer's balance under the Plan will be "trued-up", assuming payment of the June Monthly Payment Amount will be paid when due. This "true-up" will result in the Plan account balance (debit or credit) being spread over the succeeding twelve-month period and, when combined

with updated consumption and pricing estimates for the new Plan year, will be reflected in a revis Monthly Payment Amount.

g. **Customer Notices.** Each enrolled Customer shall be notified, by U.S. mail, of any revision to the Monthly Payment Amount established as the result of any semi-annual Plan review by the Company. Enrolled customers shall also be appropriately advised as to how any debit or credit balance (at the Plan year-end review) was applied to their account as set forth above.

h. **Failure to Pay Monthly Payment Amount by Due Date:** If an enrolled Customer fails to pay the required Monthly Payment Amount due under the Plan on or before the due date as printed on their monthly billing from the Company, the Customer will be subject to a Late Payment Charge as set forth in Rule No. 24. If a Customer fails to pay the required Monthly Payment Amount more than once in any twelve month period, the Customer may, at the Company's sole option, be removed from the Plan, and any debit balance existing under the Plan at that time shall be immediately due and payable in full. If there is a credit balance, said credit will be applied against future billings to the Customer at the current account, or refunded to the Customer at the sole discretion of the Company, if appropriate.

30. **RESTRICTIONS, LIMITATIONS, CURTAILMENTS AND PRIORITIES OF SERVICE:**

When sufficient volumes of gas are not available to the Company to meet all existing and reasonably anticipated demands, the Company shall have the right to restrict, limit, or curtail gas service within any of its systems, regardless of the class of service, and in accordance with the provisions of this Rule.

a. **Definitions.** For the purpose of this rule, certain terms shall have the following meanings:

(1) **"Off-System" Transportation Customer:** A Transportation Customer shall mean a Customer for which Company has no contractual obligation to provide natural gas from its system supply, and for whose natural gas needs and requirements Company is not contractually committed to pay interstate pipeline charges of any kind.

(2) **Interruptible Customer.** An Interruptible Customer shall mean a Customer purchasing natural gas on an interruptible service basis under any applicable rate schedule(s) of the Company.

(3) **Firm Customer.** A Firm Customer shall mean a Customers purchasing natural gas on a firm service basis under any applicable tariff schedule(s) of the Company.

(4) **Residential and Small Volume Commercial Customer.** Residential and Small Volume Commercial Customer shall mean any customer purchasing natural gas to provide service for one or more residential units or for one or more commercial units where the annual volume of gas required for each residential unit or for each commercial unit does not exceed the maximum annual usage specified in the Company's rate sheet(s) applicable to such customer(s). Customers who sell services or commodities to the general public are considered commercial accounts, and shall include churches and other public and private not-for-profit groups and organizations.

(5) **Large Volume Firm Customer.** A Large Volume Firm Customer shall mean any Firm Customer whose annual usage of natural gas exceeds the minimum annual usage specified in the Company's rate sheet(s) applicable to such customer.

(6) **Large Volume Interruptible Customer.** A Large Volume Interruptible Customer shall mean any Interruptible Customer whose annual usage of natural gas exceeds the minimum annual usage specified in the Company's rate sheet(s) applicable to such customer.

(7) **Industrial Customer.** An Industrial Customer shall mean any Customer whose primary use(s) of natural gas include product processing, feed stock, or plant protection, and shall include any production entity that does not sell its products directly to the general public.

b. **Restrictions on New and Additional Service.** The Company shall have the right to refuse to provide new or additional service to applicants or existing customers as may be necessary due to a lack of system capacity or other physical or supply limitations.

c. **Normal Monthly Consumption of Large Volume Firm Customers and all Industrial Customers.** The Company shall have the right to establish a "Normal Monthly Consumption" for each Large Volume Firm Customer and each Industrial Customer in accordance with the following:

(1) **Normal Monthly Consumption.** The Normal Monthly Consumption of each Large Volume Firm Customer and each Industrial Customer shall be that volume of gas purchased by such Large Volume Firm Customer or Industrial Customer during each billing month of the Base Period specified by the Company.

(2) **Base Period.** The Base Period shall be the twelve consecutive billing months as may be specified by the Company, from time to time.

(3) **Notice to Large Volume Firm Customers and all Industrial Customers.** As soon as practicable after the provisions of this paragraph shall be invoked by the Company, the Company shall give written notice to each Large Volume Firm Customer and each Industrial Customer of its Normal Monthly Consumption as determined under provision c.(1) above.

d. **Interruptions, Limitations and Curtailments of Service.** The Company shall have the right to interrupt, limit, or curtail service to its Customers in the following order:

(1) **"Off-System" Transportation Customer.** Deliveries to each Transportation Customer in any billing month shall be limited to the lesser of its daily nomination, or the pipeline's daily allocated volumes to said Customer.

(2) **Interruptible Customers.** Deliveries to Interruptible Customers may be interrupted in accordance with the provisions of the applicable rate schedule.

(3) **Large Volume Firm Customers and all Industrial Customers.** Deliveries to Large Volume Firm Customers and all Industrial Customers in any billing month shall be limited to their Normal Monthly Consumption, and may be curtailed on a pro-rata basis as specified by the Company.

(4) **Commercial Customers.**

(5) **Residential Customers.**

e. **Penalty for Unauthorized Gas Use.**

(1) If a Customer operating under a curtailment order/request issued by the Company takes delivery of volumes of natural gas in excess of 102% of the volume specified during any annual, seasonal, monthly or daily period, the Customer shall pay the Company an overrun penalty, in addition to all other charges and penalties payable under the Company's rate schedules, the greater of Three Dollars ($3.00) per Therm for all gas taken in excess of the specified volume, or the actual overrun penalties assessed to Company by its pipeline service provider.

(2) The Company shall have the right, without obligation, to waive the penalty for any unauthorized overrun if the Company's other Customers or its pipeline operations were not adversely affected by same. However, any Customer having such an unauthorized overrun, shall have its next allocation reduced by the amount of the unauthorized overrun.

f. **Applicability.** The terms, conditions and provisions of this Rule No. 30 shall take precedence over any other terms, conditions or provisions that may be contained in any Company tariff or rate schedule, or in any contract, agreement or other written instrument which may exist between the Company and any Customer.

31. **FORCE MAJEURE:**

a. Neither Company nor Customer shall be liable for any damages to the other due to any act, omission, or circumstances occasioned by or resulting as a consequence of any act of God, strike, lockout, act of the public enemy, war, blockade, insurrection, riot, epidemic, landslide, lightning, earthquake, fire, storm, flood, washout, arrest, restraint or suspension of lawful governmental authority, civil disturbance, explosion, breakage or accident to machinery or pipe; temporary failure of gas supply, binding order of any court or governmental authority, and any other cause, whether of the kind herein enumerated, or otherwise, not within the control of the party claiming suspension of performance and which, by the employment of due diligence, the other party is unable to prevent.

b. The occurrence of a cause or contingency resulting in non-performance shall not be lawful justification for relieving either Company or Customer of any duty or liability upon the finding of concurring negligence. Further, upon the finding of a failure of either Company or Customer to timely employ reasonable due diligence to remedy the cause for non-performance, eliminate the occurrence of a stated contingency, and to promptly reinitiate performance, the occurrence of said finding(s) shall be grounds for the imposition of liability for the failure to exercise the contractual duty to perform. Finally, no occurrence of a cause or contingency resulting in non-performance shall constitute lawful grounds for either Company or Customer to suspend, relieve, discharge or otherwise interrupt the prompt and timely payment of such sums and amounts that became due prior to the declaration of a force majeure.

32. **ASSIGNMENT:**

The benefits and obligations of any service agreement shall begin when the Company commences to supply natural gas service and shall inure to and be binding upon the heirs, successors, assigns, and executors or administrators of both the Company and the Customer.

33. **AGENTS:**

No agent has the power to amend, modify, alter, or waive any of the terms and conditions of any contract or agreement between the Company and any Customer or to bind the Company by making any promise or representation not contained therein.

34. **AMENDMENT OF GENERAL RULES AND REGULATIONS APPLICABLE TO GAS SERVICE:**

The Company reserves the right to modify, alter, or amend these General Rules and Regulations Applicable to Gas Service or to file additional General Rules and Regulations Applicable to Gas Service, as experience and conditions may suggest or as the Company may deem necessary in the conduct of its business. All such modifications, alterations, amendments, additions or deletions shall be subject to approval of the IURC.

OHIO VALLEY GAS CORPORATION
535 N EASTERN AVE
P O BOX 445
CONNERSVILLE, IN 47331-0445

ACCOUNT NUMBER	4-27-6912-0-3
AMOUNT DUE BY 04/07/07	**238.93**
AMOUNT DUE AFTER 04/07/07	245.90

☐ PLACE AN "X" IN THE BOX IF YOU INCLUDED DIRECT DEBIT INFORMATION ON THE REVERSE.

000132**001**001*******AUTOCR**R001

GUILFORD IN 47022-9780

OHIO VALLEY GAS CORPORATION
P O BOX 445
CONNERSVILLE, IN 47331-0445

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

ACCOUNT ACTIVITY

ACCOUNT NUMBER: 4-27-6912-0-3
RATE: 41 DATE BILLED: 03/21/07 DATE DUE: 04/07/07
SERVICE ADDRESS.
SERVICE TYPE: RESIDENTIAL HEATING

PREVIOUS BALANCE		231.85
PAYMENT(S) RECEIVED - THANK YOU		231.85 CR
PREVIOUS BALANCE CARRIED FORWARD		.00
CURRENT CHARGES		
SERVICE AND DELIVERY	40.57	
GAS COSTS: 159 THERMS @ $1.1625/TH	184.84	
SALES TAX	13.52	
TOTAL CURRENT CHARGES		238.93

AMOUNT DUE BY 04/07/07 $ 238.93

AMOUNT DUE AFTER 04/07/07 $ 245.90

CONSUMPTION INFORMATION

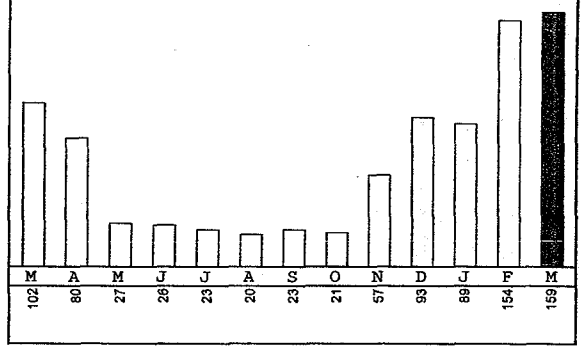
PREVIOUS READ DATE	CURRENT READ DATE	DAYS OF SERVICE
02/16/07	03/16/07	28

PREVIOUS READING	CURRENT READING	GAS USED IN CCFS
2204	2359	155

GAS USED IN CCFS	X	MULTIPLIER	=	GAS USED IN THERMS
155		1.0270		159

CONSUMPTION HISTORY (THERMS)

TOTAL CONSUMPTION PREVIOUS 12 MONTHS: 715
AVERAGE CONSUMPTION PREVIOUS 12 MONTHS: 60



Current period was 35% WARMER than previous period.
Current period was 11% COLDER than same period last year.

IMPORTANT MESSAGES FROM OHIO VALLEY GAS TO BETTER SERVE YOU

Energy Assistance Program (EAP): Financial assistance is available for residential customers with household income at or below 150% of the poverty income level. Example: a family of four with income of $30,000 or less would be eligible for assistance. Contact your local Community Action Agency for further information and/or to apply for this assistance as soon as possible.

Help Thy Neighbor Energy Assistance Fund (HTN): Financial assistance is available for residential customers with household income between 150% and 200% of the poverty income level and who are at risk of having their gas service disconnected for non-payment. Example: a family of four with income of $30,000 to $40,000 would be eligible for assistance. Call the Ohio Valley Gas office number shown on this bill during regular business hours for further information and/or to apply for this assistance as soon as possible.

535 N EASTERN AVE
P O BOX 445
CONNERSVILLE, IN 47331-0445

OHIO VALLEY GAS
WWW.OVGC.COM

TELEPHONE (765) 825-1148
TOLL FREE 1-(800) 326-1148

BUSINESS HOURS
MONDAY – FRIDAY
7:00 A.M. – 4:00 P.M.

ONLY EMERGENCIES WILL BE RESPONDED TO AFTER 4:00 P.M.
TELEPHONE (765) 825-1149
TOLL FREE 1-(800) 326-1148

ADDITIONAL INFORMATION ON REVERSE

OVG OFFICE USE ONLY

M ☐ Amt Received $_____

ND ☐ Amt Owed $_____

CK ☐ Change $_____

Complete this form only for new enrollments or changes.

DIRECT DEBIT PAYMENT PLAN ENROLLMENT (PRINT IN BLACK INK ONLY)

Payment will be deducted from your financial institution on the due date. Your bill will state the due date and amount to be deducted. Please continue bill payments until your bill states that a bank transfer will be made.

Phone (Home) Work OVG Account Number (See Reverse)

Name on Financial Institution Account Customer Name (See Reverse)

Routing Number (9 Digit) Financial Institution Account Number

(ENCLOSE COPY OF VOIDED CHECK OR DEPOSIT SLIP)

Signature Date

I authorize Ohio Valley Gas to debit the financial institution account listed for monthly payment of my bill. I understand I may stop this service ten (10) or more business days before the due date by calling the telephone number on the reverse.

For the above to be acknowledged, you must "x" the box on the reverse of this form.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

PAYMENT TERMS: This bill is based on a non-penalty period of seventeen (17) days. If payment is not received by the due date indicated, a late payment charge is added to the current amount due. A late payment charge is assessed on the delinquent amount at 10% of the first $3.00 or less, plus 3% of the amount greater than $3.00. The due date applies to the current month's billing amount; any previous billing amount is now past due and should be paid immediately to avoid disconnection of service. A Budget Plan payment received after the due date is subject to a late payment charge, which is added to the customer's account balance.

CURRENT CHARGES:

- *Service and Delivery* – Charges to recover the cost of providing service to the customer and the delivery of natural gas.
- *Gas Costs* – The market cost of natural gas consumed by the customer.

MISCELLANEOUS CHARGES: Examples of miscellaneous charges may include, but are not limited to, returned check charges and collection fees.

THERM: A therm(TH) is the energy equivalent of burning 100 cubic feet (CCF) of natural gas at standard temperature and pressure and is used by public utilities to measure and bill natural gas consumption.

MULTIPLIER: The multiplier is a factor used to convert CCFs to therms and to calculate consumption on meters with greater than standard delivery pressure.

ESTIMATED BILLS: An estimated bill utilizes estimated consumption when actual meter readings are not obtainable. An "E" following the meter reading indicates an estimated reading.

FINAL BILLS: A final bill is issued when an account is closed and a final meter reading is obtained. If an account has a security deposit, the deposit and accrued interest will be applied to the final bill.

BILLING QUESTIONS: If you have questions about your bill or our service, please visit or call your District Office during business hours at the telephone number on the reverse; e-mail your District Office at our website; or write to the address shown on the reverse. **INDIANA CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas, you may call the Indiana Utility Regulatory Commission (IURC) toll-free at 1-800-851-4268 from 8:00a.m. to 5:00p.m. weekdays, or visit the IURC website at www.in.gov/iurc. Residential customers may also call the Office of the Utility Consumer Counselor (OUCC) toll-free at 1-888-441-2494, or visit the OUCC website at www.in.gov/oucc. **OHIO CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas you may call the Public Utilities Commission of Ohio (PUCO) toll-free at 1-800-686-7826 or 1-614-466-3292, or for TDD/TTY toll-free at 1-800-686-1570 or 1-614-466-8180, from 8:00a.m. to 5:30p.m. weekdays, or visit the PUCO website at www.PUCO.ohio.gov.

RATES: Rate information is available from your District Office at the address or telephone number shown on the reverse, and at the Ohio Valley Gas website www.ovgc.com.

EMERGENCIES: For emergencies outside of business hours, call the emergency telephone number shown on the reverse. **Do not contact us by e-mail for emergencies**. Our stand-by emergency service personnel will respond only to emergencies during non-business hours. Delinquent (past due) accounts are not considered emergencies.

OHIO VALLEY GAS CORPORATION
535 N EASTERN AVE
P O BOX 445
CONNERSVILLE, IN 47331-0445

ACCOUNT NUMBER	4-27-6360-0-0
AMOUNT DUE BY 04/07/07	**108.00**

A BUDGET PAYMENT RECEIVED AFTER THE DUE DATE WILL BE SUBJECT TO A LATE PAYMENT CHARGE.

☐ PLACE AN "X" IN THE BOX IF YOU INCLUDED DIRECT DEBIT INFORMATION ON THE REVERSE.

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GUILFORD IN 47022-8933

OHIO VALLEY GAS CORPORATION
P O BOX 445
CONNERSVILLE, IN 47331-0445

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

ACCOUNT ACTIVITY

ACCOUNT NUMBER: 4-27-6360-0-0
RATE: 41 DATE BILLED: 03/21/07 DATE DUE: 04/07/07
SERVICE ADDRESS:
SERVICE TYPE: RESIDENTIAL HEATING

PREVIOUS BALANCE		38.46
PAYMENT(S) RECEIVED - THANK YOU		108.00 CR
PREVIOUS BALANCE CARRIED FORWARD		69.54 CR
CURRENT CHARGES		
SERVICE AND DELIVERY	38.32	
GAS COSTS: 146 THERMS @ $1.1625/TH	169.73	
SALES TAX	12.48	
TOTAL CURRENT CHARGES		220.53
CURRENT ACCOUNT BALANCE*		150.99

*This represents the amount you would owe, if you left the Budget Plan.

BUDGET PAYMENT PLAN SUMMARY

PREVIOUS BUDGET PAYMENT DUE	108.00
BUDGET PAYMENTS(S) RECEIVED - THANK YOU	108.00 CR
BUDGET PAYMENT DUE CARRIED FORWARD	.00
CURRENT BUDGET PAYMENT DUE	108.00

AMOUNT DUE BY 04/07/07 $ 108.00

CONSUMPTION INFORMATION

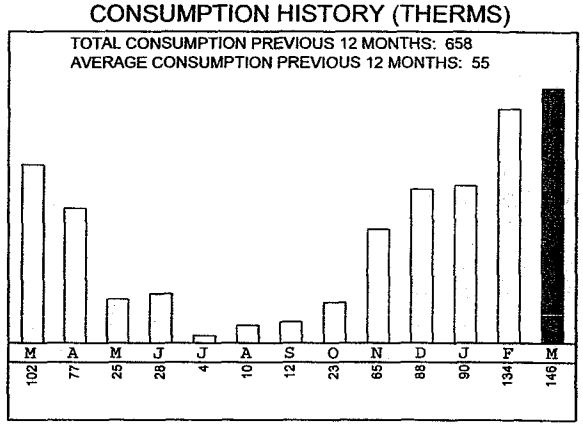
PREVIOUS READ DATE	CURRENT READ DATE	DAYS OF SERVICE
02/16/07	03/16/07	28

PREVIOUS READING	CURRENT READING	GAS USED IN CCFS
7223	7365	142

GAS USED IN CCFS	X	MULTIPLIER	=	GAS USED IN THERMS
142		1.0270		146

CONSUMPTION HISTORY (THERMS)

TOTAL CONSUMPTION PREVIOUS 12 MONTHS: 658
AVERAGE CONSUMPTION PREVIOUS 12 MONTHS: 55



Current period was 35% WARMER than previous period.
Current period was 11% COLDER than same period last year.

IMPORTANT MESSAGES FROM OHIO VALLEY GAS TO BETTER SERVE YOU

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535 N EASTERN AVE
P O BOX 445
CONNERSVILLE, IN 47331-0445

OHIO VALLEY GAS
WWW.OVGC.COM

TELEPHONE (765) 825-1148
TOLL FREE 1-(800) 326-1148

BUSINESS HOURS
MONDAY – FRIDAY
7:00 A.M. – 4:00 P.M.

ONLY EMERGENCIES WILL BE RESPONDED TO AFTER 4:00 P.M.
TELEPHONE (765) 825-1149
TOLL FREE 1-(800) 326-1148
ADDITIONAL INFORMATION ON REVERSE

OVG OFFICE USE ONLY

M ☐ Amt Received $_____

ND ☐ Amt Owed $_____

CK ☐ Change $_____

Complete this form only for new enrollments or changes.

DIRECT DEBIT PAYMENT PLAN ENROLLMENT (PRINT IN BLACK INK ONLY)

Payment will be deducted from your financial institution on the due date. Your bill will state the due date and amount to be deducted. Please continue bill payments until your bill states that a bank transfer will be made.

Phone (Home) Work OVG Account Number (See Reverse)

Name on Financial Institution Account Customer Name (See Reverse)

Routing Number (9 Digit) Financial Institution Account Number

(ENCLOSE COPY OF VOIDED CHECK OR DEPOSIT SLIP)

Signature Date

I authorize Ohio Valley Gas to debit the financial institution account listed for monthly payment of my bill. I understand I may stop this service ten (10) or more business days before the due date by calling the telephone number on the reverse.

For the above to be acknowledged, you must "x" the box on the reverse of this form.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

PAYMENT TERMS: This bill is based on a non-penalty period of seventeen (17) days. If payment is not received by the due date indicated, a late payment charge is added to the current amount due. A late payment charge is assessed on the delinquent amount at 10% of the first $3.00 or less, plus 3% of the amount greater than $3.00. The due date applies to the current month's billing amount; any previous billing amount is now past due and should be paid immediately to avoid disconnection of service. A Budget Plan payment received after the due date is subject to a late payment charge, which is added to the customer's account balance.

CURRENT CHARGES:

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MULTIPLIER: The multiplier is a factor used to convert CCFs to therms and to calculate consumption on meters with greater than standard delivery pressure.

ESTIMATED BILLS: An estimated bill utilizes estimated consumption when actual meter readings are not obtainable. An "E" following the meter reading indicates an estimated reading.

FINAL BILLS: A final bill is issued when an account is closed and a final meter reading is obtained. If an account has a security deposit, the deposit and accrued interest will be applied to the final bill.

BILLING QUESTIONS: If you have questions about your bill or our service, please visit or call your District Office during business hours at the telephone number on the reverse; e-mail your District Office at our website; or write to the address shown on the reverse. **INDIANA CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas, you may call the Indiana Utility Regulatory Commission (IURC) toll-free at 1-800-851-4268 from 8:00a.m. to 5:00p.m. weekdays, or visit the IURC website at www.in.gov/iurc. Residential customers may also call the Office of the Utility Consumer Counselor (OUCC) toll-free at 1-888-441-2494, or visit the OUCC website at www.in.gov/oucc. **OHIO CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas you may call the Public Utilities Commission of Ohio (PUCO) toll-free at 1-800-686-7826 or 1-614-466-3292, or for TDD/TTY toll-free at 1-800-686-1570 or 1-614-466-8180, from 8:00a.m. to 5:30p.m. weekdays, or visit the PUCO website at www.PUCO.ohio.gov.

RATES: Rate information is available from your District Office at the address or telephone number shown on the reverse, and at the Ohio Valley Gas website www.ovgc.com.

EMERGENCIES: For emergencies outside of business hours, call the emergency telephone number shown on the reverse. **Do not contact us by e-mail for emergencies**. Our stand-by emergency service personnel will respond only to emergencies during non-business hours. Delinquent (past due) accounts are not considered emergencies.

OHIO VALLEY GAS CORPORATION
535 N EASTERN AVE
P O BOX 445
CONNERSVILLE, IN 47331-0445

ACCOUNT NUMBER	4-17-4575-0-9
AMOUNT DUE BY 03/30/07	**194.38**
FINAL BILL	

☐ PLACE AN "X" IN THE BOX IF YOU INCLUDED DIRECT DEBIT INFORMATION ON THE REVERSE.

000126**001**001*******AUTOCR**R001

GUILFORD IN 47022-9766

OHIO VALLEY GAS CORPORATION
P O BOX 445
CONNERSVILLE, IN 47331-0445

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

ACCOUNT ACTIVITY

ACCOUNT NUMBER: 4-17-4575-0-9

RATE: 41 DATE BILLED: 03/20/07 DATE DUE: 03/30/07
SERVICE ADDRESS:
SERVICE TYPE: RESIDENTIAL HEATING

PREVIOUS BALANCE		350.81
PAYMENT(S) RECEIVED - THANK YOU		350.81 CR
LATE PAYMENT CHARGE		10.14
PREVIOUS BALANCE CARRIED FORWARD		10.14
CURRENT CHARGES		
SERVICE AND DELIVERY	31.98	
GAS COSTS: 122 THERMS @ $1.1625/TH	141.83	
SALES TAX	10.43	
L CURRENT CHARGES		184.24

AMOUNT DUE BY 03/30/07 $ 194.38

FINAL BILL

CONSUMPTION INFORMATION

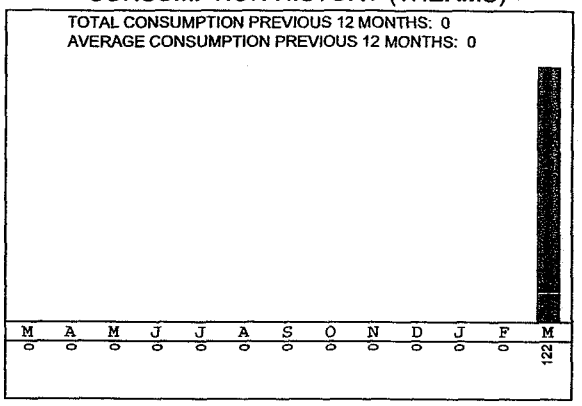
PREVIOUS READ DATE	CURRENT READ DATE	DAYS OF SERVICE
02/12/07	03/09/07	25

PREVIOUS READING	CURRENT READING	GAS USED IN CCFS
7503	7621	118

GAS USED IN CCFS	X	MULTIPLIER	=	GAS USED IN THERMS
118		1.0310		122

CONSUMPTION HISTORY (THERMS)

TOTAL CONSUMPTION PREVIOUS 12 MONTHS: 0
AVERAGE CONSUMPTION PREVIOUS 12 MONTHS: 0



IMPORTANT MESSAGES FROM OHIO VALLEY GAS TO BETTER SERVE YOU

Energy Assistance Program (EAP): Financial assistance is available for residential customers with household income at or below 150% of the poverty income level. Example: a family of four with income of $30,000 or less would be eligible for assistance. Contact your local Community Action Agency for further information and/or to apply for this assistance as soon as possible.

Help Thy Neighbor Energy Assistance Fund (HTN): Financial assistance is available for residential customers with household income between 150% and 200% of the poverty income level and who are at risk of having their gas service disconnected for non-payment. Example: a family of four with income of $30,000 to $40,000 would be eligible for assistance. Call the Ohio Valley Gas office number shown on this bill during regular business hours for further information and/or to apply for this assistance as soon as possible.

535 N EASTERN AVE
P O BOX 445
CONNERSVILLE, IN 47331-0445

OHIO VALLEY GAS
WWW.OVGC.COM

TELEPHONE (765) 825-1148
TOLL FREE 1-(800) 326-1148

BUSINESS HOURS
MONDAY – FRIDAY
7:00 A.M. – 4:00 P.M.

ONLY EMERGENCIES WILL BE RESPONDED TO AFTER 4:00 P.M.
TELEPHONE (765) 825-1149
TOLL FREE 1-(800) 326-1148

ADDITIONAL INFORMATION ON REVERSE

OVG OFFICE USE ONLY

M ☐ Amt Received $_____

ND ☐ Amt Owed $_____

CK ☐ Change $_____

Complete this form only for new enrollments or changes.

DIRECT DEBIT PAYMENT PLAN ENROLLMENT (PRINT IN BLACK INK ONLY)

Payment will be deducted from your financial institution on the due date. Your bill will state the due date and amount to be deducted. Please continue bill payments until your bill states that a bank transfer will be made.

Phone (Home) Work OVG Account Number (See Reverse)

Name on Financial Institution Account Customer Name (See Reverse)

Routing Number (9 Digit) Financial Institution Account Number

(ENCLOSE COPY OF VOIDED CHECK OR DEPOSIT SLIP)

Signature Date

I authorize Ohio Valley Gas to debit the financial institution account listed for monthly payment of my bill. I understand I may stop this service ten (10) or more business days before the due date by calling the telephone number on the reverse.

For the above to be acknowledged, you must "X" the box on the reverse of this form.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

PAYMENT TERMS: This bill is based on a non-penalty period of seventeen (17) days. If payment is not received by the due date indicated, a late payment charge is added to the current amount due. A late payment charge is assessed on the delinquent amount at 10% of the first $3.00 or less, plus 3% of the amount greater than $3.00. The due date applies to the current month's billing amount; any previous billing amount is now past due and should be paid immediately to avoid disconnection of service. A Budget Plan payment received after the due date is subject to a late payment charge, which is added to the customer's account balance.

CURRENT CHARGES:

- *Service and Delivery* – Charges to recover the cost of providing service to the customer and the delivery of natural gas.
- *Gas Costs* – The market cost of natural gas consumed by the customer.

MISCELLANEOUS CHARGES: Examples of miscellaneous charges may include, but are not limited to, returned check charges and collection fees.

THERM: A therm(TH) is the energy equivalent of burning 100 cubic feet (CCF) of natural gas at standard temperature and pressure and is used by public utilities to measure and bill natural gas consumption.

MULTIPLIER: The multiplier is a factor used to convert CCFs to therms and to calculate consumption on meters with greater than standard delivery pressure.

ESTIMATED BILLS: An estimated bill utilizes estimated consumption when actual meter readings are not obtainable. An "E" following the meter reading indicates an estimated reading.

FINAL BILLS: A final bill is issued when an account is closed and a final meter reading is obtained. If an account has a security deposit, the deposit and accrued interest will be applied to the final bill.

BILLING QUESTIONS: If you have questions about your bill or our service, please visit or call your District Office during business hours at the telephone number on the reverse; e-mail your District Office at our website; or write to the address shown on the reverse. **INDIANA CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas, you may call the Indiana Utility Regulatory Commission (IURC) toll-free at 1-800-851-4268 from 8:00a.m. to 5:00p.m. weekdays, or visit the IURC website at www.in.gov/iurc. Residential customers may also call the Office of the Utility Consumer Counselor (OUCC) toll-free at 1-888-441-2494, or visit the OUCC website at www.in.gov/oucc. **OHIO CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas you may call the Public Utilities Commission of Ohio (PUCO) toll-free at 1-800-686-7826 or 1-614-466-3292, or for TDD/TTY toll-free at 1-800-686-1570 or 1-614-466-8180, from 8:00a.m. to 5:30p.m. weekdays, or visit the PUCO website at www.PUCO.ohio.gov.

RATES: Rate information is available from your District Office at the address or telephone number shown on the reverse, and at the Ohio Valley Gas website www.ovgc.com.

EMERGENCIES: For emergencies outside of business hours, call the emergency telephone number shown on the reverse. **Do not contact us by e-mail for emergencies**. Our stand-by emergency service personnel will respond only to emergencies during non-business hours. Delinquent (past due) accounts are not considered emergencies.

OHIO VALLEY GAS CORPORATION
317 N COLUMBIA ST
P O BOX 404
UNION CITY, IN 47390-0404

ACCOUNT NUMBER	3-12-2740-5-0
DELINQUENT AMOUNT DUE BEFORE 04/02/07	**339.49**
	A

DISCONNECT NOTICE

000001**

UNION CITY OH 45390-9019

OHIO VALLEY GAS CORPORATION
P O BOX 404
UNION CITY, IN 47390-0404

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

DISCONNECT NOTICE

ACCOUNT NUMBER: 3-12-2740-5-0

03/20/07

Your gas service at will be disconnected on or after 04/02/07 for non-payment of your delinquent balance of $339.49. To avoid disconnection of service, payment of the delinquent balance must be received by our office before 04/02/07. If a company representative is sent to your premises to collect the delinquent amount, you will also be subject to a $27.00 collection fee. If your service is disconnected for non-payment, a deposit of $155.00 and a reconnection fee of $50.00 will be required in addition to payment of the delinquent balance before your service can be reconnected.

If you are unable to pay the delinquent balance before your disconnection date, please contact our office for possible payment arrangements. A partial payment will not ensure continuation of service unless a payment arrangement has been made with our office.

If you are subject to disconnection and are a residential customer, you may qualify for special **"Help Thy Neighbor Heating Fund"** assistance this year. Customers receiving, or eligible to receive, annual Energy Assistance Program (EAP) funding will not qualify for this special assistance. Please contact us **IMMEDIATELY** at the number below during our business hours with household income information to find out if you qualify.

Payment of your delinquent balance may now be made with an accepted credit or debit card. Call NCO Financial Systems, the card payment processing company, at 866-261-2990 to make payment; or contact our office for more details.

If you dispute the bill(s) in question or the scheduled disconnection, please contact our office during business hours before your disconnection date. A company representative will review the status of your account with you and the reason for the scheduled disconnection.

If payment has been made, please disregard this notice. This notice does not cancel any previous notice.

OHIO VALLEY GAS CORPORATION
317 N COLUMBIA ST
P O BOX 404
UNION CITY, IN 47390-0404

Telephone (765) 964-3101
Business Hours:
Monday-Friday, 7:00a - 4:00p

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS CORPORATION FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	CAUSE NO. 43209

PETITIONER'S EXHIBIT SMK

DIRECT TESTIMONY

OF

S. MARK KERNEY
VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

ON BEHALF OF

OHIO VALLEY GAS CORPORATION

MARCH 2007

PREPARED DIRECT TESTIMONY OF S. MARK KERNEY

OHIO VALLEY GAS CORPORATION

CAUSE NO. 43209

1. Q. Will you please state your name and business address?

A. S. Mark Kerney, 111 Energy Park Drive, Winchester, Indiana.

2. Q. By whom are you employed?

A. The Petitioner in this Cause No. 43209 - Ohio Valley Gas Corporation.

3. Q. What is your position with Petitioner?

A. Vice President and Chief Financial Officer.

4. Q. When did you begin your employment with the Petitioner?

A. On November 4, 2002.

5. Q. Will you please summarize your educational background?

A. I graduated from Indiana State University in 1976 with a Bachelor of Science degree in Accounting. Since 1982, I have been licensed as a Certified Public Accountant in Indiana in good standing. Additionally, I have attended numerous utility industry and professional seminars and courses during my career, including University of Michigan's comprehensive Utility Executive Program in 1987.

6. Q. Will you please state your employment history?

A. Upon graduation from Indiana State University, I was employed from 1976 to 1978 by the Evansville, Indiana office of Geo. S. Olive & Co, a certified public accounting firm headquartered in Indianapolis, performing client audit and tax return preparation assignments. In 1978, I joined Southern Indiana Gas & Electric Company (SIGECO), a NYSE-listed natural

gas distribution and electric generation utility headquartered in Evansville. At SIGECO, I held various tax and financial accounting positions of increasing responsibility until 1989 when I was appointed Controller of SIGECO. In this role, I was responsible for the financial and regulatory accounting and reporting, taxes, budgets, customer billing and internal audit functions. These functions included the reconciliation of estimated to actual recoverable fuel costs for the quarterly GCA and FAC filings and related accounting issues, as well as various aspects of SIGECO's periodic general gas and electric rate case filings. In 1997, the utility holding company, SIGCORP, was formed to restructure SIGECO and a growing number of non-utility subsidiaries, and I was appointed Controller of SIGCORP, as well. In March 2000, SIGCORP and Indiana Energy, a utility holding company headquartered in Indianapolis, Indiana, merged to form the utility holding company, Vectren Corporation (Vectren), headquartered in Evansville. Appointed Director of Financial Accounting for Vectren effective with the merger, I was responsible for all aspects of financial and regulatory accounting and reporting, including SEC reporting for the new holding company and its operating utilities. In November 2002, I joined the Petitioner as Chief Financial Officer, responsible for the financial and regulatory accounting and reporting, corporate taxes, treasury, gas supply, and customer billing functions of the Company and its subsidiaries, including Ohio Valley Gas, Inc. Effective June 2005, I assumed the additional responsibility for the preparation, support and representation of the Petitioner's quarterly gas cost adjustment and general rate filings before this Commission. Effective November 1, 2005, I was appointed Vice President and Chief Financial Officer of the Petitioner and its subsidiaries, including Ohio Valley Gas, Inc.

7. Q. Are you a member of any business or professional organizations?

A. I am a member of the Gas Rate & Regulatory Committee of the Indiana Energy Association (IEA) and of the IEA Joint Customer Service Committee. Additionally, I am a member of the Indiana Association of Certified Public Accountants.

8. Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC")?

A. I prepared and filed testimony for SIGECO addressing various accounting issues affecting the quarterly gas and fuel adjustment filings. Since June 2005, I have testified for the Petitioner and its subsidiary in support of the quarterly GCA filings before this Commission.

9. Q. Is the Petitioner billing its customers and maintaining its records on an equivalent heating value basis?

A. Yes. All volumes expressed in this Cause are in their equivalent heating value on a "dry" British Thermal Unit ("BTU") basis versus "wet" basis for the historical twelve months ended June 30, 2006. Both of our interstate pipelines also operate on a dry BTU measurement basis. Likewise, all purchases of natural gas are made on a dry BTU measurement basis.

10. Q. Will you please identify and explain the documents marked as Petitioner's Exhibit SMK-1?

A. This is the Balance Sheet as of September 30, 2006 per Petitioner's books. Petitioner proposes a cut-off date of September 30, 2006 for determining original cost and fair value of Petitioner's utility properties.

11. Q. Will you please identify Petitioner's Exhibit SMK-2?

A. Page 1 is the Statement of Income by pipeline service areas for the twelve months ended June 30, 2006 per Petitioner's books. Pages 2 through 7 set forth additional details of the Statement of Income by service areas for the twelve months ended June 30, 2006. Petitioner proposes a test year of twelve months ended June 30, 2006.

12. Q. Will you please identify and explain the documents marked Petitioner's Exhibit SMK-3?

A. Exhibit SMK-3 is Petitioner's financial data, prepared in this Cause No. 43209 under my supervision, to support the need for an increase in the rates and charges which we are currently authorized to charge our customers. Where applicable, the Exhibit pages show the effect of the proposed adjustment on the two pipeline service areas.

