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January 31, 2024

VIA ELECTRONIC MAIL and ELECTRONIC FILING
Honorable Sherri Golden
Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350
sherri.golden@bpu.nj.gov
board.secretary@bpu.nj.gov

RE: I/M/O the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates, for Changes in its Tariff for Gas Service Pursuant to N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18, and Other Requested Relief
BPU Docket No. GR24010071

Dear Secretary Golden:

On behalf of New Jersey Natural Gas Company ("NJNG" or the "Company"), enclosed please find a Certified Petition for filing to initiate the above-referenced docket.

In accordance with the March 19, 2020 and May 20, 2020 Board Orders in Docket No. EO20030254, hard copies are not being provided at this time, but may be submitted at a later time, if required. However, hard copies will be provided to those who previously requested them.

Kindly direct any inquiries to the undersigned. Thank you for your attention to this matter.

Sincerely,

Colleen A. Foley

Cc: Per encl. service list

SERVICE LIST

I/M/O the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates, for Changes in its Tariff for Gas Service Pursuant to N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18, and Other Requested Relief
BPU Docket No. GR24010071

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SERVICE LIST

I/M/O the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates, for Changes in its Tariff for Gas Service Pursuant to N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18, and Other Requested Relief
BPU Docket No. GR24010071

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Exhibit P-1

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS BASE RATES, FOR CHANGES IN ITS TARIFF FOR GAS SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, AND FOR CHANGES TO DEPRECIATION RATES FOR GAS PROPERTY PURSUANT TO N.J.S.A. 48:2-18, AND OTHER REQUESTED RELIEF	)	**CERTIFIED PETITION** **BPU DOCKET NO. GR24010071**

TO: THE HONORABLE COMMISSIONERS OF THE BOARD OF PUBLIC UTILITIES:

New Jersey Natural Gas Company ("NJNG," the "Company," or the "Petitioner"), a corporation of the State of New Jersey, having its principal offices at 1415 Wyckoff Road, Wall, New Jersey, respectfully petitions the New Jersey Board of Public Utilities ("BPU" or "Board") for authority pursuant to N.J.S.A. 48:2-21 and 48:2-21.1, 48:2-18, N.J.A.C. 14:1-5.12, and N.J.A.C. 14:1-5.7 to: (i) increase its base rates and charges for natural gas service; (ii) implement certain other rate and tariff revisions; and (iii) change its existing depreciation rates. In support thereof, Petitioner states as follows:

I. BACKGROUND

1. Petitioner is a local natural gas distribution company providing regulated retail natural gas service to approximately 576,000 customers located in Monmouth and Ocean counties, as well as portions of Burlington, Sussex, Middlesex and Morris counties.

2. Petitioner is subject to regulation by the Board for the purposes of setting its retail rates pursuant to N.J.S.A. 48:2-21 and 48:2-21.1, and for the provision of safe, adequate and proper natural gas service pursuant to N.J.S.A. 48:2-23. In this proceeding, the Company requests an increase in its revenue requirement of $222.60 million to reflect changes in its operating costs,

investments it has made to provide safe, adequate and proper natural gas service to its customers, and to permit the Company and its investors a fair opportunity to earn a reasonable rate of return on the value of investments made to serve customers.

3. This Petition (Exh. P-1) is accompanied and supported by the following pre-filed Direct Testimonies and accompanying exhibits and schedules that are attached hereto and made part of this Petition:

Exh. P-2 Direct Testimony of John B. Wyckoff, NJNG Vice President – Energy Delivery: Overview, Energy Delivery – Operations – Capital Expenditures;

Exh. P-3 Direct Testimony of James M. Corcoran, NJNG Director – Revenue Requirements: Proposed Revenue Increase, Rate Base and Pro Forma Income from Current Rates;

Exh. P-4 Direct Testimony of Angela M. Cahill, Controller – Regulated Services: Financial Statements;

Exh. P-5 Direct Testimony of Harold Walker, III, Manager – Financial Studies, Gannett Fleming Valuation and Rate Consultants, LLC: Cash Working Capital – Net Asset/Net Liabilities Analysis;

Exh. P-6 Direct Testimony of Dylan W. D'Ascendis, Partner, ScottMadden, Inc.: Rate of Return and Capital Structure;

Exh. P-7 Direct Testimony of Dr. Ronald E. White, President, Foster Associates Consultants, LLC: Depreciation;

Exh. P-8 Direct Testimony of Daniel P. Yardley, Principal, Yardley Associates: Cost of Service and Rate Design;

Exh. P-9 Direct Testimony of Tina M. Trebino, NJNG Director – Rates & Tariff: Rate and Tariff Modifications; and

Exh. P-10 Direct Testimony of Marissa Travaline, NJNG Vice President – Customer Service, Marketing & Energy Efficiency: Customer Service.

4. Information to support this Petition, pursuant to N.J.A.C. 14:1-5.12, 14:1-5.7, 14:1-4.1, and 14:1-5.1, is being filed herewith, either as schedules to witnesses' Direct Testimony or attached to this Petition, as follows:

Exhibit P-1

TABLE OF SCHEDULES AND ATTACHMENTS

Description	Reference
Draft Public Notice for the Newspapers	Exhibit P-1 Attachment 1
Draft Notice to the County and Municipal Clerks of All Counties and Municipalities served by NJNG	Exhibit P-1 Attachment 2
Draft Non-Disclosure Agreement	Exhibit P-1 Attachment 3
Balance Sheets as of December 31, 2021, 2022, and September 30, 2023	Exhibit P-4 Schedule AMC-1
Statements of Income for the Years Ended December 31, 2021, 2022, and for the Fiscal Year Ended September 30, 2023	Exhibit P-4 Schedule AMC-2
Statement of Gas Operating Revenues for the Years Ended December 31, 2021**,** 2022, and for the Fiscal Year Ended September 30, 2023	Exhibit P-4 Schedule AMC-3
Allocations to Affiliates during the Years Ended December 31, 2021, 2022 and Fiscal Year Ended September 30, 2023	Exhibit P-4 Schedule AMC-4
Test Year Income Statement	Exhibit P-4 Schedule AMC-5
Distribution Sales by Class of Business	Exhibit P-4 Schedule AMC-6
Customers Billed by Class of Business	Exhibit P-4 Schedule AMC-7
Operating Expenses for the Years Ended December 31, 2021, 2022, and the Fiscal Year Ended September 30, 2023	Exhibit P-4 Schedule AMC-8
Test Year Customer Accounts and Information	Exhibit P-4 Schedule AMC-9
Administrative and General Salaries and Expenses	Exhibit P-4 Schedule AMC-10
Test Year Depreciation	Exhibit P-4 Schedule AMC-11
Test Year Taxes Other than Income Taxes	Exhibit P-4 Schedule AMC-12
Test Year Current and Deferred Income Taxes	Exhibit P-4 Schedule AMC-13
Statements for the 12-month period ending June 30, 2024 on an estimated basis as follows:	Exhibit P-4 Schedule AMC-14
Income Account	Exhibit P-4 Schedule AMC-14

Exhibit P-1

Description	Reference
Revenue by Class of Business	Exhibit P-4 Schedule AMC-14
Operating Expenses	Exhibit P-4 Schedule AMC-14
Adjustments – Present Rates	Exhibit P-4 Schedule AMC-14
Pro Forma Operating Income – Proposed Rates	Exhibit P-4 Schedule AMC-14
Operating Income, Year-End Rate Base and Rate of Return – Present and Proposed Rates	Exhibit P-4 Schedule AMC-14
Net Investment Rate Base at Test Year End	Exhibit P-4 Schedule AMC-14
Operating Income, Average Rate Base During the Test Year, and Rate of Return – Present and Proposed Rates	Exhibit P-4 Schedule AMC-14
Average Net Investment Rate Base	Exhibit P-4 Schedule AMC-14
Proposed Tariff for Gas Service, NJNG, B.P.U. No. 12 (clean)	Exhibit P-9 Schedule TMT-1
Proposed Tariff for Gas Service, NJNG, BPU No. 12 (redlined)	Exhibit P-9 Schedule TMT-2
Summary of Proposed Tariff Changes	Exhibit P-9 Schedule TMT-3
Proposed Changes to the Balancing Charge	Exhibit P-9 Schedule TMT-4
Impact of Proposed Rates on Customers	Exhibit P-9 Schedule TMT-5

II. NEED FOR RATE RELIEF

5. The $222.60 million rate relief requested herein is required to ensure the Company's continued ability to construct, operate and maintain its natural gas system for the purpose of providing safe, adequate, and proper utility service pursuant to N.J.S.A. 48:2-23. This additional revenue is needed to provide NJNG the opportunity to recover operating revenues through base rates sufficient to meet operating expenses, taxes, and fixed charges, and to provide a reasonable rate of return on its rate base investments providing service to customers. *See* Exh. P-3, Schedule JMC-1. A typical residential heating customer using 100 therms monthly will see an increase of approximately $34.85 per month or 23.4%.

6. The Company's last base rate case was filed on March 30, 2021. Since that time, NJNG has continued to manage its business responsibly and effectively, and to provide reliable service at just and reasonable rates to its customers. As explained in further detail in the Direct Testimony of Mr. Wyckoff, the Company's commitment to providing safe and reliable utility service has been recognized by third-party entities and customers alike. For example, in 2023, the Company once again received top honors for customer satisfaction in the J.D. Power Gas Utility Residential Customer Satisfaction Study among large utilities in the eastern region. In addition, NJNG was named one of the most trusted utilities in the nation according to the 2023 Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential report from Escalent. These awards attest to the success of the Company's efforts to meet customers' energy needs in a safe and reliable manner.

7. In order to effectuate this quality utility service, the Company is engaged in the on-going construction, operation and maintenance of its natural gas distribution and transmission system throughout its service territory to better serve its approximately 576,000 customers. To that end, NJNG has made significant investments in facilities to serve customers. Since the Company's last base rate case and through June 30, 2024 (the end of the Test Year), NJNG's planned capital investments will have resulted in an increase in Utility Plant in Service ("UPIS") of approximately $850 million. These needed capital investments, along with other cost increases, are the primary drivers of the Company's request in this proceeding.

8. The Company's present base rates and charges for natural gas service are not sufficient at their current level and, if left unchanged, will impair NJNG's ability to meet operating and maintenance expenses, taxes, and fixed charges, as well as its ability to earn a reasonable rate of return on the fair value of the Company's property devoted to the provision of service to its customers. Without appropriate rate relief in this proceeding, allowing NJNG a fair opportunity to earn a reasonable return of and return on the Company's investments, the Company's ability to attract capital

at reasonable rates in the future will be impaired.

9. The Company's calculated rate of return on rate base for the test year, the twelve months ending June 30, 2024 ("Test Year"), is approximately 2.85 percent (*see* Exh. P-4, Schedule AMC-14, p. 7 of 10) and is inadequate as demonstrated by the Company's Direct Testimony included with this Petition. The Direct Testimony of Dylan W. D'Ascendis (Exh. P-6) provides a comprehensive analysis supporting a recommended weighted average cost of capital ("WACC") (*i.e.*, the overall Rate of Return ("ROR")) of 7.57 percent, including a rate of return on common equity ("ROE") of 10.42 percent. As discussed in James M. Corcoran's Direct Testimony (Exh. P-3), NJNG's request for rate relief in this proceeding reflects the bottom of Mr. D'Ascendis's recommended ROE range and is an effort to mitigate the magnitude of the requested rate increase while also allowing NJNG the opportunity to earn a reasonable return on its investment in utility property.

III. NEED FOR INFRASTRUCTURE INVESTMENT

10. The need to invest in utility infrastructure has continued since NJNG last filed a base rate case petition with the Board on March 30, 2021. The Company has made significant investments in its system so that it can continue to meet its responsibility to provide safe, adequate and reliable utility service. As explained in Mr. Wyckoff's Direct Testimony (Exh. P-2), this additional system investment is comprised of numerous smaller, but important, initiatives focused on system reliability and integrity. For example, Mr. Wyckoff describes the Company's program to replace vintage pipe, particularly pre-1970's protected steel mains, at a cost of $74.2 million during the Test Year. As Mr. Wyckoff explains, this initiative is important to reducing the amount of leak prone mains and to reducing methane emissions due to leaks.

11. The Company is proposing a Test Year comprised of the twelve months beginning July 1, 2023 through June 30, 2024, as adjusted for known and measurable investment and operating

costs. In the Post-Test Year period, NJNG is seeking to include in rates a single government-mandated project that is major in nature and consequence, known and measurable, and which is expected to be in service within the six-month Post-Test Year period ending December 31, 2024. (*See* Exh. P-3, Schedule JMC-28).

12. The Test Year utilized in this filing is based on five (5) months of actual data and seven (7) months of estimated data. The Company requests that the tariff reflecting new rates be effective March 1, 2024, but in no event later than November 1, 2024 (the end of the statutory suspension period(s)). During the processing of this case, assuming the Petition is suspended by the statutory periods, the Company will update its testimonies and exhibits, as appropriate, to reflect actual results. It is anticipated that by the conclusion of this case, assuming utilization of the full statutory suspension periods, the entire Test Year ending June 30, 2024 will reflect actual results with the exception of certain Post-Test Year adjustments.

13. In accordance with N.J.A.C. 14:1-5.12(a)(4), the amount of operating revenue derived from intrastate service during the twelve months ended December 31, 2023 will be provided following the filing of the Company's 10Q in early February 2024.

14. Pursuant to N.J.A.C. 14:1-5.12(a)(10), affected utilities are to provide a calculation of a Consolidated Tax Adjustment ("CTA") as part of base rate case filings. The Company has included a CTA calculation using the Board-approved methodology as part of this filing. *See* Direct Testimony of James M. Corcoran, Schedule JMC-2. However, certain pieces of the data underlying this CTA calculation are confidential. Therefore, the Company will furnish such information upon execution of a Non-Disclosure Agreement. A proposed draft Non-Disclosure Agreement is attached to this Petition as Attachment 3.

IV. CHANGES TO DEPRECIATION RATES

15. The Company also hereby petitions the Board for authority to revise its depreciation rates for its utility property pursuant to N.J.S.A. 48:2-18. The Company's current depreciation rates were agreed to in a Stipulation of Settlement and approved in the Board's Final Order dated November 17, 2021, in Docket No. GR21030679, in the Company's 2021 base rate case.

16. Company witness Dr. Ronald White has completed a depreciation study to determine the appropriate depreciation rates for the recovery of the Company's investment property, a copy of which is attached to Dr. White's Testimony (*see* Exh. P-7, Exh. REW-1).

17. A comparison of the Company's current versus proposed depreciation rates for its utility property is set forth in Table 2 of Dr. White's depreciation study. Of the 31 property accounts included in Dr. White's study, he has recommended rate reductions for seven (7) accounts, rate increases for 20 accounts, and no change for four (4) accounts. The Company's existing and proposed methods of determining depreciation rates are also detailed in Exhibit P-7.

18. The effect of the proposed changes in depreciation rates on operating expenses and income is incorporated in Mr. Corcoran's Direct Testimony and exhibits (Exh. P-3).

19. The Company respectfully requests that the Board approve the proposed depreciation rates for its property as recommended in Dr. White's Direct Testimony, and that those depreciation rates become effective with the Board's approval of the proposed base rates set forth herein.

V. COST OF SERVICE, RATE DESIGN, TARIFF CHANGES AND THE BALANCING CHARGE

20. Petitioner also files herewith its Proposed Tariff for Gas Service, New Jersey Natural Gas Company, B.P.U. No. 12 (Exh. P-9, Schedule TMT-1). The proposed rates and charges for service included in the Proposed Tariff are supported by the Direct Testimony of Mr. Daniel Yardley (Exh. P-8). The Company will be submitting in workpapers an alternative ACOSS using Board

Staff's average and peak methodology as required by the Stipulation and Order in the Company's 2021 base rate case. Other proposed Tariff modifications are supported by Ms. Tina Trebino's Direct Testimony (Exh. P-9).

21. With respect to its Balancing Charge rate, the Company is proposing a change to the current Balancing Charge rate. The Company's Balancing Charge has two (2) components: (i) carrying charges on inventory costs, and (ii) pipeline demand charges. In accordance with the Board's Order, in BPU Docket No. GR07110889, the Balancing Charge related to inventory is to be updated in a base rate case, and the pipeline demand charges component is to be updated in the Company's annual Basic Gas Supply Service ("BGSS") filings. In this proceeding, the Company proposes to update the Balancing Charge component related to inventory to reflect test period inventory balances and the Company's proposed pre-tax rate of return of 9.83% (included in Exh. P-3, Schedule JMC-3). The result of these updates is an increase in the Balancing Charge, as shown on Schedule TMT-4. As explained in Ms. Trebino's Direct Testimony, the inventory component will be further updated to reflect 12 months of actual balances, and both the inventory and demand charge components will be updated to include the volumes from the Company's 2025 BGSS filing to be submitted by June 1, 2024 ("2025 BGSS filing"). The demand charge component of the Balancing Charge will also include updated demand charges from the 2025 BGSS filing. *See* Exh. P-9, Schedule TMT-4.