13. Q. Will you please explain Exhibit SMK-3, Pages 0 though 0C?

A. Page 0 through 0C is the Index of all Exhibit SMK-3 Pages.

14. Q. Will you please explain Exhibit SMK-3 Pages 1 through 1E?

A. Page 1 is the Total Company Adjusted Statement of Income for the twelve months ended June 30, 2006 reflecting adjustments for various fixed, known, and measurable changes to occur within twelve months following June 30, 2006. Pages 1A and 1B show the Adjusted Statement of Income for the twelve months ended June 30, 2006 for the ANR Pipeline Service Area and the Texas Gas Service Area, respectively. Each reflects adjustments for various fixed, known, and measurable changes to occur within twelve months following June 30, 2006. Pages 1C, 1D, and 1E summarize the year-end adjustments made for the respective service areas on a line-by-line basis with a reference to applicable Exhibit SMK-3 adjustment details.

15. Q. Will you please explain the purpose of Exhibit SMK-3, Pages 2 through 2D?

A. The purpose of this adjustment is to level and normalize the Gas Cost Adjustment (GCA) revenues for the test period. Page 2 shows the summary effect of restating the GCA calculation on an annual leveling and normalization basis using the adjusted cost of purchased gas (SMK-3, Pages 6-6D) and the test year actual revenues generated by the various GCA factors in effect during the test period. Page 2A is the GCA annual leveling and

normalization calculation for the ANR Pipeline Service Area. Page 2B is for the Texas Gas service area.

The demand allocators are those used for the quarterly GCA filings. The demand allocators for the ANR Pipeline Service Area are per IURC Cause No. 37353-GCA87, approved June 8, 2005. The demand allocators for the Texas Gas Service Area are from Cause No. 37354-GCA87, approved June 8, 2005. Pages 2C and 2D are the summaries of the monthly GCA revenue generations for the respective service areas for the test period.

16. Q. Will you please explain Exhibit SMK-3, Pages 3 through 3J?

A. Page 3 is the summary of test period pro forma adjusted revenues from transport customers receiving service under Rate No. T15, Rate No. T45, Rate No. T16 and Rate No. T46 compared to transportation revenues per Petitioner's books.

Pages 3A through 3J provide details of the monthly test period pro forma therms and revenues for each transportation customer.

17. Q. Will you please explain Exhibit SMK-3, Pages 3AA?

A. Page 3AA details by customer the test year pro forma changes to the therms and revenues for sales customers receiving service under Rate No. 12, Rate No. 13, Rate No. 42 and Rate No. 43 caused by plant closures, migration from sales rates to transportation rates, and significant changes to natural gas consumption due to replacement with energy-efficient equipment.

18. Q. Will you please explain Exhibit SMK-3, Pages 3BB?

A. Page 3BB details the pro forma adjustment of the test year therms and revenues for Rate No. 11 and Rate No. 41 customers due to the decline in number of such customers for the twelve months following June 30, 2006, based on the percentage decline in number of such

customers receiving service during January 2006 compared to January 2007. Petitioner has experienced a decline in the number of such customers each year for the past several years, and that decline continued past the test year.

19. Q. Will you please explain Exhibit SMK-3, Pages 4 through 4C?

A. The adjustment shows the details of the calculation of the net change in unbilled revenues, including the net change in sales volumes. The purpose of the unbilled sales and revenue adjustment is to remove the timing differences of Petitioner's various billing cycle months versus the calendar month used for purchasing natural gas supplies for the system.

20. Q. Will you please explain the purpose of Exhibit SMK-3, Pages 5 through 5B?

A. The purpose of this adjustment is to compensate for deviations from the 30-year normal temperatures as compiled by the NOAA. The total sales volumes for the three heating revenue classifications (residential, commercial, and public authorities) for the twelve months ending June 30, 2006, have each been adjusted for non-space heating volumes included therein. This was accomplished by assuming that all July, August, and September billing cycle sales for these customers were for non-space heating purposes, and then annualizing same. Historically, these three billing cycle months reflect the lowest three consecutive consumption months (June, July and August) of the year.

The normal and actual degree days used in the adjustment for all of Petitioner's customer service districts, excepting Petitioner's Tell City district, are based on NOAA data for the Indianapolis International Airport Reporting Station. The NOAA data for the Evansville Regional Airport Reporting Station was used for the Tell City district customers. Petitioner used the most recent thirty-year average issued by NOAA which covers the period of 1971 through 2000 for the normal degree days.

The twelve-month period ending June 30, 2006 was approximately 11% warmer than the NOAA thirty-year average (thirty years ending 2000) in all of Petitioner's customer service areas. Accordingly, Petitioner adjusted test year revenues upward to reflect the effect of twelve months of therm sales on a weather-normalized basis.

Page 5 is the summary of the entire adjustment. Page 5A is the calculation of the adjustment for the ANR Pipeline Service Area, and Page 5B is for the Texas Gas Service Area.

21. Q. Will you please explain the purpose of Exhibit SMK-3, Pages 6 through 6D?

A. The purpose of this adjustment is to reflect the annualizing of purchased gas costs, including pipeline delivery service costs, and the impact of test year adjusted therm sales on purchased gas costs. Page 6 is a summary of this adjustment. Petitioner utilized applicable Federal Energy Regulatory Commission ("FERC") approved tariffs for demand, capacity, and reservation cost calculations. The latest date of tariffs used is October 1, 2006. The commodity price used for the adjustment is the actual cost paid for natural gas delivered to Petitioner's system for the twelve months ended June 30, 2006. Regardless of the prices used to calculate this adjustment, Petitioner's customers will be charged what the gas cost adjustment ("GCA") mechanism dictates, not what Petitioner has included in this general rate filing. The amounts used in this Exhibit will generate the unit "base cost of gas" for the GCA mechanism used subsequent to the issuance of an order in this Cause.

Pages 6A and 6B are the calculations applicable to the ANR Pipeline Service Area. Pages 6C and 6D are the calculations applicable to the Texas Gas Service Area.

All calculations are based on a dry BTU measurement basis to coincide with the billing mechanisms used by our interstate pipelines and applicable natural gas suppliers.

22. Q. Does Petitioner have a contract with ANR Pipeline Company ("ANR") for transportation service?

A. Yes. Petitioner has a transportation contract with ANR Pipeline Company ("ANR") for transport service with delivery points of:

At Center, Indiana in Jay County to serve the communities of Bluff Point, Center, College Corner, Pennville, Portland, and rural areas in Jay and northern Randolph Counties, Indiana.

At Lynn, Indiana in Randolph County to serve the communities of Deerfield, Fountain City, Harrisville, Haysville, Lynn, Randolph, Ridgeville, Saratoga, Union City, Winchester, and rural areas of Randolph and Wayne Counties, Indiana.

At Ferdinand, Indiana in Dubois County to serve the communities of Ferdinand and St. Meinrad, and rural areas of Dubois and Spencer Countries, Indiana.

At St. Anthony, Indiana in Dubois County to serve the communities of St. Anthony, St. Marks (Dubois County), Bretzville, Maltersville, and rural areas of Dubois County, Indiana.

23. Q. Does Petitioner have a contract with Texas Gas Transmission, LLC ("TGT") for transportation service?

A. Yes. Petitioner has a transportation contract with TGT for transport service with delivery points of:

At Guilford, Indiana in Dearborn County to serve the communities of Brownsville, Clinton Corners, Connersville, Dover, Everton, Guilford, Lawrenceville, Liberty, Logan, Lyonsville, Negangard Corner, New Alsace, Penntown, St. Leon, Springersville, Sunman, Yorkville, and rural areas of Dearborn, Fayette, Franklin, Ripley, and Union Counties, Indiana.

At Tell City, Indiana in Perry County to serve the communities of Tell City, Troy, and rural areas of Perry and Spencer Counties, Indiana.

At Cannelton, Indiana in Perry County to service the community of Cannelton and rural areas of Perry County, Indiana.

24. Q. What types of transportation agreements does Petitioner have with the two interstate pipelines that transport natural gas to Petitioner's city gate stations and how is your natural gas supply arranged?

A. With ANR, Petitioner has two Enhanced Transportation Service Agreements, two Firm Transportation Service Agreements, two Firm Storage Service Agreements, one Interruptible Storage Agreement, and two No Notice Transportation Service Agreements.

With TGT, Petitioner has a No Notice Transportation Service Agreement, a Small General Transportation Service Agreement, and three Firm Transportation Agreements.

Petitioner has a natural gas supply contract with BP Canada Energy Marketing, Inc. (BP) to provide all natural gas requirements for both the ANR Pipeline Service Area and the Texas Gas Service Area. Petitioner's natural gas supply is purchased from BP under firm and index price arrangements. The majority of the purchases from BP are under (multiple) firm price arrangements between Petitioner and BP for delivery in future months, and pricing is driven by the NYMEX (New York Mercantile Exchange) at the time each contract is executed. The remaining gas supply is purchased under a two-fold index pricing arrangement. Natural gas nominated by Petitioner beyond the contractual obligations under the firm price arrangements is based on prices in the first monthly posting of the publication Inside F.E.R.C.'s Gas Marketing Report. Subsequent changes to the nominated quantities to be purchased under the monthly index price are priced at the daily price survey (midpoint) as shown in the publication Gas Daily for the balance of the calendar month. The firm-price arrangements are structured to result in multiple purchases for each month to enable "dollar-cost averaging" of

the purchases, yet executed when Petitioner believes the prices are reasonable based on market conditions. Decisions to purchase gas are guided by an informal committee consisting of the General Manager, Chief Financial Officer and Gas Supply Director and resources used include, but are not limited, to Planalytics, Gas Daily, BTU's Daily Gas Wire, BP, and other industry resources.

25. Q. To what volumes of gas is Petitioner contractually entitled under their respective contracts?

A. Petitioner's agreement with ANR provides for transportation deliveries of 18,500 Dth of natural gas per day. Petitioner's agreement with TGT provides for transportation deliveries of 23,581 Dth of natural gas per day during the summer months (April through October) and 25,081 Dth of natural gas per day during the winter months (November through March).

26. Q. Will you please explain Exhibit SMK-3, Page 7?

A. This adjustment reflects the application of payroll rates in effect on April 23, 2006 for the entire test period. It also calculates the applicable amount for operation and maintenance expense. The prorata General Office payroll expense amount applicable to Petitioner's subsidiary has been effectively allocated and assigned to the subsidiary, and is excluded.

27. Q. Will you please explain Exhibit SMK-3, Page 8?

A. This adjustment reflects the application of the Federal Insurance Contributions Act ("FICA") (includes both Medicare and social security) rates, State Unemployment Compensation ("ST UC") rates, and Federal Unemployment Tax Act ("FUTA") rates to the applicable payroll expense from Exhibit SMK-3, Page 7. The eligible wage bases applicable to these payroll taxes used in the various calculations are those in effect on January 1, 2007.

28. Q. Will you please explain Exhibit SMK-3, Page 9?

1 A. This adjustment deletes operating expenses incurred by Petitioner during the test year ended
2 June 30, 2006 required to comply with the new Pipeline Safety Act (PSA) requirements more
3 fully discussed in Exhibit RLL. It is anticipated that these expenses will be subject to
4 recovery from Petitioner's customers through a future PSA cost recovery tracker to be
5 implemented subsequent to the issuance of an order in this Cause.
6 29. Q. Will you please explain Exhibit SMK-3, Page 10?
7 A. This adjustment reflects the decreased cost of liability and other insurance coverages
8 compared to the costs incurred during the test year period. The premiums used for the
9 adjustment are those paid by Petitioner for coverages in effect for the period July 1, 2006
10 through June 30, 2007.
11 30. Q. Will you please explain Exhibit SMK-3, Pages 11 through 11B?
12 A. This downward adjustment to postage expense reflects the decrease in postage costs
13 resulting from annualizing the impact of Petitioner's implementation of the carrier route
14 barcode address rate – the lowest available postage rate for its bills and related notices –
15 during the test year period. The barcode rate used in the adjustment was the rate in effect at
16 January 1, 2007, and does not reflect the anticipated rate increase to $.312 per piece
17 currently pending approval by the postal rate commission and Congress. Page 11 is the
18 summary of the adjustment by service areas. Pages 11A and 11B are the details of the
19 calculation of annualized cost applicable to the mailing of monthly utility bills for natural gas
20 service, final utility bills to disconnected customers, shut-off notices to customers who fail to
21 pay their bills by the due date, and Budget Plan notices.
22 31. Q. Will you please explain Exhibit SMK-3, Page 12?

A. This adjustment reflects the estimated cost of this rate case incremental to Petitioner's ongoing expenses. The rate case expense adjustment reflects the amortized expense of the outside professionals required by statute or by the Petitioner to accomplish this general rate increase proceeding. The outside professional services include legal counsel, expert witness testimony regarding the cost of equity capital, and expert witness testimony regarding cost of service study and rate design. Petitioner is requesting an amortization period of three (3) years for the rate case expenses. Also included are the cost of printing and mailing the required notices of the rate increase to our customers (two mailings).

32. Q. Will you please explain exhibit SMK-3, Page 13?

A. This adjustment reflects the decreased cost of group insurance for Petitioner's full-time employees based on latest known premiums, less the amount applicable to Petitioner's parent company, and the cost of Petitioner's General Office employees applicable to Petitioner's subsidiary. One-third of dependent coverage elected by the employee is paid by Petitioner and is included in the adjustment to the extent applicable to group insurance expense. The rates shown on Line 2 are the costs per insured per annum effective May 1, 2006, the most recent annual renewal period for those coverages, and such rates reflect increased cost-sharing by Petitioner's employees through increased employee deductible and co-insurance payment amounts, as well as lower claims experience. The rates shown on Line 9 are the costs per insured per annum effective January 1, 2005, the last time rates were established for these coverages. The rates on Line 16 are the costs per insured per annum effective May 1, 2006, the most recent annual renewal period for those coverages, as well.

The rates shown in columns (3), (4), and (5) are not the actual cost of the coverage but represent the portion of the total cost paid by Petitioner, equating to one-third of the total cost of the coverage. Petitioner pays the entire cost of the group term life insurance and it is applicable to all full-time employees. The life insurance plan provides reduced benefits for those employees over age 70. No dental, medical, or group term life insurance coverage for retired employees is provided, and no such cost is included in this adjustment.

33. Q. Will you please explain Exhibit SMK-3, Page 13A?

A. This adjustment reflects the scholarship awards granted in May 2006 for the 2006-2007 school year for employee dependents attending schools of higher learning. Only the portion applicable to Petitioner is included in the adjustment.

34. Q. Will you please explain Exhibit SMK-3, Pages 13B through 13D?

A. The adjustment reflects the decreased cost of worker's compensation insurance coverage based on the payroll included in Exhibit SMK-3, Page 7 and on insurance rates effective July 1, 2006. Pages 13B and 13C are the detailed calculations and Page 13D shows the summary of the adjustment.

35. Q. Will you please explain Exhibit SMK-3, Page 14?

A. This adjustment reflects the change in Public Utility Fee due to the changes in gross revenues by the adjustments previously explained. The rate shown was the latest known rate at the time the Exhibit was prepared and was based on the billings due July 1, 2006 through April 1, 2007.

36. Q. Will you please explain Exhibit SMK-3, Page 15?

A. This adjustment reflects the changes in Indiana Utility Receipts Tax due to the changes in gross revenues by the adjustments previously explained. The adjustment was based on the

1 rate of 1.4% which is the rate in effect at the time of this filing, for natural gas sales and
2 transportation sales revenues.
3 37. Q. Will you please explain Exhibit SMK-3, Page 16?
4 A. This page reflects the adjustment to book depreciation expense to annualize the depreciation
5 expense for the changes in the Utility Plant in Service account during the test period. The
6 adjustment is based on the depreciation rate of 2.9% which was approved by this Commission
7 in Cause No. 32049 on January 23, 1970.
8 38. Q. Will you please explain Exhibit SMK-3, Page 16A?
9 A. This adjustment increases the annual depreciation expense on Petitioner's investment in
10 Acct 391 - Office Equipment and Acct 397 - Communications Equipment by increasing the
11 annual depreciation rate applied to this utility plant in service from 2.9% to 10.0% to reflect
12 the much shorter lives of the technology investments contained in these plant accounts, than
13 is reflected by the much lower historical depreciation rate.
14 39. Q. Will you please explain Exhibit SMK-3, Page 17?
15 A. This downward adjustment to test year property tax expense per books reflects the
16 annualized expense based on the application of the latest known average tax rates to the
17 March 1, 2006 assessment. The average tax rates were developed from payments made in
18 May and September 2006.
19 40. Q. Will you please explain Exhibit SMK-3, Page 18?
20 A. This page reflects the adjustment to Indiana Adjusted Gross Income Tax due to the eligible
21 adjustments explained on the previous pages of Exhibit SMK-3. The adjustment is calculated
22 on the rate of 8.5%, the rate in effect at the time of this filing.
23 41. Q. Will you please explain Exhibit SMK-3, Page 19?

A. This page reflects the adjustment to Federal Income Tax due to the eligible adjustments explained on the previous pages of Exhibit SMK-3. This adjustment is calculated on the rate of 34%, the rate applicable to Petitioner.

42. Q. Will you please explain Exhibit SMK-3, Page 20?

A. This page details the calculations to support a change in Petitioner's current minimum reconnection charge of $50.00, to a new proposed minimum reconnection charge of $80.00. This charge is for the reconnection of service to the same customer at the same service address, and includes the cost of the disconnection as well as the reconnection. The increase in this charge is required because the actual cost to handle the reconnections as shown in the calculations is much greater than the current authorized charge.

43. Q. Will you please explain Exhibit SMK-3, Page 20A?

A. This page details the calculation of the various taxes and overhead charges used to determine the actual costs for reconnection charges, collection charges and returned check charges.

44. Q. Will you please explain Exhibit SMK-3, Page 21?

A. This page details the calculation to support a change in Petitioner's current collection charge of $27.00, to a proposed collection charge of $30.00. This charge covers the cost of making a collection trip to the premises of the customer for the purpose of collecting an unpaid natural gas bill or required customer security deposit. The increase in this collection charge is required because of the increased cost to make these collection trips to the customer's premises. Petitioner charges for a collection trip when it becomes necessary to send an employee or agent to the customer's premises to collect a specific unpaid natural gas bill or a

customer security deposit. If multiple trips are required during any one billing cycle, only one such collection charge is assessed per billing cycle.

45. Q. Will you please explain Exhibit SMK-3, Page 22?

A. This page details the calculation to support a change in Petitioner's current returned check charge of $20.00, to a new proposed returned check charge of $21.00. This charge is to cover the cost of processing a returned check, including a direct debit to a customer's financial institution account, to Petitioner by Petitioner's financial institutions due to customer's insufficient funds. This proposed charge is less than the returned check charge currently in effect at many, if not most, commercial businesses in the areas Petitioner serves. The proposed applicable rate schedules also provide that any charges to Petitioner by its financial institutions will be added to the returned check charge and recovered from the applicable customer.

46. Q. Will you please explain Exhibit SMK-3, Page 23?

A. This Page shows the calculation of Petitioner's average investment in materials and operating supplies, as well as propane fuel inventory, based on the thirteen months ended September 30, 2006, for use in determining the book value of total rate base.

Also included on the Page is the calculation of Petitioner's 13-month average investment in stored natural gas applicable to the ANR Pipeline Service Area. This natural gas is purchased by Petitioner and stored in ANR Pipeline's allocated storage facilities in the Midland, Michigan area. Petitioner has no other natural gas storage, either on-system or off-system, available to it on the ANR Pipeline Service Area. The cost of natural gas in storage is carried in the rate base of Petitioner and not in the rate base of ANR Pipeline Company.

In the Texas Gas Service Area, allocated storage is handled differently, inasmuch as Texas Gas retained title and control of all natural gas in storage at the commencement of FERC Order 636 on November 1, 1993. Petitioner must replace any gas withdrawn from Texas Gas storage during the winter period in the following summer period. The cost of natural gas in storage is carried in the rate base of Texas Gas and not the Petitioner.

47. Q. Will you please explain Exhibit SMK-3, Page 24?

A. This page shows the summary of the lead/lag study calculation for required working capital for the twelve months ended June 30, 2006, which resulted in negative working capital requirements for both the ANR Pipeline and Texas Gas Service Areas.

48. Q. Will you please explain Exhibit SMK-3, Pages 25 through 25D?

A. Page 25 is a summary of Petitioner's rate base components at September 30, 2006. The average inventory figure was computed on Exhibit SMK-3, Page 23 and the lead/lag calculation for working capital requirements was computed on Exhibit SMK-3, Page 24.

Pages 25A, 25B, and 25C show the details of Utility Plant in Service at September 30, 2006 by functional plant and by FERC plant account number for Petitioner's two service areas. Utility plant common to both service areas was allocated based on customer count, a historically accepted allocation basis.

Page 25D details the calculation of the reserve for depreciation at September 30, 2006 for each of Petitioner's service areas.

49. Q. Will you please explain Exhibit SMK-3, Pages 26 and 26A?

A. Page 26 sets forth the computation of the factors used to allocate the costs of Petitioner's General Office staff and operations and certain other administrative and general costs, such as liability insurance, as identified in various Pages of this Exhibit. The computation is based

on the average ratios of net plant, operating revenues, volumes of gas sold and transported, and number of customers to totals for Petitioner and its subsidiary. The percentage allocation determined for Petitioner is 88.18%. Page 26A sets forth the computation of the factors used to assign Petitioner's share of the above allocated costs to Petitioner's two service areas. The computation is based on the same factors: net plant, operating revenues, volumes of gas sold and transported, and number of customers in each of the two service areas. The percentage allocation for the ANR Pipeline Service Area is 40.63% and for the Texas Gas Service Area, 59.37%.

50. Q. Will you please explain Exhibit SMK-3, Page 27 through 27C?

A. Page 27 summarizes the number of customers billed each month during the test period by service area and respective average customers billed. The results on Line 16 are used for the "Customer" factor on Page 26, Line 13 and on Page 26A, Line 13. Page 27 also reflects the pro forma adjustment to customer count for the decline in rate suffix 1 customers during the twelve months following June 30, 2006 (Page 3BB), included in the adjusted number of bills on Pages 28 and 29.

Pages 27A and 27B set forth the number of customers billed in each operating district and the percentages of each to the total of the respective pipeline service areas. Page 27C sets forth the number of customers for the Tell City operating district served by the respective pipeline service areas and included in the respective totals on Pages 27A and 27B. Pages 27A through 27C are summarized on Page 27.

51. Q. Will you please explain Exhibit SMK-3, Pages 28 through 28D?

A. Pages 28 and 28A summarize the adjusted test period bills and adjusted sales and transportation volumes for the two pipeline service areas by the rates in effect at the time of this filing.

Pages 28B and 28C show the calculation of adjusted test year sales and transportation volumes for the two service areas, by rate, beginning with the actual test year volumes and adjusting for the weather normalization, unbilled sales, customer changes, etc. adjustments previously discussed.

Page 28D shows the calculation of adjusted sales revenue by service area by rate for the test year beginning with actual test year sales revenues and adjusting for the various revenue adjustments previously discussed.

52. Q. Will you please explain Exhibit SMK-3, Page 29?

A. This Page details the calculation of the additional revenue resulting from the proposed changes to Petitioner's reconnection charge, collection charge, and returned check charge and the proposed additional revenue to be generated from gas sales and transportation sales.

53. Q. Will you please explain Exhibit SMK-3, Page 30?

A. This adjustment calculates the applicable taxes and public utility fee impact on the additional revenue required as determined on Page 32, Line 12.

54. Q. Will you please explain Exhibit SMK-3, Pages 31 through 31C?

A. Page 31 is the Total Company (combined pipeline service areas) proposed Statement of Income for the twelve months ended June 30, 2006 reflecting the proposed additional revenue requirements and adjustments for applicable taxes and public utility fee.

Pages 31A and 31B are the proposed Statements of Income for the twelve months ended June 30, 2006 for the ANR Pipeline Service Area and the Texas Gas Service Area respectively, with each reflecting the proposed additional revenue requirements and adjustments for applicable taxes and public utility fee.

Page 31C summarizes the adjustments for additional revenue required and the applicable taxes and public utility fee thereon for each of the two service areas on a line-by-line basis and reflected in Pages 31A and 31B.

55. Q. Will you please explain Exhibit SMK-3, Pages 32 and 32A?

A. Page 32 details Petitioner's capitalization at September 30, 2006 and the calculation of the overall rate of return using an assigned return on equity of 11.75 percent. This Page sets forth the proposed utility operating income for Petitioner and by the two service areas based on the 11.75 percent return on equity, and the required additional utility operating income necessary to achieve the proposed utility operating income. Lines 12 through 14 of Page 32 show the calculation of the additional revenue required to generate the proposed additional utility operating income, by applying a 1.6812 revenue conversion factor to the proposed utility operating income, and results in total proposed operating revenues.

Page 32A details the calculation of the1.6812 revenue conversion factor.

56. Q. Will you please explain Exhibit SMK-3, Page 33?

A. This Page sets forth the calculation of the amount (volumes) and percentage of unaccounted for gas to be included in base rates and provides the basis for the calculation of the base cost of gas applicable to unaccounted for gas for the GCA mechanism per Pages 34A and 34B. The average percentage of unaccounted for gas is based on the average of the results of five

(5) twelve – month periods ending August 31, 2006, coinciding with such evaluation in Petitioner's GCA filings.

57. Q. Will you please explain Exhibit SMK-3, Page 34 and 34A?

A. These Pages set forth the calculation of the base cost of gas to be used for the GCA mechanism following a Commission order in this proceeding, and will be updated if necessary to reflect the Commission's findings and final order in this Cause. The results shown are based on all applicable adjustments proposed in Exhibit SMK-3.

58. Q. Will you please explain Exhibit SMK-3, Pages 35 and 35A?

A. These Pages list by year the Net Income to common shareholders for the period 1950 through June 30, 2006 and the amount of common stock dividends paid during the same period. Less than 33% of Petitioner's available income has been paid to shareholders as dividends. The balance has been reinvested in Petitioner's utility operations and used to pipe new service areas, extend facilities in existing service areas, upgrade transmission and distribution plant in existing areas, and other prudent and necessary expenditures required to effectively and safely serve Petitioner's customers. The level of dividend payout for this industry is considerably higher. Since October 2003, the payment of a dividend on the common stock of Petitioner has been suspended due to the low level of net income.

59. Q. Will you please explain Exhibit SMK-3, Pages 36 and 36A?

A. These Pages list by year the investment made by Petitioner in Utility Plant in Service from 1949 through June 30, 2006. A review of Pages 35 and 36 indicate that Petitioner has reinvested substantial funds in the form of new plant and plant improvements. This is further supported by the absence of any long-term debt or preferred stock outstanding for many years.

60. Q. Will you please explain Exhibit SMK-3, Page 37?

A. This Page is a listing by year of the general and umbrella liability coverage and related premiums paid for the periods July 1, 1976 through June 30, 2007, including the levels of coverage during the applicable periods.

61. Q. Have you reviewed your operating revenues and operating expenses in connection with this Cause?

A. Yes. Petitioner has adjusted those operating revenues and operating expenses, where Petitioner has been able to determine that fixed, known, and measurable changes will occur during the twelve months following June 30, 2006, and will affect a particular operating revenue or operating expense. There are various expenses which are expected, or likely, to increase during the next twelve months (contracted services, wages and benefits, postage rates, utility bills, gasoline purchases, operating supplies and materials, etc) but they are not sufficiently fixed, known, and measurable for Petitioner to specifically identify or quantify. Additionally, no costs have been included in operating expenses for Petitioner's employee retirement income plan (Plan) for the test period, nor for many years preceding the test period, due to the funded status of the Plan.

62. Q. Does this conclude your direct testimony in the Cause?

A. Yes, it does.

OHIO VALLEY GAS CORPORATION

Balance Sheet at September 30, 2006

LN NO	(1) ASSETS AND OTHER DEBITS	(2)
	UTILITY PLANT	
1	Utility Plant in Service	$52,367,323
2	Less Accumulated Provision for Depreciation	23,442,150
3	**Net Utility Plant in Service**	$28,925,174
4	Construction Work in Progress	399,549
5	**Total Utility Plant**	$29,324,722
	OTHER PROPERTY AND INVESTMENTS	
6	Non-Utility Property	$928,695
7	Investment in Associated Companies	4,346,363
8	**Total Other Property and Investments**	$5,275,058
	CURRENT ASSETS AND ACCRUED ASSETS	
9	Cash	$1,599,267
10	Special Deposits	624
11	Working Funds	23,846
12	Temporary Cash Investments	1,000,000
13	Notes Receivable	1,132
14	Accounts Receivable	(65,405)
15	Other Accounts Receivable	285,693
16	Accumulated Provision for Uncollectible Accounts	(185,743)
17	Accounts Receivable from Associated Companies	124,882
18	Fuel Stock	213,465
19	Plant Materials and Operating Supplies	770,176
20	Stores Expense	141,643
21	Gas Stored Underground - Current	3,779,994
22	Prepayments	263,456
23	Accrued Utility Revenue	441,124
24	Interest & Dividends Receivable	(815)
25	**Total Current Assets**	$8,393,339
	DEFERRED DEBITS	
26	Miscellaneous Deferred Debits	$41,293
27	**TOTAL ASSETS**	$43,034,412

OHIO VALLEY GAS CORPORATION

Balance Sheet at September 30, 2006

LN NO	(1) SHAREHOLDERS' EQUITY AND LIABILITIES	(2)
	SHAREHOLDERS' EQUITY	
1	Common Stock Issued - No Par - No Stated Value	$23,117,015
2	Treasury Stock	(1,947,077)
3	Miscellaneous Paid-in Capital	24,438
4	Unappropriated Retained Earnings	8,544,531
5	Retained Earnings of Subsidiary	346,363
6	**Total Shareholders' Equity**	$30,085,270
	CURRENT AND ACCRUED LIABILITIES	
7	Notes Payable	$2,000,000
8	Accounts Payable	2,409,076
9	Accounts Payable to Associated Companies	2,419,968
10	Customer Deposits	2,371,153
11	Taxes Accrued	(226,809)
12	Interest Accrued	772,739
13	Tax Collections Payable	76,949
14	Miscellaneous Current and Accrued Liabilities	686,709
15	**Total Current and Accrued Liabilities**	$10,509,786
	DEFERRED CREDITS	
16	Customer Advances for Construction	$262,582
17	Other Deferred Credits	(2,363,061)
18	**Total Deferred Credits**	($2,100,479)
	CONTRIBUTIONS IN AID OF CONSTRUCTION	
19	Contributions in Aid of Construction	$258,667
	ACCUMULATED DEFERRED INCOME TAXES	
20	Accumulated Deferred Income Taxes	$4,281,167
21	**TOTAL SHAREHOLDERS' EQUITY AND LIABILITIES**	$43,034,412

OHIO VALLEY GAS CORPORATION

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	OPERATING REVENUES			
1	Gas Sales	$36,717,411	$16,627,645	$20,089,766
2	Forfeited Discounts	138,638	61,471	77,167
3	Miscellaneous Operating Revenues	112,209	39,211	72,997
4	Transportation Revenues	664,002	218,039	445,964
5	**Total Operating Revenues**	$37,632,260	$16,946,366	$20,685,894
	OPERATING EXPENSES			
6	Production	$4,448	$863	$3,586
7	Purchased Gas	27,573,704	12,399,807	15,173,897
8	Transmission	176,659	15,513	161,146
9	Distribution	2,361,364	1,011,548	1,349,816
10	Customer Accounting	1,287,015	605,136	681,879
11	Administrative & General	2,615,164	1,087,323	1,527,841
12	Depreciation	1,384,285	514,920	869,364
13	Taxes - General	1,437,748	628,612	809,137
14	Taxes - Income - State	87,416	70,489	16,926
15	Taxes - Income - Federal	219,979	201,663	18,317
16	Provisions for Deferred Federal Income Taxes	30,414	6,040	24,374
17	**Total Operating Expenses**	$37,178,196	$16,541,914	$20,636,283
18	**Utility Operating Income**	**$454,064**	**$404,452**	**$49,611**
	OTHER INCOME			
19	Other Income - Net	$66,653	$24,720	$41,934
	INCOME DEDUCTIONS			
20	Interest on Debt to Associated Companies	$0	$0	$0
21	Other Interest	138,116	67,482	70,634
22	Miscellaneous Income Deductions	12,349	8,822	3,527
23	Allow for Funds Used During Construction	(36,076)	(19,006)	(17,070)
24	**Total Income Deductions**	$114,389	$57,298	$57,091
25	**NET INCOME**	$406,328	$371,874	$34,453

OHIO VALLEY GAS CORPORATION

Detailed Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	GAS SALES			
1	Residential Non-Heating	$48,982.84	$18,035.08	$30,947.76
2	Residential Heating	22,230,803.96	9,209,094.40	13,021,709.56
3	Commercial Non-Heating	648,841.79	349,025.18	299,816.61
4	Commercial Heating	5,908,597.07	2,638,097.34	3,270,499.73
5	Industrial Firm	4,620,065.99	2,958,310.74	1,661,755.25
6	Industrial Interruptible	592,047.07		592,047.07
7	Public Authorities	2,430,312.27	1,203,225.48	1,227,086.79
8	Unbilled Revenue	237,760.00	251,857.00	(14,097.00)
9	**Total Gas Sales**	$36,717,410.99	$16,627,645.22	$20,089,765.77
	OTHER OPERATING REVENUES			
10	487 - Forfeited Discounts	$138,638.17	$61,470.95	$77,167.22
11	488 - Miscellaneous Service Revenues	112,209.10	39,211.44	72,997.66
12	489 - Transportation Revenues	664,002.44	218,038.80	445,963.64
13	**Total Other Operating Revenues**	$914,849.71	$318,721.19	$596,128.52
14	**Total Operating Revenues**	$37,632,260.70	$16,946,366.41	$20,685,894.29
	PRODUCTION			
15	717- Liquified Petroleum Gas Expense	$1,210.05	197.53	1012.52
16	735 - Miscellaneous Production Expense	$1,947.15	$0.00	$1,947.15
17	**Total Production Operation Expense**	$3,157.20	$197.53	$2,959.67
18	741 - Maintenance of Structures & Improvements	275.84	110.84	165.00
19	742 - Maintenance of Production Equipment	1,015.23	554.40	460.83
20	**Total Production Maintenance Expense**	$1,291.07	$665.24	$625.83
21	**Total Production Expense**	$4,448.27	$862.77	$3,585.50

OHIO VALLEY GAS CORPORATION

Detailed Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	PURCHASED GAS			
1	804 - Purchased Gas	$30,336,501.50	$13,569,782.14	$16,766,719.36
2	805 - Amortization of Variances & Refunds	(2,762,797.04)	(1,169,975.00)	(1,592,822.04)
3	**Total Purchased Gas**	$27,573,704.46	$12,399,807.14	$15,173,897.32
	TRANSMISSION			
4	850 - Operation Supervision & Engineering	$39,325.03	$14.50	$39,310.53
5	856 - Mains Expense	38,490.82	6,158.96	32,331.86
6	857 - Measuring & Regulating Expense	4,412.87	4,412.87	
7	859 - Other Expense	39,797.68	135.15	39,662.53
8	860 - Rent	3,600.00		3,600.00
9	**Total Transmission Operation Expense**	$125,626.40	$10,721.48	$114,904.92
10	861 - Maintenance, Supervision & Engineering	$1,413.04	$438.87	$974.17
11	863 - Maintenance Mains	33,893.35	364.76	33,528.59
12	865 - Maint of Measuring & Reg Station Equip	15,726.13	3,988.28	11,737.85
13	**Total Transmission Maintenance Expense**	$51,032.52	$4,791.91	$46,240.61
14	**Total Transmission Expense**	$176,658.92	$15,513.39	$161,145.53
	DISTRIBUTION			
15	870 - Operation Supervision & Engineering	$739,466.31	$314,914.01	$424,552.30
16	874 - Main & Service Expense	187,850.75	50,904.33	136,946.42
17	875 - Measuring & Regulating Expense	467.22	340.29	126.93
18	878 - Meter & House Regulator Expense	292,659.57	86,754.87	205,904.70
19	879 - Customer Installation Expense	189,959.05	114,612.97	75,346.08
20	880 - Other Expense	140,191.25	75,815.65	64,375.60
21	881 - Rent	5,633.00	81.00	5,552.00
22	**Total Distribution Operation Expense**	$1,556,227.15	$643,423.12	$912,804.03

OHIO VALLEY GAS CORPORATION

Detailed Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
1	885 - Maintenance Supervision & Engineering	$117,918.09	$40,624.92	$77,293.17
2	886 - Maintenance Structures & Improvements	95.07		95.07
3	887 - Maintenance of Mains	263,009.13	151,398.66	111,610.47
4	889 - Maintenance Measuring & Regulating Equipment	63,402.95	22,048.15	41,354.80
5	890 - Maintenance Meas. & Reg. Equipment - Industrial	24,548.35	11,550.88	12,997.47
6	891 - Maintenance City Gate Stations	5,481.11	3,709.92	1,771.19
7	892 - Maintenance Services	47,906.51	26,247.67	21,658.84
8	893 - Maintenance Meter & Regulators	153,409.91	70,387.17	83,022.74
9	894 - Maintenance Other Equipment	129,365.74	42,157.30	87,208.44
10	**Total Distribution Maintenance Expense**	$805,136.86	$368,124.67	$437,012.19
11	**Total Distribution Expense**	$2,361,364.01	$1,011,547.79	$1,349,816.22
	CUSTOMER ACCOUNTING			
12	901 - Supervision	$146,762.01	$87,829.11	$58,932.90
13	902 - Meter Reading Expense	230,030.63	104,557.39	125,473.24
14	903 - Collection Expense	525,852.66	258,769.24	267,083.42
15	904 - Uncollectible Expense	76,210.80	25,814.85	50,395.95
16	905 - Miscellaneous Expense	67,680.51	28,837.24	38,843.27
17	907 - Billing Department Expense	240,478.87	99,328.54	141,150.33
18	**Total Customer Accounting**	$1,287,015.48	$605,136.37	$681,879.11
	SALES PROMOTION			
19	914 - Revenue - M&J Work	($89,788.41)	($18,969.98)	($70,818.43)
20	915 - Expense - M&J Work	65,662.72	11,823.36	53,839.36
21	**Total Sales Promotion**	($24,125.69)	($7,146.62)	($16,979.07)