22. Petitioner respectfully requests that the Tariff proposed in this filing be approved to go into effect March 1, 2024, but in no event later than November 1, 2024 (the end of the statutory suspension period(s)).

VI. PUBLIC NOTICE

23. Pursuant to N.J.A.C. 14:1-5.12, NJNG will provide notice of the filing of this Petition to all of its customers through the publication of a notice in newspapers of general circulation in the Company's service territory. A copy of the proposed draft public notice is provided as Attachment 1

to this Petition. The Company will also provide notice to customers with the requisite bill message.

24. The municipalities and counties served by Petitioner's operations will be notified of the filing of this Petition by letter, sent electronically, upon publication of the public notice, pursuant to N.J.A.C. 14:1-5.12. A copy of the proposed draft letter is provided as Attachment 2 to this Petition.

25. Notice of this filing along with all testimony, schedules, exhibits, and attachments shall be sent to the Deputy Attorneys General at the Department of Law and Public Safety, to the Director of the Division of Rate Counsel ("Rate Counsel"), and to the persons identified in the Service List attached hereto by electronic mail only. This is consistent with the Board's March 19, 2020 Order issued in connection with *I/M/O of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, at BPU Docket No. EO20030254. Moreover, the Company's filing will be available on the Company's website at: www.njng.com.

26. NJNG respectfully requests that the public comment hearings be conducted virtually, via teleconference, to permit the public to participate in the hearings. Virtual public comment hearings have been conducted in other matters before the Board, and the Company believes it would be in the public interest to do so in this instance as well.

VII. MISCELLANEOUS ISSUES

27. During the course of this proceeding, NJNG will submit any non-privileged confidential, proprietary, and/or competitively sensitive information requested once a mutually agreed-upon Non-Disclosure Agreement has been executed by and among the Company, Board Staff, Rate Counsel and its and/or their consultants, and any permitted intervenors. As noted above, a proposed draft Non-Disclosure Agreement has been included as Attachment 3 to the Petition.

28. It is understood that any final rate relief found by the Board to be just and reasonable may be allocated by the Board for consistency with the provisions of N.J.S.A. 48:2-21, and for other

good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, based upon the Board's decision, final rates for individual customers may increase or decrease from those proposed herein.

29. Communications and correspondence related to the Petition should be sent as follows:

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30. The Company respectfully requests that this matter be retained by the Board and that a Commissioner be designated as Presiding Officer to set a procedural schedule, rule on motions, and conduct any evidentiary hearings, if necessary, as expeditiously as possible.

31. The Company also respectfully requests that a pre-hearing order be issued and a procedural schedule be established that will enable a decision by the Board on this matter in the shortest practical time frame, within the law.

WHEREFORE, Petitioner respectfully requests that the Board determine, pursuant to N.J.S.A. 48:2-21, 48:2-21.1 and 48:2-18, that:

a. The base rates and charges for service set forth in the Present Tariff for Gas Service, New Jersey Natural Gas Company, B.P.U. No. 11 are unjust, unreasonable, and insufficient to permit the Company to maintain its financial integrity and provide safe, adequate and proper service to its customers, pursuant to N.J.S.A. 48:2-23;

b. The proposed $222.60 million of rate relief is just and reasonable and will provide operating revenues sufficient to meet operating and maintenance expenses, taxes, and fixed charges, and provide a reasonable rate of return on the fair value of the Company's property;

c. Petitioner's requested rate of return, represented by a WACC of 7.57%, on its rate base of $3.36 billion, is just and reasonable;

d. The proposed base rates and charges for service set forth in Exh. P-9, Schedule TMT-1, should be approved as just and reasonable on or before March 1, 2024, but in no event later than November 1, 2024 (the end of the statutory suspension period(s));

e. The proposed Tariff modifications set forth herein are just and reasonable, in the public interest, and should be approved in their entirety;

f. The proposed depreciation rates for property set forth in Exh. P-7 should be approved as just and reasonable;

g. The regulatory assets recorded on the Company's balance sheet and detailed in Exh. P-4 (and identified in Exh. P-3) and its accompanying schedules, as authorized by the Board, and the amortization of these assets, as set forth herein, should be approved as just and reasonable;

h. The Board should retain this matter and a Commissioner should be designated as Presiding Officer to set a procedural schedule, rule on motions, and conduct any evidentiary hearings, if necessary, as expeditiously as possible; and

i. The Board should grant such other and further relief as may be required.

Saul Ewing LLP
Attorneys for Petitioner
New Jersey Natural Gas Company

Dated: January 31, 2024

By: _____
Colleen A. Foley, Esq.

IN THE MATTER OF THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS BASE RATES AND FOR CHANGES IN ITS TARIFF FOR GAS SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1; AND FOR CHANGES TO DEPRECIATION RATES FOR GAS PROPERTY PURSUANT TO N.J.S.A. 48:2-18 (2024)	)	**CERTIFIED PETITION** **BPU DOCKET NO. GR24010071**

CERTIFICATION IN SUPPORT OF PETITION

MARK G. KAHRER, of full age, certifies as follows:

1. I am Senior Vice President, Regulatory Affairs for New Jersey Natural Gas Company ("NJNG"), the Petitioner in the foregoing Petition. I am duly authorized to make this Certification on behalf of NJNG.

2. I hereby certify that I have read the annexed Petition, and the matters and things contained therein are true to the best of my knowledge, information, and belief. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Mark G. Kahrer

Dated: January 31, 2024

NOTICE TO NEW JERSEY NATURAL GAS COMPANY CUSTOMERS

I/M/O THE PETITION OF NEW JERSEY NATURAL GAS COMPANY'S REQUEST FOR APPROVAL OF AN INCREASE IN GAS BASE RATES, FOR CHANGES IN ITS TARIFF FOR GAS SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, FOR CHANGES TO DEPRECIATION RATES FOR GAS PROPERTY PURSUANT TO N.J.S.A. 48:2-18, AND OTHER REQUESTED RELIEF
BPU Docket No. GR24010071; OAL Docket No. PUC_____

PLEASE TAKE NOTICE that on January 31, 2024, New Jersey Natural Gas Company ("NJNG" or "Company") filed a petition with the Board of Public Utilities ("Board" or "BPU") requesting an increase in the Company's base rate charges for natural gas service ("Base Rate Petition"). NJNG's Base Rate Petition states that the requested rate increase is necessary to support the Company's ability to continue to operate and maintain its natural gas distribution system in a safe, adequate, and proper manner. In the Base Rate Petition, the Company requested a natural gas revenue increase of $222.60 million, including a change in the Company's overall rate of return to 7.57 percent. The impact of this request on the average residential heating customer using 100 therms per month is a $34.85 increase in the customer's monthly bill, or approximately 23.4 percent. Monthly bill impacts for residential and other customers are shown in the table below.

Included in the Base Rate Petition is a request pursuant to N.J.S.A. 48:2-18 to change certain depreciation rates based upon a Depreciation Study. The Company proposed that the requested changes in its depreciation rates be approved for implementation simultaneously with the effective date of the proposed new natural gas rates.

The effect of the total proposed rate changes on the typical residential, general service small and general service large monthly bill for natural gas service is estimated as shown in the table below. The estimated bills shown below are based upon current NJNG delivery rates and the applicable Basic Gas Supply Service charges, and assume that customers receive commodity service from NJNG.

		Total Bill			
Customer Type	Therm Level (Usage)	Monthly Bill as of 1-Jan-24	Monthly Bill with Proposed Base Rate Increase	Net Dollar Increase	Percent Increase
Residential Heat	100	$148.90	$183.75	$34.85	23.4%
Residential Non-Heat	25	$44.15	$55.86	$11.71	26.5%
General Service Small	100	$168.99	$214.31	$45.32	26.8%
General Service Large	1200	$1,741.16	$2,024.34	$283.18	16.3%

The Company proposes other changes to its tariff including, but not limited to, an increase in its Balancing Charge, and changes to reflect current operating requirements and Board regulations.

Any rate increase found by the Board to be just and reasonable may be allocated by the Board and applied to any class or classes of customers or any rate schedule or rate schedules as the Board may determine. Accordingly, the final rates approved by the Board in this proceeding for any rate class or classes may be higher or lower than those set forth herein.

A copy of this Notice of Filing and Public Hearings on this matter is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory. The Petition and this Notice have also been sent to the New Jersey Division of Rate Counsel, who will represent the interests of New Jersey ratepayers in this proceeding. Copies of NJNG's January 31, 2024 filing can be reviewed on the Company's website, www.njng.com/regulatory in the "Filings & Updates" subsection of the "Regulatory Info" section listed.

PLEASE TAKE FURTHER NOTICE that virtual public hearings will be conducted on the following date and times so that members of the public may present their views on the Company's filing.

VIRTUAL PUBLIC HEARINGS
Date: XXX, 2024
Hearing Times: 4:30 pm and 5:30 pm

LOCATION
Zoom Virtual Webinar
Join: https://_____
Meeting ID: _____
Passcode: _____
Dial-In Number: +1-_____

Representatives of the Company, the Board's Staff and Rate Counsel will participate in the virtual public hearings.

Members of the public are invited to participate by utilizing the Meeting ID or the Dial-In Number set forth above and may express their views on this Petition. All comments will be made part of the final record of the proceeding to be considered by the Board. In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, such as interpreters, or listening assistance, 48 hours prior to the above hearing to the Board Secretary at board.secretary@bpu.nj.gov.

The Board is also accepting written and electronic comments. Comments may be submitted directly to the specific docket listed above using the "Post Comments" button on the Board's Public Document Search tool at https://publicaccess.bpu.state.nj.us/. Comments are considered public documents for purposes of the State's Open Public Records Act. Only public documents should be submitted using the "Post Comments" button on the Board's Public Document Search tool. Any confidential information should be submitted in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. In addition to hard copy submissions, confidential information may also be filed electronically via the Board's e-filing system or by email to the Secretary of the Board. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage at https://www.nj.gov/bpu/agenda/efiling/.

Emailed and/or written comments may also be submitted to:
Sherri L. Golden, Secretary of the Board
44 South Clinton Ave., 1st Floor
PO Box 350
Trenton, NJ 08625-0350
Phone: 609-913-6241
Email: board.secretary@bpu.nj.gov

New Jersey Natural Gas Company
Andrew K. Dembia, Esq.

Exhibit P-1
Attachment 2

New Jersey Natural Gas

_____, 2024

Via Electronic Mail

To: The Office of the County Clerk, Municipal Clerk and County Administrator

Re: In the Matter of the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service Pursuant to N.J.S.A. 48:2-21 and 48:2-21.1, for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18, and Other Requested Relief
BPU Docket No. GR24010071

Pursuant to N.J.S.A. 48:2-2-21 and 48:2-21.1, New Jersey Natural Gas Company (the "Company" or "NJNG") hereby advises you that on January 31, 2024 the Company filed a request with the New Jersey Board of Public Utilities for an increase in the Company's rates for natural gas service. A complete copy of the Company's filing is available for review on NJNG's website at www.njng.com. Please be further advised that the Company hereby serves upon you the attached Notice of Public Hearings in the above referenced matter. The virtual public comment hearings are scheduled for _____, 2024 at 4:30 P.M. and 5:30 P.M. Log-In instructions are included below.

Location: Zoom Virtual Webinar

Join by holding down control button and clicking on the below link:
[to be completed]

Meeting ID: [XXXXXXXX]
Dial-In Phone Number: 1-XXX-XXX-XXXX
Access Code: XXXXXX

Respectfully,

Andrew K. Dembia, Esq.
Regulatory Affairs Counsel

Attachments

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS BASE RATES, FOR CHANGES IN ITS TARIFF FOR GAS SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1, FOR CHANGES TO DEPRECIATION RATES FOR GAS PROPERTY PURSUANT TO N.J.S.A. 48:2-18, AND OTHER REQUESTED RELIEF

AGREEMENT OF NON-DISCLOSURE OF INFORMATION CLAIMED TO BE CONFIDENTIAL

BPU DOCKET NO. GR24010071

It is hereby AGREED, as of the __ day of February 2024, by and among New Jersey Natural Gas Company ("Petitioner"), the Staff of the New Jersey Board of Public Utilities ("Board Staff") and Division of Rate Counsel ("Rate Counsel") (collectively, the "Parties"), who have agreed to execute this Agreement of Non-Disclosure of Information Claimed to be Confidential ("Agreement"), and to be bound thereby that:

WHEREAS, in connection with the above-captioned proceeding before the Board of Public Utilities (the "Board"), Petitioner and/or another party ("Producing Party") may be requested or required to provide petitions, pre-filed testimony, other documents, analyses and/or other data or information regarding the subject matter of this proceeding that the Producing Party may claim constitutes or contains confidential, proprietary or trade secret information, or which otherwise may be claimed by the Producing Party to be of a market-sensitive, competitive, confidential or proprietary nature (hereinafter sometimes referred to as "Confidential Information" or "Information Claimed to be Confidential"); and

WHEREAS, the Parties wish to enter into this Agreement to facilitate the exchange of information while recognizing that under Board regulations at N.J.A.C. 14:1-12 et seq., a request for confidential treatment shall be submitted to the Custodian who is to rule on requests made pursuant to the Open Public Records Act ("OPRA"), N.J.S.A. 47:1A-1 et seq., unless such information is to be kept confidential pursuant to court or administrative order (including, but not limited to, an Order by an Administrative Law Judge sealing the record or a portion thereof pursuant to N.J.A.C. 1:1-14.1, and the parties acknowledge that an Order by an Administrative Law Judge to seal the record is subject to modification by the Board), and also recognizing that a request may be made to designate any such purportedly confidential information as public through the course of this administrative proceeding; and

WHEREAS, the Parties acknowledge that unfiled discovery materials are not subject to public access under OPRA; and

WHEREAS, the Parties acknowledge that, despite each Party's best efforts to conduct a thorough pre-production review of all documents and electronically stored information ("ESI"), some work product material and/or privileged material ("protected material") may be inadvertently disclosed to another Party during the course of this proceeding; and

WHEREAS, the undersigned Parties desire to establish a mechanism to avoid waiver of privilege or any other applicable protective evidentiary doctrine as a result of the inadvertent disclosure of protected material;

NOW, THEREFORE, the Parties hereto, intending to be legally bound thereby, DO HEREBY AGREE as follows:

1. The inadvertent disclosure of any document or ESI which is subject to a legitimate claim that the document or ESI should have been withheld from disclosure as protected material shall not waive any privilege or other applicable protective doctrine for that document or ESI or for the subject matter of the inadvertently disclosed document or ESI if the Producing Party, upon becoming aware of the disclosure, promptly requests its return and takes reasonable precautions to avoid such inadvertent disclosure.

2. Except in the event that the receiving party or parties disputes the claim, any documents or ESI which the Producing Party deems to contain inadvertently disclosed protected material shall be, upon written request, promptly returned to the Producing Party or destroyed at the Producing Party's option. This includes all copies, electronic or otherwise, of any such documents or ESI. In the event that the Producing Party requests destruction, the receiving party shall provide written confirmation of compliance within thirty (30) days of such written request. In the event that the receiving party disputes the Producing Party's claim as to the protected nature of the inadvertently disclosed material, a single set of copies may be sequestered and retained by and under the control of the receiving party until such time as the Producing Party has received final determination of the issue by the Board of Public Utilities or an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge.

3. Any such protected material inadvertently disclosed by the Producing Party to the receiving party pursuant to this Agreement shall be and remain the property of the Producing Party.

4. Any Information Claimed to be Confidential that the Producing Party produces to any of the other Parties in connection with the above-captioned proceeding and pursuant to the terms of this Agreement shall be specifically identified and marked by the Producing Party as Confidential Information when provided hereunder. If only portions of a document are claimed to be confidential, the producing party shall specifically identify which portions of that document are claimed to be confidential. Additionally, any such Information Claimed to be Confidential shall be provided in the form and manner prescribed by the Board's regulations at N.J.A.C. 14:1-12 et seq., unless such information is to be kept confidential pursuant to court or administrative order. However, nothing in this Agreement shall require the Producing Party to file a request with the Board's Custodian of Records for a confidentiality determination under N.J.A.C. 14:1-12 et seq. with respect to any Information Claimed to be Confidential that is provided in discovery and not filed with the Board.

5. With respect to documents identified and marked as Confidential Information, if the Producing Party's intention is that not all of the information contained therein should be given protected status, the Producing Party shall indicate which portions of such documents contain the Confidential Information in accordance with the Board's regulations at N.J.A.C. 14:1-12.2 and 12.3. Additionally, the Producing Party shall provide to all signatories of this Agreement full and complete copies of both the proposed public version and the proposed confidential version of any information for which confidential status is sought.

6. With respect to all Information Claimed to be Confidential, it is further agreed that:

(a) Access to the documents designated as Confidential Information, and to the information contained therein, shall be limited to the Party signatories to this Agreement and their identified attorneys, employees, and consultants whose examination of the Information Claimed to be Confidential is required for the conduct of this particular proceeding.