OHIO VALLEY GAS CORPORATION

Detailed Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	ADMINISTRATIVE & GENERAL			
1	920.1 - Officers Salaries	$445,605.63	$182,847.45	$262,758.18
2	920.2 - General Office Salaries	298,288.16	122,407.36	175,880.80
3	921.1 - Officers Expenses	21,587.36	8,858.33	12,729.03
4	921.2 - General Office Expense	34,438.64	14,132.06	20,306.58
5	921.3 - General Office Supplies & Expense	126,823.70	52,012.66	74,811.04
6	923.1 - Outside Services	75,132.37	30,833.34	44,299.03
7	924.1 - Property Insurance Expense	13,965.00	5,730.54	8,234.46
8	925.1 - Liability Insurance Expense	237,010.47	97,256.84	139,753.63
9	925.2 - Worker's Compensation Cost	69,758.28	28,626.20	41,132.08
10	925.3 - Miscellaneous Insurance Expense	847.91	224.83	623.08
11	925.4 - Worker's Compensation Benefits	8,588.59	2,307.60	6,280.99
12	926.1 - Group Medical/Dental Insurance Expense	641,395.47	263,204.57	378,190.90
13	926.3 - Vacation Pay	248,258.63	101,864.10	146,394.53
14	926.4 - Holiday Pay	155,822.78	69,789.73	86,033.05
15	926.5 - Sick Pay	95,578.15	52,629.12	42,949.03
16	926.6 - Education Expense	27,785.88	11,697.29	16,088.59
17	926.7 - Employee Group Functions	20,999.48	8,154.21	12,845.27
18	926.8 - Jury Duty Pay	233.53	160.30	73.23
19	926-9 - Fees for School, Etc.	9,184.52	3,768.67	5,415.85
20	930.1 - Miscellaneous General Expense	4,002.68	1,617.30	2,385.38
21	**Total Administrative & General Operation Exp.**	$2,535,307.23	$1,058,122.50	$1,477,184.73
22	932.1 - Maintenance General Plant	$79,856.95	$29,200.96	$50,655.99
23	**Total Maintenance General Plant**	$79,856.95	$29,200.96	$50,655.99
24	**Total Administrative & General Maintenance Exp.**	$2,615,164.18	$1,087,323.46	$1,527,840.72
25	**Total Operation and Maintenance Expense**	$33,994,229.63	$15,113,044.30	$18,881,185.33
	ACCOUNT 403 - DEPRECIATION EXPENSE			
26	403 - Depreciation Expense	$1,384,284.68	$514,920.21	$869,364.47
27	Total Depreciation Expense	$1,384,284.68	$514,920.21	$869,364.47

OHIO VALLEY GAS CORPORATION

Detailed Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	ACCOUNT 408 - TAXES - GENERAL			
1	408.1 - Real Estate & Personal Property Tax-IN	$522,466.55	$199,981.74	$322,484.81
2	408.1 - Real Estate & Personal Property Tax-OH	6,544.44	6,544.44	
3	408.2 - Indiana Utility Receipt Tax	542,847.62	245,538.31	297,309.31
4	408.2 - Ohio Excise Tax and MCF Tax	45,215.45	45,215.45	
5	408.3 - Federal Insurance Contributions Act	292,452.32	129,203.26	163,249.06
6	408.4 - Federal Unemployment Tax	5,503.48	2,485.86	3,017.62
7	408.5 - State Unemployment Tax	14,278.34	6,411.84	7,866.50
8	408.6 - Public Utility Fee	29,959.15	12,871.74	17,087.41
9	408.9 - Miscellaneous Tax	(21,519.05)	(19,640.86)	(1,878.19)
10	**Total Taxes - General**	$1,437,748.30	$628,611.78	$809,136.52
	ACCOUNT 409 - TAXES - INCOME			
11	409.1 - Income Tax - Federal	$219,979.34	$201,662.76	$18,316.58
12	409.2 - Income Tax - State	87,415.61	70,489.18	16,926.43
13	**Total Taxes - Income**	$307,394.95	$272,151.94	$35,243.01
	ACCOUNT 410 - PROVISION FOR DEFERRED TAXES			
14	410.1 - Prov. Def. Fed. Inc. Tax - Depr.	$113,690.13	$42,213.98	$71,476.15
15	410.3 - Prov Def. Fed Inc. Tax - Bad Debts	3,467.95	1,436.16	2,031.79
16	410.5 - Prov Def. Fed Inc. Tax - Acc. Vacation	1,217.76	504.20	713.56
17	410.8 - Prov. Def. Fed. Inc. Tax - Prepayments	(111,624.10)	(45,806.28)	(65,817.82)
18	410.2 - Prov Def. State Inc. Tax - Depr	52,880.32	19,676.77	33,203.55
19	410.4 - Prov Def. State Inc. Tax - Bad Debts	947.52	392.40	555.12
20	410.6 - Prov Def. State Inc. Tax - Acc Vacation	332.73	137.78	194.95
21	410.9 - Prov. Def. State Inc. Tax - Prepayments	(30,498.37)	(12,515.37)	(17,983.00)
22	**Total Provision for Deferred Taxes**	$30,413.94	$6,039.64	$24,374.30
	INTEREST INCOME			
23	419.1 - Interest Income - Taxable	$76,433.77	$31,363.61	$45,070.16
24	419.7 - State Income Tax Expense	(6,221.62)	(2,552.97)	(3,668.65)
25	419.8 - Federal Income Tax Expense	(23,872.13)	(9,795.62)	(14,076.51)
26	**Total Interest Income**	$46,340.02	$19,015.02	$27,325.00

OHIO VALLEY GAS CORPORATION

Detailed Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	MISCELLANEOUS NONOPERATING INCOME			
1	421.1 - Miscellaneous Nonoperating Income	$818.14	$556.66	$261.48
3	421.3 - State Income Tax Expense	511.78	193.53	318.25
4	421.4 - Federal Income Tax Expense	1,963.92	742.73	1,221.19
5	421.9 - Miscellaneous Expense	(7,106.16)	(2,934.69)	(4,171.47)
6	**Total Miscellaneous Operating Income**	($3,812.32)	($1,441.77)	($2,370.55)
	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
7	**420 - Allowance for Funds Used During Construction**	($36,075.86)	($19,006.16)	($17,069.70)
8	**Total Allowance for Funds Used During Construction**	($36,075.86)	($19,006.16)	($17,069.70)
	MISCELLANEOUS INCOME DEDUCTIONS			
9	426 - Miscellaneous Income Deductions	$12,349.37	$8,822.34	$3,527.03
10	**Total Miscellaneous Income Deductions**	$12,349.37	$8,822.34	$3,527.03
	INTEREST ON DEBT TO ASSOCIATED COMPANIES			
11	430 - Interest on Debt to Associated Companies	$0.00	$0.00	$0.00
12	**Total Interest on Debt to Associated Companies**	$0.00	$0.00	$0.00
	OTHER INTEREST EXPENSE			
13	431.1 - Interest on Customer Deposits	$138,075.93	$67,461.49	$70,614.44
14	431.2 - Interest on Employee Stock Purchase Plan	39.69	20.23	19.46
15	**Total Interest Expense**	$138,115.62	$67,481.72	$70,633.90
16	**NET INCOME**	$406,327.77	$371,873.89	$34,453.88

OHIO VALLEY GAS CORPORATION

Page	Description of Page
1	Total Company Adjusted Statement of Income for the Twelve Months Ended June 30, 2006.
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1C - 1E	Summary of Year End Adjustments Line by Line by service areas as of June 30, 2006.
2	Summary of Adjustment to compensate for GCA leveling and normalization.
2A - 2D	Details of Adjustment to compensate for GCA leveling and normalization.
3	Summary of Adjustment to Transportation Customer Revenues.
3A – 3J	Details of Proforma Transportation Customer Revenues and Volumes.
3D	Details of Adjustment to Sales Customer Revenues.
3BB	Details of Adjustment for Customer Decline
4	Summary of Unbilled Revenue Adjustment.
4A – 4C	Details of Adjustment for Unbilled Revenues.
5	Summary of Adjustment for Weather Normalization.
5A - 5B	Details of Adjustment for Weather Normalization.
6	Summary of Adjustment for Annualizing Purchased Gas Rates.
6A - 6D	Details of Adjustment for Annualizing Purchased Gas Rates.
7	Details of Adjustment for Annualizing Payroll Rates.
8	Details of Adjustment for FICA/ST UC/FUTA Payroll Taxes based on Adjusted Payroll Charges and Changes in Rates and Bases.
9	Details of Adjustment for New Pipeline Safety Act Expenses Subject to Recovery Through Annual Tracker.

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11	Summary of Adjustment for Postage Rates.
11A - 11B	Details of Adjustment for Postage Rates.
12	Details of Adjustment for Rate Case Expense.
13	Details of Adjustment for Group Insurance.
13A	Details of Adjustment for Scholarships.
13B - 13D	Details of Adjustment for Worker's Compensation Insurance.
14	Details of Adjustment for Public Utility Fee.
15	Details of Adjustment for Indiana Utility Receipts Tax.
16	Details of Adjustment for Depreciation Expense due to Plant Additions.
16A	Details of Adjustment for Depreciation Expense due to Rate Change on Certain Plant.
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18	Details of Adjustment for Indiana Adjusted Gross Income Tax Expense.
19	Details of Adjustment for Federal Income Tax Expense.
20	Details of Calculation of Proposed Change in the Reconnection Charge.
20A	Supporting Details for Proposed Change in Reconnection, Collection, and Returned Check Charges.
21	Details of Calculation of Proposed Change in the Collection Charge.
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24	Summary of Lead/Lag Study for Working Capital Requirements.
25	Summary of Various Components of Rate Base at September 30, 2006.
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26	Details of Formula Used for Allocation of Certain Expenses Between Petitioner and its Subsidiary.
26A	Details of Formula Used for Allocation of Certain Expenses Between Petitioner's Two Pipeline Service Areas.
27	Summary of Customers Billed for the Twelve Months Ended June 30, 2006.
27A - 27C	Details of Customers Billed for the Twelve Months Ended June 30, 2006 in Petitoner's Two Service Areas.
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30	Details of Effect on Taxes and Other Fees due to Proposed Revenue Increase.
31	Total Company Proposed Statement of Income for the Twelve Months Ended June 30, 2006.

OHIO VALLEY GAS CORPORATION

Page	Description of Page
31A - 31B	ANR Pipeline and Texas Gas Service Areas Proposed Statement of Income for the Twelve Months Ended June 30, 2006.
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33	Calculation of Unaccounted For Gas Percentage.
34 - 34A	Details of Calculation of Base Cost of Gas for GCA Mechanism by Service Area.
35 – 35A	Schedule of Net Income to Common Shareholders and Dividends Paid from 1950 through June 30, 2006.
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37	Analysis of General and Umbrella Liability Coverage and Premiums Paid from July 1, 1976 through June 30, 2007.

OHIO VALLEY GAS CORPORATION

Adjusted Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1) TOTAL COMPANY	(2) PER BOOKS AT 6-30-2006	(3) YEAR END ADJUSTMENTS	(4) ADJUSTED AT 6-30-2006
	OPERATING REVENUES			
1	Gas Sales	$36,717,411	$3,317,434	$40,034,845
2	Forfeited Discounts	138,638		138,638
3	Miscellaneous Operating Revenues	112,209		112,209
4	Transportation Revenues	664,002	(90,024)	573,978
5	**Total Operating Revenues**	$37,632,260	$3,227,410	$40,859,670
	OPERATING EXPENSES			
6	Production	$4,448	$277	$4,725
7	Purchased Gas	27,573,704	3,816,675	31,390,379
8	Transmission	176,659	(29,229)	147,430
9	Distribution	2,361,364	125,775	2,487,139
10	Customer Accounting	1,287,015	68,425	1,355,440
11	Administrative & General	2,615,164	100,409	2,715,573
12	Depreciation	1,384,285	131,865	1,516,150
13	Taxes - General	1,437,748	41,734	1,479,482
14	Taxes - Income - State	87,416	(81,820)	5,596
15	Taxes - Income - Federal	219,979	(338,571)	(118,592)
16	Provisions for Deferred Income Taxes	30,414		30,414
17	**Total Operating Expenses**	$37,178,196	$3,835,540	$41,013,736
18	**Utility Operating Income**	**$454,064**	**($608,130)**	**($154,066)**

OHIO VALLEY GAS CORPORATION

Adjusted Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1) ANR PIPELINE SYSTEM	(2) PER BOOKS AT 6-30-2006	(3) YEAR END ADJUSTMENTS	(4) ADJUSTED AT 6-30-2006
	OPERATING REVENUES			
1	Gas Sales	$16,627,645	$1,738,842	$18,366,487
2	Forfeited Discounts	61,471		61,471
3	Miscellaneous Operating Revenues	39,211		39,211
4	Transportation Revenues	218,039	$6	218,045
5	**Total Operating Revenues**	$16,946,366	$1,738,848	$18,685,214
	OPERATING EXPENSES			
6	Production	$863	$69	$932
7	Purchased Gas	12,399,807	1,814,709	14,214,516
8	Transmission	15,513	311	15,824
9	Distribution	1,011,548	56,042	1,067,590
10	Customer Accounting	605,136	33,877	639,013
11	Administrative & General	1,087,323	45,067	1,132,390
12	Depreciation	514,920	59,990	574,910
13	Taxes - General	628,612	20,298	648,910
14	Taxes - Income - State	70,489	(20,487)	50,002
15	Taxes - Income - Federal	201,663	(97,042)	104,621
16	Provisions for Deferred Income Taxes	6,040		6,040
17	**Total Operating Expenses**	$16,541,914	$1,912,834	$18,454,748
18	**Utility Operating Income**	**$404,452**	**($173,985)**	**$230,467**

OHIO VALLEY GAS CORPORATION

Adjusted Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1) TEXAS GAS SYSTEM	(2) PER BOOKS AT 6-30-2006	(3) YEAR END ADJUSTMENTS	(4) ADJUSTED AT 6-30-2006
	OPERATING REVENUES			
1	Gas Sales	$20,089,766	$1,578,592	$21,668,358
2	Forfeited Discounts	77,167		77,167
3	Miscellaneous Operating Revenues	72,997		72,997
4	Transportation Revenues	445,964	(90,030)	355,934
5	**Total Operating Revenues**	$20,685,894	$1,488,561	$22,174,455
	OPERATING EXPENSES			
6	Production	$3,586	$208	$3,794
7	Purchased Gas	15,173,897	2,001,966	17,175,863
8	Transmission	161,146	(29,540)	131,606
9	Distribution	1,349,816	69,733	1,419,549
10	Customer Accounting	681,879	34,548	716,427
11	Administrative & General	1,527,841	55,342	1,583,183
12	Depreciation	869,364	71,875	941,239
13	Taxes - General	809,137	21,437	830,574
14	Taxes - Income - State	16,926	(61,333)	(44,407)
15	Taxes - Income - Federal	18,317	(241,529)	(223,212)
16	Provisions for Deferred Income Taxes	24,374		24,374
17	**Total Operating Expenses**	$20,636,283	$1,922,706	$22,558,989
18	**Utility Operating Income**	**$49,611**	**($434,145)**	**($384,534)**

OHIO VALLEY GAS CORPORATION

Summary Of Year End Adjustments As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) ANR PIPELINE DETAIL ADJ.	(4) TEXAS GAS DETAIL ADJ.
	OPERATING REVENUES			
	GAS SALES			
1	GCA Leveling & Normalization	2	$1,244,124	$1,431,699
2	Customer Changes	3AA	($154,426)	($692,500)
3	Weather Normalization	5	$760,428	$932,966
4	Customer Decline	3BB	($111,284)	($93,573)
5	**Total Gas Sales Adjustments**		$1,738,842	$1,578,592
	OTHER OPERATING REVENUES			
6	Transportation - Net Change	3	$6	($90,030)
7	**Total Other Operating Revenues Adjustments**		$6	($90,030)
8	**Total Operating Revenues**		$1,738,848	$1,488,561
	OPERATING EXPENSES			
	PRODUCTION			
9	Payroll Adjustment	7	$69	$208
10	**Total Production Adjustments**		$69	$208
	PURCHASED GAS			
11	Purchased Gas Adjustment	6	$1,814,709	$2,001,966
12	**Total Purchased Gas Adjustments**		$1,814,709	$2,001,966
	TRANSMISSION			
13	Payroll Adjustment	7	311	6,431
14	Pipeline Safety Act Compliance Adjustment	9	0	(35,971)
15	**Total Transmission Adjustments**		$311	($29,540)
	DISTRIBUTION			
16	Payroll Adjustment	7	56,042	69,733
17	**Total Distribution Adjustments**		$56,042	$69,733

OHIO VALLEY GAS CORPORATION

Summary Of Year End Adjustments As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) ANR PIPELINE DETAIL ADJ.	(4) TEXAS GAS DETAIL ADJ.
	CUSTOMER ACCOUNTING			
1	Payroll Adjustment	7	$35,644	$37,097
2	Postage Adjustment	11	(1,767)	(2,549)
3	**Total Customer Accounting Adjustments**		$33,877	$34,548
	ADMINISTRATIVE & GENERAL			
4	Payroll Adjustment	7	$57,494	$79,724
5	Group Insurance Adjustment	13	(29,416)	(36,569)
6	Scholarship Adjustment	13A	7,503	(3,289)
7	Worker's Compensation Adjustment	13D	(1,652)	(5,982)
8	Rate Case & Outside Professional Service	12	15,936	23,287
9	Liability Insurance Adjustment	10	(4,798)	(1,829)
10	**Total Administrative & General Adjustments**		$45,067	$55,342
	DEPRECIATION			
11	Annualized Depreciation Exp Adjust	16	$16,117	$14,779
12	Depreciation Rate Adjustment	16A	$43,873	$57,096
13	**Total Depreciation Expense Adjustment**		$59,990	$71,875
	TAXES - GENERAL			
14	FICA/State UC/FUTA Tax Adjustment	8	$9,687	$18,447
15	Public Utility Fee Adjustment	14	5,825	6,228
16	Indiana Utility Receipts Tax Adjustment	15	24,344	20,840
17	Real Estate & Personal Property Tax Adjustment	17	(19,558)	(24,078)
18	**Total Taxes - General Adjustments**		$20,298	$21,437
	TAXES - INCOME - STATE			
19	Adjusted Gross Income Tax	18	($20,487)	($61,333)
20	**Total Taxes - Income - State Adjustments**		($20,487)	($61,333)
	TAXES - INCOME - FEDERAL			
21	Federal Income Tax Adjustment	19	($97,042)	($241,529)
22	**Total Taxes - Income - Federal**		($97,042)	($241,529)

OHIO VALLEY GAS CORPORATION

Summary Of Year End Adjustments As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) ANR PIPELINE DETAIL ADJ.	(4) TEXAS GAS DETAIL ADJ.
1	Total Operating Expenses		$1,912,834	$1,922,706
2	Net Effect on Utility Operating Income		($173,985)	($434,145)
3	Total Operating Expense Adj Applicable to Indiana Adjust Gross Income Tax Calculation		$2,006,019	$2,204,728
4	Total Operating Expense Applicable to Federal Income Tax Calculation		$2,009,876	$2,164,235

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate For Leveling of GCA Factors And Normalization Of GCA Factors

LN NO	(1) MONTH	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
	GCA LEVELING ADJUSTMENT			
1	Annualized revenue from annualized GCA Factors (Pg. 2A, L13, Pg. 2B, L13)	$13,081,321	$5,560,261	$7,521,060
	Revenues generated by various GCA factors for the twelve months ending June 30, 2006 (Pages 2C and 2D):			
2	July 2005	$11,010	($24,453)	$35,463
3	August	59,279	28,559	30,720
4	September	106,268	73,400	32,868
5	October	415,553	195,136	220,417
6	November	876,944	400,444	476,500
7	December	1,644,043	756,338	887,705
8	January 2006	2,038,117	777,500	1,260,617
9	February	2,275,686	893,832	1,381,854
10	March	1,822,311	717,906	1,104,405
11	April	529,914	242,227	287,687
12	May	399,852	165,593	234,259
13	June 2006	226,521	89,655	136,866
14	Totals for twelve months ended 6-30-06	10,405,498	4,316,137	6,089,361
15	Year End Adjustment	$2,675,823	$1,244,124	$1,431,699
16	Applicable Rate Suffix 1	$3,079,629	$1,281,583	$1,798,046
17	Applicable Rate Suffix 2	(218,946)	$145	(219,091)
18	Applicable Rate Suffix 3	(198,305)	(46,409)	(151,896)
19	Applicable Rate Suffix 4	13,445	8,805	4,640
20	Total	$2,675,823	$1,244,124	$1,431,699

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate For Leveling Of GCA Factors

	(1)	(2)	(3)	(4)	(5)	(6)
LN NO	ANR PIPELINE SYSTEM	TOTALS	RATE 11	RATE 12	RATE 13	RATE 14
1	Demand allocators from I.U.R.C. Cause No. 37353-GCA87	100.00%	89.84%	9.78%	0.41%	-0.03%
2	Adjusted cost of purchased gas (Pg. 6B, L20)	$14,214,516				
3	Cost of unaccounted for gas and Company use gas (Pg. 6B, L14 plus L16 times L23)	$161,256	$146,066	$12,659	$1,677	$854
4	Demand cost in L2	$2,137,725	$1,920,532	$209,070	$8,765	($642)
5	Commodity cost less cost of unaccounted for gas and Company use gas in L2	$11,915,535	$10,793,092	$935,369	$123,922	$63,152
6	Test year adjusted sales	13,229,687	11,983,754	1,038,195	137,321	70,417
7	Line 6 percent of total	100.00%	90.58%	7.85%	1.04%	0.53%
8	Non-allocated cost per Therm sales (L5/L6)		$0.9006	$0.9010	$0.9024	$0.8968
9	Demand cost per therm sales (L4/L6)		$0.1603	$0.2014	$0.0638	($0.0091)
10	Total cost of gas allocated (L8 +L9)		$1.0609	$1.1024	$0.9662	$0.8877
11	Less base cost of gas from I.U.R.C. Cause No. 42239		$0.6431	$0.6471	$0.5583	$0.5363
12	Annualized GCA factor per therm (L10 - L11)		$0.4178	$0.4553	$0.4079	$0.3514
13	Annualized revenues from GCA factor (L6 X L12)	$5,560,261	$5,006,813	$472,690	$56,013	$24,745

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate For Leveling Of GCA Factors

(1)	(2)	(3)	(4)	(5)	(6)
LN NO TEXAS GAS SYSTEM	TOTALS	RATE 41	RATE 42	RATE 43	RATE 44
1 Demand allocators from I.U.R.C. Cause No. 37354-GCA87	100.00%	92.99%	1.96%	4.86%	0.19%
2 Adjusted cost of purchased gas (Pg. 6D, L23)	$17,175,863				
3 Cost of unaccounted for gas and Company use gas (Pg. 6D, L5L7,L13&L15 times L26)	$258,742	$254,861	$0	$3,364	$517
4 Demand cost in L2	$1,628,188	$1,514,052	$31,912	$79,130	$3,094
5 Commodity cost less cost of unaccounted for gas and Company use gas in L2	$15,288,933	$15,059,599	$0	$198,756	$30,578
6 Test year adjusted therm sales	14,961,473	14,736,712	0	193,962	30,799
7 Line 6 percent of total	100.00%	98.50%	0.00%	1.30%	0.20%
8 Non-allocated cost per Therm sales (L5/L6)		$1.0219	$0.0000	$1.0247	$0.9928
9 Demand cost per therm sales (L4/L6)		$0.1027	$0.0000	$0.4080	$0.1005
10 Total cost of gas allocated (L8 +L9)		$1.1246	$0.0000	$1.4327	$1.0933
11 Less base cost of gas from I.U.R.C. Cause No. 42239		$0.6266	$0.5450	$0.5866	$0.5067
12 Annualized GCA factor per therm (L10 - L11)		$0.4980	($0.5450)	$0.8461	$0.5866
13 Annualized revenues from GCA factor (L6 X L12)	$7,521,060	$7,338,882	$0	$164,111	$18,067

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate
For Normalization Of GCA Factors

(1)	(2)	(3)	(4)	(5)	(6)
LN NO MONTH	TOTALS	RATE 11	RATE 12	RATE 13	RATE 14
ANR PIPELINE SYSTEM					
(Amounts are per applicable GCA Sch. 6, L11)					
1 July 2005	($24,453)	($33,157)	$7,107	$1,606	($9)
2 August	28,559	18,107	8,284	2,168	0
3 September	73,400	61,982	8,505	2,902	11
4 October	195,136	157,898	29,431	4,996	2,811
5 November	400,444	327,528	48,107	12,421	12,388
6 December	756,338	645,297	85,981	24,537	523
7 January 2006	777,500	679,791	79,323	18,293	93
8 February	893,832	795,193	78,966	19,656	17
9 March	717,906	639,242	64,943	13,697	24
10 April	242,227	215,541	24,948	1,723	15
11 May	165,593	144,358	20,863	354	18
12 June 2006	89,655	73,450	16,087	69	49
13 Totals	$4,316,137	$3,725,230	$472,545	$102,422	$15,940

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate
For Normalization Of GCA Factors

	(1)	(2)	(3)	(4)	(5)	(6)
LN NO	MONTH	TOTALS	RATE 41	RATE 42	RATE 43	RATE 44
	TEXAS GAS SYSTEM					
	(Amounts are per applicable GCA Sch. 6, L11)					
1	July 2005	$35,463	$25,451	$5,088	$4,986	($62)
2	August	30,720	23,609	5,315	1,796	0
3	September	32,868	19,251	5,738	7,879	0
4	October	220,417	182,896	12,705	18,593	6,223
5	November	476,500	423,784	22,223	24,606	5,887
6	December	887,705	819,900	32,803	33,999	1,003
7	January 2006	1,260,617	1,172,711	34,819	52,999	88
8	February	1,381,854	1,282,089	36,554	63,045	166
9	March	1,104,405	1,005,814	30,185	68,374	32
10	April	287,687	254,132	13,662	19,821	72
11	May	234,259	210,364	10,875	13,011	9
12	June 2006	136,866	120,835	9,124	6,898	9
13	Totals	$6,089,361	$5,540,836	$219,091	$316,007	$13,427

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

LN NO	(1)		(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
1	Portland Forge, Inc.	Rate T15	$52,696	$52,696	
2	Meshberger Bros	Rate T15	15,724	15,724	
3	Createc Corp	Rate T15	13,975	13,975	
4	Doane Pet Food Company	Rate T15	16,386	16,386	
5	Tyson Foods Inc	Rate T15	25,790	25,790	
6	Cocoa Cola Bottling Co	Rate T16	11,502	11,502	
7	Cast Metals Technology	Rate T15	12,229	12,229	
8	Meshberger Bros	Rate T16	20,072	20,072	
9	Arch Abby	Rate T16	17,843	17,843	
10	Aristokraft Inc Plt #4	Rate T16	21,141	21,141	
11	Aristokraft Inc Plt #22	Rate T16	10,687	10,687	
12	Waupaca Foundry	Rate T45	88,189		88,189
13	Visteon Corporation	Rate T45	37,574		37,574
14	Fayette County School Corp	Rate T46	10,928		10,928
15	Delhi Flower	Rate T46	14,856		14,856
16	Fayette Memorial Hospital	Rate T46	24,390		24,390
17	Hassler Textile	Rate T46	15,253		15,253
18	Indalex	Rate T46	20,900		20,900
19	Reclaimed Energy	Rate T46	20,454		20,454
20	Consolidated Recycling	Rate T45	50,680		50,680
21	Perry Co Memorial Hospital	Rate T46	11,823		11,823
22	Webb Wheel Products	Rate T46	11,760		11,760
23	Can Clay Products	Rate T46	12,734		12,734
24	Bebco Hardwood Inc	Rate T46	10,965		10,965
25	Parker Hannifin Corp	Rate T46	13,920		13,920
26	Stewart Warner South	Rate T46	11,508		11,508
27	Totals		$573,979	$218,045	$355,934
28	Less transport revenue as per books for the twelve months ended 6-30-06		664,002	218,039	445,964
29	Year end adjustment		($90,023)	$6	($90,030)

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	PORTLAND FORGE, INC.				
1	July 2005		1	269,629	$4,135
2	August		1	296,591	4,486
3	September		1	257,949	3,983
4	October		1	309,226	4,619
5	November		1	267,886	4,086
6	December		1	261,991	4,010
7	January 2006		1	328,756	4,904
8	February		1	273,799	4,189
9	March		1	319,748	4,787
10	April		1	266,212	4,330
11	May		1	287,873	4,631
12	June 2006		1	280,972	4,536
13	Totals	T-15	12	3,420,632	$52,696
	MESHBERGER BROS				
14	July 2005		1	48,430	911
15	August		1	57,881	966
16	September		1	62,512	1,443
17	October		1	59,002	1,391
18	November		1	58,754	1,388
19	December		1	55,873	1,351
20	January 2006		1	67,413	1,506
21	February		1	56,186	1,360
22	March		1	56,042	1,359
23	April		1	46,754	1,280
24	May		1	54,129	1,382
25	June 2006		1	54,477	1,387
26	Totals	T-15	12	677,453	$15,724
	CREATEC CORP				
27	July 2005		1	20,016	$890
28	August		1	33,432	1,065
29	September		1	33,276	1,063
30	October		1	35,442	1,087
31	November		1	39,784	1,143
32	December		1	35,800	1,092
33	January 2006		1	50,266	1283
34	February		1	47,793	1251
35	March		1	46,834	1239
36	April		1	44,492	1248
37	May		1	48,308	1301
38	June 2006		1	49,103	1,313
39	Totals	T-15	12	484,546	$13,975

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

	(1)		(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	DOANE PET CARE				
1	July 2005		1	38,617	$1,132
2	August		1	39,916	1,149
3	September		1	43,797	1,199
4	October		1	49,850	1,273
5	November		1	62,454	1,436
6	December		1	78,002	1,636
7	January 2006		1	73,351	1,583
8	February		1	66,818	1,499
9	March		1	63,825	1,460
10	April		1	50,090	1,326
11	May		1	54,340	1,385
12	June 2006		1	48,759	1,308
13	Totals	T-15	12	669,819	$16,386
	TYSON FOODS				
14	July 2005		1	119,183	2,179
15	August		1	130,344	2,324
16	September		1	103,668	1,978
17	October		1	114,109	2,102
18	November		1	115,667	2,122
19	December		1	120,112	2,179
20	January 2006		1	115,479	2,131
21	February		1	115,994	2,138
22	March		1	123,222	2,232
23	April		1	110,117	2,161
24	May		1	113,633	2,210
25	June 2006		1	100,999	2,034
26	Totals	T-15	12	1,382,527	$25,790
	COCA COLA BOTTLING				
27	July 2005		1	8,032	$855
28	August		1	7,590	835
29	September		1	7,143	816
30	October		1	6,792	800
31	November		1	11,857	1,023
32	December		1	18,381	1,311
33	January 2006		1	14,663	1,148
34	February		1	14,517	1,142
35	March		1	14,855	1,157
36	April		1	7,937	858
37	May		1	5,523	749
38	June 2006		1	6,837	808
39	Totals	T-16	12	124,127	$11,502

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	CAST METALS TECHNOLOGY				
1	July 2005		1	28,123	$996
2	August		1	29,950	1,019
3	September		1	14,911	824
4	October		1	30,553	1,024
5	November		1	27,210	981
6	December		1	32,000	1,043
7	January 2006		1	38,644	1,133
8	February		1	38,837	1,135
9	March		1	36,506	1,105
10	April		1	24,475	970
11	May		1	26,118	993
12	June 2006		1	27,021	1,006
13	Totals	T-15	12	354,348	$12,229
	MESHBERGER BROS				
14	July 2005		1	41,648	2,041
15	August		1	35,722	1,822
16	September		1	55,006	2,932
17	October		1	55,142	2,932
18	November		1	48,064	2,620
19	December		1	2,530	612
20	January 2006		1	10	500
21	February		1	0	500
22	March		1	0	500
23	April		1	32,584	1,970
24	May		1	37,773	2,204
25	June 2006		1	20,812	1,439
26	Totals	T-16	12	329,291	$20,072
	ARCH ABBY				
27	July 2005		1	11,282	$999
28	August		1	11,392	1,003
29	September		1	11,612	1,013
30	October		1	16,486	1,227
31	November		1	36,099	2,092
32	December		1	55,164	2,933
33	January 2006		1	3,777	667
34	February		1	47,254	2,589
35	March		1	39,275	2,236
36	April		1	16,138	1,228
37	May		1	10,793	987
38	June 2006		1	8,180	869
39	Totals	T-16	12	267,452	$17,843

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	ARISTOKRAFT INC PLT#4				
1	July 2005		1	13,239	$1,085
2	August		1	12,763	1,064
3	September		1	13,675	1,104
4	October		1	23,101	1,519
5	November		1	37,201	2,141
6	December		1	60,083	3,150
7	January 2006		1	44,845	2,482
8	February		1	45,347	2,504
9	March		1	39,198	2,233
10	April		1	18,395	1,330
11	May		1	20,115	1,407
12	June 2006		1	13,794	1,122
13	Totals	T-16	12	341,756	$21,141
	ARISTOKRAFT INC PLT#22				
14	July 2005		1	30	$501
15	August		1	30	501
16	September		1	245	511
17	October		1	4,648	705
18	November		1	14,164	1,125
19	December		1	32,901	1,951
20	January 2006		1	18,092	1,300
21	February		1	19,810	1,376
22	March		1	12,076	1,034
23	April		1	2,154	597
24	May		1	1,837	583
25	June 2006		1	70	503
26	Totals	T-16	12	106,057	$10,687

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	WAUPACA FOUNDRY				
1	July 2005		1	160,178	$6,180
2	August		1	182,438	6,919
3	September		1	156,200	6,048
4	October		1	184,155	6,976
5	November		1	198,428	7,450
6	December		1	272,777	9,918
7	January 2006		1	242,392	8,909
8	February		1	243,161	8,935
9	March		1	227,071	8,401
10	April		1	151,768	5,901
11	May		1	168,091	6,443
12	June 2006		1	158,051	6,109
13	Totals	T-45	12	2,344,710	$88,189
	VISTEON CORPORATION				
14	July 2005		1	0	$0
15	August		1	0	0
16	September		1	0	0
17	October		1	50,000	2,522
18	November		1	125,000	5,012
19	December		1	175,000	6,672
20	January 2006		1	200,000	7,502
21	February		1	200,000	7,502
22	March		1	150,000	5,842
23	April		1	50,000	2,522
24	May		1	0	0
25	June 2006		1	0	0
26	Totals	T-45	12	950,000	$37,574
	FAYETTE CO. SCHOOL CORP (Connersville HS)				
27	July 2005		1	541	$524
28	August		1	777	535
29	September		1	1,157	552
30	October		1	5,235	736
31	November		1	12,681	1,071
32	December		1	26,241	1,681
33	January 2006		1	19,357	1,371
34	February		1	20,988	1,444
35	March		1	15,147	1,182
36	April		1	5,683	756
37	May		1	1,097	549
38	June 2006		1	598	527
39	Totals	T-46	12	109,502	$10,928

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	DELHI FLOWER				
1	July 2005		1	9,029	$906
2	August		1	2,049	592
3	September		1	3,709	667
4	October		1	12,686	1,071
5	November		1	20,315	1,414
6	December		1	23,738	1,568
7	January 2006		1	17,659	1,295
8	February		1	29,562	1,830
9	March		1	48,438	2,680
10	April		1	17,604	1,292
11	May		1	9,018	906
12	June 2006		1	3,004	635
13	Totals	T-46	12	196,811	$14,856
	FAYETTE HOSPITAL				
14	July 2005		1	26,838	$1,708
15	August		1	27,206	1,724
16	September		1	28,573	1,786
17	October		1	33,111	1,990
18	November		1	36,476	2,141
19	December		1	37,389	2,183
20	January 2006		1	38,187	2,218
21	February		1	34,363	2,046
22	March		1	37,302	2,179
23	April		1	36,436	2,140
24	May		1	39,539	2,279
25	June 2006		1	33,248	1,996
26	Totals	T-46	12	408,668	$24,390
	HASSLER TEXTILE				
27	July 2005		1	14,708	$1,232
28	August		1	15,509	1,198
29	September		1	15,296	1,260
30	October		1	16,429	1,314
31	November		1	15,530	1,271
32	December		1	15,472	1,268
33	January 2006		1	16,181	1,302
34	February		1	14,808	1,236
35	March		1	16,973	1,340
36	April		1	15,902	1,288
37	May		1	16,161	1,301
38	June 2006		1	14,950	1,243
39	Totals	T-46	12	187,919	$15,253

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	INDALEX				
1	July 2005		1	18,646	$1,339
2	August		1	21,961	1,488
3	September		1	21,728	1,478
4	October		1	24,696	1,611
5	November		1	27,069	1,718
6	December		1	25,025	1,626
7	January 2006		1	38,145	2,217
8	February		1	34,789	2,066
9	March		1	35,053	2,078
10	April		1	28,803	1,796
11	May		1	28,689	1,791
12	June 2006		1	26,493	1,692
13	Totals	T-46	12	331,097	$20,900
	RECLAIMED ENERGY				
14	July 2005		1	21,431	$1,464
15	August		1	26,164	1,677
16	September		1	26,219	1,680
17	October		1	28,039	1,762
18	November		1	28,247	1,771
19	December		1	34,124	2,036
20	January 2006		1	30,144	1,856
21	February		1	26,451	1,690
22	March		1	27,013	1,716
23	April		1	22,785	1,525
24	May		1	26,542	1,694
25	June 2006		1	24,067	1,583
26	Totals	T-46	12	321,226	$20,454
	CONSOLIDATED RECYCLING				
27	July 2005		1	99,635	$4,170
28	August		1	85,577	3,703
29	September		1	86,801	3,744
30	October		1	95,723	4,040
31	November		1	96,611	4,070
32	December		1	113,304	4,624
33	January 2006		1	125,307	5,022
34	February		1	95,969	4,048
35	March		1	108,493	4,464
36	April		1	104,703	4,338
37	May		1	108,003	4,448
38	June 2006		1	94,784	4,009
39	Totals	T-45	12	1,214,910	$50,680