(b) Recipients of Confidential Information shall not disclose the contents of the documents produced pursuant to this Agreement to any person(s) other than their identified employees and any identified experts and consultants whom they may retain in connection with this proceeding, irrespective of whether any such expert is retained specially and is not expected to testify, or is called to testify in this proceeding. All consultants or experts of any Party to this Agreement who are to receive copies of documents produced pursuant to this Agreement shall have previously executed a copy of the Acknowledgement of Agreement attached hereto as "Attachment 1", which executed Acknowledgement of Agreement shall be forthwith provided to counsel for the Producing Party, with copies to counsel for Board Staff and Rate Counsel.

(c) No other disclosure of Information Claimed to be Confidential shall be made to any person or entity except with the express written consent of the Producing Party or their counsel, or upon further determination by the Custodian, or order of the Board, the Government Records Council or of any court of competent jurisdiction that may review these matters.

7. The undersigned Parties have executed this Agreement for the exchange of Information Claimed to be Confidential only to the extent that it does not contradict or in any way restrict any applicable Agency Custodian, the Government Records Council, an Administrative

Law Judge of the State of New Jersey, the Board, or any court of competent jurisdiction from conducting appropriate analysis and making a determination as to the confidential nature of said information, where a request is made pursuant to OPRA, N.J.S.A. 47:1A-1 et seq. Absent a determination by any applicable Custodian, Government Records Council, an Administrative Law Judge, the Board, or any court of competent jurisdiction that a document(s) is to be made public, the treatment of the documents exchanged during the course of this proceeding and any subsequent appeals is to be governed by the terms of this Agreement.

8. In the absence of a decision by the Custodian, Government Records Council, an Administrative Law Judge, or any court of competent jurisdiction, the acceptance by the undersigned Parties of information which the Producing Party has identified and marked as Confidential Information shall not serve to create a presumption that the material is in fact entitled to any special status in these or any other proceedings. Likewise, the affidavit(s) submitted pursuant to N.J.A.C. 14:1-12.8 shall not alone be presumed to constitute adequate proof that the Producing Party is entitled to a protective order for any of the information provided hereunder.

9. In the event that any Party seeks to use the Information Claimed to be Confidential in the course of any hearings or as part of the record of this proceeding, the Parties shall seek a determination by the trier of fact as to whether the portion of the record containing the Information Claimed to be Confidential should be placed under seal. Furthermore, if any Party wishes to challenge the Producing Party's designation of the material as Confidential Information, such Party shall provide reasonable notice to all other Parties of such challenge and the Producing Party may make a motion seeking a protective order. In the event of such challenge to the designation of material as Confidential Information, the Producing Party, as the provider of the

Information Claimed to be Confidential, shall have the burden of proving that the material is entitled to protected status. However, all Parties shall continue to treat the material as Confidential Information in accordance with the terms of this Agreement, pending resolution of the dispute as to its status by the trier of fact.

10. Confidential Information that is placed on the record of this proceeding under seal pursuant to a protective order issued by the Board, an Administrative Law Judge, provided that the Board has not modified or rejected an order by the Administrative Law Judge, or any court of competent jurisdiction shall remain with the Board under seal after the conclusion of this proceeding. If such Confidential Information is provided to appellate courts for the purposes of an appeal(s) from this proceeding, such information shall be provided, and shall continue to remain, under seal.

11. This Agreement shall not:

(a) Operate as an admission for any purpose that any documents or information produced pursuant to this Agreement are admissible or inadmissible in any proceeding;

(b) Prejudice in any way the right of the Parties, at any time, on notice given in accordance with the rules of the Board, to seek appropriate relief in the exercise of discretion by the Board for violations of any provision of this Agreement.

12. Within forty five (45) days of the final Board Order resolving the above-referenced proceeding, all documents, materials and other information designated as "Confidential Information," regardless of format, shall be destroyed or returned to counsel for the Producing Party. In the event that such Board Order is appealed, the documents and materials

designated as "Confidential Information" shall be returned to counsel for the Producing Party or destroyed within forty-five (45) days of the conclusion of the appeal.

Notwithstanding the above return requirement, Board Staff and Rate Counsel may maintain in their files copies of all pleadings, briefs, transcripts, discovery and other documents, materials and information designated as "Confidential Information," regardless of format, exchanged or otherwise produced during these proceedings, provided that all such information and/or materials that contain Information Claimed to be Confidential shall remain subject to the terms of this Agreement. The Producing Party may request consultants who received Confidential Information who have not returned such material to counsel for the Producing Party as required above to certify in writing to counsel for the Producing Party that the terms of this Agreement have been met upon resolution of the proceeding.

13. The execution of this Agreement shall not prejudice the rights of any Party to seek relief from discovery under any applicable law providing relief from discovery.

14. The Parties agree that one original of this Agreement shall be created for each of the signatory parties for the convenience of all. The signature pages of each original shall be executed by the recipient and transmitted to counsel of record for Petitioner, who shall send a copy of the fully executed document to all counsel of record. The multiple signature pages shall be regarded as, and given the same effect as, a single page executed by all Parties.

IN WITNESS THEREOF, the undersigned Parties do HEREBY AGREE to the form and execution of this Agreement.

NEW JERSEY NATURAL GAS COMPANY

By:_____
Andrew K. Dembia, Esq.
Regulatory Affairs Counsel

MATTHEW J. PLATKIN
ATTORNEY GENERAL OF
NEW JERSEY
Attorney for the Staff of the Board of Public Utilities

By:_____
_____, Esq.
Deputy Attorney General

BRIAN O. LIPMAN, ESQ.
DIRECTOR
DIVISION OF RATE COUNSEL

By:_____
_____, Esq.
Deputy Rate Counsel

DATE:

ATTACHMENT 1

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS BASE RATES, FOR CHANGES IN ITS TARIFF FOR GAS SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1, FOR CHANGES TO DEPRECIATION RATES FOR GAS PROPERTY PURSUANT TO N.J.S.A. 48:2-18, AND OTHER REQUESTED RELIEF	**AGREEMENT OF NON-DISCLOSURE OF INFORMATION CLAIMED TO BE CONFIDENTIAL** **BPU DOCKET NO. GR24010071**

ACKNOWLEDGMENT OF AGREEMENT

The undersigned is an attorney, employee, consultant and/or expert witness for the Division of Rate Counsel or an intervenor who has received, or is expected to receive, Confidential Information provided by New Jersey Natural Gas Company or by another party (Producing Party) which has been identified and marked by the Producing Party as "Confidential Information." The undersigned acknowledges receipt of the Agreement of Non-Disclosure of Information Claimed to be Confidential and agrees to be bound by the terms of the Agreement.

Dated: By:_____

(Name, Title and Affiliation)

Exhibit P-2

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY OF
JOHN B. WYCKOFF
VICE PRESIDENT – ENERGY DELIVERY

I. INTRODUCTION AND BACKGROUND

Q. Please state your name, affiliation and business address.

A. My name is John B. Wyckoff and I am a Vice President – Energy Delivery for New Jersey Natural Gas Company (the "Company" or "NJNG"). My business address is 1415 Wyckoff Road, Wall, New Jersey 07719.

Q. Please describe your responsibilities as Vice President – Energy Delivery for NJNG.

A. As Vice President – Energy Delivery, I lead NJNG's process of engineering, installing, replacing and expanding its natural gas infrastructure, and operating and maintaining its transmission system, regulator facilities, and two Liquefied Natural Gas ("LNG") facilities. I also have executive responsibility for the gas control, safety, training, transportation, and other related functions associated with operating NJNG's facilities.

Q. What is the purpose of your Direct Testimony in this proceeding?

A. My Direct Testimony supports NJNG's petition for an increase in base rates by addressing three topics directly related to NJNG's Energy Delivery operations. Specifically, I will describe the Company's existing infrastructure and operations, including efforts to maintain safe and reliable service to its customers. Second, I will provide information related to a number of capital projects that address critical infrastructure needs of the Company and its customers, including ongoing integrity management and capacity projects. I will also touch briefly upon the projects that are part of NJNG's Infrastructure

Improvement Program ("IIP"). Third, I discuss the Company's Pipeline Integrity Management ("PIM") activities and associated operating expenses.

Q. Are you sponsoring any schedules as part of your Direct Testimony?

A. Yes. I am sponsoring the following schedules, which were prepared by me or under my direct supervision and control: Schedule JBW-1 (Actual Capital Investment of NJNG by Category – Fiscal Years 2021 and 2022); and Schedule JBW-2 (Test Year and Post-Test Year Capital Investment by Category).

Q. Have you previously participated in any proceedings before the New Jersey Board of Public Utilities ("BPU" or "Board")?

A. Yes, I submitted testimony before the Board in NJNG's most recent base rate case, BPU Docket No. GR21030679.

II. OVERVIEW OF THE COMPANY'S INFRASTRUCTURE AND OPERATIONS

Q. Please provide a brief description of NJNG's distribution and transmission systems.

A. NJNG serves approximately 576,000 retail customers in Monmouth, Ocean, and portions of Morris, Sussex, Middlesex, and Burlington counties. The Company operates a network of 250 miles of large diameter transmission lines, approximately 7,600 miles of distribution mains, and approximately 550,000 service lines for an aggregate length of approximately 8,300 miles. NJNG's distribution mains range in diameter from 2 to 16 inches. The distribution system also includes various other forms of infrastructure, including line valves, pressure regulators, and meter stations.

The natural gas network operates in various pressure configurations depending on a variety of factors, including material type and vintage. Specifically, portions of the NJNG system operate at a maximum allowable operating pressure ("MAOP") of 722 pounds per

square inch gauge ("psig") (transmission), while others operate at an MAOP of only 15 psig (distribution). Finally, the distribution system consists of two LNG peak shaving facilities located in Howell Township and in Stafford Township. The LNG facilities provide important pressure support to the system in addition to serving as storage for LNG supplies, making them critical to meeting customer requirements during peak winter periods and providing support during required system integrity work.

Q. How are the Company's operations separated geographically?

A. The Company's operations are separated geographically into two distinct operating areas: (i) the smaller Northern Division serves customers primarily located in Morris County, and (ii) the larger Central Division serves customers primarily located in Monmouth County and Ocean County. Each operating Division is interconnected with interstate pipelines necessary to reliably serve customers. In the Northern Division, the Company is served by the following interstate pipeline systems: Algonquin Gas Transmission, LLC ("Algonquin"), Columbia Gas Transmission, LLC ("Columbia"), Tennessee Gas Pipeline, LLC ("Tennessee"), and Texas Eastern Transmission, LP ("Texas Eastern"). In the Central Division, the Company is served by the Texas Eastern and Transcontinental Gas Pipe Line Company, LLC ("Transco") interstate pipeline system.

Q. Please describe NJNG'S operational goals and objectives.

A. NJNG's operational objectives are threefold: safety, reliability, and efficiency. The safe operation of NJNG's natural gas distribution and transmission systems is the Company's primary operational goal. Safety is essential to the health and well-being of the customers, residents, and businesses in the communities the Company serves, and to the employees who are responsible for operating the system. NJNG also focuses on providing service on

a reliable basis to customers who depend on natural gas service for heating and other essential needs. Reliability and integrity of the natural gas systems requires planning to meet the needs of customers during extreme cold weather when demand escalates and peaks, as well as during major storm events. In addition, the Company seeks to achieve the safe and reliable operation of its system in a cost-effective and efficient manner.

There are a variety of operational requirements associated with achieving these goals. For instance, one requirement is the ongoing repair and maintenance of existing facilities. A second requirement is the engineering, planning, and construction of new facilities to provide for growth and increased operating flexibility, including appropriate operating redundancies. A third requirement is the need to rehabilitate or replace existing facilities to address aging infrastructure concerns or to meet enhanced safety goals. In all aspects of NJNG's operations, the Company works to continuously improve and adopt best practices of the gas distribution industry.

Q. Please provide an overview of each of the primary functions associated with operating the Company's natural gas system.

A. NJNG engages in four general types of activities that comprise its operations in very broad terms: (1) system operation; (2) system maintenance and repair; (3) system replacement and modernization; and (4) system expansion. The majority of these operational activities, excluding system expansion, focus on managing the ongoing operational integrity of the Company's natural gas system.

System operation encompasses many activities, including gas control operations, system monitoring, leak detection, responding to leak calls, and periodic facility inspections. System maintenance and repair includes both emergency and non-

emergency efforts to maintain all aspects of NJNG's distribution and transmission facilities, including routine maintenance to regulators, meters and valves, as well as repairs to pipe facilities. System replacement and modernization includes various projects that address challenges associated with aging elements of NJNG's facilities where it has been deemed more cost effective to proactively replace than continually maintain and repair. When making replacements, NJNG incorporates the latest technologies to enhance safety, integrity and reliability. Lastly, system expansion includes the construction of new facilities to connect new natural gas customers and loads to the system.

Q. How does NJNG track, and improve upon the achievement of, its operational goals?

A. NJNG is committed to continuous improvement in its operations and uses a combination of internal and external tools to assess and improve upon its performance across many areas of its operations. The Company employs a structured scorecard to measure its own performance for activities, such as: on-time service calls, leak response time, leaks per mile, and safety incidents. Objective monitoring of performance against appropriate targets enables the Company to identify and address potential issues that may degrade performance or to target areas for process improvement.

NJNG also participates in the American Gas Association ("AGA") Best Practices Benchmarking Project, an industry-wide initiative that focuses on key operating processes to identify innovative and cost- efficient practices among national natural gas distribution companies. NJNG and participating companies discuss and document current work management processes in specific areas and share these practices with participating sponsors. The information and data obtained from these roundtables is incorporated in the

Company's ongoing process improvement efforts when appropriate. NJNG also participates in the AGA Peer Review Program. The Peer Review Program is a voluntary peer-to-peer safety and operational practices review program that allows local utilities throughout the United States to observe their peers, share leading practices, and identify opportunities to better serve customers and communities.

Q. Has the Company recently been recognized for its operational performance?

A. Yes, it has. The Company's outstanding performance has been recognized by both industry peers and the Company's customers. In 2022, NJNG was awarded the annual Industry Leader in Accident Prevention safety award by the American Gas Association in recognition of its overall safety record. The Company also received this recognition in 2018, 2019 and 2021.

The Company also continues to receive top honors in the J.D. Power Gas Utility Residential Customer Satisfaction Survey for the eastern region among large utilities – having been so named from 2015 – 2021, and also in 2023. The Company was named one of the most trusted utilities in the nation, according to the 2023 Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential report from Escalent. The Company has been recognized nine out of the past 10 years for brand trust among customers. These high marks for customer satisfaction demonstrate NJNG's success in its operational performance and ability to listen to and respond to customer needs regarding reliability of service.

Q. Are there federal and state regulatory requirements related to NJNG'S operations?

A. Yes. The safety of natural gas transmission and distribution pipelines is regulated by a combination of federal and state laws, regulations, and agencies. In New Jersey, the BPU

is responsible for setting and administering pipeline safety regulations with oversight carried out by the Pipeline Safety Bureau in the Division of Reliability and Security. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") is responsible for federal pipeline safety oversight and the administration of federal pipeline safety laws. Both the BPU and PHMSA inspect pipeline facilities, oversee required reporting, and investigate potential concerns associated with the safety of the natural gas transmission and distribution system. PHMSA may delegate some of its inspection responsibilities to state agencies, such as the BPU.

Over the last two decades, several laws have been enacted that have materially expanded operator requirements and PHMSA responsibilities, particularly in the area of integrity management. These include the Pipeline Safety Improvement Act of 2002; the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("2006 PIPES Act"); the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011; the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("2020 PIPES Act"); and the Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments of 2022 ("Megarule"). These five acts apply to interstate and intrastate pipelines, Local Distribution Companies ("LDCs"), and other gas distributors considered system operators.

Of significance, the 2006 PIPES Act required PHMSA to lead a stakeholder process to develop new Distribution Integrity Management Plan ("DIMP") requirements applicable to gas distributors, such as NJNG. The 2020 PIPES Act mandates operators to update inspection and maintenance plans to address eliminating hazardous leaks and minimizing

releases of natural gas from pipeline facilities. NJNG had already proactively addressed these mandates by replacing pipelines known to leak due to material through its SAFE and SAFE II programs (and now continuing with its pre-1970's vintage pipe replacement efforts, which are discussed later in this testimony), thereby significantly reducing existing and future fugitive emissions; and is further reducing vented emissions via drawdown compression.

III. PIPELINE INTEGRITY MANAGEMENT

Q. Please describe the unique requirements that apply to operating the Company's transmission pipeline distribution facilities.

A. NJNG's 250 miles of transmission pipeline facilities are subject to PHMSA safety regulations including required PIM requirements. These requirements necessitate the development of a comprehensive plan to manage the integrity of a pipeline operator's facilities. An appropriate pipeline integrity plan should incorporate appropriate system assessments, identification of threats, remediation plan for identified concerns and record-keeping. Requirements for pipeline segments that traverse high consequence areas ("HCAs") are more stringent than for those that do not traverse an HCA. An HCA represents a location where the consequences to life and property of an incident are higher, taking into account population and building density factors.

NJNG operates the largest network of transmission pipeline among all of the New Jersey LDCs and has taken a number of steps to maintain the highest safety standards for its transmission assets. The first of these steps is to meet or exceed the HCA inspection requirements for its entire transmission pipeline, regardless of whether it meets the HCA criteria. Second, NJNG's transmission facilities are all configured to utilize internal

inspection tools, which is the most effective means of assessing the integrity of the facilities. This also allows the Company to take advantage of state-of-the-art advancements to the pipeline inspection devices, or "smart pigs," relied upon to detect anomalies such as pitting, cracks, dents or corrosion, and to clean facilities. Through the Company's efforts, NJNG has had only 60 PHMSA reportable actionable anomalies since 2004, and none since 2018. Additionally, many of our transmission pipeline segments have already been through their third round of integrity assessment.

Q. To what does the term "integrity management" refer?

A. "Integrity management" generally refers to the process of identifying, evaluating, and addressing potential or direct threats to system integrity. PHMSA categorizes potential hazards according to the following eight sources: (1) corrosion, (2) natural forces, (3) excavation, (4) other outside force damage, (5) material or welds, (6) equipment, (7) operations, and (8) other. Integrity management applies to all eight of these potential threats and requires management and industry focus in order to maintain safety.

Q. Please explain the essential requirements of DIMP?

A. The DIMP regulations mandated that a risk-based approach to distribution main and service integrity management plans be prepared by each operator no later than August 2011. While the new regulations prescribe a specific framework for documenting operating practices and procedures into a plan, the regulations provide significant operator flexibility to satisfy the requirements. At a minimum, each distribution pipeline operator's DIMP must address seven major elements. NJNG's DIMP reflects important documentation of the Company's risk-based approach to integrity management tracking the required elements as follows: (1) Knowledge; (2) Identify Threats; (3) Evaluate and

Rank Risks; (4) Identify and Implement Measures to Address Risks; (5) Measure Performance, Monitor Results; and Evaluate Effectiveness; (6) Periodic Evaluation and Improvement; and (7) Report Results.

Q. Please describe in more detail NJNG's planning associated with system enhancement and maintenance activities.

A. Planning to successfully address the safety risks associated with operating a natural gas distribution system is multi-faceted. A natural distinction exists between planning for emergency response activities and planning to address non-emergency risks.

Planning for emergency response must ensure that adequate levels of construction and maintenance crews, heavy equipment, tools, materials, and supplies are available and ready to repair any emergency leaks or other hazards that require immediate attention. Emergency planning must take into account the peak emergency demands that coincide with impacts from major storm events, extreme cold weather, and the location of infrastructure in the Company's service territory that spans more than 1,500 square miles.

Non-emergency planning entails medium and long-range planning to optimize NJNG's system improvement and leak management efforts. This type of planning is proactive and relies extensively on NJNG's analysis processes. Non-emergency planning also considers the most effective means of potentially reducing the impact of a major storm event while coordinating that work with affected municipalities.

Q. What resources are required to carry out the system enhancement and maintenance functions of the Company?

A. NJNG dedicates considerable capital and staffing resources to managing the integrity of its system, reflecting both the importance of and challenges associated with its commitment

to safety. The Company's Energy Delivery business units are the largest within NJNG, both in terms of capital and Operations and Maintenance ("O&M") budgets and staffing levels. NJNG consistently invests in maintaining and enhancing the safety of its system, as reflected in its short- and long-term capital budgets. In terms of staffing, the Energy Delivery business units include approximately 600 NJNG employees and oversee outside construction firms performing the majority of NJNG's planned construction activities (including for both planned and emergency main and service replacements, as well as the installation and upgrading of regulator stations, and new business mains and services installation). Energy Delivery employees are supported by field offices located throughout the service area as well as the Company's investment in vehicles and equipment necessary to address all needs and operating circumstances. Additionally, a portion of the Energy Delivery staff provides important management, engineering, and construction oversight for the business unit.

IV. NJNG'S CAPITAL PROJECTS

Q. Please describe NJNG's capital planning process.

A. NJNG's capital budgeting integrates a number of operational and design considerations, including, among other things, consistent monitoring of the performance and integrity of existing facilities and beneficial system improvements. These factors contribute to longer-term plans for specific system upgrade, rehabilitation, and replacement projects to maintain safe and reliable operations for the Company's customers and the communities it serves.

On an annual basis, prior to the beginning of the fiscal year, NJNG prepares a five-year capital plan that includes individuals from Energy Delivery and other business units. Energy Delivery develops a capital budget based upon system needs and identifies in which

of the five years the planned upgrade, rehabilitation, and replacement projects will take place. In addition to the specific larger-scale projects, the Company also budgets for high-volume, smaller scale capital improvements on a blanket basis. Prioritization of construction projects is done by incorporating many factors such as long-range planning, vintage facilities, external influences affecting NJNG infrastructure (*i.e.*, municipal/state project relocation) and input from field management. Software tools such as DNV's Synergi and MRP, NJNG's risk management tool, are used to analyze new customer forecasts, leak history and other factors to help prioritize future, long-range capital replacement and upgrade projects. The cost estimates for the large-scale projects and blanket needs are based upon preliminary analysis of the project needs and historical cost data for similar projects. The capital budget is reviewed and approved by NJNG's management and then is submitted to New Jersey Resources ("NJR"), NJNG's parent, for approval by the NJR Board of Directors.

After the budget has been approved, the Company's capital budgeting process incorporates appropriate controls to ensure all capital costs are prudently incurred and contained to the degree possible. Additionally, the process incorporates sufficient analysis and flexibility to prioritize system needs on an ongoing basis so that safety and reliability are maintained cost-effectively. The application of this process to meet NJNG's extensive capital needs ensures that the anticipated benefits of various types of capital investment are achieved at reasonable cost.

Q. Please describe NJNG's capital expenditures as shown on Schedule JBW-2.

A. The Company expects to incur an additional $369.9 million, for capital expenditures during the test year ending June 30, 2024, and $219.6 million, for capital expenditures for projects

that are major in nature and consequence during the post-test year period ending December 31, 2024. These increases are the result of capital expenditures for necessary replacement and upgrade of the distribution and transmission systems to ensure the continuation of safe and reliable service; system expansions required to serve new and existing customers; and pipeline integrity management.

Q. Please highlight the ongoing and anticipated new capital projects being constructed by NJNG.

A. As stated previously, capital investments ensure that NJNG continues to meet and enhance the safety and overall integrity of its operations, as well as enable the Company to meet the growing needs of its customers for reliable gas service. In this section of my testimony, I will describe several recently completed and ongoing capital projects and the benefits associated with each. I will also provide an update concerning the ongoing capital projects associated with NJNG's IIP. Last, I will describe investments needed to meet system growth and improvement needs.

Q. Please describe the capital projects related to system integrity that have been completed since the filing of the Company's last base rate case in 2021.

A. The Company completed a number of projects related to system integrity, including: (1) those needed to maintain adequate system pressures based on projected near-term customer growth, including looping and reinforcement projects, as well as pipeline replacement projects to accommodate size and capacity constraints; (2) replacement of vintage distribution lines due to age and/or cathodic protection concerns, which generally tend to be larger in scope and cost; and (3) replacement of vintage trunk and transmission lines due to age, integrity issues or concerns, capacity limitation and/or diversity of supply; and

(4) installation of new regulator stations to support system improvement projects and address capacity concerns, as well as the replacement of existing regulator stations due to age, antiquated equipment, and/or capacity, for system reliability needs.

As shown on Schedule JBW-1, these projects accounted for capital expenditures totaling approximately $107.7[1] million in Fiscal Year 2022, and will account for planned capital expenditures totaling approximately $111.4 million in the Test Year.

Q. Please provide an update on NJNG's efforts to replace its pre-1970's pipe in the system.

A. Sure. The Company is continuing its replacement of vintage 1950's and 1960's protected steel distribution main throughout its service territory as part of its long-term proactive program that is similar to NJNG's previous SAFE replacement programs. The benefits to customers of these replacements are many, including: (1) reducing the number of leak prone mains in the system; (2) reducing methane emissions due to leaks; (3) minimizing potential leak calls and subsequent leak response; and (4) minimizing potential incidents resulting from leak migration. This plan continues to support the mandates of the 2020 PIPES Act, along with New Jersey's recent requirements set forth in N.J.A.C 14:7-1.19.

In fiscal year 2022, NJNG replaced 25 miles of protected steel mains at a cost of $23.4 million. NJNG expects to spend $74.2 million (70 miles) for replacements under this program through the end of the Test Year.

[1] Total includes the following "Type" of work categories: System Improvement, Transmission, System Renewal, IIP Base, and IIP.

Q. What system replacement work has NJNG completed since the last base rate case in 2021 and how much of does it anticipate will be done through December 31, 2024?

A. The Company routinely completes a variety of system replacement work, the timing of which is driven by both internal and external factors. Internal drivers could include cathodic protection issues, material reliability concerns, and pipeline integrity considerations. Whereas, external drivers could include conflicts or coordination with local municipal or county infrastructure projects.

The benefits of these system replacements include:

- Reducing the number of leak prone mains and services in the system;
- Reducing methane emissions due to leaks;
- Minimizing potential leak calls and subsequent leak response;
- Minimizing potential incidents resulting from leak migration;
- Minimizing potential impacts due to material failures; and
- Minimizing potential damages by third parties during construction.

In fiscal year 2022, NJNG completed $32.5 million for system replacements, and expects to spend $28.7 million and $30.6 million for this work in Fiscal Years 2023 and 2024, respectively.

Q. Can you quantify any of the benefits, from a leaks perspective, of the pre-1970's pipe replacements and system replacements to NJNG and its customers?

A. Yes. The success of the long-term proactive replacement of pre-1970's protected steel mains and other systematic and continual system replacement work has led to NJNG continuing to have the lowest leak rate among New Jersey's natural gas LDCs – its leak rate was 0.06 leaks per mile of main in both Fiscal Years 2022 and 2023.

Q. Please generally provide an update on NJNG's IIP Program and level capital investments made pursuant to that program.

A. The Company' s IIP consists solely of a T&D Component, which is a series of natural gas facility transmission and distribution replacements and enhancements. The T&D Component projects are comprised of a group of capital investment projects that enhance the safety, reliability, and resiliency of NJNG's gas distribution system through infrastructure replacements, upgrades, or redundancies. The projects include the following six specific projects or categories of projects: (1) Reliability and Resiliency Projects, (2) Replacement and Reinforcement Projects, (3) Regulator Station Reconstruction Project, (4) Trunk Line Replacement Projects, (5) EFV Installation Project, and (6) Regulator Protection Project.

All of the projects included in the IIP program are on schedule for completion by the end of June 2025. The Company spent $34.4 million on IIP projects in Fiscal Year 2022, $36.4 million in Fiscal Year 2023, and is anticipating to spend another $28 million in Fiscal Year 2024. The costs related to IIP projects are recovered through a separate filing and included in base rates on an annual basis.

V. CONCLUSION

Q. Does this conclude your Direct Testimony?

A. Yes, it does. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

EXHIBIT P-2
SCHEDULE JBW-1

TYPE	FY 2021 ACTUAL ($000)	FY 2022 ACTUAL ($000)	TOTAL
SYSTEM IMPROVEMENT	$25,848	$32,983	$58,831
TRANSMISSION	$13,500	$8,493	$21,994
SOUTHERN RELIABILITY LINK	$109,737	$1,980	$111,717
SAFETY TOWN	$16,909	$1,648	$18,556
LAND & STRUCTURES	$48,511	$5,523	$54,034
PRODUCTION & CATHODIC PROTECTION	$7,174	$3,441	$10,615
SYSTEM RENEWAL	$36,376	$30,916	$67,292
IIP BASE SPENDING	$3,000	$3,000	$6,000
SAFE BASE SPENDING	$8,500	$0	$8,500
BASELINE CAPITAL SPENDING	$269,556	$87,984	**$357,540**
SAFE	$46,493	$0	$46,493
NJ RISE	$4,067	$0	$4,067
Pre 70s Replacement	$44	$23,394	$23,437
IIP	$8,832	$32,329	$41,160
CUSTOMER GROWTH	64,512	53,876	$118,388
COST OF REMOVAL	$49,496	$35,534	$85,030
ADDITIONAL CAPITAL SPENDING	$173,443	$145,132	**$318,575**

TOTAL CAPITAL SPENDING	$442,998	$233,116	**$676,114**

EXHIBIT P-2
SCHEDULE JBW-2

$(000)

TYPE	Test Year (Jul 2023 - Jun 2024)			Post Test Year (Jul 2024 - Dec 2024)	Total
	Total	Actuals	Forecast		
SYSTEM IMPROVEMENT	$11,830	$3,699	$15,529	$13,690	$25,520
TRANSMISSION	$43,370	$11,216	$32,155	$28,473	$71,843
LAND & STRUCTURES	$22,934	$14,392	$8,541	$4,823	$27,757
PRODUCTION & CATHODIC PROTECTION	$26,659	$7,766	$18,893	$33,129	$59,789
SYSTEM RENEWAL	$21,318	$9,295	$12,022	$12,225	$33,543
IIP BASE SPENDING	$3,000	$1,500	$1,500	$1,500	$4,500
BASELINE CAPITAL SPENDING	$129,111	$40,470	$88,641	$93,841	**$222,952**
Pre 70s Replacement	$74,161	$42,184	$31,977	$37,635	$111,796
IIP	$31,910	$16,847	$15,063	$16,254	$48,164
CUSTOMER GROWTH	$92,169	$52,426	$39,742	$50,591	$142,759
COST OF REMOVAL	$42,569	$30,441	$12,128	$21,285	$63,854
ADDITIONAL CAPITAL SPENDING	$240,809	$141,898	$98,911	$125,764	$366,573
TOTAL CAPITAL SPENDING	$369,920	$182,368	$187,552	$219,605	$589,525

Exhibit P-3

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY
OF
JAMES M. CORCORAN
DIRECTOR – REVENUE REQUIREMENTS

I. INTRODUCTION AND BACKGROUND

Q. Please state your name, affiliation and business address.

A. My name is James M. Corcoran and I am the Director – Revenue Requirements for New Jersey Natural Gas Company ("NJNG" or the "Company"). My business address is 1415 Wyckoff Road, Wall, New Jersey 07719.

Q. Please describe your education and experience.

A. I received a Bachelor of Science degree in Accounting from Seton Hall University. In May 2010, I received a Master's of Business Administration – Finance from Seton Hall University. I was employed by the State of New Jersey – Board of Public Utilities ("BPU" or "Board") beginning in July 1986 as an Accountant-Trainee and over a 20-year career moved into various Analyst positions of increased responsibility. In March 2007, I accepted a Senior Regulatory Analyst position at Public Service Electric and Gas Company with responsibilities that included preparing the requisite testimony and financial schedules for various rate recovery mechanisms. In August 2007, I was promoted to the position of Principal Staff Regulatory Analyst and, in August 2011, I was promoted to the position of Revenue Requirements Manager.

I joined NJNG in July 2014 as the Manager – Revenue Requirements. On January 2, 2018, I was promoted to the position of Director – Revenue Requirements.

My responsibilities include supporting the Regulatory Affairs department with the preparation of testimony regarding all rate recovery matters. I also participate on behalf of NJNG in the New Jersey Resources ("NJR") financial reporting committee.

As Director – Revenue Requirements, I perform the calculation of revenue requirements for NJNG's base rates as well as its cost recovery riders.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I have submitted Direct Testimony before the Board in NJNG's three most recent base rate cases (BPU Docket No. GR21030679, BPU Docket No. GR19030420 and BPU Docket No. GR15111304), and various other proceedings, including: the SAVEGREEN 2020 case (BPU Docket Nos. QO19010040 and GO20090622), SAVEGREEN 2023 case (BPU Docket No. QO23120868), the Infrastructure Investment Program (BPU Docket No. GR19020278), the NJ Reinvestment in System Enhancement ("NJ RISE") cost recovery petition (BPU Docket No. GR15050638), as well as various Societal Benefit Charge cost recovery matters. In addition, I have provided testimony on behalf of PSEG Power, LLC in a rate matter proceeding before the Connecticut Public Utilities Regulatory Authority in PURA Docket No. 12-07-17.

Q. Please summarize the purpose of your Direct Testimony.

A. In this rate case, I am serving as the Company's financial witness. My Direct Testimony addresses NJNG's proposed revenue requirements, which encompass the rate base and Operating Income for the test year ending June 30, 2024, with appropriate pro forma adjustments. In addition, I will also explain the need for rate relief associated with the Company's investment in rate base, including capital investments supporting capital replacement of mains and services, distribution and transmission infrastructure, as well as increased operation and maintenance expenses ("O&M"). NJNG's utility

plant in service ("UPIS"), through its annual construction programs, has increased by approximately $850 million since the resolution of the Company's last base rate case in 2021. These increases are the result of capital expenditures for necessary replacement and upgrade of the distribution and transmission systems to ensure the continuation of safe and reliable service; system expansions required to serve new and existing customers; and pipeline integrity management. The Direct Testimony of John B. Wyckoff (Exh. P-2) describes in detail the Company's transmission and delivery operations.