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

(1)			(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	PERRY MEM HOSPITAL				
1	July 2005		1	8,611	$888
2	August		1	9,211	914
3	September		1	9,528	929
4	October		1	10,670	980
5	November		1	12,113	1,045
6	December		1	16,007	1,220
7	January 2006		1	11,757	1,029
8	February		1	12,719	1,072
9	March		1	11,493	1,017
10	April		1	9,499	927
11	May		1	9,575	931
12	June 2006		1	8,238	871
13	Totals	T-46	12	129,421	$11,823
	WEBB WHEEL PRODUCTS				
14	July 2005		1	5,781	$760
15	August		1	4,896	720
16	September		1	6,410	788
17	October		1	8,970	904
18	November		1	9,680	934
19	December		1	13,372	1,102
20	January 2006		1	12,919	1,081
21	February		1	17,892	1,305
22	March		1	15,525	1,199
23	April		1	11,498	1,017
24	May		1	10,354	966
25	June 2006		1	10,758	984
26	Totals	T-46	12	128,055	$11,760

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

	(1)		(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	CAN CLAY CORP				
1	July 2005		1	22,012	$1,491
2	August		1	831	537
3	September		1	45,887	2,565
4	October		1	30,606	1,877
5	November		1	3,922	676
6	December		1	5,623	753
7	January 2006		1	6,943	812
8	February		1	13,044	1,087
9	March		1	0	500
10	April		1	12,216	1,050
11	May		1	7,969	859
12	June 2006		1	588	526
13	Totals	T-46	12	149,641	$12,734
	BEBCO HARDWOOD INC				
14	July 2005		1	10,527	$974
15	August		1	6,973	814
16	September		1	4,257	692
17	October		1	5,715	757
18	November		1	9,773	940
19	December		1	9,727	938
20	January 2006		1	6,355	786
21	February		1	9,963	948
22	March		1	11,998	1,040
23	April		1	11,840	1,033
24	May		1	10,522	973
25	June 2006		1	12,676	1,070
26	Totals	T-46	12	110,326	$10,965
	PARKER HANNIFIN CORP				
27	July 2005		1	7,162	822
28	August		1	7,021	816
29	September		1	7,162	822
30	October		1	10,712	982
31	November		1	19,433	1,374
32	December		1	31,155	1,902
33	January 2006		1	24,867	1,619
34	February		1	26,281	1,683
35	March		1	21,629	1,473
36	April		1	8,555	885
37	May		1	7,137	821
38	June 2006		1	4,889	720
39	Totals	T-46	12	176,003	$13,920

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

	(1)		(2)	(3)	(4)
LN NO	MONTH		TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	STEWART WARNER SOUTH				
1	July 2005		1	5,140	$731
2	August		1	5,124	731
3	September		1	5,104	730
4	October		1	6,248	781
5	November		1	12,322	1,054
6	December		1	22,751	1,524
7	January 2006		1	16,078	1,224
8	February		1	16,709	1,252
9	March		1	13,875	1,124
10	April		1	7,528	839
11	May		1	5,663	755
12	June 2006		1	5,853	763
13	Totals	T-46	12	122,395	$11,508

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Customer Changes

LN NO	(1)	(2) NO. BILLS	(3) THERMS	(4) REVENUES
	ANR PIPELINE SERVICE AREA			
1	Venture			
2	Sales Rate 12 customer discontinued service effective January 1, 2006, plant closed.	(6)	(29,930)	($26,833)
3	Sisters of St Benedict Customer transferred from sales Rate No. 13 to sales Rate 11 on April 1, 2006			
4	Applicable decrease - Rate No. 13	(9)	(85,765)	($65,413)
5	Applicable increase - Rate No. 11	9	85,765	$70,453
6	York Casket Company Sales Rate 12 customer discontinued service effec April 18, 2006, plant closed.			
7	Applicable decrease - Rate No. 12	(10)	(151,973)	($124,875)
8	Mobel, Inc Customer transferred from sales Rate No 12 to sales Rate No 11effect October 1, 2006			
9	Applicable decrease - Rate No. 12	(12)	(82,016)	($75,175)
10	Applicable increase - Rate No. 11	12	82,016	$67,417
11	Net Decrease in Sales Revenues	(16)	(181,903)	($154,426)
	TEXAS GAS PIPELINE SERVICE AREA			
12	Dresser Roots Inc Customer transferred from sales Rate No 43 to Rate 41 effect November 1, 2006			
13	Applicable decrease - Rate No 43	(12)	(274,175)	($244,226)
14	Applicable increase - Rate No 41	12	274,175	$219,496
15	Dresser Roots Inc Customer load reduction due to high efficiency			
16	boiler replacement - applic decrease Rate 41		(82,225)	($65,780)
17	Can Clay Corp Customer transferred from sales Rate No 43 to Rate T46 effect July 1, 2006			
18	Applicable decrease - Rate No 43	(12)	(183,700)	($164,391)
19	Bebco Hardwood Inc Customer transferred from sales Rate No 43 to Rate T46 effect Jan 1, 2007			
20	Applicable decrease - Rate No 43	(12)	(110,326)	($99,646)
21	Parker Hannifin Corp Customer transferred from sales Rate No 42 to Rate T46 effect Feb 1, 2007			
22	Applicable decrease - Rate No 42	(12)	(176,003)	($165,260)
23	Stewart Warner South Customer transferred from sales Rate No 42 to Rate T46 effect Jan 1, 2007			
24	Applicable decrease - Rate No 42	(12)	(122,395)	($119,389)
25	Delhi Flower (two sales accounts) Customer transferred from sales Rate No 43 and Rate No 42 to transportation Rate No. T46 effect December 1, 2005			
26	Applicable decrease - Rate No 43	(5)	(31,194)	($28,482)
27	Applicable decrease - Rate No 42	(5)	(16,594)	(26,978)
28	General Electric Motors Transportation customer Rate T46 discontinued operations September 2006			
29	and transferred to Rate No.41	12	2,500	$2,156
30	Net Decrease in Sales Revenues	(46)	(719,937)	($692,500)

Revenue adjustments include only base rate revenue, demand charge and monthly service charge revenue. GCA factor revenue is adjusted via Pg 2 (GCA Leveling Adj).

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To
General Service Customer Decline

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LN NO	TOTAL COMPANY	ANR	Portland	Winchester	T C (ANR)	TEXAS GAS	Connersville	T C (TGT)
1 Rate suffix 1 customers billed during January 2007	24,668	10,095	3021	5555	1,519	14,573	9772	4,801
2 Rate suffix 1 customers billed during January 2006	24,867	10,195	3039	5644	1512	14,672	9832	4840
3 Customer decrease	(199)	(100)				(99)		
4 Percentage decrease		-0.98%				-0.67%		
5 Total Rate 1 customers billed July 1, 2005 - June 30 ,2006	294,059	120,682				173,377		
6 Annualized Rate suffix 1 customer billings adjustment (L 4 times L 5)	(2,345)	(1,183)	(353)	(655)	(175)	(1,162)	(778)	(383)
7 Monthly service charge - Rate suffix 1	$13.00	$13.00				$13.00		
8 Decrease in service charge revenue (L 6 times L 7)	($30,480)	($15,379)				($15,101)		
9 Rate suffix 1 therm sales per books (P 28B, 28C)	24,332,546	11,012,059				13,320,487		
10 Rate suffix 1 therm adjustment for weather normalization (P 28B,28C)	2,093,445	927,238				1,166,207		
11 Rate suffix 1 therm adjustment for unbilled sales (P 28B,28C)	147,277	(6,381)				153,658		
12 Total Rate suffix 1 therm sales subject to adjustment	26,573,268	11,932,916				14,640,352		
13 Decrease in Rate suffix 1 therm sales due to customer decline (L 12 times L 4)	(215,033)	(116,943)	(34,859)	(64,740)	(17,344)	(98,090)	(65,732)	(32,358)
14 Base Rate suffix 1 per therm (P 5A,B, L4)		$0.8201				$0.8000		
15 Revenue per therm applicable to this adjustment		$0.8201				$0.8000		
16 Decr in Rate 1 sales revenue due to annualized customer decline (L 13 X L 16)	($174,377)	($95,905)				($78,472)		
17 Total decrease in Rate suffix 1 revenue due to customer decline (L 8 plus L 17)	($204,857)	($111,284)				($93,573)		

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
1	Unbilled Revenues at June 30, 2006	$124,676	($61,378)	$186,054
2	Unbilled Revenues at June 30, 2005	(113,084)	(313,235)	200,151
3	Increased Unbilled Revenues at June 30, 2006	$237,760	$251,857	($14,097)
4	Less Unbilled Revenues as per books for the twelve months ended June 30, 2006	$237,760	$251,857	($14,097)
5	Year End Adjustment	$0	$0	$0
6	Add:Unbilled therms sales at June 30, 2006	98,412	(51,971)	150,383
7	Add:Unbilled therms sales at August 31, 2005	(104,233)	(337,805)	233,572
8	Less:Unbilled therms sales at June 30, 2005	(153,098)	(383,395)	230,297
9	Net change	147,277	(6,381)	153,658

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM -Grp1	(4) ANR PIPELINE SYSTEM-Grp2	(5) TEXAS GAS SYSTEM
	June 30, 2006				
1	Therm sales September 1, 2005				
2	through June 30, 2006	25,997,149	5,414,650	6,706,350	13,876,149
3	Less 9-05 appl. 8-05 purchases	280,882	58,499	54,839	167,544
4	Therm sales 9-05 to 6-06	25,716,267	5,356,151	6,651,511	13,708,605
5	Therm purchases September 1,				
6	2005 through June 30, 2006	26,009,940	5,252,120	6,807,620	13,950,200
7	Less unaccounted for gas and Company use gas	195,261	32,739	71,310	91,212
8	Net therm purchase 9-05 to 6-06	25,814,679	5,219,381	6,736,310	13,858,988
9	Unbilled therm sales at June 30, 2006	98,412	(136,770)	84,799	150,383
10	June consumption rate		$1.1810	$1.1810	$1.2372
11	Unbilled revenue	$124,676	($161,525)	$100,147	$186,054

12 All of Rates 12, 13, 42, and 43 are read and billed on a calendar month basis, and few Rate 14 and
13 Rate 44 sales occur in June.
14 Accordingly all unbilled sales and revenue at June 30 are assigned to Rate 11 and 41.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM -Grp1	(4) ANR PIPELINE SYSTEM-Grp2	(5) TEXAS GAS SYSTEM
	August 31, 2005				
1	Therm sales September 1, 2004				
2	through August 31, 2005	31,065,903	6,289,641	8,251,849	16,524,413
6	Less 9-05 appl. 8-05 purchases	298,008	61,649	58,826	177,533
7	Therm sales 9-04 to 8-05	30,767,895	6,227,992	8,193,023	16,346,880
8	Therm purchases September 1,				
9	2004 through August 31, 2005	31,044,480	6,007,170	8,273,970	16,763,340
13	Less unaccounted for gas and Company use gas	380,818	70,373	127,557	182,888
14	Net therm purchase 9-04 to 8-05	30,663,662	5,936,797	8,146,413	16,580,452
15	Unbilled therm sales at August 31, 2005	(104,233)	(291,195)	(46,610)	233,572

18 All of Rates 12, 13, 42, and 43 are read and billed on a calendar month basis, and few Rate 14 and
19 Rate 44 sales occur in June.
20 Accordingly all unbilled sales and revenue are assigned to Rate 11 and 41.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM -Grp1	(4) ANR PIPELINE SYSTEM-Grp2	(5) TEXAS GAS SYSTEM
	June 30, 2005				
1	Therm sales September 1, 2004				
2	through June 30, 2005	29,995,741	6,047,496	8,007,318	15,940,927
3	Less 9-05 appl. 8-05 purchases	298,008	61,649	58,826	177,533
4	Therm sales 9-04 to 6-05	29,697,733	5,985,847	7,948,492	15,763,394
5	Therm purchases September 1,				
6	2004 through June 30, 2005	29,908,960	5,719,460	8,020,860	16,168,640
7	Less unaccounted for gas and Company use gas	364,325	67,100	122,276	174,949
8	Net therm purchase 9-04 to 6-05	29,544,635	5,652,360	7,898,584	15,993,691
9	Unbilled therm sales at June 30, 2005	(153,098)	(333,487)	(49,908)	230,297
10	June consumption rate		$0.8170	$0.8170	$0.8691
11	Unbilled revenue	($113,084)	($272,459)	($40,776)	$200,151

12 All of Rates 12, 13, 42, and 43 are read and billed on a calendar month basis, and few Rate 14 and
13 Rate 44 sales occur in June.
14 Accordingly all unbilled sales and revenue are assigned to Rate 11 and 41.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues and Expenses
Due to Weather Normalization

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SYSTEM	(4) TEXAS GAS SYSTEM
1	Change in Operating Revenues	$1,736,599	$760,428	$932,966

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Revenues and Expenses
Due to Weather Normalization

LN NO	(1) ANR PIPELINE SERVICE AREA	(2) TOTAL	(3) PORTLAND AREA	(4) WINCHESTER/ UNION CITY AREA	(5) TELL CITY AREA
1	Total therm sales in heat sensitive classes for twelve months ended 6-30-06	9,833,451	2,963,511	5,711,225	1,158,715
2	Less non-heat sensitive therm sales for July, August, and September billing cycles annualized	2,092,212	708,188	1,130,236	253,788
3	Heat sensitive therm sales (Line 1 less Line 2)	7,741,239	2,255,323	4,580,989	904,927
4	Base rate per therm		$0.8201	$0.8201	$0.8201
5	Degree days for twelve months ended 6-30-06		4933	4933	4107
6	NOAA 30-year average (1971-2000)		5521	5521	4617
7	Percentage of normal		89.3498%	89.3498%	88.9539%
8	Change to therm sales due to weather normalization (Line 3 / Line 7, Less Line 3)	927,238	268,827	546,039	112,372
9	Change in operating revenues (L4 times L8)	$760,428	$220,465	$447,807	$92,156

10 All areas are warmer than normal.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Revenues and Expenses
Due to Weather Normalization

LN NO	(1) TEXAS GAS SERVICE AREA	(2) TOTAL	(3) CONNERSVILLE AREA	(4) TELL CITY AREA
1	Total therm sales in heat sensitive classes for twelve months ended 6-30-06	12,507,161	8,880,908	3,626,253
2	Less non-heat sensitive therm sales for July, August, and September billing cycles annualized	2,831,664	1,799,200	1,032,464
3	Heat sensitive therm sales (Line 1 less Line 2)	9,675,497	7,081,708	2,593,789
4	Base rate per therm		$0.8000	$0.8000
5	Degree days for twelve months ended 6-30-06		4933	4107
6	NOAA 30-year average (1971-2000)		5521	4617
7	Percentage of normal		89.3498%	88.9539%
8	Decreased therm sales due to weather normalization (Line 3 / Line 7, Less Line 3)	1,166,207	844,116	322,091
9	Change in operating revenues (L4 times L8)	$932,966	$675,293	$257,673

10 All areas are warmer than normal.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Expenses
Due To Annualizing Purchased Gas Rates

(1)		(2)	(3)
LN NO		Dth Purchased	Increased Cost
1	ANR Pipeline Company	1,338,149	$1,814,709
2	Texas Gas Transmission Corporation	1,519,031	$2,001,966
3	Totals	2,857,180	$3,816,675

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses
Due To Annualizing Purchased Gas Rates

LN NO	(1) ANR PIPELINE SERVICE AREA	(2) MONTHLY	(3) ANNUAL
	Demand/Capacity Reservation Basis		
1	Group 1 - FSS - Delivery reservation fee	4,166	49,992
2	Group 1 - FSS - Capacity reservation fee	17,392	208,704
3	Group 1 - ETS - Storage to City Gate capacity reservation fee - 5 months	4,125	20,625
4	Group 1 - ETS - City Gate to Storage capacity reservation fee - 7 months	1,198	8,386
5	Group 1 - ETS - Supply Area to City Gate capacity reservation fee - SW	1,650	19,800
6	Group 1 - ETS - Supply Area to City Gate capacity reservation fee - SE	1,725	20,700
7	Group 1 - NNS - Capacity reservation fee	1,500	18,000
8	Group 2 - FSS - Delivery reservation fee	6,110	73,320
9	Group 2 - FSS - Capacity reservation fee	25,508	306,096
10	Group 2 - FTS-1 - Storage to City Gate capacity reservation fee - 5 months	6,050	30,250
11	Group 2 - FTS-1 - City Gate to Storage capacity reservation fee - 7 months	1,758	12,306
12	Group 2 - FTS-1 - Supply Area to City Gate capacity reservation fee - SW	2,420	29,040
13	Group 2 - FTS-1 - Supply Area to City Gate capacity reservation fee - SE	2,530	30,360
14	Group 2 - NNS - Capacity reservation fee	1,500	18,000
	Demand/Capacity Reservation Fees at January 1, 2007		
15	FSS - Delivery reservation fee		$2.4210
16	FSS - Capacity reservation fee		$0.3946
17	ETS - Storage to City Gate capacity reservation fee		$6.5180
18	ETS - City Gate to Storage capacity reservation fee		$6.5180
19	ETS - Supply Area to City Gate capacity reservation fee - SW		$11.5180
20	ETS - Supply Area to City Gate capacity reservation fee - SE		$8.7680
21	NNS - Capacity reservation fee		$6.1480
22	FTS-1 - Storage to City Gate capacity reservation fee		$5.9100
23	FTS-1 - City Gate to Storage capacity reservation fee		$5.9100
24	FTS-1 - Supply Area to City Gate capacity reservation fee - SW		$10.9100
25	FTS-1 - Supply Area to City Gate capacity reservation fee - SE		$8.1600
	Calculation of Demand/Capacity Reservation Fees - Group 1		
26	FSS - Delivery reservation fee (Line 1 times Line 15)		$121,031
27	FSS - Capacity reservation fee (Line 2 times Line 16)		82,355
28	NNS - Capacity reservation fee (Line 7 time Line 21)		110,664
29	ETS - Storage to City Gate capacity reservation fee (Line 3 times Line 17)		134,434
30	ETS - City Gate to Storage capacity reservation fee (Line 4 times Line 18)		54,660
31	ETS - Supply Area to City Gate capacity reservation fee - SW (Line 5 times Line 19)		228,056
32	ETS - Supply Area to City Gate capacity reservation fee - SE (line 6 time Line 20)		181,498
33	Total Demand/Capacity Reservation Fees - Group 1 (Sum of Lines 26 thru 32)		$912,698

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses
Due To Annualizing Purchased Gas Rates

LN NO	(1)	(2)
	ANR PIPELINE SERVICE AREA - Continued	
	Calculation of Demand/Capacity Reservations Fees - Group 2	
1	FSS - Delivery reservation fee (Line 8, Pg. 6A times Line 15, Pg. 6A)	$177,508
2	FSS - Capacity reservation fee (Line 9, Pg. 6A times Line 16, Pg. 6A)	120,785
3	NNS - Capacity reservation fee (Line 14, Pg. 6A times Line 21, Pg. 6A)	110,664
4	FTS-1 - Storage to City Gate capacity reservation fee (Line 10, Pg. 6A times Line 22, Pg. 6A)	178,778
5	FTS-1 - City Gate to Storage capacity reservation fee (Line 11, Pg. 6A times Line 23, Pg. 6A)	72,728
6	FTS-1 - Supply Area to City Gate capacity reserv fee - SW (Line 12, Pg. 6A times Line 24, Pg. 6A)	316,826
7	FTS-1 - Supply Area to City Gate capacity reserv fee - SE (line 13, Pg. 6A times Line 25, Pg. 6A)	247,738
8	Total Demand/Capacity Reservation Fees - Group 2 (Sum of Lines 1 thru 7)	$1,225,027
9	Total Demand/Capacity Reservation Fees (Line 33, Pg. 6A plus Line 8, Pg. 6B)	$2,137,725
10	Rate 11 adjusted test period therm sales	11,983,754
11	Rate 12 adjusted test period therm sales	1,038,195
12	Rate 13 adjusted test period therm sales	137,321
13	Rate 14 adjusted test period therm sales	70,417
14	Company use, etc.	82,177
15	Sub-total	13,311,864
16	Unaccounted for gas (Line 15 divided 1 less Pg. 32, Line 21, Col. 3, less Line 15)	69,622
17	Adjusted test year purchases	13,381,486
18	Average commodity cost delivered to city gate for twelve months ended 6-30-06	$0.9025
19	Commodity cost (Line 17 times Line 18)	$12,076,791
20	Total adjusted purchased gas cost (Line 9 plus Line 19)	$14,214,516
21	Less cost as per books for twelve months ended June 30, 2006	12,399,807
22	Year End Adjustment	$1,814,709
23	Average cost of gas based on adjusted purchased gas (Line 20 divided by Line 17)	$1.0623

24 Group 1 covers deliveries at Portland, Ferdinand, and St. Anthony.
25 Group 2 covers deliveries at Lynn.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses
Due To Annualizing Purchased Gas Rates

LN NO	(1) TEXAS GAS SERVICE AREA	(2) DAYS	(3) DAILY	(4) ANNUAL
	Demand Basis			
1	Z3 - FT - Demand - November thru March	151	2,000	302,000
2	Z3 - FT - Demand - April thru October	214	1,500	321,000
3	Z4 - FT - Demand - November thru March	151	2,000	302,000
4	Z4 - FT - Demand - April thru October	214	1,000	214,000
5	Z4 - NNS - Demand - November thru March	151	13,586	2,051,486
6	Z4 - NNS - Demand - May thru September	153	3,003	459,459
7	Z4 - NNS - Demand - April	30	9,174	275,220
8	Z4 - NNS - Demand - October	31	11,031	341,961
	Demand rates at January 1, 2007			
9	Z3 - FT			$0.2494
10	Z4 - FT			$0.3142
11	Z4 - NNS			$0.4190
	Demand Charges			
12	Z3 - FT - Demand charges (Line 1 plus Line 2 times Line 9)			$155,376
13	Z4 - FT - Demand charges (Line 3 plus Line 4 times Line 10)			162,127
14	Z4 - NNS Demand charges (Sum of Line 5 thru 8 times Line 11)			1,310,685
15	Total Demand Charges (Sum of Lines 12 thru 14)			$1,628,188

16 Z3 is Zone 3 and covers deliveries at Cannelton and Tell City.
17 Z4 is Zone 4 and covers deliveries at Guilford for Connersville area.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses
Due To Annualizing Purchased Gas Rates

LN NO	(1)	(2)
	TEXAS GAS SERVICE AREA - Continued	
	Zone 3	
1	Rate 41 adjusted test period Dth sales	4,337,904
2	Rate 42 adjusted test period Dth sales	0
3	Rate 43 adjusted test period Dth sales	57,727
4	Rate 44 adjusted test period Dth sales	0
5	Company use, etc.	3,760
6	Sub-total	4,399,391
7	Unaccounted for gas (Line 6 divided 1 less Page 32, Line 21, Col. 4, less Line 6)	48,218
8	Adjusted test year purchases - Zone 3	4,447,609
	Zone 4	
9	Rate 41 adjusted test period Dth sales	10,398,808
10	Rate 42 adjusted test period Dth sales	0
11	Rate 43 adjusted test period Dth sales	136,235
12	Rate 44 adjusted test period Dth sales	30,799
13	Company use, etc.	60,390
14	Sub-total	10,626,232
15	Unaccounted for gas (Line 14 divided 1 less Page 32, Line 21, Col. 4, less Line 14)	116,465
16	Adjusted test year purchases - Zone 4	10,742,697
17	Total adjusted test year purchases (Line 8 plus Line 16)	15,190,306
18	Average commodity cost delivered to City Gate for twelve months ended June 30, 2006 - Zone 3	$1.0661
19	Average commodity cost delivered to City Gate for twelve months ended June 30, 2006 - Zone 4	$1.0059
20	Commodity cost - Zone 3 (Line 8 times Line 18)	$4,741,596
21	Commodity cost - Zone 4 (Line 16 times Line 19)	10,806,079
22	Total Commodity cost (Line 20 plus Line 21)	$15,547,675
23	Total adjusted purchased gas cost (Line 15, Pg. 6C plus Line 22, Pg. 6D)	$17,175,863
24	Less cost as per books for twelve months ended June 30, 2006	15,173,897
25	Year End Adjustment	$2,001,966
26	Average cost of gas based on adjusted purchased gas (Line 21 divided Line 15)	$1.1307
27	Average commodity cost of gas (Line 20 divided Line 15)	$1.0235

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses
Due To Changes In Payroll Rates And Employees

LN NO	(1)	(2)	(3)	(4)
1	Total annual payroll based on rates in effect 04-23-06			$5,077,090
2	Portion applicable to operation and maintenance expense (Line 1 times 85.73%, the test period experience)			$4,352,589
3	Less payroll charged to expense as per books for the twelve months ended June 30, 2006			4,006,864
4	Year End Adjustment			$345,726

	PERCENTS	TOTAL COMPANY	ANR PIPELINE SERVICE AREA	TEXAS GAS SERVICE AREA
5	Production	0.08%	0.02%	0.06%
6	Transmission	1.95%	0.09%	1.86%
7	Distribution	36.38%	16.21%	20.17%
8	Customer Accounting	21.04%	10.31%	10.73%
9	Sales Promotion	0.86%	0.16%	0.70%
10	General & Administrative	39.69%	16.63%	23.06%
11	Totals	100.00%	43.42%	56.58%
	YEAR END ADJUSTMENT			
12	Production	$277	$69	$208
13	Transmission	6,742	311	6,431
14	Distribution	125,775	56,042	69,733
15	Customer Accounting	72,741	35,644	37,097
16	Sales Promotion	2,973	553	2,420
17	General & Administrative	137,218	57,494	79,724
18	Totals	$345,726	$150,113	$195,613

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased FICA/ST UC/FUTA Payroll Taxes Due To Increased Payroll And Tax Rate And Base Changes

	(1)	(2)	(3)	(4)	(5)
LN NO		SOC. SEC	MEDICARE	STATE UC	FUTA
1	Total payroll subject to tax	$4,917,528	$5,077,090		$819,000
2	Indiana			$763,000	
3	Nebraska			$63,000	
4	Florida			$14,000	
5	Current rate	6.20%	1.45%		0.80%
6	Indiana			1.50%	
7	Nebraska			0.80%	
8	Florida			0.12%	
9	Tax (Line 1 times Line 5)	$304,887	$73,618	$11,966	$6,552
10	Total Tax (Line 9, Col. (2) thru (5))				$397,023
11	Portion applicable to operation and maintenance expense (85.73% times Line 10)				$340,368
12	Less FICA/ST UC/FUTA payroll tax expense for the twelve months ended 6-30-06				312,234
13	Year End Adjustment				$28,134

Allocation of Line 11 above (percentages from Page 7, Line 11)

	YEAR END ADJUSTMENT	TOTAL COMPANY	ANR PIPELINE SERVICE AREA	TEXAS GAS SERVICE AREA
14	Allocate Line 11 above	$340,368	$147,788	$192,580
15	Less FICA/ST UC/FUTA payroll tax expense for the twelve months ended June 30, 2006	312,234	138,101	174,133
16	Year End Adjustment	$28,134	$9,687	$18,447

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses For New Pipeline Safety Act Expenses Subject to Recovery Through Annual PSA Tracker

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SERVICE AREA	(4) TEXAS GAS SERVICE AREA
1	July 2005	$826		$826
2	August	405		405
3	September	991		991
4	October			
5	November	30,071		30,071
6	December	3,455		3,455
7	January 2006			
8	February			
9	March			
10	April			
11	May			
12	June 2006	224		224
13	Total	$35,971		$35,971

14 Expenditures incurred during the test period pertain to the new Pipeline Safety Act requirements and are incremental.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased Liability And Related Insurance Costs

LN NO	(1) CATEGORY	(2) TOTAL PREMIUM	(3) APPLICABLE OHIO VALLEY GAS CORP.	(4) APPLICABLE OHIO VALLEY GAS, INC.
1	Property Insurance Premium for the period July 1, 2006 through June 30, 2007:	$14,020		
2	Applicable to OVGC - Texas Gas only	$2,681	$2,681	
3	Applicable to OVGC & OVGI	11,339	9,999	$1,340
4	Commercial General Liability Insurance Premium for the period July 1, 2006 through June 30, 2007	79,649	70,234	9,415
5	Commercial Automobile Insurance Premium for the period July 1, 2006 through June 30, 2007	71,240	62,819	8,421
6	Umbrella Liability Insurance Premium for the period July 1, 2006 through June 30, 2007	100,775	88,863	11,912
7	Directors & Officers Liability Insurance Premium for the period February 12, 2006 through February 11, 2007	10,559	9,311	1,248
8	Dishonesty Bond for the period July 1, 2006 through June 30, 2007	500	441	59
9	Total Premiums (Sum of Lines 2 through 8)	$276,743	$244,348	$32,395

	CATEGORY	TOTAL PREMIUM	ANR PIPELINE SVC. AREA	TEXAS GAS SVC. AREA
10	Property Insurance	$12,680	$4,063	$8,617
11	Commercial General Liability Insurance	70,234	28,536	41,698
12	Commercial Automobile Insurance	62,819	25,523	37,296
13	Umbrella Liability Insurance	88,863	36,105	52,758
14	D&O Liability Insurance	9,311	3,783	5,528
15	Dishonesty Bond Insurance	441	179	262
16	Total Premiums (Sum of Lines 10 thru 15)	$244,348	$98,189	$146,159
17	Less per books for twelve months ended June 30, 2006	250,975	102,987	147,988
18	Year End Adjustment	($6,627)	($4,798)	($1,829)

19 Allocations made on the basis of general spread.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Expenses Due To
To Postage Savings

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Current Costs			
1	Utility bills	$84,980	$34,794	$50,186
2	Final bills	775	301	474
3	Shut Off Notices	7,402	2,920	4,482
4	Budget Plan Notices	1,795	831	964
5	Total Current Costs (Sum of Lines 1 thru 3)	$94,952	$38,846	$56,106
6	Less postage costs as per books for the twelve months ended June 30, 2006	99,268	40,613	58,655
7	Year End Adjustment	($4,316)	($1,767)	($2,549)

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Postage Savings

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Utility Bills			
1	Total customers billed for the twelve months ended June 30, 2006	290,034	118,751	171,283
	Utility Bill Mailings			
2	Mailed at barcode rate	290,034	118,751	171,283
3	Mailed at residual rate	0	0	0
4	Total (Line 2 plus Line 3)	290,034	118,751	171,283
	Utility Bill Mail Costs			
5	Barcode cost (Line 2 times $.293)	$84,980	$34,794	$50,186
6	Residual cost (Line 3 times $.39)	0	0	0
7	Total (Line 5 plus Line 6)	$84,980	$34,794	$50,186
	Final Bills			
8	Mailed at barcode rate	2,647	1029	1618
9	Mailed at residual rate	0	0	0
10	Total (Line 8 plus Line 9)	2,647	1,029	1,618
11	Barcode cost (Line 8 times $.293)	$775	$301	$474
12	Residual cost (Line 9 times $.39)	0	0	0
13	Total (Line 11 plus Line 12)	$775	$301	$474
	Shut-Off Notices, Etc.			
14	Mailed at barcode rate	25,263	9967	15296
15	Mailed at residual rate	0	0	0
16	Total (Line 14 plus Line 15)	25,263	9,967	15,296
17	Barcode cost (Line 14 times $.293)	$7,402	$2,920	$4,482
18	Residual cost (Line 15 times $.39)	0	0	0
19	Total (Line 17 plus Line 18)	$7,402	$2,920	$4,482

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Postage Savings

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Budget Plan Notices, etc			
1	Mailed at barcode rate	6,125	2,835	3,290
2	Barcode cost (Line 1 times $.293)	$1,795	$831	$964
3	Total (Line 2)	$1,795	$831	$964

Note: postal barcode rate increase to $.312 is pending approval by postal rate commission and Congress, to be effective May 2007. As such, the anticipated increase has not been reflected.

	Postage Costs As Per Books For The Twelve Months Ended June 30, 2006			
4	Utility bills	$88,741	$36,324	$52,417
5	Final bills	770	299	471
6	Shut-off notices, etc.	7,586	2,986	4,600
7	Post cards	2,171	1,004	1,167
8	Total Costs	$99,268	$40,613	$58,655

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due Costs Related To Rate Case Expense And Employment of Outside Professionals, Etc.