Schedule JMC-1 shows the operating income required to provide a just and reasonable return on NJNG's investment in rate base, the pro forma operating income for the test period, and the additional revenue necessary to satisfy the operating income requirement. Schedule JMC-2 summarizes NJNG's rate base, and Schedule JMC-12 reflects Operating Income as of June 30, 2024, on a five-month actual and seven-month estimated basis. The Revenue Factor is presented on Schedule JMC-4. The individual amounts shown on these Schedules are further supported by NJNG's accounting records and its operating and capital budgets for the period ending June 30, 2024. The books and records of NJNG are maintained in accordance with the Uniform System of Accounts prescribed by the Board and the Federal Energy Regulatory Commission ("FERC"). The Direct Testimony of Angela M. Cahill (Exh. P-4) describes in detail the Company's financial schedules.

The balance of my Direct Testimony supports the rate base, operating income, and the pro forma adjustments necessary for the period ending June 30, 2024. The additional revenue of $222.60 million requested in this case, as calculated on Schedule JMC-1, is needed to provide NJNG the opportunity to recover operating revenues

through base rates sufficient to meet operating expenses, taxes, and fixed charges, and to provide a reasonable return on its rate base investments, in the provision of service to customers.

Schedules JMC-13 through JMC-28 provide the pro forma adjustments and the detail of Operating Income, which I discuss later in my Direct Testimony.

II. RATE CASE OVERVIEW

Q. Please provide an overview of the NJNG rate case petition.

A. NJNG's last base rate case decision was approved by the BPU in an Order effective November 24, 2021 (Docket No. GR21030679).[1] Since that time, the Company has continued to provide safe and reliable service to its customers, and is committed to providing the same in the future.

The Company is requesting an increase in its base rate revenues of $222.60 million based on the test year ending June 30, 2024, with adjustments to reflect certain known and measurable changes through December 31, 2024. Financial integrity and strength are key components to the Company's ability to deploy the necessary capital and to cover the operating expenses necessary to maintain and improve its distribution and transmission systems, and to continue to provide safe and reliable service to approximately 576,000 residential and commercial customers in its service territory. The health and safety of NJNG's customers and employees is the Company's number one priority and maintaining a strong financial position in the marketplace is a necessary ingredient to accomplishing this goal.

[1] Add full cite?

Q. What test period is NJNG using to support its base rate case request?

A. The test period in this base rate case proceeding is the 12-month period ending June 30, 2024. This filing consists of five months actual data ending November 30, 2023, and seven months estimated data through June 30, 2024.

Q. Please describe the New Jersey Resources Service Company ("Service Company") and its role in providing service to NJNG.

A. The Service Company provides shared administrative services to NJNG. These services include, but are not limited to, financial, shared facilities, information technology, human resources, office services, security, communications, legal, and internal auditing.

The Service Company allocates its costs to the affiliate benefiting from the work performed. These costs are either directly charged to affiliates or charged to intermediate expense pools that are then charged to users of these services based on cost drivers. The type of cost driver assigned to each expense pool will best match the benefit of the receiving affiliate and may include time sheets, square footage, equipment usage, headcount, etc. Timesheets are submitted monthly whereas all other cost drivers are updated annually or during a major organizational change. No costs are retained at the Service Company.

III. DEVELOPMENT OF RATE BASE

Q. Please describe Schedule JMC-2.

A. Schedule JMC-2 presents total rate base, as of June 30, 2024, of $3.36 billion. The NJNG rate base consists of the utility's investment in natural gas plant, net of accumulated depreciation of utility plant; natural gas commodity in storage and LNG inventory; materials and supplies; prepayments and cash working capital, offset by

customer advances in aid of construction ("CIAC") and accumulated deferred income taxes ("ADIT"); and a consolidated tax adjustment ("CTA"). I will now address each individual component of the Company's Revenue Requirement.

Q. Has the Company included a CTA in accordance with the Board's current methodology?

A. Yes. The Company has calculated and included a CTA in accordance with the requirements set out in N.J.A.C. 14:1-5.12(a)(10). The calculated CTA reduces rate base by $7.62 million. *See* Schedule JMC-2.

Q. Please describe Schedule JMC-3.

A. Schedule JMC-3 provides NJNG's capital structure components and their respective embedded cost rates to calculate the requested weighted average cost of capital ("WACC") to establish the proper operating income requirement. The Direct Testimony of Mr. Dylan D'Ascendis (Exh. P-6) supports the capital structure, the long-term debt cost rate and the return on common equity ("ROE") utilized in the WACC. I have incorporated the low-point recommendation of Mr. D'Ascendis and have utilized a 10.42% ROE in the Company's capital structure.

Q. Please explain Schedule JMC-4.

A. Schedule JMC-4 presents the revenue factor utilized by the Company in this proceeding, which is 1.4027. The factor includes State of New Jersey Corporate Business Tax, Federal Income Tax, the Assessments for the Board and the New Jersey Division of Rate Counsel ("Rate Counsel") and Uncollectibles.

Q. Please explain UPIS Schedules JMC-5 and JMC-6.

A. The NJNG UPIS, as shown on Schedule JMC-5, is $4.14 billion at June 30, 2024. Since

August 2021, UPIS has increased by approximately $850 million. This growth is, in part, attributable to investment in Board-approved infrastructure programs for distribution and transmission mains and services, as well as safety and reliability upgrades in the Company's service territory. Distribution and transmission plant investments are discussed in the testimony of Mr. John B. Wyckoff (Exh. P-2). Schedule JMC-6 provides a further breakdown of the Plant Additions summarized on Schedule JMC-5.

Q. Please describe the Accumulated Depreciation of Utility Plant – Schedule JMC-7.

A. Plant in service investments have an estimated useful life, which normally extends over many years as the asset provides natural gas service to customers. The systematic recovery of these investments is accomplished by the recognition in rates and operating expense of annual depreciation charges, with accumulated depreciation primarily representing the cumulative recovery of depreciation expense. This accumulated recovery of depreciation is used to reduce rate base. This has been, and continues to be, an acceptable principle in developing rate base, since the accumulated depreciation reserve balance infers that these amounts have already been charged to income and recovered from customers. The accumulated depreciation reserve balance of $675.26 million includes the accumulated recognition of depreciation expense, salvage, and cost of removal. The accumulated depreciation reserve balance does not recognize the legal Asset Retirement Obligation liabilities associated with the Statement of Financial Accounting Standards No. 143 and Financial Accounting Standards Board Interpretation Number 47.

The Company has proposed new distribution depreciation rates based on a fiscal year 2023 Gas Depreciation Study, supported by the testimony of Dr. Ronald E. White

(Exh. P-7). The proposed depreciation rates and related depreciation expense have been annualized for plant balances at June 30, 2024 and are reflected in the Company's revenue requirement.

As detailed on Schedule JMC-7, the Company has increased its June 30, 2024 Accumulated Depreciation Reserve balance by $25.61 million, representing an adjustment equal to one-half of the annualized period-end depreciation expense plus one-half of the annualized depreciation rate change impact as shown on Schedule JMC-21. This test year adjustment to the Accumulated Depreciation Reserve balance annualizes the period-end depreciation expense and the proposed new depreciation rates resulting from Dr. White's depreciation study for plant balances at June 30, 2024.

Q. Please describe Schedule JMC-8.

A. As a normal part of utility business, the costs of construction related to advances made by the Company's customers (*i.e.*, CIAC) are capitalized and included in the Net Plant In Service balance. Therefore, it is appropriate to reduce plant costs for these construction related customer advances. As shown on Schedule JMC-2, rate base has been reduced by $2.58 million, based upon the 13-month average of actual CIAC received through November 30, 2023. This amount will be updated throughout the case.

Q. Please describe the Natural Gas Supply & Liquefied Natural Gas ("LNG") inventory component of rate base – Schedule JMC-9.

A. Included in rate base is a representative amount of natural gas supply and LNG inventory maintained by NJNG to serve its customers. The natural gas supply and LNG inventory, in the amount of $107.68 million, is based on a 13-month projected average as of June 30, 2024. This amount will be updated throughout the case.

Q. Please describe the Working Capital component of rate base.

A. The Company's proposed working capital allowance is $163.88 million, consisting of three components: cash (Lead/Lag and Net Assets/Net Liabilities Analysis) of $127.34 million; materials and supplies at a 13-month actual average of $20.94 million; and prepayments at a 13-month actual average of $15.60 million. The cash working capital requirements associated with the Lead/Lag study are discussed in the Direct Testimony of Harold Walker, III. (Exh. P-5). I will, however, further discuss the rate treatment for the Materials and Supplies and Prepayments components.

Q. Please explain the development of the materials and supplies component of the working capital allowance, Schedule JMC-9.

A. Included in rate base is $20.94 million of materials and supplies necessary for ongoing utility operations. This amount is a 13-month actual average balance representing general store items held in NJNG's inventory for O&M and capital purposes as of November 30, 2023. This amount will be updated throughout the case.

Q. Please describe the calculation of the prepayments component of the working capital allowance, Schedule JMC-10.

A. The Company is required to make advance payments for certain operating costs, such as insurance and assessments, prior to those amounts being charged to operating expenses. The NJNG prepayments, which are similar to the materials and supplies, represent a permanent, ongoing investment by the Company. Accordingly, I have included in rate base the 13-month actual average of prepayments at November 30, 2023 of $15.60 million. This amount will be updated throughout the case.

Q. Please describe the ADIT portion of rate base – Schedule JMC-11.

A. ADIT represents the accumulated tax effect for the timing differences between when an item is recognized for tax purposes and when it is recognized for book purposes in Utility Operating Income. Since the ADIT balances shown on Schedule JMC-11 relate either to utility assets included in rate base or to expenses, both of which are utilized in setting customer rates, a rate base deduction is appropriate. The ADIT reduction to rate base is estimated to be $240.42 million at June 30, 2024.

Q. Has the Company included any costs associated with the annual cost recovery filing for its Infrastructure Investment Program ("IIP') in this instant proceeding?

A. No. The investments related to the IIP that have been placed in-service from July 1, 2023 through June 30, 2024 are excluded from the Company's rate base. By March 31, 2024, the Company will file its annual cost recovery petition for the IIP investments for the July 1, 2023 through June 30, 2024 period.

IV. PRO FORMA OPERATING INCOME ADJUSTMENTS

Q. Please describe the Operating Income level at current rates.

A. Schedule JMC-12 presents NJNG's income statement for the test year ended June 30, 2024.

Q. Please describe the Operating Income and the Pro forma adjustments at June 30, 2024.

A. I have made the following pro forma adjustments to Operating Income to recognize a normalized test year ending June 30, 2024:

Pro Forma Operating Income – Schedule JMC-13

This Schedule presents a summary of the pro forma adjustments applied to NJNG's test period Operating Income. The pro forma adjustments modify test year Operating Income for known and measurable changes to expense and income levels that will be incurred when the rates are established in this proceeding. Adoption of these adjustments by the Board will provide the Company with an opportunity to earn a reasonable return on its investments during the period when the proposed base rates are in effect.

Annualization of Wages – Schedule JMC-14

This adjustment of $6.52 million ($4.69 million, net) represents the annualization of labor costs applicable to represented and non-represented employees at NJNG at June 30, 2024, plus an adjustment for known and measurable changes to include in the test year the December 2024 wage increase.

The Company and its Union, Local 1820 of the International Brotherhood of Electrical Workers, are operating under a three-year agreement that was ratified on December 13, 2023. The contract contains an agreed-upon annual percentage increase of 4.25 percent, effective on December 8, 2023, and a 3.75 percent increase, effective on December 8, 2024. For represented employees, this ratemaking adjustment annualizes the December 2023 wages and calculates the pro forma impact of the contractual December 2024 union contract increase for employees.

The adjustment also annualizes the December 2023 increase and calculates the pro forma impact of a December 2024 increase applicable to the Company's non-represented employees. The identical percent increases afforded the represented work force have been applied to the non-represented employees. The adjustment to labor

expense also includes the wage increases associated with the labor dollars charged to NJNG for the Service Company employees in a similar manner.

The Company's employees are a critical element in meeting the service and reliability needs of NJNG's customers, and this adjustment to the test year operating expenses ensures that the Company's base rates will reasonably reflect the cost of this workforce during the time these proposed base rates are in effect.

Annualization of Payroll Taxes – Schedule JMC-15

This adjustment of $499,000 ($359,000, net) annualizes the test year for changes in payroll taxes and represents the increases in the Federal Insurance Contribution Act ("FICA") Tax for increases in taxable wages. The test period has been annualized for the statutorily mandated rates of 6.20 percent and 1.45 percent for Social Security and Medicare Benefits, respectively.

Interest Synchronization (Tax Savings) – Schedule JMC-16

The Board has historically adopted an adjustment to synchronize the federal income tax savings associated with interest expense in the test period with the tax savings, based on an interest calculation using the weighted average cost of debt in the capital structure utilized to support rate base.

As shown on Schedule JMC-16, the interest-bearing components of the capitalization supporting the NJNG rate base produce interest expenses of $60.39 million. This is $694,000 more than the recorded test year period interest expense of $59.70 million. This adjustment of $694,000 ($195,000, net) increases Operating Income attributable to the tax savings on the interest component.

Medical and Benefits Expense – Schedule JMC-17

An adjustment in the amount of $3.57 million ($2.57 million, net) represents an

operating expense increase and reflects the necessary adjustments in medical and dental expenses and fringe transfer expense over the test period amounts included in operating income. This level of expense reflects the forecasted medical and dental expenses and fringe benefits transfer though fiscal year 2025 (*i.e.*, October 1, 2024 through September 30, 2025).

BPU and Rate Counsel Assessments – Schedule JMC-18

In accordance with N.J.S.A. 48:2-60 and N.J.S.A. 52:27EE-52, the Company provides funding to the State of New Jersey associated with the operations of the Board and Rate Counsel. These assessments are predicated on rates established by the State of New Jersey and are applied to each gross intrastate revenue dollar recorded by the Company for the preceding year. The current assessment rates are 0.2130 percent for the Board and 0.0502 percent for Rate Counsel. By applying these rates to year-end 2022 intrastate operating revenues, the Company has estimated its funding obligation for the Board and Rate Counsel at $2.51 million. The adjustment of $501,000 ($360,000, net) increases the test year operating expenses to that level. The adjustment recognizes test year expense for this item at a level that the Company will incur while new rates are in effect, assuming the assessment rate remains stable, and is therefore, appropriate to be adopted in this proceeding.

Basic Gas Supply Service ("BGSS") Incentive Margin – Schedule JMC-19

Included in test period Operating Income is a level of net BGSS incentive margin that should be excluded from the calculation of base rates in the amount of $10.78 million ($7.75 million, net). This incentive margin should be excluded to prevent NJNG's base rates from being reduced, which would eliminate the incentive margins earned by NJNG pursuant to the Board's separately approved program.

Rate Case - Outside Services – Schedule JMC-20

This adjustment represents a normalized level of expense incurred for rate case expense. The expenses are then ratably amortized over an appropriate time to determine an appropriate level of operating expense recovery in base rates. In accordance with the Board's long-standing policy, I have reflected a 50%/50% sharing of rate case expense between shareholders and NJNG's customers. The resulting adjustment represents an increase in operating expense of $272,000 ($196,000, net).

Annualization of Depreciation – Schedule JMC-21

The depreciation rate changes reflect the results of the depreciation study completed by Dr. White. The difference between the annualized depreciation expense at current rates and the amount of depreciation expense included in the test year has been recognized, as well as the annualization of the depreciation rate change on Plant In Service investments at June 30, 2024. The adjustment to depreciation expense represents an increase in operating expense of $51.22 million ($36.82 million, net). Depreciation expense is a vital component of NJNG's recovery of its investment in utility plant over its service life, as well as the recovery of the cost of removal for the replacement of existing structures and other plant investment.

SAVEGREEN Margin – Schedule JMC-22

Included in test period Operating Income is a level of SAVEGREEN margin that should be excluded from the calculation of base rates in the amount of $11.15 million ($8.02 million, net). This margin should be excluded to prevent NJNG's base rates from being reduced, which would eliminate the margin earned by NJNG pursuant to the Board's separately approved program.

Real Estate Taxes – Schedule JMC-23

This adjustment of $48,000 ($34,000, net) increases the test year operating expense to be representative of the level of real estate property tax expense that is expected to be accrued and paid by NJNG on its real estate property in the 12-month period following when new base rates go into effect.

Insurance – Schedule JMC-24

This adjustment addresses the items for which NJNG carries insurance policies with outside vendors (*e.g.*, Automobile & Workers Compensation) for which the Company pays annual premiums of approximately $9.22 million. This adjustment of $1.05 million ($757,000, net) for the test year operating expense increase is representative of the level of insurance expense that is expected to be accrued and paid in the 12-month period following when new base rates go into effect, *i.e.*, the rate year.