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Estimated legal expense	$35,272	$14,331	$20,941
2	Estimated cost of capital expert witness expense	30,863	12,540	18,323
3	Estimated cost of service study and rate design expert	39,681	16,122	23,559
4	Cost of printing required notices for rate increase	705	286	419
5	Cost of mailing required notices for rate increase	11,150	4,530	6,620
6	Total estimated rate case expense (Sum of Lines 1 thru 4)	$117,671	$47,809	$69,862
7	Cost applicable to next twelve months (Line 5 divided 3 years)	$39,223	$15,936	$23,287

8 Costs allocated on the basis of the general expense allocation per Page 26, L 16.

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Decreased Group Insurance Premiums

	(1)	(2)	(3)	(4)	(5)
LN		TYPE OF COVERAGE			
NO	MEDICAL	EMPLOYEE	SPOUSE	CHILDREN	FAMILY
1	District Office lives	70	11	5	2
2	Rate per life (OVGC cost)	$5,252.28	$1,506.48	$1,030.56	$2,537.16
3	Cost (Line 1 times Line 2)	$367,660	$16,571	$5,153	$5,074
4	General Office lives	38	11	2	2
5	Cost (Line 4 times Line 2)	$199,587	$16,571	$2,061	$5,074
6	Appl. Petitioner (L5 * 88.18%)	$175,996	$14,612	$1,817	$4,474
7	Total Medical Cost (L3+L6)				$591,357
	DENTAL	EMPLOYEE	SINGLE DEP.	MULTIPLE DEP.	
8	District Office lives	68	14	12	
9	Rate per life	$210.12	$97.44	$194.88	
10	Cost (Line 8 times Line 9)	$14,288	$1,364	$2,339	
11	General Office lives	38	18	5	
12	Cost (line 9 times Line 11)	$7,985	$1,754	$974	
13	Appl. Petitioner (L12*88.18%)	$7,041	$1,547	$859	
14	Total Dental Cost (L10+L13)				$27,438
	LIFE	FULL	REDUCED 32.5k	REDUCED 25k	
15	District Office lives	72	0	0	
16	Rate per annum (OVGC cost)	$168.00	$151.32	$67.08	
17	Cost (Line 15 times Line 16)	$12,096	$0	$0	
18	General Office lives	39	1	1	
19	Cost (Line 18 times Line 16)	$6,552	$151	$67	
20	Appl. Petitioner (L19*88.18%)	$5,778	$133	$59	
21	Total Life Cost (L17+L20)				$18,066
22	Total Group Insurance Cost				$636,861
23	Less group insurance expense applicable to parent company				32,755
24	Less group insurance expense capitalized (Line 22 less Line 23 times 4.75%)				28,695
25	Group insurance cost applicable to expense (Line 22 less Lines 23 and 24)				$575,411
26	Less group insurance expense as per books for the twelve months ended 6-30-06				641,395
27	Year End Adjustment				($65,984)

Allocation of Line 25 above using general spread formula

		TOTAL COMPANY	ANR PIPELINE SVC AREA	TEXAS GAS SVC AREA
28	Allocate Line 25 above	$575,411	$233,789	$341,622
29	Less group insurance expense as per books for the twelve months ended 6-30-06	641,395	263,205	378,191
30	Year End Adjustment	($65,984)	($29,416)	($36,569)

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Expenses Due To Scholarship Award
Changes In Number Of Participants And Level Of Benefit

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Number of participants 2006-2007			
1	Applicable to OVGC & OVGI (see below) *	1	0	1
2	Applicable to ANR and Texas Gas *	4	2	2
3	Applicable to ANR	4	4	
4	Applicable to Texas Gas	1		1
5	Totals	10	6	4
6	Authorized award for 2006-2007 per participant	$3,200		
7	Cost allocation	$32,000	$19,200	$12,800
8	Less cost as per books for the twelve months ended June 30, 2006	27,786	11,697	16,089
9	Year End Adjustment	$4,214	$7,503	($3,289)

10	Applicable to OVGC and OVGI	1
11	OVGC	1
12	OVGI	0

13 * General Expense Allocation schedule, p 26

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased Worker's Compensation Insurance Due To Increased Payroll And Increased Rates

	(1)	(2)	(3)	(4)	(5)
LN		STATE OF COVERAGE			
NO	TOTAL COMPANY	INDIANA	FLORIDA	NEBRASKA	TOTAL
1	Payroll basis - clerical	$1,873,282	$61,780	$531,607	$2,466,669
2	- gas ops	2,590,581			2,590,581
3	Total	$4,463,863	$61,780	$531,607	$5,057,250
4	Rate basis - clerical - per $100	$0.32	$0.58	$0.42	
5	- gas ops - per $100	$1.72			
6	Worker's Compensation Costs				
7	Clerical	$5,995	$358	$2,233	$8,586
8	Gas Ops	44,558			44,558
9	Sub-total (Line 7 plus Line 8)	$50,553	$358	$2,233	$53,144
10	Waiver of Subrogation premium	$425	$0	$0	$425
11	Subtotal (L 9 plus L10)	$50,978	$358	$2,233	$53,569
12	Increased limits percentage	0.30%	1.40%	0.30%	
13	Increased limits (L 11 times L12)	$153	$5	$7	$165
14	Sub-total (Line 11 plus Line 13)	$51,131	$363	$2,240	$53,734
15	Minimum premium adjustment	$0	$0	$0	$0
16	Sub-total (Line 14 plus Line 15)	$51,131	$363	$2,240	$53,734
17	Experience modification factor	135.00%	135.00%	135.00%	
18	Adjusted premium (L16 X L17)	$69,027	$490	$3,024	$72,541
19	Schedule Rating factor	-0.60%	$0	-1.50%	
20	Schedule Rating adj L18 X L19)	($414)	$0	($45)	($459)
21	Sub-total (Line 18 plus Line 20)	$68,613	$490	$2,979	$72,082
22	Premium Discount factor	-4.43%	-3.27%	-7.90%	
23	Premium Discount (L 21 X L 22)	($3,040)	($16)	($235)	($3,291)
24	Subtotal (L 21 plus L 23)	$65,573	$474	$2,744	$68,791
25	Expense constant	$250	$0	$0	$250
26	Dom, For Ter (L3 X .0004;.0003;.0004	$1,786	$19	$213	$2,017
27	Sub-total (Line 24 plus Line 25 & 26)	$67,609	$493	$2,956	$71,058
28	2nd injury fund surcharge	0.41%	0.00%	0.00%	
29	2nd injury fund surcharge (L27 X L28)	$274	$0	$0	$274
30	Sub-total (Line 27 plus Line 29)	$67,883	$493	$2,956	$71,332
31	Total worker's compensation cost	$67,883	$493	$2,956	$71,332

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased Worker's Compensation Insurance Due To Increased Payroll And Increased Rates

	(1)	(2)	(3)	(4)	(5)
LN		STATE OF COVERAGE			
NO	General Office	INDIANA	FLORIDA	NEBRASKA	TOTAL
1	Payroll basis - clerical	$930,152	$0	$531,607	$1,461,759
2	- gas ops	671,639			671,639
3	Total	$1,601,791	$0	$531,607	$2,133,398
4	Rate basis - clerical - per $100	$0.32	$0.58	$0.42	
5	- gas ops - per $100	$1.72			
6	Worker's Compensation Costs				
7	Clerical	$2,976	$0	$2,233	$5,209
8	Gas Ops	11,552			11,552
9	Sub-total (Line 7 plus Line 8)	$14,528	$0	$2,233	$16,761
10	Waiver of Subrogation premium	$499	$0	$0	$499
11	Subtotal (L 9 plus L10)	$15,027	$0	$2,233	$17,260
12	Increased limits percentage	0.30%	1.40%	0.30%	
13	Increased limits (L 11 times L12)	$45	$0	$7	$52
14	Sub-total (Line 11 plus Line 13)	$15,072	$0	$2,240	$17,312
15	Minimum premium adjustment	$0	$0	$0	$0
16	Sub-total (Line 14 plus Line 15)	$15,072	$0	$2,240	$17,312
17	Experience modification factor	135.00%	135.00%	135.00%	
18	Adjusted premium (L16 X L17)	$20,347	$0	$3,024	$23,371
19	Schedule Rating factor	-0.60%	$0	-1.50%	
20	Schedule Rating adj L18 X L19)	($122)	$0	($45)	($167)
21	Sub-total (Line 18 plus Line 20)	$20,225	$0	$2,979	$23,204
22	Premium Discount factor	-4.43%	-3.27%	-7.90%	
23	Premium Discount (L 21 X L 22)	($896)	$-0	($235)	($1,131)
24	Subtotal (L 21 plus L 23)	$19,329	$0	$2,744	$22,073
25	Expense constant	$250	$0	$0	$250
26	Dom, For Ter (L3 X .0004;.0003;.0004	$641	$0	$213	$853
27	Sub-total (Line 24 plus Line 25 & 26)	$20,220	$0	$2,956	$23,176
28	2nd injury fund surcharge	0.41%	0.00%	0.00%	
29	2nd injury fund surcharge (L27 X L28)	$82	$0	$0	$82
30	Sub-total (Line 27 plus Line 29)	$20,302	$0	$2,956	$23,258
31	Total worker's compensation cost	$20,302	$0	$2,956	$23,258
32	Applicable to OVGC & OVGI (42.03%)			$1,243	
33	Applicable to OVGI (14.84%)	$3,013		$439	$3,451

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Worker's Compensation Insurance

LN NO	(1)	(2)	(3)	(4)
				TOTAL
1	Total Worker's Compensation Cost (Page 13B, Line 31 less Page 13C, Line 33)			$67,880
2	Portion applicable to operating expenses (Line 1 times 91.52%)			$62,124
3	Less Worker's Compensation Cost as per books for twelve months ended June 30, 2006			69,758
4	Year End Adjustment			($7,634)
5	Allocation of Line 4 above (percentages from Page 7, Line 11)			
		TOTAL COMPANY	ANR PIPELINE SVC AREA	TEXAS GAS SVC AREA
6	Allocate Line 2 above	$62,124	$26,974	$35,150
7	Less Worker's Compensation Cost as per books for the twelve months ended June 30, 2006	69,758	28,626	41,132
8	Year End Adjustment	($7,634)	($1,652)	($5,982)

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Tax Expense Due To Public Fee
Computation On Revenue Changes

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Eligible revenue as per books for the twelve months ended June 30, 2006	$36,327,982	$15,864,808	$20,463,174
2	GCA leveling revenue adjustment	2,675,823	1,244,124	1,431,699
3	Transport adjustment	(90,024)	6	(90,030)
4	Customer change adjustment	(846,926)	(154,426)	(692,500)
5	Unbilled revenue adjustment	0	0	0
6	Weather normalization adjustment	1,693,394	760,428	932,966
7	Customer decline adjustment	(204,857)	(111,284)	(93,573)
8	Adjusted Total Revenue (Sum Lines 1 to 7)	$39,555,392	$17,603,656	$21,951,735
9	Public Utility Fee (Line 8 times Line 12)	$42,012	$18,697	$23,315
10	Less Public Utility Fee as per books for the twelve months ended June 30, 2006	29,959	12,872	17,087
11	Year End Adjustment	$12,053	$5,825	$6,228
12	Latest annual available fee	0.106210%		

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Tax Expense Due To Indiana Utility Receipts
Tax Changes Due to Revenue Changes

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Eligible utility receipts per books for the twelve months ended June 30, 2006	$38,774,830	$17,538,450	$21,236,380
2	GCA leveling revenue adjustment	2,675,823	1,244,124	1,431,699
3	Transport adjustment	(90,024)	6	(90,030)
4	Customer change adjustment	(846,926)	(154,426)	(692,500)
5	Unbilled revenue adjustment	0	0	0
6	Weather normalization adjustment	1,693,394	760,428	932,966
7	Customer decline adjustment	(204,857)	(111,284)	(93,573)
8	Adjusted Total Utility Receipts (Sum L1 to 7)	$42,002,240	$19,277,298	$22,724,941
9	Utility Receipts Tax (Line 8 times Line 12)	$588,031	$269,882	$318,149
10	Less Utility Receipts Tax as per books for the twelve months ended June 30, 2006	542,848	245,538	297,309
11	Year End Adjustment	$45,183	$24,344	$20,840
12	Current effective rate	1.400000%		

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Depreciation Expense Due To
Property Added During Base Period

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Total Utility Plant In Service at June 30, 2006	$52,367,323	$19,556,765	$32,810,559
	Less Non-Depreciable Property & Transportation Equipment			
2	Acct. 301 - Organization Expense	$9,503	$0	$9,503
3	Acct. 302 - Franchises & Consents	2,232	186	2,046
4	Acct. 303 - Miscellaneous Intangible Plant	15,481	0	15,481
5	Acct. 304 - Production Land and Land Rights	92,963	23,006	69,957
6	Acct. 365.1 - Transmission Land and Land Rights	4,165	4,165	0
7	Acct. 365.2 - Transmission Right of Ways	383,969	19,418	364,551
8	Acct. 374 - Distribution Land and Land Rights	572,977	133,417	439,560
9	Acct. 389 - General Land and Land Rights	429,016	125,238	303,777
10	Acct. 392 - Transportation Equipment	2,057,718	939,708	1,118,010
11	Total Non-Depreciable Property	$3,568,022	$1,245,138	$2,322,885
12	Depreciable Utility Plant in Service at 6-30-06	$48,799,301	$18,311,627	$30,487,674
13	Depreciation Expense (Line 12 times Line 16)	$1,415,180	$531,037	$884,143
14	Less Depreciation Expense as per books for the twelve months ended June 30, 2006	1,384,284	514,920	869,364
15	Year End Adjustment	$30,896	$16,117	$14,779
16	Current approved depreciation rates as per IURC Cause No. 32049 approved January 23, 1970	2.90%		

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Depreciation Expense Due To Increased Depreciation Rate on Certain Plant

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Plant in Service - June 30, 2006:			
1	Acct 391- Office Equipment	$780,540	$334,495	$446,045
2	Acct 397- Communications Equipment	641,554	283,431	358,123
3	Total	1,422,094	617,926	804,168
4	Depreciation Expense at 10.0%	$142,209	$61,793	$80,417
5	Less: Depreciation Expense at 2.90% on Pg 16	41,241	17,920	23,321
6	Depreciation Adjustment	$100,969	$43,873	$57,096

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Tax Expense Due To Real Estate And Personal Property Taxes

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Calculated assessment	$18,811,573	$6,806,133	$12,005,440
2	Calculated average rate		$0.026509	$0.024856
3	Calculated property taxes (L1 times L2)	$478,831	$180,424	$298,407
4	Less Property Tax Expense as per books for the twelve months ended June 30, 2006	522,467	199,982	322,485
5	Year End Adjustment	($43,636)	($19,558)	($24,078)

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Income Tax Expense Due To Indiana Adjusted Gross Income Tax Changes Due To Revenue and Expense Changes

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Utility Operating Income as per books for the twelve months ended June 30, 2006	$454,063	$404,452	$49,611
	ADD BACK:			
2	Depreciation - Book Basis	$1,384,285	$514,920	$869,364
3	Federal Income Tax	219,980	201,663	18,317
4	Deferred Fed & State Income Taxes	30,414	6,040	24,374
5	Indiana Adjusted Gross Income Tax	87,415	70,489	16,926
6	Ohio Excise Tax	45,215	45,215	0
7	Indiana Utility Receipts Tax	542,848	245,538	297,309
8	Nondeductible meals expense (50%)	18,856	6,417	12,439
9	Total Add Back per books (Sum of L2 through 8)	$2,329,013	$1,090,283	$1,238,730
10	Add Year End Adjustments to Operating Revenues	3,227,410	1,738,848	1,488,561
11	Less Year End Adjustments to Operating Expenses	4,210,747	2,006,019	2,204,728
12	Adjusted Total (L 1 plus L9 plus L10 less L11)	$1,799,739	$1,227,565	$572,174
	LESS DEDUCTIONS:			
13	Depreciation - Tax Basis	$1,941,275	$722,007	$1,219,268
14	Net deferred timing differences	($321,754)	($140,005)	($181,749)
15	Interest Expense	114,389	57,298	57,091
16	Total Deductions	$1,733,911	$639,300	$1,094,611
17	Income Subject to Adjusted Gross Income Tax	$65,828	$588,264	($522,436)
18	Adjusted Gross Income Tax (L17 X L 21)	$5,595	$50,002	($44,407)
19	Less Adjusted Gross Income Tax as per books for the twelve months ended 6-30-06	87,415	70,489	16,926
20	Year End Adjustment	($81,820)	($20,487)	($61,333)
21	Current rate	8.50%		

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Income Tax Expense Due To Federal Income Tax
Changes Due To Revenue And Expense Changes

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Utility Operating Income as per books for the twelve months ended June 30, 2006	$454,063	$404,452	$49,611
	ADD BACK:			
2	Depreciation - Book Basis	$1,384,284	$514,920	$869,364
3	Federal Income Tax	219,980	201,663	18,317
4	Deferred Federal Income Tax	6,752	(1,652)	8,404
5	Nondeductible meals expense (50%)	18,856	6,417	12,439
6	Total Add Back (Sum of Lines 2 through 5)	$1,629,872	$721,348	$908,524
7	Add Year End Adjustments to Operating Revenues	3,227,410	1,738,848	1,488,561
8	Less Year End Adjustments to Operating Expenses	4,174,111	2,009,876	2,164,235
9	Adjusted Total (L1 Plus L6 Plus L7 Less L8)	$1,137,234	$854,773	$282,461
	LESS DEDUCTIONS:			
10	Depreciation - Tax Basis	$1,693,396	$629,771	$1,063,625
11	Net deferred timing differences	($321,754)	($140,005)	($181,749)
12	Interest Expense	114,389	57,298	57,091
13	Total Deductions	$1,486,032	$547,064	$938,968
14	Income Subject Federal Income Tax	($348,797)	$307,709	($656,506)
15	Federal Income Tax (Line 12 times Line 16)	($118,591)	$104,621	($223,212)
16	Less Federal Income Tax as per books for the twelve months ended June 30, 2006	219,980	201,663	18,317
17	Year End Adjustment	($338,571)	($97,042)	($241,529)
18	Current rate	34.00%		

OHIO VALLEY GAS CORPORATION

Details Of Calculation Of Reconnection Charge For Same Customers At Same Service Address

LN NO	(1)	(2) TOTAL COMPANY
1	District Office processing and disconnection paperwork including preparation of final bill (fraction of hour)	0.60
2	District Office processing of reconnection paperwork (fraction of hour)	0.60
3	District Office Time	1.20
4	Service Department processing of disconnection including travel time and paperwork (fraction of hour)	0.75
5	Service Department processing of reconnection including travel time and paperwork (fraction of hour)	0.85
6	Total Service Department Time	1.60
7	Billing Department process of final bill (fraction of hour)	0.10
8	District Office labor rate average	$13.49
9	Service Department labor rate average	$17.85
10	Billing Department labor rate average	$17.71
11	Fringes (Percent of labor) (Page 20A, Line 7)	22.40%
12	Payroll Tax (Percent of labor))Page 20A, Line 3)	7.82%
13	Overheads including transportation costs (Percent of labor) (Page 20A, Line 12)	39.50%
	Recap Of Cost	
14	District Office labor (Line 3 times Line 8)	$16.19
15	Service Department labor (Line 6 times Line 9)	28.56
16	Billing Department labor (Line 7 times Line 10)	1.77
17	Total Labor Charge (Sum of Lines 14 through 16)	$46.52
18	Fringes (Line 11 times Line 17)	10.42
19	Payroll tax (Line 12 times Line 17)	3.64
20	Overheads (Line 13 times Line 17)	18.38
21	Total Cost (Sum of Lines 17 through 20)	$78.96
22	Proposed Reconnection Charge	$80.00

OHIO VALLEY GAS CORPORATION

Details Of Calculation Of Various Taxes And Overhead Charges For Reconnect, Trip Charge Fee, And Returned Check Charge

LN NO	(1)	(2) TOTAL COMPANY
	Computation Of Payroll Tax Rates:	
1	Total payroll (Page 7, Line 2)	$5,077,090
2	FICA/ST UC/FUTA payroll tax (P8, Line 10)	$397,023
3	Payroll Tax Percent (Line 2 divided by Line 1)	7.82%
	Computation Of Fringe Benefits:	
4	Account 926 - Employee Benefits as per books	$1,199,258
5	Year end adjustments	(61,770)
6	Total Fringe Benefits	$1,137,488
7	Fringe Benefits Percentage (Line 6 divided by Line 1)	22.40%
	Computation Of Administrative Overheads Less Fringes:	
8	Total Accounts 920 through 932 less Account 926 as per books	$1,415,906
9	Year end adjustments (Page 1, Line 11 less Line 5 above)	162,180
10	Total Administrative Overheads Less Fringes	$1,578,086
11	Applicable Operating Expenses (Page 1, Lines 6 & 8 through 10)	$3,994,734
12	Administrative Overheads (Line 10 divided by Line 11)	39.50%

OHIO VALLEY GAS CORPORATION

Details Of Calculation Of Collection Charge On Unpaid Accounts Requiring Visit To Premises

LN NO	(1)	(2) TOTAL COMPANY
1	District Office processing of paperwork (fraction of hour)	0.60
2	Service Department processing including travel time (fraction of hour)	0.55
3	Total District Office Time (Line 1 plus Line 2)	1.15
	Recap Of Cost:	
4	Office labor (Line 1 times Page 20, Line 8)	$8.09
5	Service Department labor (Line 2 times , Page 20, Line 9)	9.82
6	Total Labor Charge	$17.91
7	Fringes (Line 6 times , Page 20A, Line 7)	4.01
8	Payroll tax (Line 6 times Page 20A, Line 3)	1.40
9	Administrative overheads (Line 6 times Page 20A, Line 12)	7.07
10	Total Cost	$30.39
11	Proposed Collection Charge	$30.00

OHIO VALLEY GAS CORPORATION

Details Of Calculation Of Returned Check Charge For Items Returned To Petitioner From Customers Financial Institution Not Paid

LN NO	(1)	(2) TOTAL COMPANY
1	District Office processing paperwork and telephone contact (fraction of hour)	0.90
	Recap Of Cost:	
2	Office labor rate (Line 1 times Page 20, Line 8)	$12.14
3	Fringes (Line 1 times Page 20A, Line 7)	2.72
4	Payroll tax (Line 6 times Page 20A, Line 3)	0.95
5	Administrative overheads (Line 6 times Page 20A, Line 12)	4.80
6	Total Cost	$20.61
7	Proposed Returned Check Charge	$21.00

OHIO VALLEY GAS CORPORATION

Calculation Of Average Inventory For Use In Computing Rate Base At September 30, 2006

LN NO	(1) MONTHS ENDING	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	MATERIALS AND OPERATING SUPPLIES, DIESEL, AND PROPANE			
1	September 2005	$999,039	$435,144	$563,895
2	October	1,088,791	460,071	628,720
3	November	1,070,738	449,771	620,967
4	December	1,024,508	407,322	617,186
5	January 2006	1,024,299	407,913	616,386
6	February	1,017,806	413,175	604,631
7	March	1,023,332	414,332	609,000
8	April	1,048,745	416,393	632,352
9	May	1,136,404	447,972	688,432
10	June	1,112,925	439,796	673,129
11	July	1,109,240	438,593	670,647
12	August	1,110,359	440,085	670,274
13	September 2006	1,125,295	430,793	694,502
14	Totals	$13,891,481	$5,601,360	$8,290,121
15	Average (Line 14 divided 13)	$1,068,576	$430,874	$637,702
16	Materials and Operating Supplies	$862,908	$357,234	$505,674
17	Fuel Stock - Diesel	3,167	1,772	1,395
18	- Propane	202,501	71,868	130,633
19	Total	$1,068,576	$430,874	$637,702
	STORED NATURAL GAS	**ANR PIPELINE**	**GROUP 1**	**GROUP 2**
20	September 2005	$2,929,697	$1,063,449	$1,866,248
21	October	2,862,184	1,064,685	1,797,499
22	November	2,602,590	920,292	1,682,298
23	December	1,901,836	640,702	1,261,134
24	January 2006	2,006,385	770,559	1,235,826
25	February	1,907,102	839,469	1,067,633
26	March	2,026,238	876,076	1,150,162
27	April	2,077,348	755,776	1,321,572
28	May	2,284,405	865,365	1,419,040
29	June	2,698,344	1,099,069	1,599,275
30	July	3,011,602	1,193,687	1,817,915
31	August	3,358,683	1,399,130	1,959,553
32	September 2006	3,779,993	1,557,747	2,222,246
33	Totals	$33,446,407	$13,046,006	$20,400,401
34	Average (Line 33 divided 13)	$2,572,801	$1,003,539	$1,569,262

OHIO VALLEY GAS CORPORATION

Summary Of Lead/Lag Study For
The Twelve Months Ended June 30, 2006

LN NO	(1) DESCRIPTION	(2) EXPENSE AMOUNT	(3) EXPENSE LEAD(LAG)	(4) ** NET DAYS	(5) **** DAILY PERCENT	(6) REQUIREMENT PROVISION
1	Purchased Gas	$27,573,704	38.75	(3.29)	-0.90%	($248,163)
2	Payroll	3,780,381	10.00	25.46	6.98%	263,871
3	General Insurance	321,582	(175.88)	211.34	57.90%	186,196
4	Other O&M Expenses	2,318,563	(1.05)	36.51	10.00%	231,856
5	Total O&M Expenses	$33,994,230				$433,760
	Tax Expense					
6	Indiana Property Tax	$522,467	376.50	(341.04)	-93.44%	(488,193)
7	Ohio Property Tax	6,544	305.00	(269.54)	-73.85%	(4,833)
8	Indiana Gross Receipts Tax	542,848	49.05	(13.59)	-3.72%	(20,194)
9	Ohio Excise Tax	41,370	230.00	(194.54)	-53.30%	(22,050)
10	Ohio MCF Tax	3,845	96.12	(60.66)	-16.62%	(639)
11	FICA Tax - Employer	292,452	13.00	22.46	6.15%	17,986
12	FUTA Tax	5,503	75.13	(39.67)	-10.87%	(598)
13	State Unemployment Tax	14,278	75.14	(39.68)	-10.87%	(1,552)
14	IURC Fee	29,959	502.02	(466.56)	-127.82%	(38,294)
15	Federal Income Tax	103,893	(66.78)	102.24	28.01%	29,100
16	State Income Tax	107,375	42.00	(6.54)	-1.79%	(1,922)
17	Miscellaneous Tax	(21,519)	49.05	(13.59)	-3.72%	801
18	Total Tax Expense	$1,649,015				($530,388)
19	Total Cash Working Capital Requirement					($96,628)
	Allocation (General Expense alloc, p 26A)					
20	ANR Pipeline Service Area					($39,260)
21	Texas Gas Service Area					(57,368)
22	Total Cash Working Capital Requirement					($96,628)
23	Revenue Lag (Days)	35.46				

24 ** Net days equals Revenue Lag less the Expense Lead(Lag).
25 ****Daily percent equals Net Days divided by 365.

OHIO VALLEY GAS CORPORATION

Rate Base Components As Per Books At September 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Utility Plant in Service	$52,575,814	$19,629,319	$32,946,495
2	Less Accumulated Provision for Depreciation	23,350,089	9,828,888	13,521,201
3	Less Contributions in Aid of Construction	258,667	132,906	125,761
4	Less Customer Advances for Construction	262,582	151,344	111,238
5	Net Plant	$28,704,476	$9,516,181	$19,188,295
6	Inventory	1,068,576	430,874	637,702
7	Stored Gas	2,572,801	2,572,801	0
8	Working Capital - Lead/Lag Study	(96,628)	(39,260)	(57,368)
9	Total Rate Base	$32,249,225	$12,480,596	$19,768,629

OHIO VALLEY GAS CORPORATION

Details Of Utility Plant In Service At September 30, 2006

LN NO	(1) BY FUNCTIONAL PLANT	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA	(5) GENERAL OFFICE ALLOCATED	(6) TELL CITY ALLOCATED
1	Intangible	$27,215	$186	$27,029	$0	$0
2	Production	875,817	366,826	508,991	0	0
3	Transmission	9,262,053	2,105,586	7,156,467	0	0
4	Distribution - Direct	28,887,214	11,518,363	17,368,851	3,019,300	0
5	Distribution - Allocated	3,019,300	1,258,142	1,761,158	(3,019,300)	0
6	General Plant - Direct	4,570,999	2,153,446	2,417,553	4,703,700	1,229,516
7	General Plant - Allocated	5,933,216	2,226,770	3,706,446	(4,703,700)	(1,229,516)
8	Utility Plant In Service	$52,575,814	$19,629,319	$32,946,495	$0	$0
	BY PLANT ACCOUNT					
	Intangible Plant					
9	Acct. 301 - Organization Expense	$9,503	$0	$9,503	$0	$0
10	Acct. 302 - Franchises & Consents	2,232	186	2,046	0	0
11	Acct. 303 - Misc. Intangible Plant	15,480	0	15,480	0	0
12	Total Intangible Plant	$27,215	$186	$27,029	$0	$0
	Production Plant					
13	Acct. 304 - Land & Land Rights	$92,963	$23,006	$69,957	$0	$0
14	Acct. 305 - Structures & Improve	171,090	88,018	83,072	0	0
15	Acct. 311 - Production Equipment	611,764	255,802	355,962	0	0
16	Total Production Plant	$875,817	$366,826	$508,991	$0	$0
	Transmission Plant					
17	Acct. 365.1 - Land & Land Rights	$4,165	$4,165	$0	$0	$0
18	Acct. 365.2 - Rights of Way	383,968	19,417	364,551	0	0
19	Acct. 366 - Structures & Improve	12,190	4,914	7,276	0	0
20	Acct. 367 - Transmission Mains	8,066,621	1,581,649	6,484,972	0	0
21	Acct. 369 - Meas. & Reg. Stations	795,109	495,441	299,668	0	0
22	Total Transmission Plant	$9,262,053	$2,105,586	$7,156,467	$0	$0

OHIO VALLEY GAS CORPORATION

Details Of Utility Plant In Service At September 30, 2006

LN NO	(1) BY PLANT ACCOUNT	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA	(5) GENERAL OFFICE ALLOCATED	(6) TELL CITY ALLOCATED
	Distribution Plant					
1	Acct. 374 - Land & Land Rights	$576,592	$134,634	$441,958	$0	$0
2	Acct. 375 - Structures & Improve	28,462	8,903	19,559	0	0
3	Acct. 376 - Distribution Mains	20,438,067	7,891,390	12,546,677	0	0
4	Acct. 378 - Meas. & Reg. Stations	483,330	176,646	306,684	0	0
5	Acct. 379 - Town Border Stations	443,994	329,856	114,138	0	0
6	Acct. 380 - Services	6,836,209	2,929,674	3,906,535	0	0
7	Acct. 381 - Meters - Direct	0	0	0	2,060,181	0
8	Acct. 381 - Meters - Allocated	2,060,181	858,477	1,201,704	(2,060,181)	0
9	Acct. 383 - House Regulators - Direct	0	0	0	959,119	0
10	Acct. 383 - House Reg. - Allocated	959,119	399,665	559,454	(959,119)	0
11	Acct. 385 - Industrial Meas. & Reg. Sta	80,560	47,260	33,300	0	0
12	Total Distribution Plant	$31,906,514	$12,776,505	$19,130,009	$0	$0
13	Total Distribution Plant - Direct	$28,887,214	$11,518,363	$17,368,851	$3,019,300	$0
14	Total Distribution Plant - Allocated	3,019,300	1,258,142	1,761,158	(3,019,300)	0
15	Total Distribution Plant	$31,906,514	$12,776,505	$19,130,009	$0	$0

OHIO VALLEY GAS CORPORATION

Details Of Utility Plant In Service At September 30, 2006

LN NO	(1) BY PLANT ACCOUNT	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA	(5) GENERAL OFFICE ALLOCATED	(6) TELL CITY ALLOCATED
	General Plant					
1	Acct. 389 - Land & Land Rights - Direc	$244,815	$60,507	$184,308	$120,268	$63,933
2	Acct. 389 - Land & Land Rights - Alloc	184,201	64,732	119,469	(120,268)	(63,933)
3	Acct. 390 - Structures & Imp. - Direct	1,340,230	483,936	856,294	3,233,077	146,755
4	Acct. 390 - Structures & Imp. - Alloc.	3,379,832	1,363,032	2,016,800	(3,233,077)	(146,755)
5	Acct. 391 - Off. Furn. & Equip. - Direct	161,443	85,302	76,141	582,751	35,119
6	Acct. 391 - Off. Furn. & Equip. - Alloc.	617,870	247,761	370,109	(582,751)	(35,119)
7	Acct. 392 - Transportation Equip. - Dir.	1,204,895	683,903	520,992	318,133	462,975
8	Acct. 392 - Transportation Equip. - Allc	781,108	241,725	539,383	(318,133)	(462,975)
9	Acct. 394 - Tools & Work Equip. - Dire	1,321,247	684,676	636,571	89,855	461,703
10	Acct. 394 - Tools & Work Equip. - Allo	551,558	147,666	403,892	(89,855)	(461,703)
11	Acct. 395 - Laboratory Equip. - Direct	8,803	5,714	3,089	46,361	1,882
12	Acct. 395 - Laboratory Equip. - Alloc.	48,243	19,491	28,752	(46,361)	(1,882)
13	Acct. 397 - Communications Equip. - D	282,120	145,374	136,746	303,444	55,990
14	Acct. 397 - Comm. Equip. - Alloc.	359,434	138,056	221,378	(303,444)	(55,990)
15	Acct. 398 - Miscellaneous Equip. - Dir.	7,446	4,034	3,412	9,811	1,159
16	Acct. 398 - Misc. Equip. - Allocated	10,970	4,307	6,663	(9,811)	(1,159)
17	Total General Plant	$10,504,215	$4,380,216	$6,123,999	$0	$0
18	Total General Plant - Direct	$4,570,999	$2,153,446	$2,417,553	$4,703,700	$1,229,516
19	Total General Plant - Allocated	5,933,216	2,226,770	3,706,446	(4,703,700)	(1,229,516)
20	Total General Plant	$10,504,215	$4,380,216	$6,123,999	$0	$0
21	Total Plant in Service	$52,575,814	$19,629,319	$32,946,495	$0	$0

22	Plant in Service June 30, 2006	$52,367,323
23	Net Plant placed in service during July 1-Sept 30, 2006	208,491
24	Plant in Service Sept 30, 2006	$52,575,814

OHIO VALLEY GAS CORPORATION

Details Of Reserve For Depreciation As Of September 30, 2006

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Account 108.1 - Utility Plant In Service Reserve			
1	2006 Computation	$17,096,337	$7,207,145	$9,889,192
2	Allocate Tell City Common	251,165	60,254	190,911
3	Allocate General Office	2,470,195	1,014,509	1,455,686
4	2006 Computation	$19,817,697	$8,281,908	$11,535,789
5	Line 4 percent of total	100.00%	41.79%	58.21%
6	Allocate 108.1 as per books at 9-30-06	$21,675,187	$9,058,061	$12,617,126
7	Plant retirements 7-1-06 thru 9-30-06 not reflected in 108.3	(18,711)	(10,394)	(8,317)
8	Cost of removal 7-1-06 through 9-30-06	(6,010)	(3,021)	(2,989)
9	Adjusted Acct 108.1 at 9-30-06	$21,650,466	$9,044,646	$12,605,820
	Account 108.2 - Transportation Reserve			
10	Transportation Ledger	$1,060,444	$539,597	$520,847
11	Allocate Tell City Common	224,015	53,742	170,273
12	Allocate General Office	287,219	117,961	169,258
13	Transportation Ledger	$1,571,678	$711,300	$860,378
14	Line 10 percent of total	100.00%	45.26%	54.74%
15	Allocate 108.2 as per books at 9-30-06	$1,766,793	$799,650	$967,143
16	Plant retirements 7-1-06 thru 9-30-06	(71,716)	(14,081)	(57,635)
17	Salvage value 7-1-06 through 9-30-06	4,376	200	4,176
18	Adjusted Acct 108.2 at 9-30-06	$1,699,453	$785,769	$913,684
	Account 108.4 - Limited Term Reserve			
19	Account 302 as per books	$2,232	$186	$2,046
20	Line 13 percent of total	100.00%	8.33%	91.67%
21	Allocate Acct 108.4 as per books at 9-30-06	$1,851	$154	$1,697
	Account 108.3 - Retirement Work in Progress			
22	Actual as per books at 9-30-06	($1,681)	($1,681)	$0
23	Total Adjusted Reserve For Depreciation at September 30, 2006 (Sum of Lines 9, 18, 21, & 22)	$23,350,089	$9,828,888	$13,521,201

OHIO VALLEY GAS CORPORATION

Details Of Computation Of Factors Used For Allocation Of Certain Expenses Between Petitioner And Its Subsidiary Based on June 30, 2006 Data

	(1)	(2)	(3)	(4)
LN NO		Total	Petitioner	Subsidiary
	Utility Plant Factor			
1	Utility Plant in Service	$59,609,025	$52,367,323	$7,241,702
2	Less Depreciation Reserve	28,036,567	23,055,273	4,981,293
3	Net Utility Plant in Service	$31,572,458	$29,312,050	$2,260,409
4	Line 3 percent of total	100.00%	92.84%	7.16%
	Operating Revenues Factor			
5	Gas Sales - Net Billings	$43,041,212	$36,717,411	$6,323,801
6	Forfeited Discounts	164,692	138,638	26,054
7	Miscellaneous Service Revenues	121,949	112,209	9,739
8	Transportation Revenues	675,272	664,002	11,270
9	Total Operating Revenues	$44,003,125	$37,632,261	$6,370,864
10	Line 9 percent of total	100.00%	85.52%	14.48%
	Total Volumes Factor (Dth)			
11	Total Dth Volumes	5,059,100	4,565,366	493,734
12	Line 11 percent of total	100.00%	90.24%	9.76%
	Customers			
13	Average Customers at June 30, 2006	29,208	24,573	4,635
14	Line 13 percent of total	100.00%	84.13%	15.87%
15	Total (Sum of Lines 4, 10, 12, and 14)	400.00%	352.73%	47.27%
16	Line 15 percent of total	100.00%	88.18%	11.82%

OHIO VALLEY GAS CORPORATION

Details Of Computation Of Factors Used For Allocation Of Certain Expenses Between Petitioner's Two Service Areas Based on June 30, 2006 Data

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Utility Plant Factor			
1	Utility Plant in Service	$52,367,323	$19,556,765	$32,810,559
2	Less Depreciation Reserve	23,055,273	10,474,076	12,581,198
3	Net Utility Plant in Service	$29,312,050	$9,082,689	$20,229,361
4	Line 3 percent of total	100.00%	30.99%	69.01%
	Operating Revenues Factor			
5	Gas Sales - Net Billings	$36,717,411	$16,627,645	$20,089,766
6	Forfeited Discounts	138,638	61,471	77,167
7	Miscellaneous Service Revenues	112,209	39,211	72,998
8	Transportation Revenues	664,002	218,039	445,964
9	Total Operating Revenues	$37,632,261	$16,946,366	$20,685,894
10	Line 9 percent of total	100.00%	45.03%	54.97%
	Total Volumes Factor (Dth)			
11	Total Dth Volumes	4,565,366	2,074,400	2,490,966
12	Line 11 percent of total	100.00%	45.44%	54.56%
	Customers			
13	Average Customers at June 30, 2006	24,573	10,093	14,480
14	Line 13 percent of total	100.00%	41.07%	58.93%
15	Total (Sum of Lines 4, 10, 12, and 14)	400.00%	162.53%	237.47%
16	Line 15 percent of total	100.00%	40.63%	59.37%

OHIO VALLEY GAS CORPORATION

Summary Of Customers Billed For The Twelve Months Ended June 30, 2006

LN NO	(1) MONTH	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	July 2005	24,355	10,014	14,341
2	August	24,274	9,980	14,294
3	September	24,231	9,949	14,282
4	October	24,262	9,973	14,289
5	November	24,604	10,100	14,504
6	December 2005	24,889	10,214	14,675
7	January	24,940	10,234	14,706
8	February	24,930	10,235	14,695
9	March	24,905	10,232	14,673
10	April	24,760	10,176	14,584
11	May	24,460	10,048	14,412
12	June 2006	24,265	9,959	14,306
13	Actual Totals	294,875	121,114	173,761
14	Customer Decline adj (Page 3BB, L 6)	(2,345)	(1,183)	(1,162)
15	Adjusted Totals	292,530	119,931	172,599
16	Average Actual (Line 13 divided 12)	24,573	10,093	14,480
17	Percent of total	100.00%	41.07%	58.93%

OHIO VALLEY GAS CORPORATION

Details Of Customers Billed For The Twelve Months Ended June 30, 2006

LN NO	(1) MONTH	(2) ANR PIPELINE SVC AREA	(3) PORTLAND AREA	(4) WIN/UC AREA	(5) TELL CITY AREA
1	July 2005	10,014	2,991	5,523	1,500
2	August	9,980	2,983	5,496	1,501
3	September	9,949	2,974	5,473	1,502
4	October	9,973	2,969	5,503	1,501
5	November	10,100	3,005	5,583	1,512
6	December 2005	10,214	3,038	5,656	1,520
7	January	10,234	3,051	5,664	1,519
8	February	10,235	3,050	5,663	1,522
9	March	10,232	3,060	5,648	1,524
10	April	10,176	3,058	5,598	1,520
11	May	10,048	3,009	5,527	1,512
12	June 2006	9,959	2,984	5,468	1,507
13	Totals	121,114	36,172	66,802	18,140
14	Customer Decline adj	(1,183)	(353)	(655)	(175)
15	Adjusted Totals	119,931	35,819	66,147	17,965
16	Average Actual (Line 13/ 12)	10,093	3,014	5,567	1,512
17	Percent of total	100.00%	29.86%	55.16%	14.98%

OHIO VALLEY GAS CORPORATION

Details Of Customers Billed For The Twelve Months Ended June 30, 2006

LN NO	(1) MONTH	(2) TEXAS GAS SVC AREA	(3) CONNERSVILLE AREA	(4) TELL CITY AREA
1	July 2005	14,341	9,587	4,754
2	August	14,294	9,551	4,743
3	September	14,282	9,530	4,752
4	October	14,289	9,525	4,764
5	November	14,504	9,711	4,793
6	December 2005	14,675	9,840	4,835
7	January	14,706	9,856	4,850
8	February	14,695	9,852	4,843
9	March	14,673	9,840	4,833
10	April	14,584	9,775	4,809
11	May	14,412	9,638	4,774
12	June 2006	14,306	9,557	4,749
13	Actual Totals	173,761	116,262	57,499
14	Customer Decline adj	(1,162)	(778)	(383)
15	Adjusted Totals	172,599	115,484	57,116
16	Average Actual (Line 13 divided 12)	14,481	9,689	4,792
17	Percent of total	100.00%	66.91%	33.09%