Annual Review of Commercial Customer Usage – Schedule JMC-25

Pursuant to the Company's Tariff, at least once annually, small and large commercial customers' usage is reviewed to determine their appropriate service classification and highest monthly average daily ("HMAD") usage, if applicable. This review is typically performed in September. The Company is proposing an adjustment to reflect the margin impact of the anticipated switching of commercial customers between small and large classes, as well as HMAD changes. The margin accrued during the test year will not accrue at the conclusion of this rate case. A pro forma adjustment to reflect the change in margin and income that results from the annual review of commercial customers' usage is necessary.

Schedule JMC-25 shows the estimated adjustment necessary to reflect the reduction in margin anticipated from the annual review of commercial customers'

usage. The adjustment results in a decrease to operating income of $968,000 ($696,000, net). This adjustment will be updated throughout the case.

Revenue– Schedule JMC-26

Schedule JMC-26 reflects four adjustments to annualize the Company's revenues for its IIP Program and the Conservation Incentive Program ("CIP") component, an extra billing cycle in 2024 and the loss of Nestle, a large commercial customer.

The IIP Program adjustment annualizes the test year revenues for the IIP rate change that occurred on October 1, 2023. As the proposed Test Year for this rate case begins on July 1, 2023, the Company has increased its revenues to reflect three additional months for this change.

The CIP adjustment normalizes the test year revenue to recognize that, through the resetting of the CIP baseline use per customer in the NJNG Tariff Rider I – Conservation Incentive Program in this base rate case, this margin will not be earned effective with the new base rates and CIP baseline use per customer emanating from this case.

Based on the timing of this Test Year, the Company's revenues reflect 239 billing cycles as opposed to a "normal" period of 240 billing cycles. Therefore, the Company has adjusted its revenues to reflect this additional billing cycle.

Finally, the Company has been notified that the Nestle plant has ceased operations and I have reflected the loss of revenue associated with this account. Nestle operated a coffee factory located in Freehold, New Jersey.

These four adjustments represent an increase in operating expense of $6.08 million ($4.37 million, net).

Regulatory Assets – Schedule JMC-27

This schedule reflects the proper amortization of three regulatory assets: (1) COVID Arrearages; (2) the BPU-mandated Management/Affiliated Standards Audit; and (3) the BPU-ordered Benchmarking Study.

COVID Arrearages – Pursuant to the BPU's Order dated July 2, 2020, at Docket No. AO20060471, affected utilities were authorized to create a COVID-19 regulatory asset to defer on their books and records any arrearages incurred due to the COVID-19 pandemic during the period March 9, 2020 through March 15, 2023.[2] NJNG ceased deferring COVID-19 costs at December 31, 2022. As of December 31, 2022, NJNG has recorded a regulatory asset of $3.89 million.

Management/Affiliated Standards Audit – Pursuant to the BPU's Order dated September 7, 2022, at Docket No. GA22020074, the BPU authorized the Liberty Consulting Group to perform a two-phase audit of NJNG for the period January 1, 2014 through December 31, 2023. Phase One was to be an audit of affiliated transactions of NJNG and New Jersey Resources, NJNG's affiliates and any competitive services it offers and its compliance with the Board's Affiliate and Fair Competition Standards. Phase Two was to consist of a comprehensive management audit. Accordingly, the costs incurred by NJNG for this audit have been deferred on the Company's books and records for recovery in NJNG's base rate case. The Company is seeking to recover $1.75 million related to this proceeding.

Benchmarking Study – By Order dated September 7, 2022, at Docket No. QO21071023, the BPU required NJNG to perform a benchmarking study as a result of

[2] By Board Order dated December 21, 2022, at Docket No. AO20060471, the BPU extended the deferral period from December 31, 2022 through March 15, 2023.

the Clean Energy Act. The Order permitted the Company to defer on its books and records the cost of this study to be recovered in its next base rate case. NJNG has recorded and deferred $158,000 for this matter.

These adjustments utilize a two-year amortization period representing an increase to operating expense by $2.90 million ($2.08 million, net) for these BPU-mandated regulatory assets.

Transportation Safety Administration ("TSA") – Schedule JMC-28

The Company is requesting authority for recovery of, and on, capital expenses incurred due to various TSA Security Directives. Schedule JMC-28 reflects the estimated revenue requirement to reflect the return on capital investment, deferred taxes and the depreciation expense associated with this mandate. Based on the most recent data available, this adjustment represents an increase in operating expense of $355,000 ($320,000, net).

Q. Please discuss if you anticipate making any additional pro forma adjustments during these proceedings.

A. As stated previously, pro forma adjustments modify test year Operating Income for known or measurable changes. Adoption of these known and measurable adjustments provides an opportunity for the Company to earn a reasonable return on its investment during the period when rates set from this process are in effect.

It is quite possible that additional pro forma adjustments may be necessary during the course of this proceeding as a result of changes to energy policy, capital investment and operating practices.

V. CONCLUSION

Q. Please summarize your Direct Testimony.

A. The Company has continued to provide safe and reliable service to customers, as well as stable and reasonable base rates. The Company has now reached the point where the cost of operations and the level of capital investments required to serve its customers need to be updated from those reflected in NJNG's current base rates. Company employees and management have worked hard to provide safe and reliable gas service to a growing service territory at reasonable rates.

As further discussed in detail in the Direct Testimony of other Company witnesses, NJNG has consistently made efforts in all areas of its operations to provide efficient and cost-effective service to NJNG's customers. The Company's proposed base rates are just and reasonable in terms of affording the Company an opportunity to earn a fair rate of return and to provide safe and reliable cost-based service to NJNG's customers. Accordingly, an increase in base rates is required at this time and is in the best interests of the Company and its customers.

Q. Does this conclude your Direct Testimony at this time?

A. Yes. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

EXHIBIT P-3
SCHEDULE JMC-1

NEW JERSEY NATURAL GAS COMPANY

DETERMINATION OF REVENUE REQUIREMENTS
($000)

Rate Base	$	3,358,691
Rate of Return		7.57%
Operating Income Requirement	$	254,342
Pro-Forma Operating Income	$	95,648
Operating Income Deficiency	$	158,694
Revenue Factor		1.4027
Revenue Requirements	**$**	**222,600**

EXHIBIT P-3
SCHEDULE JMC-2

NEW JERSEY NATURAL GAS COMPANY

RATE BASE
($000)

		Balance at June 30, 2024
Plant In Service	$	4,139,905
Accumulated Depreciation Reserve		(675,257)
Customer Advances		(2,577)
Net Plant In Service		3,462,071
Gas Supply & LNG Inventory		107,678
Working Capital:		
Cash (Lead/Lag)	$	127,341
Materials and Supplies		20,936
Prepayments		15,604
Net Working Capital		163,881
Deferred Taxes		(240,415)
Excess Deferred Tax		(126,901)
Consolidated Tax Adjustment		(7,624)
Total Rate Base	**$**	**3,358,691**

Source(s):

Workpaper	JMC - 1	LL Summary
Workpaper	JMC - 2	Excess DFIT
Workpaper	JMC - 3	Consolidated Taxes - Confidential

EXHIBIT P-3
SCHEDULE JMC-3

NEW JERSEY NATURAL GAS COMPANY

WEIGHTED AVERAGE COST OF CAPITAL
($000)

	Amount	Percent	Embedded Cost	Weighted Cost	Net of Tax	Pre-tax
Long-Term Debt	$ 1,573,225	44.58%	4.03%	1.80%	1.29%	1.80%
Common Equity	$ 1,955,691	55.42%	10.42%	5.77%	5.77%	8.03%
Total	$ 3,528,917	100.00%		7.57%	7.07%	9.83%

Source(s):

Workpaper JMC - 4 Long Term Debt

EXHIBIT P-3
SCHEDULE JMC-4

NEW JERSEY NATURAL GAS COMPANY

REVENUE FACTOR

Revenue Increase	100.0000	222,600
Uncollectible Rate	0.5677	1,264
BPU Assessment Rate	0.2130	474
Rate Counsel Assessment Rate	0.0502	112
Income before State of NJ Bus. Income Tax	99.1690	220,750
State of NJ Bus. Income Tax @ 9.00%	8.9252	19,868
Income Before Federal Income Taxes	90.2438	200,883
Federal Income Taxes @ 21%	18.9512	42,188
Return	71.2926	158,694
Revenue Factor	**1.4027**	**1.4027**

Source(s):

Workpaper JMC - 5 Uncollectible Rate

EXHIBIT P-3
SCHEDULE JMC-5

NEW JERSEY NATURAL GAS COMPANY

UTILITY PLANT IN-SERVICE
($000)

		Test Year June 30, 2024
Beginning Balance @ July 1, 2023	$	3,739,873
Total Direct Additions	$	427,325
Retirements:		
Production	$	-
Storage		-
Transmission		(664)
Distribution		(8,079)
General		(4,667)
Total Retirements	$	(13,410)
Other:		
IIP		(13,883)
Total Utility Plant In-Service	**$**	**4,139,905**

Source(s):

Workpaper JMC - 6 Plant-Reserve

EXHIBIT P-3
SCHEDULE JMC-6

NEW JERSEY NATURAL GAS COMPANY

DIRECT ADDITIONS TO PLANT IN-SERVICE
($000)

	Test Year June 30, 2024
Production	$ -
Storage	224
Transmission	7,361
Distribution	287,275
General	132,464
Total Direct Additions	**$ 427,325**

Source(s):

Workpaper JMC - 6 Plant-Reserve

EXHIBIT P-3
SCHEDULE JMC-7

NEW JERSEY NATURAL GAS COMPANY

ACCUMULATED DEPRECIATION OF UTILITY PLANT
($000)

			Test Year June 30, 2024
Beginning Balance @ July 1, 2023		$	(594,095)
Production		$	-
Storage			(1,456)
Transmission			(15,518)
Distribution			(76,272)
General			(16,927)
Total Charge to Depreciation Expense		$	(110,174)
Retirements		$	13,410
Non-Legal ARO			30,946
Total Cost of Removal	42,569		
Cost of Removal	(35,271)		
Excess Cost of Removal - Test Year			7,298
Accretion of ARO			2,968
Net Increase		$	54,622
Ending Balance		$	(649,646)
Annualization of Depreciation		$	(25,611)
Balance - Accumulated Depreciation		**$**	**(675,257)**

Source(s):

Workpaper JMC - 6 Plant-Reserve

EXHIBIT P-3
SCHEDULE JMC-8

NEW JERSEY NATURAL GAS COMPANY

CUSTOMER ADVANCES FOR CONSTRUCTION (a)
($000)

	Test Year June 30, 2024
Extensions/Deposits	$ (2,577)
Total Customer Advances for Construction	**$ (2,577)**

(a) 13-month Average Balance (November 2022 - November 2023)

Source(s):

Workpaper JMC - 7 Balance Sheet

EXHIBIT P-3
SCHEDULE JMC-9

NEW JERSEY NATURAL GAS COMPANY

WORKING CAPITAL - GAS INVENTORY AND MATERIALS & SUPPLIES
($000)

	Test Year June 30, 2024
Gas Supply and LNG Inventory (a)	$ 107,678
Materials and Supplies (b)	20,936
Total Materials and Supplies	**$ 128,614**

(a) 13-month Average Balance (June 2023 - June 2024)
(b) 13-month Average Balance (November 2022 - November 2023)

Source(s):

Workpaper	JMC - 8	Inventory
Workpaper	JMC - 7	Balance Sheet

EXHIBIT P-3
SCHEDULE JMC-10

NEW JERSEY NATURAL GAS COMPANY

WORKING CAPITAL - PREPAYMENTS
($000)

	Test Year June 30, 2024
Meter Lease (a)	$ 511
Delta Dental (a)	32
Real Estate Taxes (a)	147
Computer Lease (a)	202
Insurance (a)	2,789
Postage (a)	179
BPU & Rate Counsel Assessment	1,044
Uniform Transitional Utility Assessment (a)	10,701
Total Prepayments	$ 15,604

(a) 13-month Average Balance (November 2022 - November 2023)

Source(s):

Workpaper JMC - 7 Balance Sheet

EXHIBIT P-3
SCHEDULE JMC-11

NEW JERSEY NATURAL GAS COMPANY

ACCUMULATED DEFERRED INCOME TAXES
($000)

	Balance at June 30, 2024
Depreciation	$ (215,117)
Cost of Removal	78,097
Repairs and Maintenance	(46,545)
Section 174 - R&D	1,495
Capitalized Interest	806
Contribution-in-Aid-of-Construction	765
NJ Corporate Business Tax	(67,116)
Depreciation Study	7,199
Total Accumulated Deferred Income Taxes	$ (240,415)

Source(s):

Workpaper JMC - 9 DFIT

EXHIBIT P-3
SCHEDULE JMC-12

NEW JERSEY NATURAL GAS COMPANY

INCOME STATEMENT
($000)

	Test Year June 30, 2024
Operating Revenues	1,105,827
Operating Expenses:	
Operation Expense	715,957
Maintenance Expense	23,017
Depreciation Expense	108,727
Taxes Other Than Income Taxes	69,150
Income Taxes - Current & Deferred	24,495
Total Utility Operating Expenses	941,347
Utility Operating Income	$164,480

Source(s):

Workpaper JMC - 10 FERC Income Statement

EXHIBIT P-3
SCHEDULE JMC-13

NEW JERSEY NATURAL GAS COMPANY

PRO-FORMA DISTRIBUTION OPERATING INCOME
($000)

				Test Year June 30, 2024
Test Year Distribution Operating Income			**$**	**164,480**
Adjustment #	**Pro-Forma Adjustments:**	Schedule #		
1	Wages	JMC - 14	$	(4,689)
2	Payroll Taxes	JMC - 15	$	(359)
3	Interest Synchronization (Tax Savings)	JMC - 16	$	195
4	Medical & Fringe Benefits	JMC - 17	$	(2,569)
5	BPU/Rate Counsel Assessments	JMC - 18	$	(360)
6	BGSS Incentive Margin	JMC - 19	$	(7,752)
7	Rate Case - Outside Services	JMC - 20	$	(196)
8	Depreciation Annualization	JMC - 21	$	(36,823)
9	SAVEGREEN	JMC - 22	$	(8,018)
10	Real Estate Taxes	JMC - 23	$	(34)
11	Insurance	JMC - 24	$	(757)
12	Annual Review of Commercial Customers	JMC - 25	$	(696)
13	Revenue Adjustments	JMC - 26	$	(4,371)
14	Regulatory Assets	JMC - 27	$	(2,084)
15	Transportation Safety Administration	JMC - 28	$	(320)
	Total Pro-Forma Adjustments		$	(68,832)
Total Pro-Forma Distribution Operating Income			**$**	**95,648**

EXHIBIT P-3
SCHEDULE JMC-14

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 1
Wages
($000)

		Test Year June 30, 2024
NJNG:		
2024 Annualization	$	2,256
2025 Wage Increase		4,267
Operating Expense Increase before Taxes	$	6,523
Income Taxes @ 28.11%		1,833
Operating Income Increase (Decrease) After Taxes	$	(4,689)

Source(s):

Workpaper JMC - 11 Wages

EXHIBIT P-3
SCHEDULE JMC-15

NEW JERSEY NATURALGAS COMPANY

Adjustment No. 2
Payroll Taxes
($000)

	Test Year June 30, 2024
NJNG:	
2024 Annualization	$ 173
2025 Wage Increase	326
Operating Expense Increase before Taxes	$ 499
Income Taxes @ 28.11%	140
Operating Income Increase (Decrease) After Taxes	$ (359)

EXHIBIT P-3
SCHEDULE JMC-16

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 3
Interest Synchronization (Tax Savings)
($000)

Rate Base				$ 3,358,691
	Percent	**Embedded Cost**	**Weighted Cost**	
Debt Components:				
Long Term Debt	44.58%	4.03%	1.80%	
Total Weighted Cost of Debt				1.80%
Annualized Interest Expense				$ 60,389
Less: Test Period Interest Expense				59,695
Net Interest Expense Increase/Decrease				$ 694
Income Tax Rate				28.11%
Operating Income Increase (Decrease) After Taxes				$ 195

Source(s):

Workpaper JMC - 10 FERC Income Statement

EXHIBIT P-3
SCHEDULE JMC-17

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 4
Medical and Fringe Benefits
($000)

Fiscal Year 2025	Medical, net of employee contributions			15,822
	Dental, net of employee contributions			697
	Fringe Transfer			(6,607)
		FY 2025 Total	$	9,912
Less:				
Test Year	Medical, net of employee contributions			11,933
	Dental, net of employee contributions			828
	Fringe Transfer			(6,421)
		Total	$	6,339
Increase in Test Year Operating Expenses			$	3,573
Income Taxes @ 28.11%				1,004
Operating Income Increase (Decrease) After Taxes			$	(2,569)

Source(s):

Workpaper JMC - 12 Medical & Fringe

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 5
BPU/Rate Counsel Assessment
($000)

	BPU	Rate Counsel	Total
Year 2022 Intrastate Revenues	$ 951,501	$ 951,501	
Assessment Rate (2023 Fiscal Year)	0.2130%	0.0502%	
Estimated Assessment	$ 2,027	$ 478	$ 2,505
Less: Assessment Included in Test Year Operating Expenses	1,601	402	$ 2,004
Operating Expense Increase Before Taxes	$ 426	$ 76	$ 501
Income Taxes @ 28.11%	120	21	141
Operating Income Increase (Decrease) After Taxes	$ (306)	$ (54)	$ (360)

Source(s):
Workpaper JMC - 13 Assessment

EXHIBIT P-3
SCHEDULE JMC-19

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 6
BGSS Incentive Margin
($000)

	Test Year June 30, 2024
Net BGSS Incentive Margin	$ 10,783
Income Taxes @ 28.11%	3,031
Operating Income Increase (Decrease) After Taxes	$ (7,752)

Source(s):
Workpaper JMC - 14 BGSS Incentive Margin

EXHIBIT P-3
SCHEDULE JMC-20

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 7
Rate Case - Outside Services
($000)

			Test Year June 30, 2024
Rate Case:			
Outside Counsel	$	719	
Consultants		365	
Miscellaneous		5	
Total Rate Case Expense	$	1,089	
50/50 Sharing	$	545	
Amortization Period		2	
Normalized Rate Case Expense			$ 272
Income Taxes @ 28.11%			77
Operating Income Increase (Decrease) After Taxes			$ (196)

EXHIBIT P-3
SCHEDULE JMC-21

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 8
Annualization of Depreciation
($000)

			Test Year June 30, 2024
Annualization of Depreciation Rate Change			$ 42,275
Annualization of Depreciation at Current Rates	$	117,673	
Test Year Depreciation		108,727	
Difference			$ 8,946
Operating Expense Increase Before Taxes			$ 51,221
Income Taxes @ 28.11%			14,398
Operating Income Increase (Decrease) After Taxes			$ (36,823)

Source(s):

Workpaper	JMC - 15	Depreciation Expense
Workpaper	JMC - 10	FERC Income Statement

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 9
SAVEGREEN
($000)

	Test Year June 30, 2024
SAVEGREEN Margin	$ 11,153
Operating Expense Increase Before Taxes	$ 11,153
Income Taxes @ 28.11%	3,135
Operating Income Increase (Decrease) After Taxes	$ (8,018)

Source(s):

Workpaper JMC - 16 SAVEGREEN Margin

EXHIBIT P-3
SCHEDULE JMC-23

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 10
Real Estate Taxes
($000)

		Test Year June 30, 2024
Property Taxes	$	731
Test Year Property Taxes		683
Operating Expense Increase Before Taxes	$	48
Income Taxes @ 28.11%		13
Operating Income Increase (Decrease) After Taxes	$	(34)

Source(s):

Workpaper JMC - 17 Real Estate Taxes

EXHIBIT P-3
SCHEDULE JMC-24

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 11
Insurance
($000)

		Test Year June 30, 2024
Insurance Premium Expense	$	9,217
Test Year Insurance Premium Expense		8,164
Operating Expense Increase Before Taxes	$	1,053
Income Taxes @ 28.11%		296
Operating Income Increase (Decrease) After Taxes	$	(757)

Source(s):

Workpaper JMC - 18 Insurance

EXHIBIT P-3
SCHEDULE JMC-25

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 12
Annual Review of Commercial Customer Usage
($000)

		Test Year June 30, 2024
Class Change		1,019
HMAD		(51)
Operating Income Decrease Before Taxes	$	968
Income Taxes @ 28.11%		272
Operating Income Increase (Decrease) After Taxes	$	(696)

Source(s):
Workpaper JMC - 19 Annual Review

EXHIBIT P-3
SCHEDULE JMC-26

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 13
Revenue
($000)

	Test Year June 30, 2024
IIP	$ (245)
CIP Impact	5,166
Billing Cycles	(552)
Nestle	1,711
Operating Expense Increase Before Taxes	$ 6,080
Income Taxes @ 28.11%	1,709
Operating Income Increase (Decrease) After Taxes	$ (4,371)

Source(s):

Workpaper	JMC - 20	IIP
Workpaper	JMC - 21	CIP
Workpaper	JMC - 22	Billing Cycle
Workpaper	JMC - 23	Nestle

EXHIBIT P-3
SCHEDULE JMC-27

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 14
Regulatory Assets
($000)

Regulatory Assets		
COVID Arrearages	$	3,889
Management Audit		1,750
Benchmarking Study		158
Total Rate Case Expense		

Amortization Period 2

Normalized Expense

Income Taxes @ 28.11%

Operating Income Increase (Decrease) After Taxes

Source(s):

Workpaper JMC - 7 Balance Sheet

EXHIBIT P-3
SCHEDULE JMC-28

NEW JERSEY NATURAL GAS COMPANY

Adjustment No. 15
Transportation Safety Administration - Capital
($000)

				Amount
Capital Expenditure				
Transportation Safety Administration			$	3,288
Deferred Taxes [1]				(8)
Total			$	3,280
Rate of Return, Net of Tax				7.07%
Return on Capital Investment			$	232
Depreciation on Capital				
Transportation Safety Administration	3.74%	$ 123		
Total Depreciation		$ 123		
Total Net Expense Impact Before Tax		$ 123		
Income Taxes @ 28.11%		35		88
Operating Expense Increase After Taxes			$	320
Revenue Factor				1.4027
Revenue Requirement			**$**	**449**

(1) Deferred Taxes:

	Federal	State	Total
Tax Depreciation Basis	3,025	3,025	
MACRS Rate	5.00%	5.00%	
Tax Depreciation	151	151	
Book Depreciation Basis	3,288	3,288	
Book Rate	3.74%	3.74%	
Book Depreciation	123	123	
Difference	(28)	(28)	
Tax Rate	19.11%	9.00%	
	(5)	(3)	**(8)**

Exhibit P-4

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY OF ANGELA M. CAHILL CONTROLLER – REGULATED SERVICES

I. INTRODUCTION & BACKGROUND

Q. Please state your name, affiliation and business address.

A. My name is Angela M. Cahill and I am the Controller – Regulated Services for NJR Service Company ("NJRSC" or "Service Company"). My business address is 1415 Wyckoff Road, Wall, New Jersey 07719.

Q. Please describe your education and experience.

A. I received a Bachelor of Science degree in Accounting from Rowan University and hold the designation of Certified Public Accountant from the State of New Jersey. I was employed by American Water beginning in June 1994 as a Staff Accountant and over a 20-year career moved into various positions of increased responsibility. In February 2015, I accepted a Manager Regulatory Accounting and Reporting position at Public Service Electric and Gas Company, with responsibilities that included providing accounting support for rate proceedings, responding to interrogatories related to accounting information, and the oversight and coordination for the annual and quarterly regulatory filings with federal and state agencies.

I joined the NJRSC in October 2017 as Controller – Regulated Services, and in that role my responsibilities include leading the accounting and reporting requirements for New Jersey Natural Gas Company ("NJNG" or "Company"). I also participate on behalf of NJNG on the New Jersey Resources financial reporting committee.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I submitted direct testimony before the New Jersey Board of Public Utilities ("BPU") in NJNG's recent base rate cases (BPU Docket Nos. GR19030420 & GR21030679).

Q. Please summarize the purpose of your Direct Testimony.

A. The purpose of my Direct Testimony is to provide an analysis of the historical balance sheets and income statements that are being provided in accordance with the requirements of N.J.A.C. 14:1-5.12. Specifically, I am sponsoring the following schedules, which were prepared by my or under my direct supervision and control:

• Schedule AMC-1	Balance Sheets as of December 31, 2021, 2022 and September 30, 2023
• Schedule AMC–2	Statements of Income for the Years Ended December 31, 2021, 2022 and for the Fiscal Year Ended September 30, 2023
• Schedule AMC–3	Statement of Gas Operating Revenues for the Years Ended December 31, 2021, 2022 and for the Fiscal Year Ended September 30, 2023
• Schedule AMC–4	Allocations to Affiliates during the Years Ended December 31, 2021, 2022 and Fiscal Year End September 30, 2023
• Schedule AMC-5	Test Year Income Statement
• Schedule AMC-6	Distribution Sales by Class of Business
• Schedule AMC-7	Customers Billed by Class of Business
• Schedule AMC-8	Operating Expenses for the Years Ending December 31, 2021, 2022 and Fiscal Year End September 30, 2023

• Schedule AMC-9	Test Year Customer Accounts and Information
• Schedule AMC-10	Administrative and General Salaries and Expenses
• Schedule AMC-11	Test Year Depreciation
• Schedule AMC-12	Test Year Taxes Other Than Income Taxes
• Schedule AMC-13	Test Year Current and Deferred Income Taxes
• Schedule AMC-14	Statements for the 12-month period ending June 30, 2024 on an estimated basis as follows:

Income Account

Revenue by Class of Business

Operating Expenses

Adjustments – Present Rates

Pro Forma Operating Income – Proposed Rates

Operating Income, Year-End Rate Base and Rate of Return – Present and Proposed Rates

Net Investment Rate Base at Test Year End

Operating Income, Average Rate Base During the Test Year, and Rate of Return – Present and Proposed Rates

Average Net Investment Rate Base

Q. Please describe the Service Company and its role in providing service to NJNG.

A. The Service Company provides shared administrative services to NJNG. These services include, but are not limited to: financial, shared facilities, information technology, human resources, office services, security, communications, legal and internal auditing. The Service Company allocates its costs to the affiliate benefiting from the work performed. These costs are either direct charged to affiliates or charged to intermediate expense pools that are then charged to users of these services based on cost drivers. The type of cost driver assigned to each expense pool will best match the benefit of the receiving affiliate and will include time sheets, square footage, equipment usage, headcount, etc. Timesheets are submitted monthly, whereas all other cost drivers are updated annually or during a major organizational change. No costs are retained at the Service Company.

Q. Please describe the operating income level at current rates.

A. Schedules AMC-5 through AMC-14 represent the financial information details of NJNG's operations. Schedule AMC-5 presents NJNG's income statement for the test year ended June 30, 2024. The remaining schedules (AMC-6 through AMC-14) contain operating revenues, sales, and customer levels by class of service for the Company. Also included are gas supply expenses, operations and maintenance ("O&M") expenses by primary function, administrative and general salaries and expenses, depreciation and amortization, taxes other than income taxes, and current and deferred operating income taxes for the test year.

II. CONCLUSION

Q. Please summarize your Direct Testimony.

A. NJNG last filed a base rate case in March 2021. Since then, NJNG's employees and management have worked hard continuing to provide safe and reliable service to its growing customer base at reasonable rates. However, NJNG now has reached the point where current base rates do not appropriately reflect its cost of operations or the level of capital investments required to serve customers. Stated simply, the Company's current rates are unjust and unreasonable and must be updated.

As further discussed in detail in other witnesses' testimonies, NJNG has consistently made efforts in all areas of its operations to provide service to customers in the most efficient and cost-effective way possible. In this proceeding, NJNG has proposed base rates that are just and reasonable in terms of providing the Company with the resources to continue to provide safe and reliable cost-based service to customers, while also affording NJNG a reasonable opportunity to earn a fair rate of return. As demonstrated by the testimonies of NJNG's witnesses in this proceeding, an increase in base rates is required at this time and in the best interest of NJNG and its customers.

Q. Does this conclude your Direct Testimony at this time?

A. Yes. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

NEW JERSEY NATURAL GAS COMPANY

BALANCE SHEET

	September 30, 2023	December 31, 2022	December 31, 2021
Utility Plant			
Gas Utility Plant			
Gas Utility Plant in Service	3,842,537	3,626,864	3,397,440
Gas Construction Work in Progress	225,729	173,588	149,460
Total Gas Utility Plant	4,068,266	3,800,452	3,546,900
Accumulated Depreciation & Amortization	(569,926)	(570,274)	(523,774)
Net Utility Plant	3,498,340	3,230,178	3,023,126
Other Property and Investments			
Nonutility Plant	500	500	500
Accumulated Depreciation & Amortization	(34)	(25)	(13)
Net Nonutility Plant	466	475	487
Current and Accrued Assets			
Cash and Temporary Investments	1,346	1,554	2,447
Customer Accounts Receivable	109,652	200,676	151,394
Unbilled Revenue	10,784	106,581	71,542
Accumulated Provision for Uncollectible Accounts (credit)	(7,602)	(7,901)	(17,048)
Materials and Supplies, at average cost	22,398	16,401	14,730
Gas in Storage, at average cost	175,026	152,010	110,673
Prepayments	8,521	46,105	25,997
Derivatives, at fair market	6,153	5,603	5,266
Interest and Dividends Receivable	14	-	35
Total Current and Accrued Assets	326,292	521,029	365,036
Deferred Debits			
Regulatory Assets	488,352	423,217	441,777
Other	49,238	18,963	30,860
Total Deferred Debits	537,590	442,180	472,637
Total Assets and Other Debits	4,362,688	4,193,862	3,861,286
Capitalization			
Common Stock Equity	1,814,836	1,663,086	1,469,378
Long-Term Debt	1,467,845	1,417,845	1,192,845
Total Capitalization	3,282,681	3,080,931	2,662,223
Current Liabilities			
Current Maturities of Long Term Debt			
Short Term Debt	34,800	111,800	177,400
Gas Purchases Payable			-
Accounts Payable and Other	98,424	106,544	119,148
Accrued Taxes	(39,409)	(10,775)	(16,605)
Derivatives, at fair value	(4,736)	2,818	2,340
Customers' Credit Balances and Deposits	14,989	14,566	14,034
Miscellaneous Current Liabilities	58,143	40,939	42,323
Total Current Liabilities	162,211	265,892	338,640
Noncurrent Liabilities			
Deferred Income Taxes	440,918	406,275	378,551
Deferred Investment Tax Credits	1,783	1,911	2,115
Manufactured Gas Plant Remediation	169,390	125,718	126,872
Capital Leases	22,937	28,319	28,801
Postretirement Employee Benefit Liability	46,675	49,716	91,880
Tax Act Impact	180,347	184,112	189,131
Other Deferred Credits	461	803	1,290
Asset Retirement Obligation	55,285	50,185	41,783
Other			
Total Noncurrent Liabilities	917,796	847,039	860,423
Total Capitalization and Liabilities	$4,362,688	$4,193,862	$3,861,286

NEW JERSEY NATURAL GAS COMPANY

INCOME ACCOUNT

	12 Months Ended September 30, 2023	12 Months Ended December 31,2022	12 Months Ended December 31,2021
Operating Revenues	$ 1,067,614	$ 1,270,213	$ 856,392
Gas Operating Expenses:			
Gas Purchases	424,632	616,768	325,881
Operation and Maintenance Expense	268,399	265,019	237,956
Depreciation and Amortization	102,244	96,515	83,769
Operating Income Taxes	32,614	41,288	23,891
Energy and Other Taxes	61,484	64,179	50,572
Total Operating Expenses	889,373	1,083,769	722,069
Operating Income	178,241	186,444	134,323
Other Income	8,792	6,121	13,940
Other Income Deductions	119	(251)	267
Other Income Taxes	-	-	-
Income Before Income Taxes	8,673	6,372	13,673
Interest Charges, net	56,595	49,108	39,008
Net Income	$ 130,319	$ 143,708	$ 108,988

NEW JERSEY NATURAL GAS COMPANY

OPERATING REVENUES

	12 Months Ended September 30, 2023	12 Months Ended December 31, 2022	12 Months Ended December 31, 2021
Sales of Gas			
Residential Sales	$ 669,061	$ 702,856	$ 542,001
Commercial and Industrial Sales	129,792	145,198	106,943
Other Sales to Public Authorities	3	3	3
Reveune Transport Gas of Others	$ 91,723	$ 100,030	$ 84,884
Provision For Rate Refunds	27,257	(2,860)	1,804
Total Sales to Customers	$ 917,836	$ 945,227	$ 735,635
Other Gas Revenues			
Forfeited Discounts	627	78	(1)
Miscellaneous Service Revenues	1,679	1,380	1,046
Rent from Gas Property	-	-	276
Other Gas Revenues	147,472	323,528	119,436
Total Other Gas Revenues	149,778	324,986	120,757
Total Gas Operating Revenues	$ 1,067,614	$ 1,270,213	$ 856,392

NEW JERSEY NATURAL GAS COMPANY

TOTAL ALLOCATIONS TO NJR AFFILIATES
(Thousands)

	Twelve Months Ended September 30, 2023	Calendar Year End December 2022	December 2021
NJR Service Company to NJNG	$ 50,598	$ 48,427	$ 48,392
NJR Service Company to NJR Energy Services, Including NJNG to NJR Energy Services	3,968	4,640	5,300
NJR Service Company to NJR Home Services, Including NJNG to Home Services	6,616	6,203	6,892
NJR Service Company to NJR CR&R, Including NJNG to CR&R	131	106	53
NJR Service Company to Midstream Including NJNG to Midstream	4,914	4,437	3,766
NJR Service Company to NJRCEV Including NJNG to NJRCEV	5,847	4,805	5,163
NJR Service Company to NJR Retail Company Including NJNG to NJR Retail	214	205	34
Total Payments to Affiliates	$ 72,288	$ 68,823	$ 69,600