OHIO VALLEY GAS CORPORATION

Details Of Customers Billed For The Twelve Months Ended June 30, 2006

LN NO	(1) MONTH	(2) TELL CITY SVC AREA	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	July 2005	6,254	1,500	4,754
2	August	6,244	1,501	4,743
3	September	6,254	1,502	4,752
4	October	6,265	1,501	4,764
5	November	6,305	1,512	4,793
6	December 2005	6,355	1,520	4,835
7	January	6,369	1,519	4,850
8	February	6,365	1,522	4,843
9	March	6,357	1,524	4,833
10	April	6,329	1,520	4,809
11	May	6,286	1,512	4,774
12	June 2006	6,256	1,507	4,749
13	Totals	75,639	18,140	57,499
14	Customer Decline adj	(559)	(175)	(383)
15	Adjusted Totals	75,080	17,965	57,116
16	Average Actual (Line 13 divided 12)	6,257	1,497	4,760
17	Percent of total	100.00%	23.93%	76.07%

OHIO VALLEY GAS CORPORATION

Adjusted Number of Bills and Therms By Rate
For the Twelve Months Ended June 30, 2006

LN NO	(1) ANR PIPELINE SVC. AREA	(2) NUMBER OF BILLS	(3) DEMAND/ ADJUSTED THERMS
	Rate No. 11		
1	Bills	119,499	
2	Therms		11,983,754
	Rate No. 12		
3	Bills	96	
4	Demand Therms		97,200
5	Commodity Therms		1,038,195
	Rate No. 13		
6	Bills	12	
7	Therms		137,321
	Rate No. 14		
8	Service Charge Billed (annual)- Small	9	
9	Service Charge Billed (annual) - Large	7	
10	Therms		70,417
	Rate No. T15		
11	Bills	72	
12	Therms		6,989,325
	Rate No. T16		
13	Bills	60	
14	Therms		1,168,683
	Rate No. T18		
15	Bills-Meter Grp 1	0	
16	Bills-Meter Grp 2	0	
17	Bills -Meter Grp 3	0	
18	Therm-Meter Grp 1		0
19	Therm-Meter Grp 2		0
20	Therm-Meter Grp 3		0
21	Total ANR Pipeline Svc. Area	119,755	21,387,695

OHIO VALLEY GAS CORPORATION

Adjusted Number of Bills and Therms By Rate
For the Twelve Months Ended June 30, 2006

LN NO	(1) TEXAS GAS SVC. AREA	(2) NUMBER OF BILLS	(3) DEMAND/ ADJUSTED THERMS
	Rate No. 41		
1	Bills	172,215	
2	Therms		14,736,712
	Rate No. 42		
3	Bills	0	
4	Demand Therms		0
5	Commodity Therms		0
	Rate No. 43		
6	Bills	36	
7	Therms		193,962
	Rate No. 44		
8	Service Charge Billed (annual)- Small	9	
9	Service Charge Billed (annual) - Large	5	
10	Therms		30,799
	Rate No. T45		
11	Bills	36	
12	Therms		4,509,620
	Rate No. T46		
13	Bills	144	
14	Therms		2,371,064
	Rate No. T48		
15	Bills-Meter Grp 1	0	
16	Bills-Meter Grp 2	0	
17	Bills -Meter Grp 3	0	
18	Therm-Meter Grp 1		0
19	Therm-Meter Grp 2		0
20	Therm-Meter Grp 3		0
21	Total Texas Gas Svc. Area	172,445	21,842,157
22	Total ANR Pipeline Svc. Area and Texas Gas Svc. Area		43,229,852

OHIO VALLEY GAS CORPORATION

Calculation Of Adjusted Sales Therms By Category By Rate
For the Twelve Months Ended June 30, 2006 As Per Books Adjusted

LN NO	(1)	(2) ADJUSTED TOTAL THERMS	(3) AS PER BOOKS THERMS	(4) WEATHER NORMAL ADJUSTMENT	(5) UNBILLED REVENUE	(6) CUSTOMER CHANGES	(7) CUSTOMER DECLINE
	ANR PIPELINE SVC. AREA						
1	Rate No. 11 - Portland	3,595,421	3,367,834	268,827	(6,381)		(34,859)
2	- Tell City	1,654,116	1,391,307	112,372		167,781	(17,344)
3	- Winchester	6,734,217	6,252,918	546,039			(64,740)
4	Total Rate No. 11	11,983,754	11,012,059	927,238	(6,381)	167,781	(116,943)
5	Rate No. 12 - Portland	371,044	400,974			(29,930)	
6	- Tell City	0	82,016			(82,016)	
7	- Winchester	667,151	819,124			(151,973)	
8	Total Rate No. 12	1,038,195	1,302,114	0	0	(263,919)	0
9	Monthly Demand Annualized	97,200					
10	Rate No. 13 - Portland	137,321	137,321				
11	- Tell City	0	85,765			(85,765)	
12	- Winchester	0	0				
13	Total Rate No. 13	137,321	223,086	0	0	(85,765)	0
14	Rate No. 14 - Portland	27,889	27,889				
15	- Tell City	3,276	3,276				
16	- Winchester	39,252	39,252				
17	Total Rate No. 14	70,417	70,417	0	0	0	0
18	Total Sales Therms	13,229,687	12,607,676	927,238	(6,381)	(181,903)	(116,943)
19	Rate No. T15 - Portland	6,634,977	6,634,977				
20	- Tell City	0	0				
21	- Winchester	354,348	354,348				
22	Total Rate No. T15	6,989,325	6,989,325	0	0	0	0
23	Rate No. T16 - Portland	124,127	124,127				
24	- Tell City	715,265	715,265				
25	- Winchester	329,291	329,291				
26	Total Rate No. T16	1,168,683	1,168,683	0	0	0	0
27	Rate No. T18 - Portland	0	0				
28	- Tell City	0	0				
29	- Winchester	0	0				
30	Total Rate No. T18	0	0	0	0	0	0
31	Total ANR Pipeline Svc. Area Throughput Therms	21,387,695	20,765,684	927,238	(6,381)	(181,903)	(116,943)

OHIO VALLEY GAS CORPORATION

Calculation Of Adjusted Sales Therms By Category By Rate
For the Twelve Months Ended June 30, 2006 As Per Books Adjusted

LN NO	(1)	(2) ADJUSTED TOTAL THERMS	(3) AS PER BOOKS THERMS	(4) WEATHER NORMAL ADJUSTMENT	(5) UNBILLED REVENUE	(6) CUSTOMER CHANGES	(7) CUSTOMER DECLINE
	TEXAS GAS SVC. AREA						
1	Rate No. 41 - Connersville	10,398,808	9,318,481	844,116	107,493	194,450	(65,732)
2	- Tell City	4,337,904	4,002,006	322,091	46,165		(32,358)
3	Total Rate No. 41	14,736,712	13,320,487	1,166,207	153,658	194,450	(98,090)
4	Rate No. 42 - Connersville	0	16,594			(16,594)	
5	- Tell City	0	290,426			(290,426)	
6	Total Rate No. 42	0	307,020	0	0	(307,020)	0
7	Monthly Demand Annualized	0					
8	Rate No. 43 - Connersville	136,235	449,576			(313,341)	
9	- Tell City	57,727	351,753			(294,026)	
10	Total Rate No. 43	193,962	801,329	0	0	(607,367)	0
11	Rate No. 44 - Connersville	30,799	30,799				
12	- Tell City	0	0				
13	Total Rate No. 44	30,799	30,799	0	0	0	0
14	Total Sales Therms	14,961,473	14,459,635	1,166,207	153,658	(719,937)	(98,090)
15	Rate No. T45 - Connersville	950,000	5,029,687			(4,079,687)	
16	- Tell City	3,559,620	3,559,620				
17	Total Rate No. T45	4,509,620	8,589,307	0	0	(4,079,687)	0
18	Rate No. T46 - Connersville	1,555,223	1,507,435			47,788	
19	- Tell City	815,841	257,476			558,365	
20	Total Rate No. T46	2,371,064	1,764,911	0	0	606,153	0
21	Rate No. T48 - Connersville	0	0				
22	- Tell City	0	0				
23	Total Rate No. T48	0	0	0	0	0	0
24	Total Texas Gas Svc. Area Throughput Therms	21,842,157	24,813,853	1,166,207	153,658	(4,193,471)	(98,090)

OHIO VALLEY GAS CORPORATION

Gas Sales Revenue Adjusted By Rates
For the Twelve Months Ended June 30, 2006

	(1)	(2)	(3)	(4)	(5)	(6)
LN NO		TOTAL SVC AREA	RATE SUFFIX 1	RATE SUFFIX 2	RATE SUFFIX 3	RATE SUFFIX 4
	ANR PIPELINE SERVICE AREA					
1	Total per books	$16,375,788	$14,431,871	$1,587,866	$273,686	$82,366
2	GCA Leveling Adjustment	1,244,124	1,281,583	145	(46,409)	8,805
3	Venture Billing Adjustment	(26,833)		(26,833)		
4	Sisters of St Benedict Billing Adjust	5,040	70,453		(65,413)	
5	York Casket Co Billing Adjustment	(124,875)		(124,875)		
6	Mobel, Inc Billing Adjustment	(7,758)	67,417	(75,175)		
7	Unbilled Revenue at 6-30-05	313,235	313,235			
8	Unbilled Revenue at 6-30-06	(61,378)	(61,378)			
9	Weather Normalization Adjustment	760,428	760,428			
10	Customer Decline	(111,284)	(111,284)			
11	Total ANR Pipeline Service Area	$18,366,488	$16,752,325	$1,361,128	$161,864	$91,171
	TEXAS GAS SERVICE AREA					
12	Total per books	$20,103,862	$18,487,832	$527,638	$1,042,721	$45,671
13	GCA Leveling Adjustment	1,431,699	1,798,046	(219,091)	(151,896)	4,640
14	Dresser Roots Billing Adjustment	(24,730)	219,496		(244,226)	
15	Dresser Roots Billing Adjustment	(65,780)	(65,780)			
16	Can Clay Corp	(164,391)			(164,391)	
17	Bebco Hardwood	(99,646)			(99,646)	
18	Parker Hannifin	(165,260)		(165,260)		
19	Stewart Warner South	(119,389)		(119,389)		
20	Delhi Flower	(55,460)		(26,978)	(28,482)	
21	General Electric Motors	2,156	2,156			
22	Unbilled Revenue at 6-30-05	(200,151)	(200,151)			
23	Unbilled Revenue at 6-30-06	186,054	186,054			
24	Weather Normalization Adjustment	932,966	932,966			
25	Customer Decline	(93,573)	(93,573)			
26	Total Texas Gas Service Area	$21,668,356	$21,267,045	($3,080)	$354,080	$50,311
27	Total Company	$40,034,844	$38,019,370	$1,358,048	$515,944	$141,482

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details of Calculation Of Adjustment To Miscellaneous Service Revenues

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Reconnects during test year	421	123	298
2	Increase in proposed reconnection charge		$30	$30
3	Proposed additional revenue	$12,630	$3,690	$8,940
4	Collection trips during test year	3056	1036	2020
5	Increase in proposed collection trip charge		$3	$3
6	Proposed additional revenue	$9,168	$3,108	$6,060
7	Returned checks during test year	418	155	263
8	Increase in proposed returned check charge		$2	$2
9	Proposed additional revenue	$836	$310	$526
10	Total proposed additional revenue from miscellaneous service revenues	$22,634	$7,108	$15,526
11	Proposed increased revenue to be generated (Page 32, Line 12)	5,539,794	1,656,224	3,883,570
12	Proposed increased revenue to be generated from gas sales & transportation (L11 less L10)	$5,517,160	$1,649,116	$3,868,044

OHIO VALLEY GAS CORPORATION

Details Of Year End Adjustments As Of June 30, 2006
Details of Calculation Of Adjustment To Various Items Due To Proposed Rates

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
1	Total proposed revenue (P32, L14)	$46,399,464	$20,341,438	$26,058,025
2	Less adjusted revenue (P1, L5)	40,859,670	18,685,214	22,174,455
3	Increased revenue (Line 1 less Line 2)	$5,539,794	$1,656,224	$3,883,570
4	Increased utility receipts tax (L3 * Pg.15, L11)	$77,557	$23,187	$54,370
5	Increased public utility fee (L3 * Pg. 14, L11)	$5,884	1,759	4,125
6	Net (Line 3 less Line 4 and Line 5)	$5,456,353	$1,631,278	$3,825,075
7	Increased adjusted gross income tax L6 * Pg. 18, L17)	$463,790	$138,659	$325,131
8	Net (Line 6 less Line 7)	$4,992,563	$1,492,619	$3,499,944
9	Increased Federal income tax (L8 * Pg. 19, L18)	$1,697,471	$507,490	$1,189,981
10	Increased Utility Operating Income (L8 less L9)	$3,295,092	$985,129	$2,309,963

OHIO VALLEY GAS CORPORATION

Proposed Statement Of Income For The Twelve Months Ended June 30, 2006

LN NO	(1) TOTAL COMPANY	(2) ADJUSTED BASIS 6-30-2006	(3) PROPOSED RATE EFFECT	(4) PROPOSED BASIS 6-30-2006
	Operating Revenues			
1	Gas Sales & Tranportation	$40,608,824	$5,517,160	$46,125,984
2	Forfeited Discounts	138,638		138,638
3	Miscellaneous Service Revenues	112,208	22,634	134,842
4	Total Operating Revenues	$40,859,670	$5,539,794	$46,399,464
	Operating Expenses			
5	Production	$4,726		$4,726
6	Purchased Gas	31,390,379		31,390,379
7	Transmission	147,430		147,430
8	Distribution	2,487,139		2,487,139
9	Customer Accounting	1,355,440		1,355,440
10	Administrative and General	2,715,573		2,715,573
11	Depreciation	1,516,149		1,516,149
12	Taxes - General	1,479,483	83,441	1,562,924
13	Taxes - Income - State	5,595	463,790	469,385
14	Taxes - Income - Federal	(118,591)	1,697,471	1,578,880
15	Provision Deferred Income Taxes	30,414		30,414
16	Total Operating Expenses	$41,013,737	$2,244,702	$43,258,439
17	Utility Operating Income	($154,067)	$3,295,092	$3,141,025

OHIO VALLEY GAS CORPORATION

Proposed Statement Of Income For The Twelve Months Ended June 30, 2006

LN NO	(1) ANR PIPELINE SERVICE AREA	(2) ADJUSTED BASIS 6-30-2006	(3) PROPOSED RATE EFFECT	(4) PROPOSED BASIS 6-30-2006
	Operating Revenues			
1	Gas Sales & Transportation Revenues	$18,584,532	$1,649,116	$20,233,648
2	Forfeited Discounts	61,471		61,471
3	Miscellaneous Service Revenues	39,211	7,108	46,319
4	Total Operating Revenues	$18,685,214	$1,656,224	$20,341,438
	Operating Expenses			
5	Production	$932		$932
6	Purchased Gas	14,214,516		14,214,516
7	Transmission	15,824		15,824
8	Distribution	1,067,590		1,067,590
9	Customer Accounting	639,013		639,013
10	Administrative and General	1,132,390		1,132,390
11	Depreciation	574,910		574,910
12	Taxes - General	648,910	24,946	673,856
13	Taxes - Income - State	50,002	138,659	188,661
14	Taxes - Income - Federal	104,621	507,490	612,111
15	Provision Deferred Income Taxes	6,040		6,040
16	Total Operating Expenses	$18,454,748	$671,095	$19,125,843
17	Utility Operating Income	$230,467	$985,129	$1,215,596

OHIO VALLEY GAS CORPORATION

Proposed Statement Of Income For The Twelve Months Ended June 30, 2006

LN	(1)	(2) ADJUSTED BASIS 6-30-2006	(3) PROPOSED RATE EFFECT	(4) PROPOSED BASIS 6-30-2006
NO TEXAS GAS SERVICE AREA				
	Operating Revenues			
1	Gas Sales & Transportation	$22,024,291	$3,868,044	$25,892,335
2	Forfeited Discounts	77,167		77,167
3	Miscellaneous Service Revenues	72,997	15,526	88,523
4	Total Operating Revenues	$22,174,455	$3,883,570	$26,058,025
	Operating Expenses			
5	Production	$3,794		$3,794
6	Purchased Gas	17,175,863		17,175,863
7	Transmission	131,606		131,606
8	Distribution	1,419,549		1,419,549
9	Customer Accounting	716,427		716,427
10	Administrative and General	1,583,183		1,583,183
11	Depreciation	941,239		941,239
12	Taxes - General	830,574	58,495	889,069
13	Taxes - Income - State	(44,407)	325,131	280,724
14	Taxes - Income - Federal	(223,212)	1,189,981	966,769
15	Provision Deferred Income Taxes	24,374		24,374
16	Total Operating Expenses	$22,558,989	$1,573,607	$24,132,596
17	Utility Operating Income	($384,534)	$2,309,963	$1,925,429

OHIO VALLEY GAS CORPORATION

Summary Of Adjustments On Proposed Rates As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) ANR PIPELINE DETAIL ADJ. AMOUNT	(4) TEXAS GAS DETAIL ADJ. AMOUNT
	Gas Sales & Transportation			
1	Proposed additional revenue	29	$1,649,116	$3,868,044
2	Total Gas Sales & Transportation Rev Adj		$1,649,116	$3,868,044
	Miscellaneous Service Revenues			
3	Proposed rate effect on reconnect charges	29	$3,690	$8,940
4	Proposed rate effect on collection charges	29	3,108	6,060
5	Proposed rate effect on returned checks charge	29	310	526
6	Total Miscellaneous Service Revenues Adjustments		$7,108	$15,526
	Taxes - General			
7	Public Utility Fee adjustment	30	$1,759	$4,125
8	Indiana Gross Receipts Tax adjustment	30	23,187	54,370
9	Total Taxes - General Adjustments		$24,946	$58,495
	Taxes - Income - State			
10	Indiana Adjusted Gross Income Tax adjustment	30	$138,659	$325,131
11	Total Taxes - Income - State Adjustments		$138,659	$325,131
	Taxes - Income - Federal			
12	Federal Income Tax adjustment	30	$507,490	$1,189,981
13	Total Taxes - Income - Federal Adjustments		$507,490	$1,189,981
14	Net Effect On Utility Operating Income		$985,129	$2,309,963

OHIO VALLEY GAS CORPORATION

Capitalization As Per Books At September 30, 2006
And Computed Overall Rate Of Return Based On Proposed Return On Equity

	(1)	(2)	(3)	(4)	(5)
LN NO		AMOUNT	PERCENT OF TOTAL	ASSIGNED COST	RATE OF RETURN
	Equity				
1	Common equity	30,085,270	80.21%	11.750%	9.42%
2	Customer Deposits	2,371,153	6.32%	5.000%	0.32%
3	Accrued Interest on Deposits	768,702	2.05%	0.000%	0.00%
4	Deferred Income Tax Reserve	4,281,167	11.42%	0.000%	0.00%
5	Totals	$37,506,292	100.00%		9.74%

Proposed Utility Operating Income

6	ANR Pipeline Service Area [Pg. 25, Line 9, Col. (3) times Line 5, Col. (5)]	$1,215,610
7	Texas Gas Service Area [Pg. 25, Line 9, Col. (4) times Line 5, Col. (5)]	1,925,464
8	Total Utility Operating Income At Proposed Return On Equity	$3,141,074

Calculation Of Additional Revenue To Adjust To Proposed Level Of Return:

		TOTAL COMPANY	ANR PIPELINE SVC. AREA	TEXAS GAS SVC. AREA
9	Proposed utility operating income (Line 8)	$3,141,074	$1,215,610	$1,925,464
10	Adjusted Utility Operating Income (Pages 1A & 1B)	(154,067)	230,467	(384,534)
11	Additional Utility Operating Income (L9 less L10)	$3,295,141	$985,143	$2,309,998
12	Additional revenue required (L11 * Pg. 32A, L9)	$5,539,794	$1,656,224	$3,883,570
13	Adj'd Operating Rev at 6-30-06 (P 1, L5)	40,859,670	18,685,214	22,174,455
14	Total Proposed Operating Revenues	$46,399,464	$20,341,438	$26,058,025

OHIO VALLEY GAS CORPORATION

Computation Of Revenue Factor To Convert Additional Utility Operating Income To Additional Operating Revenue Requirements At June 30, 2006

LN NO	(1)	(2) AMOUNT
1	Gross Revenue Change	100.0000%
2	Less: Public Utility Fee (.1062097%)	0.1062%
3	Subtotal	99.8938%
4	Less: Indiana Utility Receipts Tax (at 1.40%)	1.3985%
5	Subtotal	98.4953%
6	Less: Indiana Adjusted Gross Income Tax (at 8.5%)	8.3721%
7	Subtotal	90.1232%
8	Less: Federal Income Tax (at 34%)	30.6419%
9	Change in In Net Operating Income	59.4813%
10	Revenue Conversion Factor	1.6812

OHIO VALLEY GAS CORPORATION

Unaccounted For Gas Percentage

LN NO	(1)	(2) TOTAL COMPANY	(3) ANR PIPELINE SVC AREA	(4) TEXAS GAS SVC AREA
	Twelve Months Ended August 31,			
	2006			
1	Gas Purchases - Dth	2,721,433	1,269,473	1,451,960
2	Gas Sold -Dth	2,701,004	1,265,278	1,435,726
3	Unaccounted For Gas	20,429	4,195	16,234
4	Percent Unaccounted For	0.75%	0.33%	1.12%
	2005			
5	Gas Purchases - Dth	3,092,388	1,416,054	1,676,334
6	Gas Sold -Dth	3,084,107	1,408,308	1,675,799
7	Unaccounted For Gas	8,281	7,746	535
8	Percent Unaccounted For	0.27%	0.55%	0.03%
	2004			
9	Gas Purchases - Dth	3,458,494	1,616,138	1,842,356
10	Gas Sold -Dth	3,420,764	1,603,502	1,817,262
11	Unaccounted For Gas	37,730	12,636	25,094
12	Percent Unaccounted For	1.09%	0.78%	1.36%
	2003			
13	Gas Purchases - Dth	4,018,543	1,875,355	2,143,188
14	Gas Sold -Dth	3,967,701	1,862,083	2,105,618
15	Unaccounted For Gas	50,842	13,272	37,570
16	Percent Unaccounted For	1.27%	0.71%	1.75%
	2002			
17	Gas Purchases - Dth	3,474,635	1,619,983	1,854,652
18	Gas Sold -Dth	3,449,405	1,616,186	1,833,219
19	Unaccounted For Gas	25,230	3,797	21,433
20	Percent Unaccounted For	0.73%	0.23%	1.16%
21	Five (5) Year Average Percent UAF	0.82%	0.52%	1.08%

22 Per Schedule 11 and 11A, Gas Cost Adjustment filings

OHIO VALLEY GAS CORPORATION

Details Of Calculation Of Base Cost Of Gas For GCA Mechanism For The Twelve Months Ended June 30, 2006

LN NO	(1) ANR PIPELINE SERVICE AREA	(2) TOTAL
1	Demand cost	$2,137,725
2	Commodity cost	12,076,791
3	Total cost of gas	$14,214,516
4	Less rate case cost allocated to schedules with provision for changes in gas cost	0
5	Less cost of unaccounted for gas as per Page 6B	62,833
6	Net base rate cost of gas (Line 3 less Lines 4 and 5)	$14,151,683
7	Total Dth sales as per Pg 28B	1,322,969
8	Less rate case sales under schedules 'with provision for changes in gas cost	0
9	Net base rate Dth sales (Line 7 less Line 8)	1,322,969
10	Base cost of gas per Dth (Line 6 divided by Line 9)	$10.697

OHIO VALLEY GAS CORPORATION

Details Of Calculation Of Base Cost Of Gas For GCA Mechanism For The Twelve Months Ended June 30, 2006

LN NO	(1) TEXAS GAS SERVICE AREA	(2) TOTAL
1	Demand cost	$1,628,188
2	Commodity cost	15,547,675
3	Total cost of gas	$17,183,212
4	Less rate case cost allocated to schedules with provision for changes in gas cost	0
5	Less cost of unaccounted for gas as per Page 6D	168,557
6	Net base rate cost of gas (Line 3 less Lines 4 and 5)	$17,014,655
7	Total Dth sales as per Pg 28C,	1,496,147
8	Less rate case sales under schedules 'with provision for changes in gas cost	0
9	Net base rate Dth sales (Line 7 less Line 8)	1,496,147
10	Base cost of gas per Dth (Line 6 divided by Line 9)	$11.372

OHIO VALLEY GAS CORPORATION

Analysis Of Net Income To Common And Dividends Paid
January 1, 1950 To June 30, 2006

	(1)	(2)	(3)	(4)
LN NO	YEAR	NET INCOME TO COMMON	DIVIDENDS PAID	PERCENT
1	1950	$76,284	$57,000	
2	1951	47,601	42,750	
3	1952	66,405	28,500	
4	1953	57,501		
5	1954	118,053		
6	1955	76,744	28,500	
7	1956	160,411		
8	1957	148,549	28,500	
9	1958	(133,109)	210,000	
10	1959	121,928		
11	1960	217,192	42,000	
12	1961	192,056	42,000	
13	1962	(347,556)	42,000	
14	1963	(191,438)	42,000	
15	1964	233,075	42,000	
16	1965	267,489	42,000	
17	1966	(315,098)	42,000	
18	1967	688,078	42,000	
19	1968	289,689	63,000	
20	1969	328,142		
21	1970	389,927	42,000	
22	1971	376,212	42,000	
23	1972	476,357		
24	1973	517,433	84,000	
25	1974	610,239	549,378	
26	1975	467,174	84,000	
27	1976	488,416	252,000	
28	1977	678,202	336,000	
29	1978	701,663	168,000	
30	1979	886,452	504,000	
31	1980	506,238	336,000	

OHIO VALLEY GAS CORPORATION

Analysis Of Net Income To Common And Dividends Paid
January 1, 1950 To June 30, 2006

LN NO	(1) YEAR	(2) NET INCOME TO COMMON	(3) DIVIDENDS PAID	(4) PERCENT
1	1981	$610,705	336,000	
2	1982	612,475	336,000	
3	1983	685,513	336,000	
4	1984	2,255,880	336,000	
5	1985	345,451	420,000	
6	1986	930,420	840,000	
7	1987	891,887	420,000	
8	1988	858,130	840,000	
9	1989	1,076,083	840,000	
10	1990	1,022,745	420,000	
11	1991	726,853	420,000	
12	1992	690,399	420,000	
13	1993	1,304,849	420,000	
14	1994	501,914	420,000	
15	1995	709,206	165,400	
16	1996	1,891,728	73,600	
17	1997	1,718,744	73,600	
18	1998	1,323,160	73,652	
19	1999	1,101,330	73,785	
20	2000	1,477,341	73,910	
21	2001	175,584	74,023	
22	2002	(147,184)	18,518	
23	2003	2,453,042	185,537	
24	2004	318,705		
25	2005	853,769		
26	6-30-2006	185,299		
27 Totals		$32,774,337	$10,807,653	32.98%

OHIO VALLEY GAS CORPORATION

Investment In Utility Plant During The Period
January 1, 1950 To June 30, 2006

LN NO	(1) YEAR	(2) INVESTMENT AMOUNT
1	1949	$105,538
2	1950	53,897
3	1951	58,353
4	1952	37,905
5	1953	659,220
6	1954	77,719
7	1955	174,834
8	1956	149,906
9	1957	267,558
10	1958	350,005
11	1959	181,499
12	1960	195,810
13	1961	277,133
14	1962	158,402
15	1963	821,314
16	1964	410,576
17	1965	327,737
18	1966	966,542
19	1967	862,268
20	1968	540,107
21	1969	600,600
22	1970	436,900
23	1971	444,597
24	1972	453,638
25	1973	373,045
26	1974	216,450
27	1975	458,190
28	1976	209,431
29	1977	197,902
30	1978	458,506
31	1979	593,852

OHIO VALLEY GAS CORPORATION

Investment In Utility Plant During The Period
January 1, 1950 To June 30, 2006

LN NO	(1) YEAR	(2) INVESTMENT AMOUNT
1	1980	$925,115
2	1981	633,487
3	1982	451,691
4	1983	376,802
5	1984	432,446
6	1985	608,421
7	1986	783,093
8	1987	723,156
9	1988	883,505
10	1989	1,999,162
11	1990	950,976
12	1991	1,286,491
13	1992	2,372,406
14	1993	1,911,919
15	1994	2,155,763
16	1995	2,482,503
17	1996	2,717,117
18	1997	1,642,323
19	1998	2,094,766
20	1999	5,025,106
21	2000	1,538,570
22	2001	5,075,466
23	2002	1,556,524
24	2003	1,773,117
25	2004	2,327,226
26	2005	1,239,098
27	6-30-2006	1,158,873
28 Total		$56,244,556

OHIO VALLEY GAS CORPORATION

Analysis Of General And Umbrella Liability Coverage And Premiums
For The Period July 1, 1976 Through June 30, 2006

	(1)	(2)	(3)	(4)	(5)
		GENERAL LIABILITY		UMBRELLA LIABILITY	
LN NO	PERIOD	COVERAGE	PREMIUM	COVERAGE	PREMIUM
1	07-01-76 to 07-01-77	$300,000	$31,027	$15,000,000	$51,069
2	07-01-77 to 07-01-78	300,000	64,094	15,000,000	65,517
3	07-01-78 to 07-01-79	300,000	95,839	15,000,000	94,602
4	07-01-79 to 07-01-80	300,000	104,055	15,000,000	98,277
5	07-01-80 to 07-01-81	300,000	120,092	15,000,000	81,550
6	07-01-81 to 07-01-82	300,000	65,838	20,000,000	58,000
7	07-01-82 to 07-01-83	500,000	32,686	20,000,000	21,500
8	07-01-83 to 07-01-84	500,000	32,934	20,000,000	21,500
9	07-01-84 to 07-01-85	500,000	28,719	18,000,000	23,644
10	07-01-85 to 07-01-86	500,000	32,643	5,000,000	16,699
11	07-01-86 to 07-01-87	1,000,000	76,365	10,000,000	128,370
12	07-01-87 to 07-01-88	1,000,000	76,700	10,000,000	107,798
13	07-01-88 to 07-01-89	1,000,000	92,727	10,000,000	95,392
14	07-01-89 to 07-01-90	1,000,000	90,000	9,000,000	105,750
15	07-01-90 to 07-01-91	1,000,000	92,432	9,000,000	102,551
16	07-01-91 to 07-01-92	1,000,000	108,637	9,000,000	111,713
17	07-01-92 to 07-01-93	1,000,000	108,329	9,000,000	91,945
18	07-01-93 to 07-01-94	1,000,000	105,706	9,000,000	79,540
19	07-01-94 to 07-01-95	1,000,000	116,978	9,000,000	73,800
20	07-01-95 to 07-01-96	1,000,000	97,558	9,000,000	61,500
21	07-01-96 to 07-01-97	1,000,000	52,125	9,000,000	45,000
22	07-01-97 to 07-01-98	1,000,000	31,363	9,000,000	30,750
23	07-01-98 to 07-01-99	1,000,000	31,427	9,000,000	24,600
24	07-01-99 to 07-01-00	1,000,000	37,919	9,000,000	22,900
25	07-01-00 to 07-01-01	1,000,000	39,883	9,000,000	24,890
26	07-01-01 to 07-01-02	1,000,000	43,131	9,000,000	32,530
27	07-01-02 to 07-01-03	1,000,000	73,192	9,000,000	54,422
28	07-01-03 to 07-01-04	1,000,000	85,000	9,000,000	57,150
29	07-01-04 to 07-01-05	1,000,000	90,544	9,000,000	99,999
30	07-01-05 to 07-01-06	1,000,000	90,548	9,000,000	99,999
31	07-01-06 to 07-01-07	1,000,000	79,649	9,000,000	100,775

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS, INC. FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	CAUSE NO. 43208
PETITION OF OHIO VALLEY GAS CORPORATION FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	CAUSE NO. 43209

PETITIONER'S EXHIBIT PRM
DIRECT TESTIMONY
OF
PAUL R. MOUL
ON BEHALF OF
OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.
MARCH 2007

OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.

Direct Testimony of Paul R. Moul

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Appendix A - Educational Background, Business Experience and Qualifications

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Appendix H - Capital Asset Pricing Model

Appendix I - Comparable Earnings Approach

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
g	Growth Rate
GCA	Gas Cost Adjustment
GDP	Gross Domestic Product
IURC	Indiana Utility Regulatory Commission
LDC's	Local Distribution Company
LT	Long Term
M&A	Merger and acquisition
MLP	Master Limited Partnerships
NTA	normal temperature adjustment
OVG	Ohio Valley Gas
PUHC	Public Utility Holding Company
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	represents the value that accrues to existing shareholders from selling stock at a price different from book value

OHIO VALLEY GAS CORPORATION

OHIO VALLEY GAS, INC.

CAUSE NO. 43208

CAUSE NO. 43209

Direct Testimony of Paul R. Moul

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation, and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience, and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate rate of return that the Indiana Utility Regulatory Commission ("IURC" or the "Commission") should allow Ohio Valley Gas Corporation and its subsidiary, Ohio Valley Gas, Inc., together referred to as "OVG" or the "Company," an opportunity to earn on its gas jurisdictional rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data contained in Exhibit PRM-1, which is a multi-page document divided into eleven (11) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity within a range of 11.50% to 12.00%. From this range, I recommend an 11.75% rate of return on common equity for the purpose of this case. When applied to the Company's rate base, this rate of return will compensate investors for the use of their capital.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The majority of the Company's stock is owned by Beynon Farm Products Corporation. Lesser amounts of stock are owned by two individuals and the employee stock purchase plan. As such, the common stock of OVG is not traded. Therefore, it is necessary to measure the Company's cost of equity with market data obtained from a proxy group of companies.

The Company and its subsidiary provide natural gas distribution service to approximately 30,000 customers in rural areas of Indiana. Throughput to these customers in 2005 was represented by approximately 39% to residential customers, 12% to commercial customers, 43% to industrial and transportation customers and 5% to public authorities. Industrial and transportation customers consist of 214 customers, or less than one percent of the Company's customers. This means that the energy needs of a few customers can have a significant impact on the Company's operations. Also, approximately 97% of the Company's customers use natural gas for space heating purposes. This means that the Company's revenues are highly influenced by temperature conditions over which the Company has no control. For this reason, the Company is proposing a Normal Temperature Adjustment ("NTA") clause to its tariff.

The Company's flowing gas is provided by transportation arrangements with interstate pipelines. Texas Gas Transmission LLC and ANR Pipeline Company serve Ohio Valley Gas Corporation and Texas Gas Transmission, LLC serves Ohio Valley Gas, Inc. Ohio Valley Gas Corporation supplements its flowing gas supplies with propane.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as OVG. In this regard, I relied on four well-recognized measures of the cost of equity: the Discounted

Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must provide a utility with the opportunity to cover its capital costs, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed, and support reasonable credit quality.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of seven natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey (either the basic or expanded issues), (iv) they have less than $1 billion of market capitalization of their equity, and (v) they are not currently the target of a merger or acquisition. The companies in the proxy group are identified on page 2 of Schedule 2. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not separately measured the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF	9.87%
Risk Premium	11.69%
CAPM	9.58%
Comparable Earnings	15.55%
Average	11.67%
Median	10.78%
Mid-point	12.57%

From all these measures, the rate of return on common equity developed from the Gas Group is 11.67% using the average of all of these methods and 10.78% using the median of all of the methods. To accommodate the unique risk characteristics of OVG, I adjusted the results of the Gas Group. The two adjustments that I propose were intended to recognize the small size of OVG and the lack of long-term debt in the Company's capital structure. Those adjustments will be discussed later in my testimony.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. The new competitive, regulatory, and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in natural gas commodity prices has had a negative impact on its

customers. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCA mechanism. Higher and volatile gas costs have resulted in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs. The resulting high gas prices have also had an impact on the amount of and number of delinquent customer accounts.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to rise as large end users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Q. Does the Company face competition in its natural gas business?

A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors through bypass facilities and placed more responsibilities on local distribution companies, such as OVG, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. The major problem is that the larger customers have made their own gas supply arrangements and the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

Q. How does the Company's throughput to industrial customers affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial customers. Throughput to the Company's industrial and transportation customers represents 43% of total throughput. Indeed, the Company's ten largest customers (both sales and transportation service) together represent 29% of total throughput on the Company' system. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory. This risk is especially apparent for the Company where its largest customer, Visteon Auto Systems (a Ford Motor Company spin-off) located in

Connersville, Indiana, is scheduled to close its manufacturing plant in September, 2007.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The Company projects its construction expenditures will be approximately $11.7 million in the period 2006-2010. Over this five-year period, these capital expenditures will represent approximately 38% ($11.7 million ÷ $30.9 million) of its net utility plant that was outstanding at December 31, 2005.

Q. Does your cost of equity analysis and recommendation take into account the NTA that is proposed by the Company in this case?

A. Yes. The Company proposes to include in its tariff, the NTA that is intended to adjust revenues for variations in year-to-year weather conditions from the "normal" weather assumed in establishing rates in the test year context. My cost of equity analysis that provides a range of 11.50% to 12.00% rate of return on common equity takes into account the Company's proposal.

Q. Do the LDCs included in your Gas Group already have tariff mechanisms similar to the NTA?

A. Yes, and therefore my analysis already reflects the impacts of the NTA on investor expectations through the use of market-determined models. Six of the companies in my Gas Group already have some form of revenue adjustment mechanism, related to temperature variations, and the one remaining company has a weather mitigation rate design intended to deal with the effect of weather volatility during the months of December through May. As such, the market prices of these companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for abnormal weather.

Q. How do investors assess the risk to an LDC of variations in customer usage caused by weather?

A. Investors in a gas utility can only formulate reasonable expectations based upon normal weather, although achieved results may vary significantly from those expectations from year to year due to

variations in weather. That is to say, a rational investor in a gas utility can only anticipate, and base his or her analyses on normal temperature conditions. The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year. For example, the DCF formula explicitly assumes a growth rate "approaching infinity." Additionally, as I will discuss later, analysts' forecasts of utilities' earnings and dividend growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year. Moreover, one of the standard models of the cost of equity (i.e., CAPM) suggests that there is no measurable effect on the cost of equity because weather represents a company-specific risk, which does not receive compensation in the CAPM. Therefore, the theories and models underlying my cost of capital analysis obviate the need for any adjustments based upon short-term phenomena such as weather variations which have no long-term effect. Accordingly, over the long term, the investor required cost of capital or discount rate assumed for an investment in a gas utility would be the same either with or without a NTA.

That is not to say there are no benefits to the proposed NTA. Variations in weather can significantly affect customers' bills and the Company's cash flow. Fluctuations in bad debt expense from year to year, which may also be driven in part by variations in weather, also affect the Company's cash flow. Therefore, the Company can be expected to realize a short-term benefit of improved or at least more predictable liquidity as a result of implementation of the NTA. Indeed, the NTA will remove some of the Company's cash flow variability.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular OVG?

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital. This is especially important given the Company's small size and its significant exposure to the industrial class of customers.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and its required returns are described in Appendix C. For this purpose, I have utilized the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and the Gas Group.

Q. What are the components of the S&P public utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 3. I have used this group as a broad-based measure of all types of utility companies.

Q. What criteria did you employ to assemble the Gas Group?

A. The Gas Group that I employed in this case includes companies that are (i) engaged in similar business lines, (ii) have publicly-traded common stock, (iii) are included in The Value Line Investment Survey (either the basic or expanded issues), (iv) have less than $1 billion of market capitalization of their equity, and (vi) and they are not currently the target of a merger or acquisition. The Gas Group members are identified on page 2 of Schedule 2.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the credit rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost

plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Gas Group and the S&P Public Utilities?

A. Presently, the corporate credit rating ("CCR") for Gas Group is A- from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is A3 from Moody's Investors Services ("Moody's"). Only three of the companies in the Gas Group have ratings from the bond rating agencies. It is not uncommon for small companies to have no credit rating on their debt, because much of their debt is obtained in the private placement market. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for OVG, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 1, 2 and 3. The data cover the five-year period 2001-2005. For the purpose of my analysis, I have analyzed the historical results for OVG, the Gas Group, and the S&P Public Utilities. I will highlight the important categories of relative risk as follows:

Size. In terms of capitalization, OVG is very much smaller than the average size of the Gas Group and the S&P Public Utilities. Indeed the Company's capitalization is about $30 million as compared to approximately $500 million for the Gas Group and approximately $15 billion for the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm will impact its cost of equity. This is the case for OVG. Indeed, the Company is only about one-seventh (1/17) of the average size of the Gas Group, which itself is represented by small companies. Such small size significantly elevates the Company's risk profile and increases its required return.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that

investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[1]

There are no market ratios available for OVG because its stock is owned mostly by Beynon Farm Products Corporation. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was higher for the Gas Group, as compared to the S&P Public Utilities. The five-year average market-to-book ratio was fairly similar for the Gas Group and the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. OVG employs no long-term borrowed capital in its capitalization, and hence has no financial risk. The five-year average common equity ratios, based on permanent capital, were 100.0% for OVG, 49.7% for the Gas Group and 39.5% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 1.481 (4.0% ÷ 2.7%) for OVG, 0.064 (0.7% ÷ 10.9%) for the Gas Group, and 0.231 (2.5% ÷ 10.8%) for the S&P Public Utilities. The Company displays a high risk profile as revealed by very low earnings, which are highly variable as compared to the Gas Group and the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[2] The five-year average operating ratios were 96.5% for OVG, 87.2% for the Gas Group, and 84.6% for the S&P Public Utilities. The Company has very high operating risk as revealed by its high operating ratio.

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[1] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding AFUDC) was 3.14 times for the Gas Group and 2.68 times for the S&P Public Utilities. Interest coverage multiples are not meaningful for the Company because it has no long-term debt outstanding.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for OVG, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 141.7% for OVG, 82.3% for the Gas Group, and 109.0% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line betas provided on page 2 of Schedule 2 -- .64 as the average for the Gas Group, and page 3 of Schedule 3 -- .95 as the average for the S&P Public Utilities.

Q. Please summarize your risk evaluation of OVG and the Gas Group.

A. OVG is very much smaller than the average size of the Gas Group. The Company also possesses

[3] The procedure used to calculate the beta coefficient published by Value Line is described in Appendix H. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

higher operating risk than the Gas Group. As a mitigating risk factor, OVG lacks any financial risk because it has no long-term debt outstanding. The Company has historically experienced low and highly variable rates of return on common equity. In addition, the Company's customer base is dominated by a large proportion of sales to industrial and transportation customers, many of whom are engaged in manufacturing. Overall, the fundamental risk factors indicate that the Gas Group is useful in measuring the Company's cost of equity, when OVG-unique risk traits are taken into account.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships between OVG, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix C. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix C, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and have arrived at a range of the cost of equity of 11.50% to 12.00% for OVG.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix D. I will summarize them here. The Discounted Cash Flow

("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix D, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended December 2006, the monthly dividend yields of the Gas Group are shown graphically on Schedule 4. The monthly dividend yields shown on Schedule 4 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix D.

For the twelve months ending December 2006, the average dividend yield was 3.88% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 3.81% and 3.76%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 3.81% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future.

Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix D. That adjusted dividend yield is 3.93% for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of its investment (i.e., the price per share of the stock). As I explain in Appendix D, future earnings per share growth represents its primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis can also be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth can also be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begins to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth,

payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing its capital gains expectations with its dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

Q. Before presenting your analysis of the growth rates that apply specifically to the Gas Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A. Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components

of the cost of service, especially after the troublesome issues of employees' costs, insurance costs, high fuel costs, and environmental costs are worked-out in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by fluctuations in operating expenses and capital costs.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in The Wall Street Journal, The New York Times, Fortune, Forbes, and Business Week. Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the October 10, 2006 issue of Blue Chip, those forecasts are:

Blue Chip Economic Indicators

Averages	Nominal GDP	Corporate Profits, Pretax
2008-12	5.2%	5.4%
2013-17	5.1%	5.8%

These forecasts show that growth in corporate profits generally will exceed growth in overall GDP. It also is indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.[4]

Q. What company-specific data have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 5 and 6. The bar graph provided on Schedule 5 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 5, historical

[4] Obviously, growth in corporate profits is negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since 1934.

growth in earnings per share was in the range of 4.00% to 4.93% for the Gas Group. Instances of negative growth reflected in the historical data provide no reliable guide to gauge investor expected growth for the future. Investor expectations encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics that include negative growth rates should not be given any weight when formulating a composite growth rate expectation. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers and the ongoing growth of customers mandate investor expectations of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Although investors have knowledge that negative growth and losses can occur, its expectations include positive growth. Negative historic values will not provide a reasonable representation of future growth expectations because, in the long run, investors will always expect positive growth. Indeed, rational investors expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Schedule 6 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 6 for the Gas Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the DCF model?

A. Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 6 indicates that the projected earnings per share growth rates for the Gas Group are 5.74% by IBES/First Call, 4.92% by Zacks, 5.05% by Reuters/Market Guide, and 6.33% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 6.33%) than the dividends per share (i.e., 4.17%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix D, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data?

A. Although ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm, the

circumstances of the Gas Group mandate that the greater emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industry suggests that historical evidence alone does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth. Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represents a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/Market Guide and Value Line. The IBES/First Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

With the repeal of the 1935 Public Utility Holding Company ("PUHC") act, merger and acquisition ("M&A") activity, which already has been prevalent in the utility industry, is expected to accelerate. Acquisitions are usually accomplished at premiums offered to induce stockholders to sell its shares. These premiums create a ripple effect on the stock prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a run-up of the stock prices for some utility companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities – such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of market capitalization and the book value capitalization, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

The forecasts of earnings per share growth as shown on Schedule 6 provide a range of growth rates of 4.92% to 6.33%. To those company-specific growth rates, consideration must be given to long-term growth in corporate profits. While the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.75% is within the array of earnings per share growth rates shown by the analysts' forecasts and the forecast growth in overall corporate profits. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As previously indicated, the restructuring and consolidation now taking place in the utility industry, will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts that will enhance the growth prospects for the future. As such, a 5.75% growth rate will accommodate all these factors.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield and growth.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1 / P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g ") previously developed. A flotation costs adjustment ("flot.") must be applied to the DCF result (i.e., "k") that provides an additional increment to the rate of return on equity (i.e., "K"). The factor used to develop the modification that would account for the flotation costs adjustment is provided in Schedule 7 and Appendix E. The resulting DCF cost rate is:

	D_1/P_0	+	g	=	k	x	*flot.*	=	K
Gas Group	3.93%	+	5.75%	=	9.68%	x	1.02	=	9.87%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.19% (9.87% - 9.68%) to the rate of return on common equity for the Gas Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix E. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings

multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix G. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 6.25% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 8. For the twelve months ended December 2006, the average monthly yield on Moody's A-rated index of public utility bonds was 6.07%. For the six and three-month periods ending December 2006, the yields were 6.03% and 5.86%, respectively.

Q. What factors have influenced recent interest rates?

A. The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market Committee ("FOMC") policy. In the two year period between June 2004 and June 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions, which have brought the Fed Funds rate to 5.25%, are widely interpreted as part of the process of moving toward a more neutral range for monetary policy. Current interest rates are characterized by a relatively flat to slightly inverted yield curve.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial

Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix F. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2007, and the yield spread of 1.00% that I describe in Appendix F and Schedule 9. For comparative purposes, I have also shown the Blue Chip of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2007	First	5.5%	6.4%	4.8%	1.0%	5.8%
2007	Second	5.6%	6.5%	4.8%	1.0%	5.8%
2007	Third	5.7%	6.6%	4.9%	1.0%	5.9%
2007	Fourth	5.8%	6.7%	5.0%	1.0%	6.0%
2008	First	5.8%	6.7%	5.0%	1.0%	6.0%
2008	Second	5.9%	6.8%	5.1%	1.0%	6.1%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2006 publication, the Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts				
	Corporate		30-Year	A-rated Public Utility	
Averages	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2008-12	6.1%	7.0%	5.4%	1.0%	6.4%
2013-17	6.3%	7.1%	5.5%	1.0%	6.5%

Given these forecast interest rates, a 6.25% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate

equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks. The S&P Public Utility index is reflective of the risk associated with regulated utilities than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 9, the indicated risk premiums for the various time periods analyzed are 5.37% (1928-2006), 6.40% (1952-2006), 5.61% (1974-2006), and 5.83% (1979-2005). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 9 represents the returns realized through 2006. Second, the selection of the initial year of each period was based upon the events that I described in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier

results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 9, the 1928-2006 period provides the lowest indicated risk premium, while the 1952-2006 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.72% (5.61% + 5.83% = 11.44% ÷ 2) is shown from data covering the periods 1974-2006 and 1979-2006. Therefore, 5.72% represents a reasonable risk premium for the S&P Public Utilities in this case. As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.25% represents a reasonable common equity risk premium in this case. This represents approximately 92% (5.25% ÷ 5.72% = 0.92) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

Q. What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). To that cost must be added an adjustment for common stock financing costs ("flot."). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*	+	*flot.*	=	*K*
Gas Group	6.25%	+	5.25%	=	11.50%	+	0.19%	=	11.69%

CAPITAL ASSET PRICING MODEL

Q. How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I considered the Value Line betas. As shown on page 1 of Schedule 10, the average beta is .64 for the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. For reasons explained in Appendix F, I have employed the yields on long-term Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Schedule 10, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2006, the average yield was 4.99%, as shown on page 3 of that schedule. For the six- and three-months ended December 2006, the yields on 20-year Treasury bonds were 4.96% and 4.83%, respectively. As shown on page 4 of Schedule 10, forecasts published by Blue Chip on January 1, 2007 indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.8% to 5.1% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.4% from 2008 through 2012 and 5.5% from 2013 to 2017. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 5.25% risk-free rate of return for CAPM purposes.

Q. What market premium have you used in the CAPM?

A. As developed in Appendix H, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 6.44%). For the historically based market premium, I have used the arithmetic mean. I am aware that the Commission has expressed its preference for considering both the arithmetic mean and the geometric mean. So if that approach is to be taken, much more weight should be placed on the arithmetic mean because it is the correct measure in the single-period model specification of the CAPM. The resulting market premium is 6.47% (6.5% + 6.44% = 12.94% ÷ 2), which represents the average market premium using historical and forecast data.

Q. What CAPM result have you determined using the CAPM?

A. Using the 5.25% risk-free rate of return, the leverage adjusted beta of .64 for the Gas Group, the 6.47% market premium, and the flotation cost adjustment developed previously, the following result is indicated.

	Rf	$+$	β	x	$(Rm-Rf)$	$=$	k	$+$	$flot.$	$=$	K
Gas Group	5.25%	+	0.64	x	(6.47%)	=	9.39%	+	0.19%	=	9.58%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The technical aspects of my Comparable Earnings approach are set forth in Appendix I. In order to identify the appropriate return on equity for a public utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate to view the returns experienced by firms which operate in competitive markets. One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved, or expected to be achieved, because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

There are two avenues available to implement the Comparable Earnings approach. One

method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because, regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by non-regulated firms have become increasingly relevant with the current risk profile of the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1700 firms. In the selection process, companies were excluded that are incorporated in foreign countries and are master limited partnerships (MLPs).

Q. How have you implemented the Comparable Earnings approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Schedule 11.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies,

there is some downward bias in the figures shown on page 2 of Schedule 11 because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Finally, because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 16.8% using the median value as shown on page 2 of Schedule 11. The forecast rates of return as published by Value Line are shown by the 14.3% median values also provided on page 2 of Schedule 11.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

	Historical	*Forecast*	*Average*
Group	16.80%	14.30%	15.55%

<u>CONCLUSION ON COST OF EQUITY</u>

Q. What is your conclusion concerning the cost of equity for the Gas Group?

A. Based upon the application of a variety of methods and models described previously, the cost of equity for the Gas Group is 11.67% using the average of all methods and 10.78% using the median of all methods. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations and infirmities that are inherent in each method. As I indicated previously, these results for the Gas Group require adjustment in this case for OVG.

Q. What adjustments to the Gas Group's results have you made for OVG?

A. I made two adjustments. The first adjustment relates to the issue of financial risk which is non-existent for the Company. The second adjustment relates to the Company's small size.

Q. How is the 11.67% and 10.78% cost of equity for the Gas Group adjusted for OVG's 100% common equity?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. Likewise, the return on equity decreases when the financial leverage of a firm decreases. This principle is incorporated into the adjustment to the cost of equity for the Gas Group, and recognizes that the expected return on equity decreases when it is to be applied to 100% common equity.

Q. How can the Modigliani and Miller theory be applied to calculate the rate of return on common equity with 100% common equity?

A. First it is necessary to calculate the capital structure ratios for the Gas Group based upon the market value of their capitalization. By taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) shown in the annual report for these companies and the market value of the common equity using the price of stock, the capital structure ratios calculated from the market value of their securities are:

Capitalization at Market Value

Gas Group	(Fair Value)
Long-term Debt	34.37%
Preferred Stock	0.01
Common Equity	65.61
Total	100.00%

With the capital structure ratios shown above, the cost of equity for a firm without any leverage can be calculated. The cost of equity for an unleveraged firm using the average and median values for the Gas Group are shown below.

Average

ku = ke - (((ku - i) 1-t) D / E) - (ku - d) P / E

10.23% = 11.67% - (((10.23%-6.03%) .65) 34.37%/65.61%) - (10.23% - 6.10%) 0.01%/65.61%

Median

9.57% = 10.78% - (((9.57%-6.03%) .65) 34.37%/65.61%) - (9.57% - 6.10%) 0.01%/65.61%

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt , d = dividend rate on preferred stock, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 10.23% and 9.57% using the market value of the Gas Group's capitalization.

Q. After adjustment for 100% common equity, would 10.23% and 9.57% rates of return on common equity be adequate for OVG?

A. No. As the size of a firm decreases, its risk, and hence its required return increases. In his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," by Michael Annin, it was demonstrated that the CAPM would understate the cost of equity significantly according to a company's size.

Q. How should the very small size of OVG be recognized in its equity return?

A. The 2006 SBBI Yearbook provides size premiums for mid-cap, low-cap, and micro-cap portfolios based upon returns in excess of the CAPM. The Gas Group has an average market capitalization of its equity of $430 million, which would place it in the ninth decile according to the size of the companies traded on the NYSE, AMEX and NASDAQ. Therefore, the Gas Group represents a micro-cap portfolio. OVG, however, has only $30 million of common equity which would place it in the smallest (i.e., the tenth) decile according to the 2006 SBBI Yearbook.

According to the 2006 SBBI Yearbook, the respective size premiums are 1.02% for mid-cap companies, 1.81% for low-cap companies, and 3.95% for micro-cap companies. The Company qualifies for the highest size adjustment attributed to companies in the micro-cap group. However, I have taken a conservative approach by adding just 1.81% to the Company's rate of return on common equity, corresponding to the more modest low-cap size premium. Hence, the rate of return on common equity that is related to 100% common equity would become 12.04% (10.23% + 1.81%) and 11.38% (9.57% + 1.81%), after adjustment for small size.

Q. Please summarize your recommendation concerning the appropriate rate of return on common equity for the Company.

A. Given the Company's risk traits enumerated earlier, its 100% common equity ratio, and its extremely small size, an 11.50% to 12.00% rate of return on common equity is reasonable for OVG. This return is based on the average and median results for the Gas Group after adjusting for financial risk and small size.

Q. Does this conclude your prepared direct testimony?

A. Yes.

OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.

CAUSE NO. 43208
CAUSE NO. 43209

Appendices A Through I to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Concerning

Rate of Return

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Ohio,

Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal

consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2006	Thirty-eighth Financial Forum	Society of Utility & Regulatory Financial Analysts
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida

		Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of

1 financial leverage to consumers in the form of lower revenue requirements. For non-regulated
2 companies, all benefits of financial leverage are retained by the common stockholder. Although
3 retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a
4 regulated firm's rate of return on common equity must recognize the greater financial risk shown
5 by the higher leverage typically employed by public utilities.

6 Although no single index or group of indices can precisely quantify the relative
7 investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For
8 example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the
9 price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's
10 relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators,
11 which are reflective of business risk, include the variability of the rate of return on equity, which
12 is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the
13 percentage of revenues consumed by operating expenses, depreciation, and taxes other than
14 income tax), which are indicative of profitability; the quality of earnings, which considers the
15 degree to which earnings are the product of accounting principles or cost deferrals; and the
16 level of internally generated funds. Similarly, the proportion of senior capital in a company's
17 capitalization is the measure of financial risk which is often analyzed in the context of the equity
18 ratio (i.e., the complement of the debt ratio).

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside

from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the Bluefield decision. The Bluefield decisions requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $100 ÷ $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If *P* represents price, *Kp* is the required rate of return on a preferred stock, and *D* is the annual dividend (*P* and *D* with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, *Kp*. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and *n* approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that D_1, D_2, D_3, ...D_n are systematically related to one another by a constant growth rate *(g)*, so that $D_0\ (1 + g) = D_1$, $D_1\ (1 + g) = D_2$, $D_2\ (1 + g) = D_3$ and so on approaching infinity, and if *Ks* (the required rate of return on a common stock) is greater than *g*, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0(1+g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the

[1] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend (D_0) of $0.80, the current price (P_0) of $10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be $17.10 as compared with the price per share of $16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price (P_0) of $10.00, a dividend (D_0) of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Use of DCF in Ratesetting

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a meaningful margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of $1.50 per share on a $12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost

rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., $0.75 ÷ $8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model, that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good

financial performance. As such, the DCF results should not be used alone to determine the cost of equity, but should be used along with other complementary methods.

Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Schedule 2. The 2001-2005 five-year average dividend yield was 5.1% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 4. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.875% (5.75% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 3.92% (3.81% x 1.02875) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend *(D_0)* is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 3.95% (3.81% x 1.03569) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)*, results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^4 - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments *(D_0)*:

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 0.9525% (3.81% ÷ 4) for the Gas Group. The compound dividend yield would be 3.92% (1.009659^4-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 3.93% forward-looking dividend yield is the average (3.92% + 3.95% + 3.92% = 11.79% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as

earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is <u>The Value Line Investment Survey</u> which contains estimated future projections of growth. <u>The Value Line Investment Survey</u> provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales,

earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may

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[2] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton

also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*BxR*" shown on Schedule 6 Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

FLOTATION COST ADJUSTMENT

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment which is represented by historical costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price

already considers an allowance for flotation costs. This is because investors in either fixed-income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Schedule 7. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.9% for public offerings of common stocks by gas companies from 2001 to 2005. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by

the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote non-inflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market

due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending,

> production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported, subsequently, the actually deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates).

On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate. In its January 31, 2007 press release, the FOMC stated:

> "Recent indicators have suggested somewhat firmer economic growth, and some tentative signs of stabilization have appeared in the housing market. Overall, the economy seems likely to expand at a moderate pace over coming quarters.
>
> Readings on core inflation have improved modestly in recent months, and inflation pressures seem likely to moderate over time. However, the high level of resource utilization has the potential to sustain inflation pressures.
>
> The Committee judges that some inflation risks remain. The extent and timing of any additional firming that may be needed to address these risks will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information."

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury

bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 8 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 8. There, it is shown that those spreads were about the one percentage during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 8, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005 and 1.08% in 2006. As shown by the monthly data presented on pages 4 and 5 of Schedule 8, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.08 percentage points for the twelve-months ended December 2006. For the six- and three-month periods ending December 2006, the yield spread was 1.07% and 1.03%, respectively.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 10

provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt

capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for

the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 9 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a

measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2006, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.86%	5.41%
Geometric Mean	4.25%	3.35%
Median	10.17%	7.29%
Midpoint of Range	7.21%	5.32%
Average	6.54%	5.37%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 9 should also be considered. One of these sub-periods included the 55-year period, 1952-2006. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the

financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2006 and 1979 through 2006 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 55-year, 33-year and 28-year periods, the public utility risk premiums were 6.40%, 5.61%, and 5.83% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 9.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta\,(Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it

had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient *("β")*, the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 10 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the January 19, 2007, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 10) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of January 19, 2007	1.7%	+	8.78%[1]	=	10.48%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.89%.

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.72%	(	1.05535	)	+	11.07%	=	12.89%

where:	Price (P)	at	31-Dec-2006	=	1418.30
	Dividend (D)	for	3rd Qtr '06	=	6.09
	Dividend (D)		annualized	=	24.36
	Growth (g)		First Call EpS	=	11.07%

Using these indicators, the total market return is 11.69% (10.48% + 12.89% = 23.37% ÷ 2) using both the Value Line and S&P derived returns. With the 11.69% forecast market return

[1] The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., $1.40^{.25}$ - 1).

and the 5.25% risk-free rate of return, a 6.44% (11.69% - 5.25%) market premium would be indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 10. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 10, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2006, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.47% (6.5% + 6.44% = 12.94% ÷ 2) would be

reasonable which is the average of the 6.5% using historical data and a market premium of 6.44% using forecasts.

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk

inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.

I.U.R.C. CAUSE NO. 43208
I.U.R.C. CAUSE NO. 43209

FINANCIAL EXHIBIT

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

PAUL R. MOUL

Ohio Valley Gas Corporation
Ohio Valley Gas, Inc.

Index of Schedules

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Ohio Valley Gas Corporation and Subsidary
Capitalization and Financial Statistics
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 30.4	$ 29.6	$ 29.4	$ 26.9	$ 27.0	
Short-Term Debt	$ -	$ 2.0	$ 6.8	$ 4.0	$ 6.0	
Total Capital	$ 30.4	$ 31.6	$ 36.1	$ 30.9	$ 33.0	
						Average
Capital Structure Ratios						
Based on Permanent Capital:						
Common Equity [1]	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	0.0%	6.3%	18.7%	13.0%	18.2%	11.2%
Common Equity [1]	100.0%	93.7%	81.3%	87.0%	81.8%	88.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [1]	2.5%	0.8%	9.5%	-0.7%	1.4%	2.7%
Operating Ratio [2]	96.7%	98.5%	88.2%	100.4%	98.7%	96.5%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	8.42 x	3.15 x	18.61 x	-0.15 x	1.83 x	6.37 x
Post-tax: All Interest Charges	5.03 x	2.02 x	11.50 x	0.45 x	1.86 x	4.17 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	8.33 x	3.02 x	18.50 x	-0.20 x	1.46 x	6.22 x
Post-tax: All Interest Charges	4.94 x	1.88 x	11.39 x	0.39 x	1.49 x	4.02 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	2.3%	12.9%	1.0%	-9.9%	42.7%	9.8%
Effective Income Tax Rate	45.6%	52.8%	40.4%	52.0%	-3.9%	37.4%
Internal Cash Generation/Construction [4]	167.2%	105.5%	245.8%	116.1%	73.7%	141.7%
Gross Cash Flow/ Avg. Total Debt [5]	270.4%	58.9%	89.0%	32.5%	31.5%	96.5%
Gross Cash Flow Interest Coverage [6]	15.13 x	12.36 x	19.55 x	5.64 x	5.05 x	11.55 x
Common Dividend Coverage [7]	x	x	25.78 x	87.68 x	24.44 x	45.97 x

See Page 2 for Notes.

Ohio Valley Gas Corporation and Subsidiary
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: BKD Certified financial statements

Gas Group
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 444.5	$ 430.6	$ 389.2	$ 362.3	$ 349.3	
Short-Term Debt	$ 56.2	$ 41.2	$ 62.0	$ 62.5	$ 66.8	
Total Capital	$ 500.7	$ 471.8	$ 451.2	$ 424.8	$ 416.1	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	18 x	14 x	16 x	14 x	16 x
Market/Book Ratio	192.3%	180.3%	164.1%	154.3%	149.2%	168.0%
Dividend Yield	3.7%	6.3%	4.7%	5.2%	5.4%	5.1%
Dividend Payout Ratio	63.4%	139.3%	65.6%	82.9%	76.8%	85.6%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	46.3%	48.3%	50.8%	52.8%	50.8%	49.8%
Preferred Stock	0.4%	0.4%	0.4%	0.5%	0.9%	0.5%
Common Equity [2]	53.3%	51.3%	48.8%	46.7%	48.3%	49.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	51.7%	52.4%	55.8%	59.0%	59.8%	55.7%
Preferred Stock	0.4%	0.4%	0.4%	0.5%	0.8%	0.5%
Common Equity [2]	47.9%	47.2%	43.8%	40.6%	39.4%	43.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	11.4%	10.6%	11.8%	10.0%	10.6%	10.9%
Operating Ratio [3]	87.7%	87.5%	86.0%	85.3%	89.4%	87.2%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.74 x	3.31 x	3.23 x	2.81 x	2.71 x	3.16 x
Post-tax: All Interest Charges	2.70 x	2.45 x	2.40 x	2.13 x	2.06 x	2.35 x
Overall Coverage: All Int. & Pfd. Div.	2.70 x	2.45 x	2.39 x	2.11 x	2.04 x	2.34 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.74 x	3.31 x	3.20 x	2.78 x	2.67 x	3.14 x
Post-tax: All Interest Charges	2.69 x	2.44 x	2.37 x	2.09 x	2.03 x	2.32 x
Overall Coverage: All Int. & Pfd. Div.	2.69 x	2.44 x	2.37 x	2.07 x	2.00 x	2.31 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.3%	0.5%	2.1%	2.9%	3.9%	1.9%
Effective Income Tax Rate	37.7%	37.1%	37.2%	37.6%	37.8%	37.5%
Internal Cash Generation/Construction [5]	54.7%	109.1%	107.4%	75.2%	65.0%	82.3%
Gross Cash Flow/ Avg. Total Debt [6]	18.4%	22.6%	21.9%	18.0%	17.4%	19.7%
Gross Cash Flow Interest Coverage [7]	3.90 x	4.61 x	4.52 x	4.02 x	3.39 x	4.09 x
Common Dividend Coverage [8]	2.72 x	3.69 x	3.93 x	3.45 x	3.19 x	3.39 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross contribution expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey (either the basic or expanded issues), (iv) they have less than $1 billion of market capitalization of their equity, (v) they have not cut or omitted their dividend, and (vi) they are not currently the target of a merger or acquisition.

Ticker	Company	Corporate Credit Ratings [1] Moody's	Corporate Credit Ratings [1] S&P	Stock Traded	S&P Stock Ranking	Value Line Beta
CPK	Chesapeake Utilities	-	-	NYSE	B	0.60
DGAS	Delta Natural Gas Company	-	-	NDQ	B+	0.55
ENSI	EnergySouth, Inc.	-	-	NDQ	-	0.60
LG	Laclede Group, Inc.	A3	A	NYSE	B+	0.90
NWN	Northwest Natural Gas	A3	AA-	NYSE	B+	0.75
RGCO	RGC Resources, Inc.	-	-	NDQ	-	0.35
SJI	South Jersey Industries	Baa1	BBB+	NYSE	B+	0.70
	Average	A3	A-		B+	0.64

Note: [1] Ratings are those of utility subsidiaries

Source of Information: Company Annual Reports to Stockholders
Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,644.5	$ 14,562.2	$14,658.8	$ 14,236.2	$13,783.4	
Short-Term Debt	$ 485.3	$ 278.7	$ 276.6	$ 952.3	$ 1,204.1	
Total Capital	$ 15,129.8	$ 14,840.9	$14,935.4	$ 15,188.5	$14,987.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	15 x	13 x	15 x	17 x	16 x
Market/Book Ratio	195.5%	180.1%	149.0%	151.3%	183.6%	171.9%
Dividend Yield	3.7%	3.8%	4.2%	5.0%	4.1%	4.2%
Dividend Payout Ratio	58.9%	73.3%	59.9%	75.3%	64.1%	66.3%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.6%	58.3%	59.8%	60.4%	58.9%	58.8%
Preferred Stock	1.2%	1.5%	1.6%	1.8%	2.3%	1.7%
Common Equity [2]	42.2%	40.2%	38.6%	37.8%	38.9%	39.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.5%	59.7%	61.3%	63.5%	62.9%	61.2%
Preferred Stock	1.2%	1.5%	1.6%	1.6%	2.1%	1.6%
Common Equity [2]	40.3%	38.8%	37.2%	34.9%	35.0%	37.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.9%	11.1%	9.8%	7.7%	14.5%	10.8%
Operating Ratio [3]	83.0%	84.5%	84.9%	84.5%	85.9%	84.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.01 x	2.88 x	2.51 x	2.36 x	2.84 x	2.72 x
Post-tax: All Interest Charges	2.41 x	2.32 x	2.07 x	1.95 x	2.22 x	2.19 x
Overall Coverage: All Int. & Pfd. Div.	2.37 x	2.28 x	2.03 x	1.90 x	2.17 x	2.15 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.97 x	2.85 x	2.47 x	2.31 x	2.80 x	2.68 x
Post-tax: All Interest Charges	2.37 x	2.29 x	2.03 x	1.90 x	2.18 x	2.15 x
Overall Coverage: All Int. & Pfd. Div.	2.34 x	2.25 x	1.99 x	1.86 x	2.13 x	2.11 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.9%	3.1%	1.7%	2.6%	2.0%	2.1%
Effective Income Tax Rate	31.6%	26.3%	40.9%	29.4%	28.1%	31.3%
Internal Cash Generation/Construction [5]	110.4%	127.2%	128.0%	90.6%	88.6%	109.0%
Gross Cash Flow/ Avg. Total Debt [6]	19.7%	19.7%	20.3%	18.2%	17.7%	19.1%
Gross Cash Flow Interest Coverage [7]	4.20 x	4.21 x	4.34 x	3.98 x	3.57 x	4.06 x
Common Dividend Coverage [8]	4.12 x	4.83 x	5.20 x	4.07 x	3.83 x	4.41 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities [1]

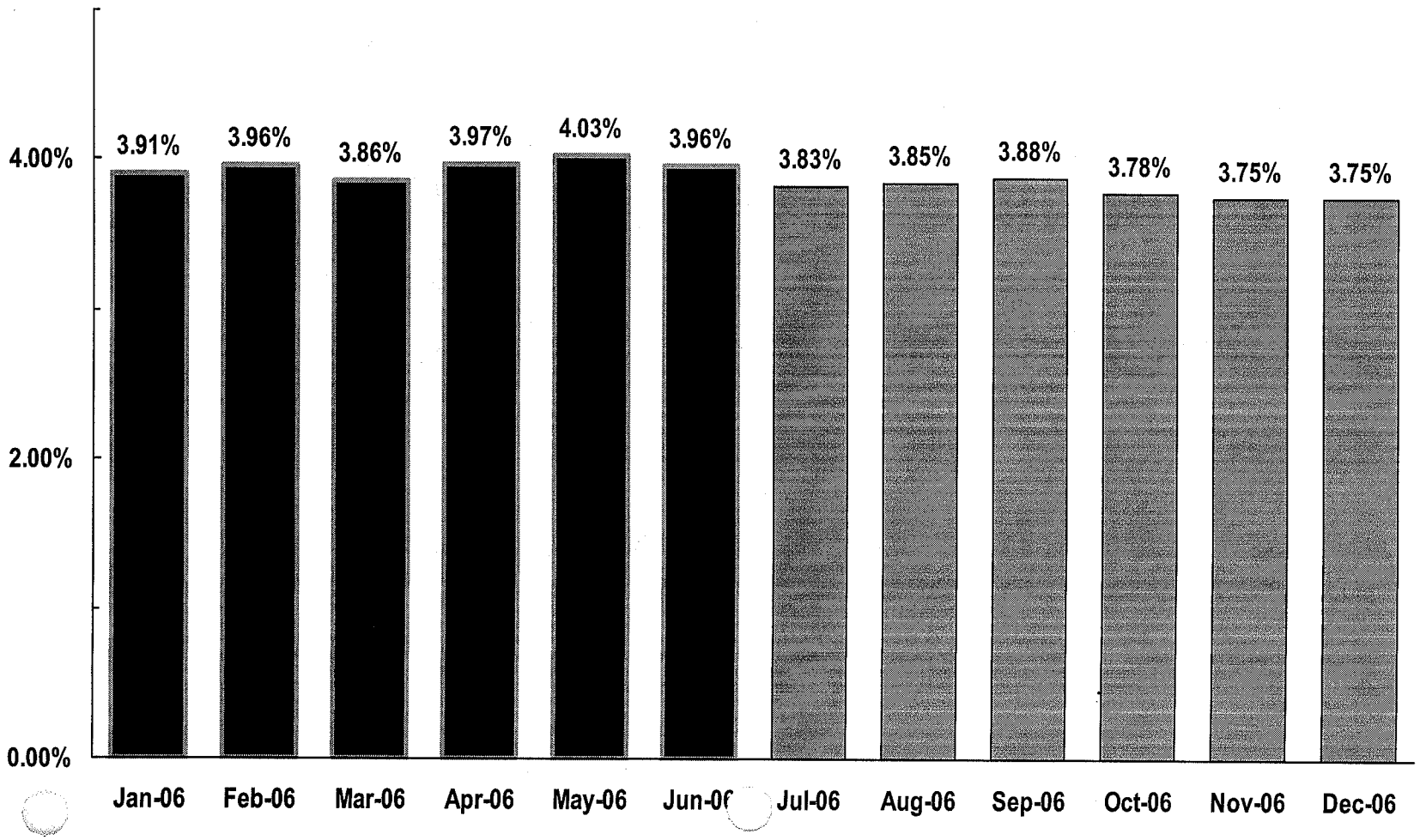
	Ticker	Credit Rating [2] Moody's	Credit Rating [2] S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Baa3	BB+	NYSE	B-	1.85
Ameren Corporation	AEE	A2	BBB+	NYSE	A-	0.75
American Electric Power	AEP	Baa2	BBB	NYSE	B	1.20
CMS Energy	CMS	Ba1	BB	NYSE	C	1.45
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.65
Consolidated Edison	ED	A1	A	NYSE	B+	0.65
Constellation Energy Group	CEG	A3	BBB+	NYSE	B	0.95
DTE Energy Co.	DTE	Baa1	BBB	NYSE	B+	0.70
Dominion Resources	D	Baa1	BBB	NYSE	B+	0.95
Duke Energy	DUK	Baa2	BBB	NYSE	B+	1.20
Edison Int'l	EIX	Baa1	BBB+	NYSE	B	1.05
Entergy Corp.	ETR	Baa2	BBB	NYSE	B+	0.85
Exelon Corp.	EXC	A3	BBB+	NYSE	B+	0.80
FPL Group	FPL	A1	A	NYSE	A-	0.80
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	B+	0.75
Keyspan Energy	KSE	A3	A	NYSE	B	0.85
NICOR Inc.	GAS	A1	AA	NYSE	B	1.15
NiSource Inc.	NI	Baa2	BBB	NYSE	B	0.80
PG&E Corp.	PCG	Baa1	BBB	NYSE	B	1.10
PPL Corp.	PPL	Baa1	A-	NYSE	B	1.00
Peoples Energy	PGL	A1	A-	NYSE	B	0.85
Pinnacle West Capital	PNW	Baa2	BBB-	NYSE	A-	0.90
Progress Energy, Inc.	PGN	Baa1	BBB	NYSE	B+	0.80
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.90
Sempra Energy	SRE	A2	A	NYSE	B	1.00
Southern Co.	SO	A2	A	NYSE	A-	0.65
TECO Energy	TE	Baa2	BBB-	NYSE	B-	1.00
TXU CORP	TXU	Baa3	BBB-	NYSE	B	1.05
Xcel Energy Inc	XEL	A3	BBB+	NYSE	B	0.80
Average for S&P Utilities		Baa1	BBB+		B	0.95

Note: [1] Includes companies contained in S&P Utility Compustat. AES Corp. and Dynegy, Inc. are not included.
[2] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

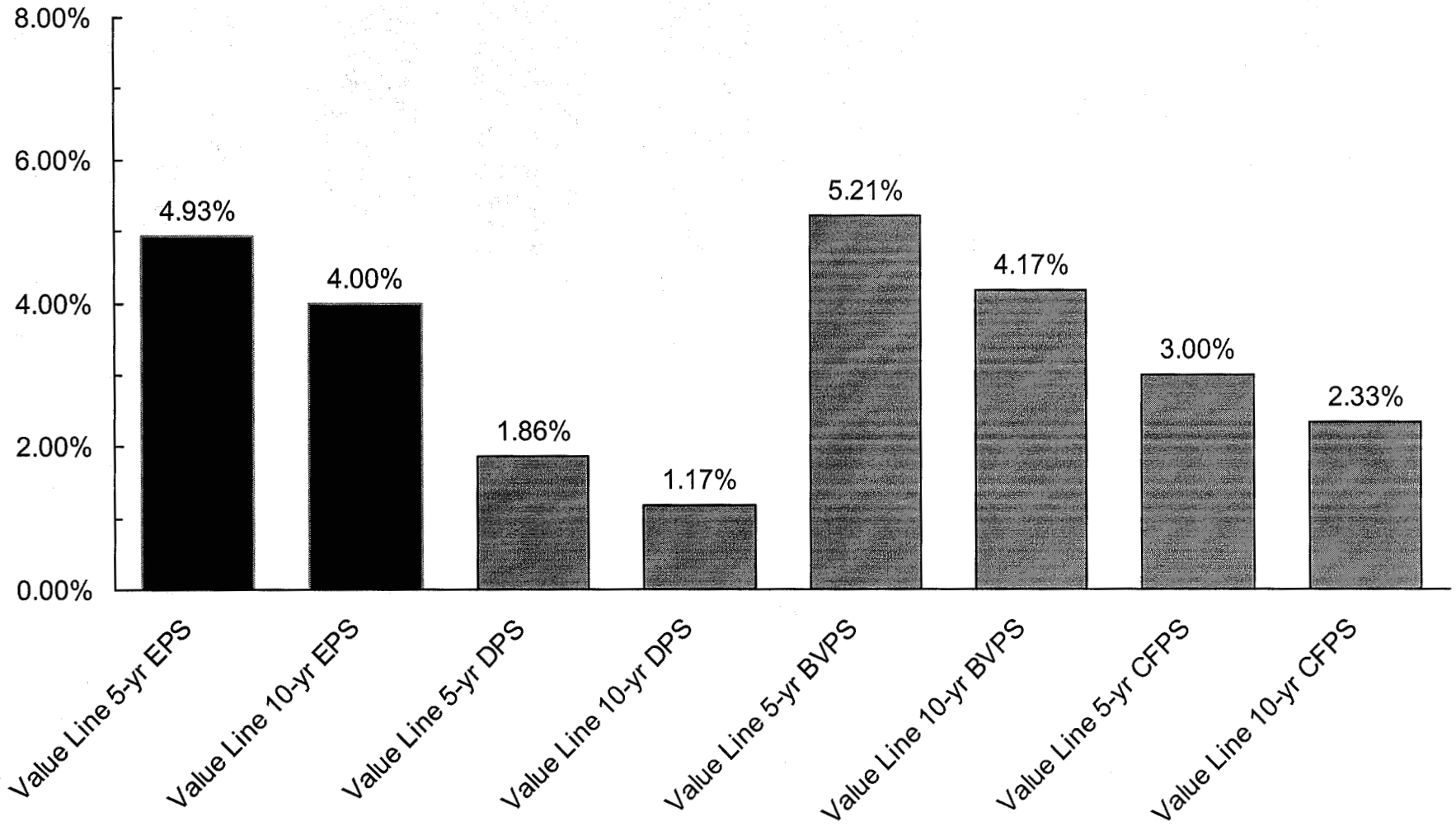
Gas Group

Monthly Dividend Yields



Gas Group

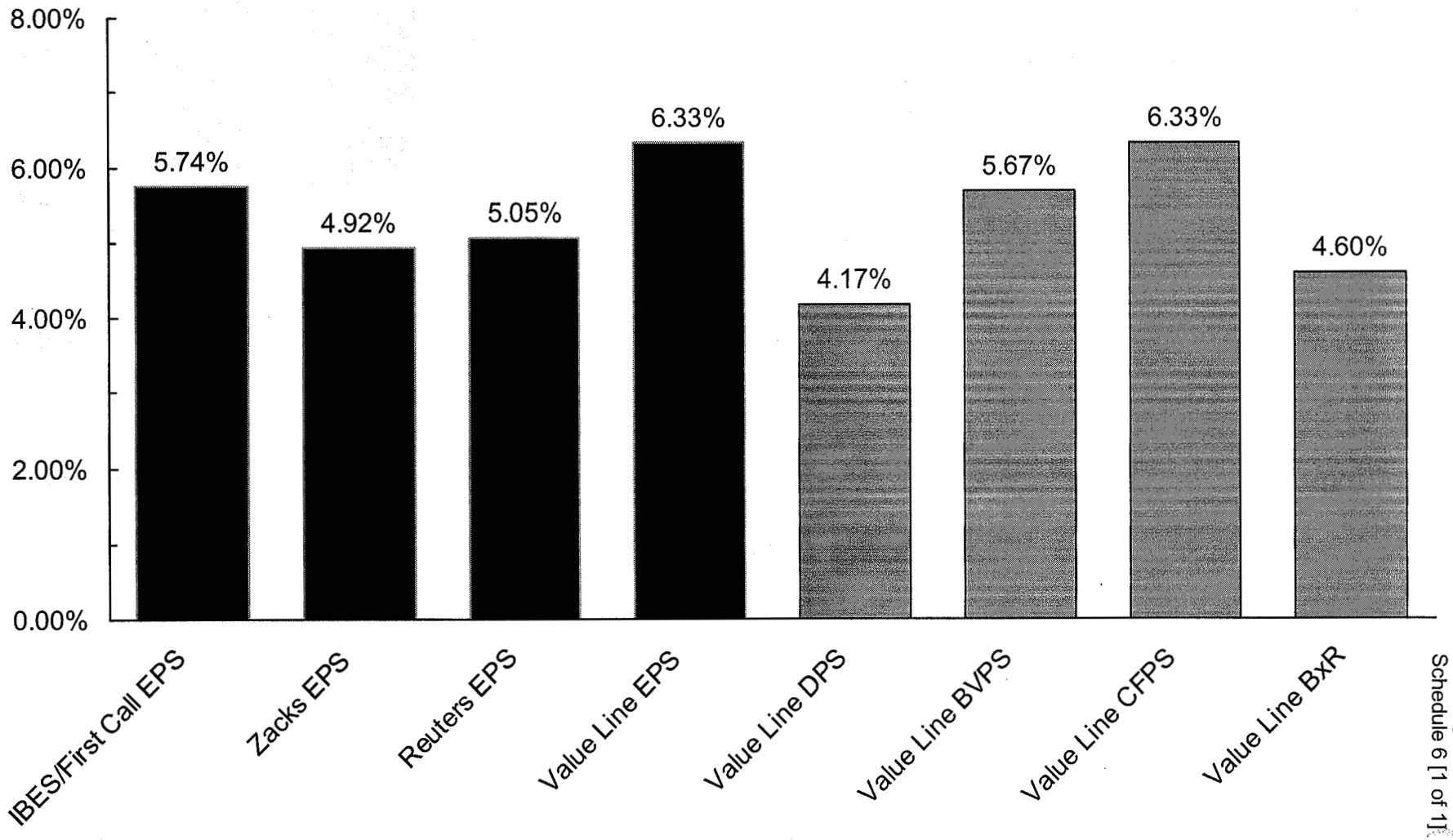
Historical Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Gas Group

Five-Year Projected Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

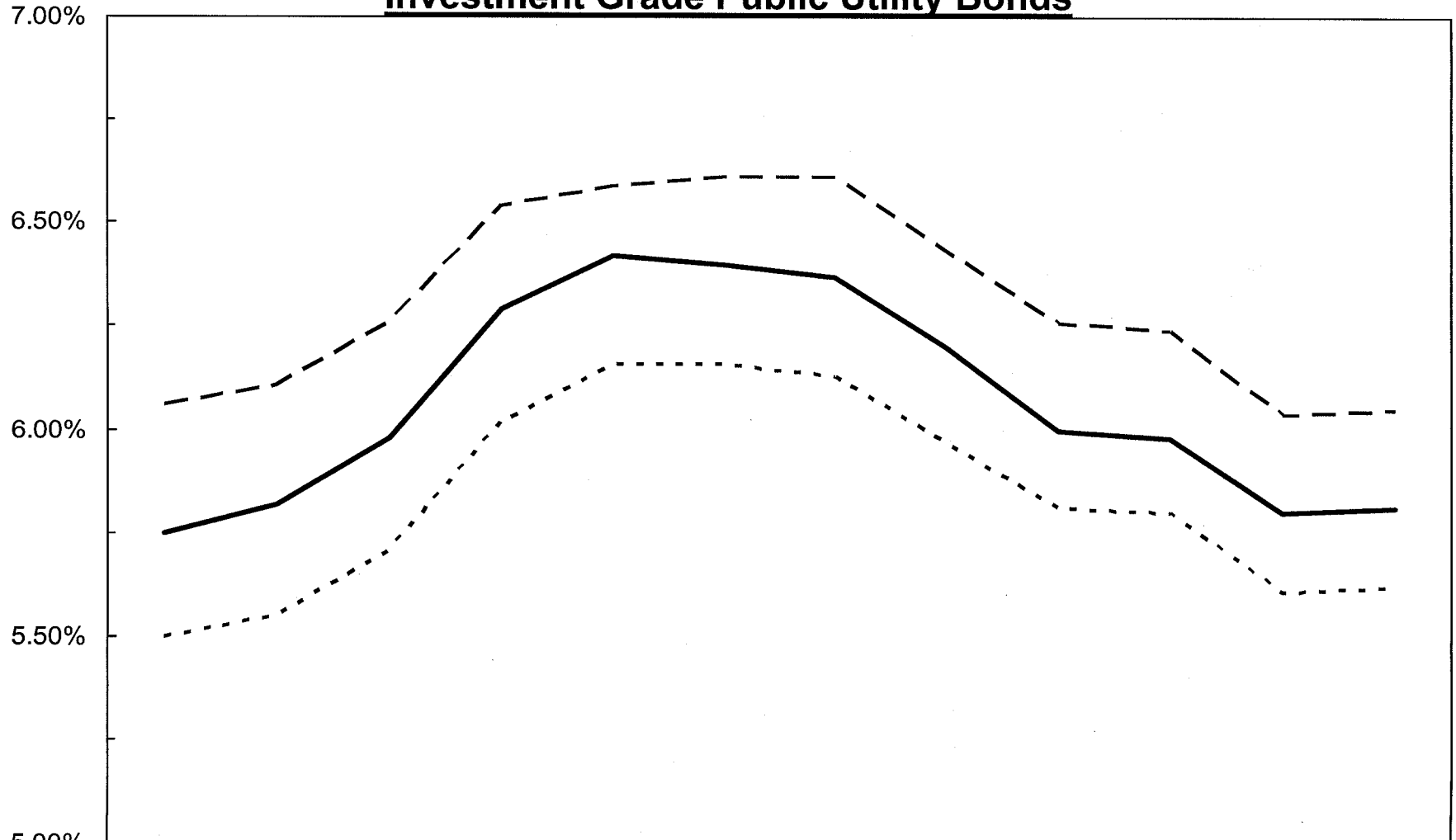
Natural Gas Industry
Analysis of Public Offerings of Common Stock
Years 2001-2005

	WGL Holdings	UTILICORP	MDU Resources	AGL RESOURCES	SOUTHERN UNION CO.	ATMOS ENERGY	VECTREN CORP.	SEMPRA ENERGY	PIEDMONT NATURAL
Date of Offering	6/26/2001	1/25/2002	11/29/2002	2/11/2003	6/5/2003	6/18/2003	8/7/2003	10/8/2003	1/20/2004
No. of shares offered (000)	1,790	11,000	2,100	5,600	9,500	4,000	6,500	15,000	4,250
Dollar amt. of offering ($000)	$ 47,847	$ 253,000	$ 50,400	$ 123,200	$ 152,000	$ 101,240	$ 148,265	$ 420,000	$ 180,625
Price to public	$ 26.730	$ 23.000	$ 24.200	$ 22.000	$ 16.000	$ 25.310	$ 22.810	$ 28.000	$ 42.500
Underwriter's discounts and commission	$ 0.895	$ 0.748	$ 0.720	$ 0.770	$ 0.560	$ 1.013	$ 0.798	$ 0.840	$ 1.490
Gross Proceeds	$ 25.835	$ 22.252	$ 23.480	$ 21.230	$ 15.440	$ 24.297	$ 22.012	$ 27.160	$ 41.010
Estimated company issuance expenses	$ 0.031	NA	$ 0.092	$ 0.045	$ 0.089	$ 0.095	$ 0.046	$ 0.033	NA
Net proceeds to company per share	$ 25.804	$ 22.252	$ 23.388	$ 21.185	$ 15.351	$ 24.202	$ 21.966	$ 27.127	$ 41.010
Underwriter's discount as a percent of offering price	3.3%	3.3%	3.0%	3.5%	3.5%	4.0%	3.5%	3.0%	3.5%
Issuance expense as a percent of offering price	0.1%	NA	0.4%	0.2%	0.6%	0.4%	0.2%	0.1%	NA
Total Issuance and selling expense as as a percent of offering price	3.4%	3.3%	3.4%	3.7%	4.1%	4.4%	3.7%	3.1%	3.5%

	UGI CORP.	NORTHWEST NATURAL	LACLEDE GROUP	SOUTHERN UNION CO.	AQUILA	ATMOS ENERGY	AGL RESOURCES	SOUTHERN UNION CO.	SEMCO Energy	Average
Date of Offering	3/18/2004	3/30/2004	5/6/2004	7/26/2004	8/18/2004	10/21/2004	11/19/2004	2/7/2005	8/9/2005	
No. of shares offered (000)	7,500	1,200	1,500	11,000	40,000	14,000	9,600	14,913	4,300	
Dollar amt. of offering ($000)	$ 240,750	$ 37,200	$ 40,200	$ 206,250	$ 102,000	$ 346,500	$ 297,696	$ 342,999	$ 27,176	
Price to public	$ 32.100	$ 31.000	$ 26.800	$ 18.750	$ 2.550	$ 24.750	$ 31.010	$ 23.000	$ 6.320	
Underwriter's discounts and commission	$ 1.404	$ 1.010	$ 0.871	$ 0.656	$ 0.099	$ 0.990	$ 0.930	$ 0.700	$ 0.253	
Gross Proceeds	$ 30.696	$ 29.990	$ 25.929	$ 18.094	$ 2.451	$ 23.760	$ 30.080	$ 22.300	$ 6.067	
Estimated company issuance expenses	$ 0.020	$ 0.146	$ 0.067	$ 0.091	NA	NA	$ 0.042	$ 0.067	$ 0.070	
Net proceeds to company per share	$ 30.676	$ 29.844	$ 25.862	$ 18.003	$ 2.451	$ 23.760	$ 30.038	$ 22.233	$ 5.997	
Underwriter's discount as a percent of offering price	4.4%	3.3%	3.3%	3.5%	3.9%	4.0%	3.0%	3.0%	4.0%	3.5%
Issuance expense as a percent of offering price	0.1%	0.5%	0.3%	0.5%	NA	NA	0.1%	0.3%	1.1%	0.4%
Total Issuance and selling expense as as a percent of offering price	4.5%	3.8%	3.6%	4.0%	3.9%	4.0%	3.1%	3.3%	5.1%	3.9%

Source of Information: Public Utility Financial Tracker

Interest Rates for
Investment Grade Public Utility Bonds



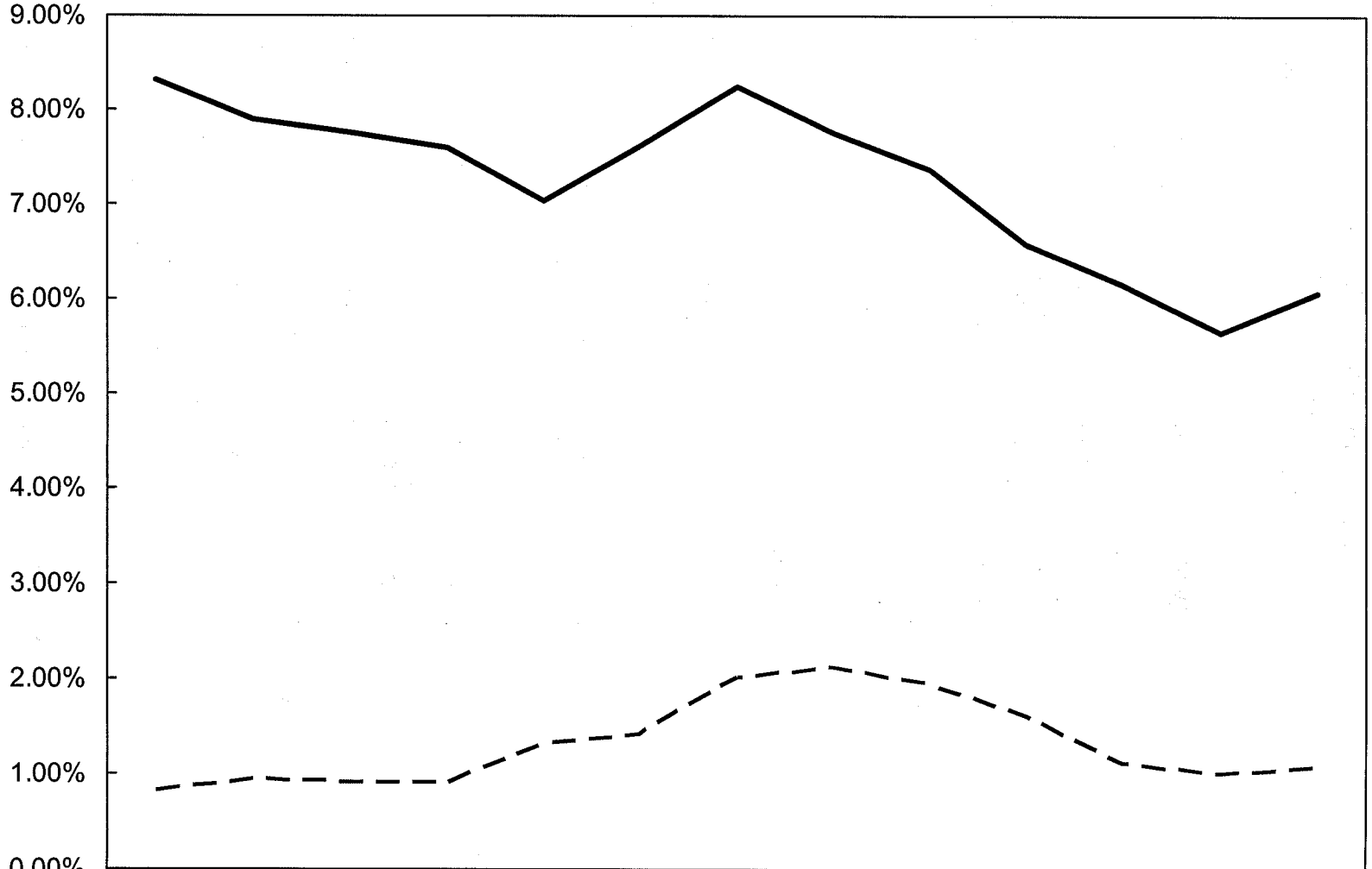
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
- - - - Aa	5.50%	5.55%	5.71%	6.02%	6.16%	6.16%	6.13%	5.97%	5.81%	5.80%	5.61%	5.62%
——— A	5.75%	5.82%	5.98%	6.29%	6.42%	6.40%	6.37%	6.20%	6.00%	5.98%	5.80%	5.81%
— — Baa	6.06%	6.11%	6.26%	6.54%	6.59%	6.61%	6.61%	6.43%	6.26%	6.24%	6.04%	6.05%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2001-2005
and the Twelve Months Ended December 2006

Years	Aa Rated	A Rated	Baa Rated	Average
2001	7.58%	7.76%	8.03%	7.72%
2002	7.19%	7.37%	8.02%	7.53%
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
2005	5.44%	5.65%	5.93%	5.67%
Five-Year Average	6.53%	6.70%	7.04%	6.75%
Months				
Jan-06	5.50%	5.75%	6.06%	5.77%
Feb-06	5.55%	5.82%	6.11%	5.83%
Mar-06	5.71%	5.98%	6.26%	5.98%
Apr-06	6.02%	6.29%	6.54%	6.28%
May-06	6.16%	6.42%	6.59%	6.39%
Jun-06	6.16%	6.40%	6.61%	6.39%
Jul-06	6.13%	6.37%	6.61%	6.37%
Aug-06	5.97%	6.20%	6.43%	6.20%
Sep-06	5.81%	6.00%	6.26%	6.03%
Oct-06	5.80%	5.98%	6.24%	6.01%
Nov-06	5.61%	5.80%	6.04%	5.82%
Dec-06	5.62%	5.81%	6.05%	5.83%
Twelve-Month Average	5.84%	6.07%	6.32%	6.08%
Six-Month Average	5.82%	6.03%	6.27%	6.04%
Three-Month Average	5.68%	5.86%	6.11%	5.89%

Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%
S[illegible]l vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.12%	1.01%	1.08%

Interest Rate Spreads
A-rated Public Utility Bonds
over 20-Year Treasuries

A rated Public Utility Bonds
over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	20-Year Treasuries Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%
Jul-05	5.51%	4.48%	1.03%
Aug-05	5.50%	4.53%	0.97%
Sep-05	5.52%	4.51%	1.01%
Oct-05	5.79%	4.74%	1.05%
Nov-05	5.88%	4.83%	1.05%
Dec-05	5.80%	4.73%	1.07%
Jan-06	5.75%	4.65%	1.10%
Feb-06	5.82%	4.73%	1.09%
Mar-06	5.98%	4.91%	1.07%
Apr-06	6.29%	5.22%	1.07%
May-06	6.42%	5.35%	1.07%
Jun-06	6.40%	5.29%	1.11%
Jul-06	6.37%	5.25%	1.12%
Aug-06	6.20%	5.08%	1.12%
Sep-06	6.00%	4.93%	1.07%
Oct-06	5.98%	4.94%	1.04%
Nov-06	5.80%	4.78%	1.02%
Dec-06	5.81%	4.78%	1.03%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2006

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
2005	4.91%	16.79%	5.87%	3.02%
2006 (p)	15.80%	20.95%	3.24%	3.94%
Geometric Mean	10.10%	8.80%	5.85%	5.45%
Arithmetic Mean	12.03%	11.14%	6.17%	5.73%
Standard Deviation	20.13%	22.55%	8.57%	7.89%
Median	14.31%	11.74%	4.14%	4.45%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2006, 1952-2006, 1974-2006, and 1979-2006

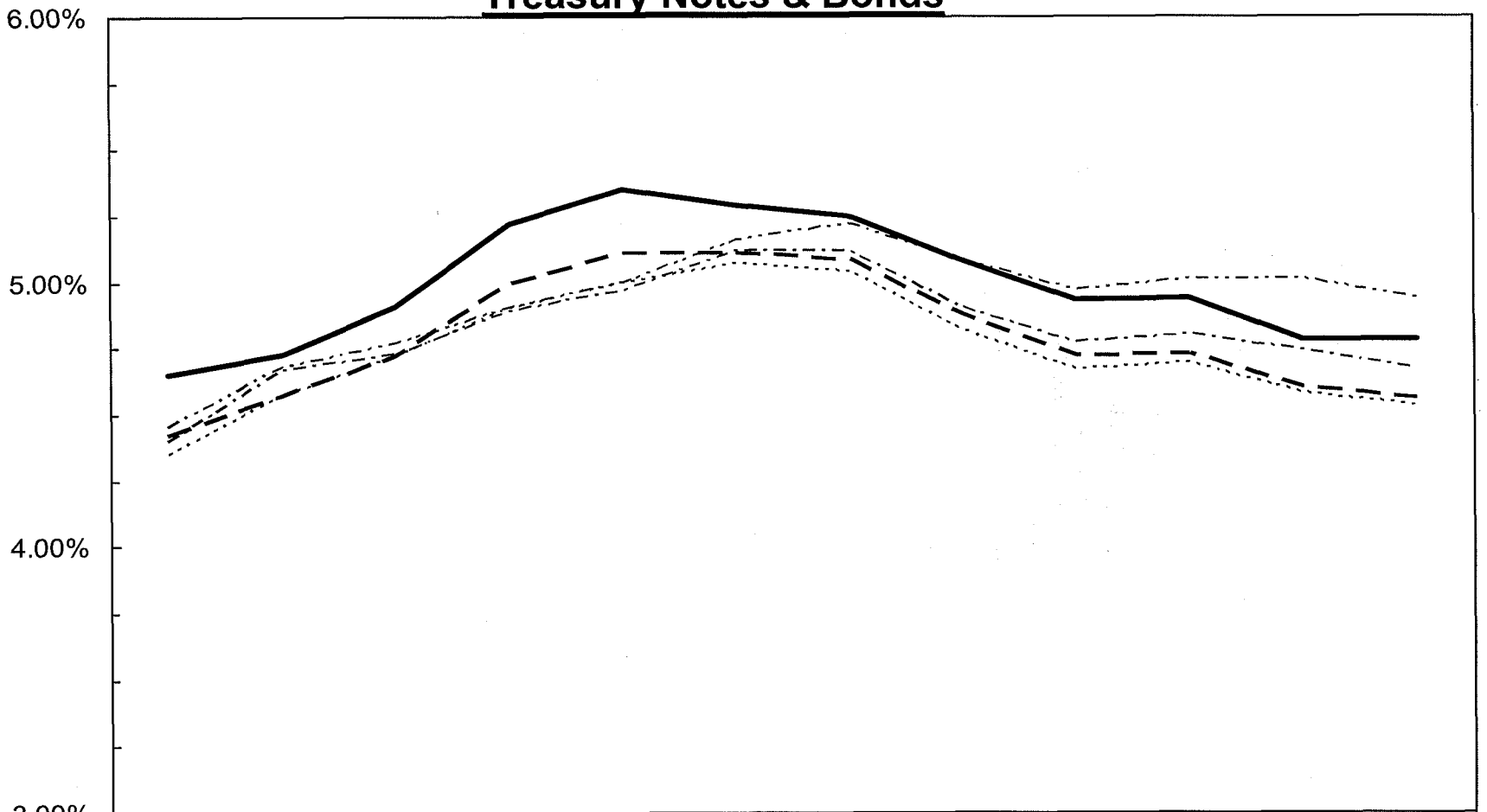
Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2006					
S&P Public Utility Index	8.80%	11.74%		11.14%	
Public Utility Bonds	5.45%	4.45%		5.73%	
Risk Differential	3.35%	7.29%	5.32%	5.41%	5.37%
1952-2006					
S&P Public Utility Index	10.99%	13.58%		12.53%	
Public Utility Bonds	6.17%	4.94%		6.47%	
Risk Differential	4.82%	8.64%	6.73%	6.06%	6.40%
1974-2006					
S&P Public Utility Index	12.79%	15.08%		14.77%	
Public Utility Bonds	8.55%	8.65%		8.90%	
Risk Differential	4.24%	6.43%	5.34%	5.87%	5.61%
1979-2006					
S&P Public Utility Index	13.42%	15.94%		15.27%	
Public Utility Bonds	8.96%	9.05%		9.29%	
Risk Differential	4.46%	6.89%	5.68%	5.98%	5.83%

Value Line Betas

Gas Group	
Chesapeake Utilities	0.60
Delta Natural Gas Company	0.55
EnergySouth, Inc.	0.60
Laclede Group, Inc.	0.90
Northwest Natural Gas	0.75
RGC Resources, Inc.	0.35
South Jersey Industries	0.70
Average	0.64

Source of Information:
Value Line Investment Survey
December 15, 2006

Yields on
Treasury Notes & Bonds



	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
1-Year	4.45%	4.68%	4.77%	4.90%	5.00%	5.16%	5.22%	5.08%	4.97%	5.01%	5.01%	4.94%
2-Year	4.40%	4.67%	4.73%	4.89%	4.97%	5.12%	5.12%	4.90%	4.77%	4.80%	4.74%	4.67%
5-Year	4.35%	4.57%	4.72%	4.90%	5.00%	5.07%	5.04%	4.82%	4.67%	4.69%	4.58%	4.53%
10-Year	4.42%	4.57%	4.72%	4.99%	5.11%	5.11%	5.09%	4.88%	4.72%	4.73%	4.60%	4.56%
20-Year	4.65%	4.73%	4.91%	5.22%	5.35%	5.29%	5.25%	5.08%	4.93%	4.94%	4.78%	4.78%

Yields for Treasury Constant Maturities
Yearly for 2001-2005
and the Twelve Months Ended December 2006

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%
2002	2.00%	2.64%	3.10%	3.82%	4.30%	4.61%	5.43%
2003	1.24%	1.65%	2.10%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.04%
2005	3.62%	3.85%	3.93%	4.05%	4.15%	4.29%	4.64%
Five-Year Average	2.45%	2.87%	3.20%	3.77%	4.14%	4.44%	5.14%
Months							
Jan-06	4.45%	4.40%	4.35%	4.35%	4.37%	4.42%	4.65%
Feb-06	4.68%	4.67%	4.64%	4.57%	4.56%	4.57%	4.73%
Mar-06	4.77%	4.73%	4.74%	4.72%	4.71%	4.72%	4.91%
Apr-06	4.90%	4.89%	4.89%	4.90%	4.94%	4.99%	5.22%
May-06	5.00%	4.97%	4.97%	5.00%	5.03%	5.11%	5.35%
Jun-06	5.16%	5.12%	5.09%	5.07%	5.08%	5.11%	5.29%
Jul-06	5.22%	5.12%	5.07%	5.04%	5.05%	5.09%	5.25%
Aug-06	5.08%	4.90%	4.85%	4.82%	4.83%	4.88%	5.08%
Sep-06	4.97%	4.77%	4.69%	4.67%	4.68%	4.72%	4.93%
Oct-06	5.01%	4.80%	4.72%	4.69%	4.69%	4.73%	4.94%
Nov-06	5.01%	4.74%	4.64%	4.58%	4.58%	4.60%	4.78%
Dec-06	4.94%	4.67%	4.58%	4.53%	4.54%	4.56%	4.78%
Twelve-Month Average	4.93%	4.82%	4.77%	4.75%	4.76%	4.79%	4.99%
Six-Month Average	5.04%	4.83%	4.76%	4.72%	4.73%	4.76%	4.96%
Three-Month Average	4.99%	4.74%	4.65%	4.60%	4.60%	4.63%	4.83%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated January 1, 2007

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	30-Year Treasury Bond
2007	First	5.0%	4.8%	4.6%	4.6%	4.8%
2007	Second	4.9%	4.8%	4.7%	4.7%	4.8%
2007	Third	4.9%	4.8%	4.7%	4.8%	4.9%
2007	Fourth	4.8%	4.8%	4.8%	4.8%	5.0%
2008	First	4.8%	4.8%	4.8%	4.9%	5.0%
2008	Second	4.8%	4.8%	4.8%	4.9%	5.1%

THE VALUE LINE Investment Survey®

Part 1 Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

January 19, 2007

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The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

18.4

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
17.3	14.1	19.6

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

1.7%

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
1.7%	2.4%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

40%

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
50%	115%	40%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

	PAGE
Advertising (21)	1917
Aerospace/Defense (24)	543
Air Transport (4)	253
Apparel (28)	1651
Auto & Truck (58)	101
Auto Parts (73)	780
Bank (74)	2101
Bank (Canadian) (32)	1563
Bank (Midwest) (72)	613
Beverage (Alcoholic) (49)	1530
Beverage (Soft Drink) (83)	1536
Biotechnology (33)	664
Building Materials (71)	845
Cable TV (1)	812
Canadian Energy (68)	426
Cement & Aggregates (64)	882
*Chemical (Basic) (14)	1232
Chemical (Diversified) (10)	1959
Chemical (Specialty) (15)	476
Coal (80)	527
Computers/Peripherals (36)	1098
Computer Software/Svcs (13)	2173
Diversified Co. (47)	1374
*Drug (59)	1242
E-Commerce (27)	1438
Educational Services (19)	1577
Electrical Equipment (46)	1001
Electric Util. (Central) (63)	695
Electric Utility (East) (70)	157
Electric Utility (West) (50)	1774
Electronics (31)	1021
Entertainment (11)	1861
Entertainment Tech (84)	1590
Environmental (54)	349
Financial Svcs. (Div.) (38)	2130
Food Processing (43)	1481
Food Wholesalers (85)	1525
Foreign Electronics (34)	1554
Furn/Home Furnishings (65)	889
Grocery (81)	1513
Healthcare Information (35)	655
Home Appliance (66)	119
Homebuilding (95)	861
Hotel/Gaming (16)	1877
Household Products (56)	938
*Human Resources (6)	1288
Industrial Services (23)	323
Information Services (44)	372
*Insurance (Life) (62)	1197
Insurance (Prop/Cas.) (22)	586
Internet (17)	2228
Investment Co. (18)	955
Investment Co.(Foreign) (42)	358
Machinery (57)	1331
Manuf. Housing/RV (93)	1546
Maritime (75)	275
Medical Services (51)	630
Medical Supplies (48)	181
Metal Fabricating (78)	564
*Metals & Mining (Div.) (3)	1220
Natural Gas (Distrib.) (92)	459
Natural Gas (Div.) (52)	440
Newspaper (60)	1905
Office Equip/Supplies (7)	1127
Oilfield Svcs/Equip. (40)	1936
Packaging & Container (20)	920
Paper/Forest Products (69)	905
Petroleum (Integrated) (45)	405
Petroleum (Producing) (88)	1926
Pharmacy Services (37)	770
Power (94)	969
*Precious Metals (53)	1211
Precision Instrument (30)	125
Publishing (12)	1891
Railroad (26)	282
*R.E.I.T. (89)	1171
Recreation (61)	1841
Restaurant (76)	291
Retail Automotive (29)	1666
Retail Building Supply (86)	875
Retail (Special Lines) (55)	1705
Retail Store (8)	1676
Securities Brokerage (5)	1421
Semiconductor (25)	1046
Semiconductor Equip (2)	1083
Shoe (39)	1694
Steel (General) (79)	575
Steel (Integrated) (67)	1411
Telecom. Equipment (41)	745
Telecom. Services (9)	718
*Thrift (91)	1161
Tire & Rubber (–)	114
Tobacco (77)	1570
Toiletries/Cosmetics (82)	801
Trucking (90)	265
Water Utility (96)	1416
Wireless Networking (87)	1457, 508

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXII, No. 21.
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See back cover for important disclosures.

Table 7

Basic Series and Portfolios

Summary Statistics of Annual Retur
From 1926 to 20

I.U.R.C. No. 43208
I.U.R.C. No. 43209
Exhibit PRM-1
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Schedule 10 [6 of 6]

Asset Class	1/1/26 to 12/31/06 Geometric Mean	Arithmetic Mean	Standard Deviation
Large Company Stocks	10.4	12.3	20.1
Small Company Stocks	12.7	17.4	32.7
Long-Term Corporate Bonds	5.9	6.2	8.5
Long-Term Government Bonds	5.4	5.8	9.2
Intermediate-Term Government Bonds	5.3	5.4	5.7
U.S. Treasury Bills	3.7	3.8	3.1
Inflation	3.0 E	3.1 E	4.3 E
90% Stocks/10% Bonds	10.1	11.7	18.1
70% Stocks/30% Bonds	9.3	10.3	14.5
50% Stocks/50% Bonds	8.4	9.0	11.5
30% Stocks/70% Bonds	7.3	7.7	9.3
10% Stocks/90% Bonds	6.1	6.4	8.8

E = Estimated

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Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++ & A;
Price Stability of 90 to 100; Betas of .35 to .90; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Assoc. Banc-Corp	BANKMID	4	2	B++	100	0.90	3
Clorox Co.	HOUSEPRD	4	2	B++	95	0.60	3
Commerce Bancshs.	BANKMID	4	1	A	100	0.90	3
Compass Bancshares	BANK	4	2	B++	100	0.90	3
Dentsply Int'l	MEDSUPPL	4	2	B++	95	0.70	3
First Midwest Bancorp	BANKMID	4	2	B++	95	0.90	3
Hormel Foods	FOODPROC	4	1	A	95	0.75	3
Kellogg	FOODPROC	4	2	B++	100	0.65	3
Weis Markets	GROCERY	4	1	A	90	0.80	3
Wiley (John) & Sons	PUBLISH	4	3	B+	90	0.75	3
Average		4	2	B++	96	0.79	3
Gas Group	Average	4	2	B++	96	0.64	2

Source of Information: Value Line Investment Survey for Windows, January, 2007

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2001-2005 and
Projected 3-5 Year Returns

Company	2001	2002	2003	2004	2005	Average	Projected 2009-11
Assoc. Banc-Corp	16.8%	16.6%	17.0%	12.8%	13.8%	15.4%	13.5%
Clorox Co.	20.2%	23.8%	42.3%	35.5%	35.5%	31.5%	49.0%
Commerce Bancshs.	14.3%	14.1%	14.2%	15.4%	16.7%	14.9%	13.0%
Compass Bancshares	15.8%	16.3%	18.3%	18.1%	18.0%	17.3%	12.5%
Dentsply Int'l	18.0%	17.5%	15.4%	13.6%	17.4%	16.4%	15.0%
First Midwest Bancorp	18.4%	18.3%	17.8%	18.6%	18.6%	18.3%	20.5%
Hormel Foods	18.3%	17.0%	14.8%	15.6%	16.1%	16.4%	16.0%
Kellogg	61.1%	79.4%	54.5%	39.5%	42.9%	55.5%	30.5%
Weis Markets	10.1%	10.4%	9.5%	10.0%	10.5%	10.1%	10.5%
Wiley (John) & Sons	23.5%	22.3%	20.7%	23.0%	31.0%	24.1%	13.5%
Average						22.0%	19.4%
Median						16.8%	14.3%