NEW JERSEY NATURAL GAS COMPANY

INCOME STATEMENT
($000)

	Test Year June 30, 2024
Operating Revenues	1,105,827
Operating Expenses:	
Operation Expense	715,957
Maintenance Expense	23,017
Depreciation Expense	108,727
Taxes Other Than Income Taxes	69,150
Income Taxes - Current & Deferred	24,495
Total Utility Operating Expenses	$941,347
Utility Operating Income	$164,480

NEW JERSEY NATURAL GAS COMPANY

DISTRIBUTION SALES BY CLASS OF BUSINESS
(Therms - 000)

	Test Year June 30, 2024
Residential:	
Residential Service	500,943
Transportation	13,563
Commercial:	
Commercial Service	99,231
Transportation	111,973
Industrial:	
Interruptible	-
Transportation	14,559
Street and Yard Light Service	3
Off-System Sales and Other	1,577,024
Total Distribution Sales By Class Of Business	2,317,296

NEW JERSEY NATURAL GAS COMPANY

CUSTOMERS BILLED BY CLASS OF BUSINESS

	Test Year June 30, 2024
Residential:	
Residential Service	527,961
Transportation	15,070
Commercial:	
Commercial Service	32,320
Transportation	8,009
Industrial:	
Interruptible	-
Transportation	25
Street and Yard Light Service	2
Off-System Sales and Other	75
Total Customers Billed By Class Of Business	583,461

NEW JERSEY NATURAL GAS COMPANY

OPERATING EXPENSES

		12 Months Ended	12 Months Ended	12 Months Ended
Operation		September 30, 2023	December 31, 2022	December 31, 2021
Gas Supply Expenses				
7290	G-Fuel Gas-Raw materials for other gas processes			
8030	Nat Gas Transmission Line Purc	425,490,231	617,511,529	326,448,390
8040	G-Op Oth-Natural gas city gate purchases	4,000	-	4,000
8050	G-Op Oth-Other gas purchases			
8051	Purchase Gas Cost Adjustments	-	-	-
8074	Purchase Gas Calculations Exp	392	448	1,926
8083	Gas Withdrawn from Storage			
8085	Gas Withdrawn from Storage			
8120	Gas Used for Utility Operation	(878,948)	(780,328)	(617,703)
8130	G-Op Oth-Other gas supply expenses	16,927	35,913	44,101
Gas Supply Expenses Total		**424,632,602**	**616,767,562**	**325,880,714**
Production Expenses				
7350	Misc Production Expense	11,223,798	-	9,876,013
7100	Operation Supervision/Engineer	-	-	274
Production Expenses Total		**11,223,798**	**-**	**9,876,287**
Other Storage Expenses				
8400	Operation Supervision/Engineer	222,330	250,723	274,608
8421	Fuel			
8422	Power	344,290	314,427	337,874
8410	G-Op Str Exp-Operation labor and expenses	458,873	443,427	454,322
Other Storage Expenses Total		**1,025,493**	**1,008,577**	**1,066,804**
Other Power Generation				
7170	G-Exp Gas-Liquefied petroleum gas expenses	-	-	-
Other Power Generation Total		**-**	**-**	**-**
Distribution Expenses				
8700	G-Mnt Trans-Operation supervision and engineering	2,205,865	2,158,307	2,131,225
8710	G-Op Dist-Distribution load dispatching	3,384,465	3,284,867	3,537,523
8740	G-Op Dist-Mains and services	6,501,350	6,574,452	7,342,998
8750	G-Op Dist-Measuring and reg station exp-general	1,011,816	599,211	471,550
8760	G-Op Dist-Measuring and reg station exp-industrial	180,779	170,704	186,774
8770	G-Op Dist-Measur & reg stat exp-city gate chk stat			
8780	G-Op Dist-Meter and house regulator expenses	2,169,092	2,093,252	1,832,174
8790	G-Op Dist-Customer installations expenses	13,621,133	12,304,793	11,863,749
8800	G-Op Dist-Other expenses	16,120,356	14,134,315	13,275,415
8801	G-Op Dist-Miscellaneous distribution expenses			
8802	G-All Other Misc Operational Expense			
8810	G-All Rents	-	-	660
Distribution Expenses Total		**45,194,856**	**41,319,901**	**40,642,068**
Transmission Expenses				
8500	Meas/Reg Station Expense	245,476	302,941	280,911
8510	G-Op Trans-Mains expenses	1,824,248	1,519,515	1,098,408
8520	Communication System Expenses - Transmission	-	-	-
8570	Meas/Reg Station Expense	2,109,982	1,903,743	1,765,645
8590	Other Expenses	135,242	167,253	122,731
8560	G-Op Trans-Mains expenses	4,653,436	3,960,315	4,027,283
Transmission Expenses Total		**8,968,384**	**7,853,767**	**7,294,978**
Customer Accounts Expenses				
9010	Supervision	961,393	804,113	759,842
9020	G-Op Cust Acct-Meter Reading Expenses	6,046,345	5,635,032	6,589,861
9030	G-Op Cust Acct-Cust records and collection expense	20,959,681.00	17,849,360.00	15,563,462.00
9040	G-Op Cust Acct-Uncollectible accounts	3,699,728	1,801,000	(1,206,407)
9050	G-Op Cust Acct-Misc customer accounts expenses	3,422,462	2,943,079	3,057,670
Customer Accounts Expenses Total		**35,089,609**	**29,032,584**	**24,764,428**
Customer Service and Informational Expenses				
9080	G-Op Cust Inf-Customer assistance expenses	39,379,127	49,706,588	34,757,265
9090	Informational/Instruction Exp	706,974	559,195	304,770
9100	G-Op Cust Inf-Misc cust service and info expenses			
Customer Service & Informational Exp Totals		**40,086,101**	**50,265,783**	**35,062,035**
Sales Expense				
9110	Supervision	333,459	259,555	522,590
9120	G-DEMONSTRATION AND SELLING EXPENSE	3,720,415	3,075,799	3,231,377
9130	G-ADVERTISING EXPENSE	203,677	137,558	94,111
9140	Economic Development			
9160	G-MISCELLANEOUS SALES EXPENSE	17,200	21,746	44,420
Sales Expense Total		**4,274,751**	**3,494,658**	**3,892,498**

		12 Months Ended	12 Months Ended	12 Months Ended
Administrative and General Expenses		September 30, 2023	December 31, 2022	December 31, 2021
9200	G-Op AG-Administrative and general salaries	7,662,892	7,190,054	4,158,641
9210	G-Op AG-Office supplies and expenses	2,030,214	1,946,837	1,997,806
9220	G-Op AG-Adminstrative Exp Transferr-Cr			
9230	G-Op AG-Outside services employed	59,404,830	55,677,330	50,548,687
9240	G-Op AG-Property insurance	430,509	376,920	282,587
9250	G-Op AG-Injuries and damages	7,002,136	6,416,570	5,443,976
9260	G-Op AG-Employee pensions and benefits	16,272,807	20,432,289	23,303,344
9280	G-Op AG-Regulatory commission expenses	4,977,491	5,372,572	6,184,399
9290	G-Op AG-Duplicate charges - credit			
9300	G-Op AG-General publicity			
9301	G-Op AG-General advertising expenses	99,645	86,607	94,034
9302	G-Op AG-Miscellaneous general expenses	4,467,183	2,629,565	4,146,738
9310	G-Op AG-Rents	111,181	117,764	53,685
Administrative and General Expenses Total		**102,458,888**	**100,246,508**	**96,213,897**
Operation Total		***672,954,482***	***849,989,340***	***544,693,709***
Maintenance				
Manufactured Gas Production				
7400	Mainten Supervision/Engineer	-	-	-
7410	G-Mnt Gas-Maint of structures and improvements			
7420	G-Mnt Gas-Maintenance of production equipment			
Manufactured Gas Production Totals		**-**	**-**	**-**
Other Storage Expense				
8432	G-Op Str Exp-Maint of structures and improvements	7,911	772,980	174,880
8433	G-Op Str Exp-Maintenance of gas holders	(5,622)	1,139,381	111,362
8436	G-Op Str Exp-Maintenance of vaporizing equipment	124,378	262,664	198,021
8437	G-Op Str Exp-Maintenance of compressor equipment	260,796	249,590	268,593
8439	Maintenance of Other Equipment	1,668,020	1,379,274	1,194,665
8438	G-Op Str Exp-Maint of measuring and reg equipment	93,872	35,997	60,386
Other Storage Expenses Total		**2,149,355**	**3,839,886**	**2,007,907**
Liquefied Natural Gas Terminaling and Processing Expenses				
8443	Liquefaction Processing Labor and Expenses	36,780	29,451	18,157
844.7	Communication System Expense	1,130	1,109	186
8451	Fuel	20	33	13
8462	Other Expenses	45,298	12,254	9,943
Liquefied Natural Gas Terminaling and Processing Exp Totals		**83,228**	**42,847**	**28,299**
Distribution Expenses				
8850	G-Mnt Dist-Maintenance supervision and engineering	2,075,162	1,864,363	1,652,887
8860	G-Mnt Dist-Maint of structures and improvements	416,497	434,500	293,150
8870	G-Mnt Dist-Maintenance of mains	5,650,809	5,128,294	6,100,117
8890	G-Mnt Dist-Maint of measuring & reg stat equip-gen	2,161,621	2,484,260	1,349,063
8900	G-Mnt Dist-Maint of measuring & reg stat equip-ind	57,324	45,784	53,454
8910	G-Mnt Dist-Maint of measuring/reg stat equip-cgcs			
8920	G-Mnt Dist-Maintenance of services	4,313,422	3,817,956	4,742,546
8930	G-Mnt Dist-Maint of meters and house regulators	1,499,471	1,393,492	1,441,011
8940	G-Mnt Dist-Maintenance of other equipment			
8941	G-Streetlight Maintenance Expense			
Distribution Expenses Total		**16,174,306**	**15,168,649**	**15,632,228**
Transmission Expenses				
8620	Mainten Sturcture/Improvements	7,793	5,013	5,645
8650	Mainten Measur/Reg Station Equ	807,580	452,079	739,956
8630	G-Mnt Trans-Maintenance of mains	854,700	912,256	729,460
Transmission Expenses Total		**1,670,073**	**1,369,348**	**1,475,061**
Administrative & General Expenses				
9320	G-Mnt AG-Operating expenses			
Administrative & General Expenses Total				
Maintenance Total		***20,076,962***	***20,420,730***	***19,143,495***
Depreciation & Amortization				
4030	G-Depreciation expense	102,244,182	96,515,527	83,768,637
4040	G-Amortization of limited-term plant			
4071	G-Amort prop loss, unrecov plt and reg study costs			
Depreciation & Amortization Total		***102,244,182***	***96,515,527***	***83,768,637***
Taxes				
IncomeTaxes				
4091	G-Income taxes, utility operating income	1,304,191	19,913,793	(8,328,133)
4101	G-Provision for defer inc tax, util op income	31,587,704	21,662,769	32,539,242
4111	G-Provision for defer inc tax-credit, util op inc	-	-	-
4114	G-Investment tax credit adj, utility operations	(278,279)	(289,135)	(321,703)
IncomeTaxes Total		**32,613,616**	**41,287,427**	**23,889,406**
Taxes Other than Income Taxes				
4081	G-Taxes other than income taxes, util op income	61,483,799	64,179,399	50,572,167
Taxes Other than Income Taxes Total		**61,483,799**	**64,179,399**	**50,572,167**
Taxes Total		***94,097,415***	***105,466,826***	***74,461,573***
Operating Expenses Total		***889,373,041***	***1,072,392,423***	***722,067,414***
Operating Income		***178,241,049***	***186,444,018***	***134,323,139***

		12 Months Ended	12 Months Ended	12 Months Ended
Other Income & Deductions		September 30, 2023	December 31, 2022	December 31, 2021
Other Income				
4150	G-Rev from merchandising,jobbing and contract work			
4160	G-Expenses of merchandising, jobbing and cont work			
4170	Revnue Nonutility Operations	1,802,552	1,130,471	458,408
4180	G-Nonoperating rental income			
4190	Gas-Interest and Dividend Income	(342,821)	4,181	319,742
4191	Allow Other Funds Used Constru	7,232,437	4,933,965	12,445,102
4210	G-Miscellaneous nonoperating income	100,022	52,335	717,465
4211	G-Gain on disposition of property			
Other Income Total		**8,792,190**	**6,120,952**	**13,940,717**
Other Income Deductions				
4261	G-Donations	77,762	75,285	44,996
4263	G-Penalties			70,625
4264	G-Exp for civic, political and related activities	-	1,654	24,000
4265	G-Other deductions	41,389	(327,815)	127,203
Other Income Deductions Total		**119,151**	**(250,876)**	**266,824**
Taxes Other Income and Deductions				
4082	G-Taxes other than inc taxes, other inc and deduct			
4092	G-Income tax, other income and deductions	-	-	-
4102	G-Provision for defer inc tax,other inc and deduct			
4112	Provision for def. Inc Tax-credit-oth Inc & Dedcts			
Taxes Other Income and Deductions		**-**	**-**	**-**
Other Income & Deductions Total		***8,673,039***	***6,371,828***	***13,673,893***
Interest Charges				
4270	G-Interest on long-term debt	54,534,824	47,037,995	40,365,023
4280	G-Amortization of debt discount and expense	1,237,433	1,113,488	(201,058)
4281	G-Amortization of loss on reacquired debt			
4282	Amort Debt Discount & Expense			
4283	Amort Debt Discount & Expense	712,989	787,207	1,134,724
4310	G-Other interest expense	3,658,930	2,728,801	2,000,753
4320	G-Allow for Borrowed funds used during construction	(3,548,853)	(2,559,604)	(4,291,064)
Interest Charges Total		***56,595,323***	***49,107,887***	***39,008,378***

NEW JERSEY NATURAL GAS COMPANY

CUSTOMER ACCOUNTS AND INFORMATION
($000)

		Test Year June 30, 2024
Customer Accounts Expenses:		
Operation:		
901	Supervision	$ 886
902	Meter Reading Expenses	6,724
903	Customer Records and Collection Expenses	24,751
904	Uncollectible Accounts	2,109
905	Miscellaneous Customer Accounts Expenses	3,571
	Total Customer Accounts Expenses	$ 38,041
Customer Service and Informational Expenses:		
Operation:		
908	Customer Assistance Expenses	$ 51,782
909	Informational/Instruction Exp	727
910	Misc. Customer Service and Informational Expenses	-
	Total Customer Service and Informational Expenses	$ 52,509
Sales Expenses:		
Operation:		
911	Supervision	$ 419
912	Demonstration and Selling Expenses	4,358
913	Advertising Expense	186
914	Economic Development	-
916	Miscellaneous Sales Expenses	2
	Total Sales Expenses	$ 4,966
Total Customer Accounts and Information		$ 95,516

NEW JERSEY NATURAL GAS COMPANY

ADMINISTRATIVE AND GENERAL SALARIES AND EXPENSES
($000)

		Test Year June 30, 2024
Operations:		
920	Salaries & Wages	$ 8,590
921	Supplies & Expenses	2,671
922	Adminstrative Exp Transferr-Cr	-
923	Outside Services	66,236
924	Property Insurance	4,847
925	Injuries and Damages	3,355
926	Pension/Benefits	14,980
928	Regulatory Commission Expenses	4,398
929	Duplicate Charges	-
930	General publicity	-
930.1	General Advertising	182
930.2	Miscellaneous	3,221
931	Rents	160
	Total Operation	$ 108,640
	Maintenance of General Plant	-
	Total Maintenance	$ -
Total Administrative and General Salaries and Expenses		$ 108,640

NEW JERSEY NATURAL GAS COMPANY

DEPRECIATION
($000)

	Test Year June 30, 2024
Depreciation and Amortization:	
403 Depreciation	$ 108,727
Total Depreciation	$ 108,727

NEW JERSEY NATURAL GAS COMPANY

TAXES OTHER THAN INCOME TAXES
($000)

	Test Year June 30, 2024
Real Estate	$ 683
FICA	7,242
State Unemployment	327
Federal Unemployment	3
Municipal and State Taxes	60,896
Total Taxes Other Than Income	$69,150

NEW JERSEY NATURAL GAS COMPANY

CURRENT AND DEFERRED INCOME TAXES
($000)

		Test Year June 30, 2024
Current:		
Federal		$ 14,195
State		7,300
ITC		(304)
	Total Current	$ 21,191
Deferred:		
Deferred		$ 3,304
	Total Deferred	$ 3,304
	Net Income Taxes	24,495

NEW JERSEY NATURAL GAS COMPANY

INCOME ACCOUNT
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Operating Revenues	1,105,827
Operating Expenses	941,347
Operating Income	164,480
Other Income and Deductions:	
Other Income	9,284
Other Deductions	(50)
Taxes on Other Income and Deductions	-
Total	9,234
Income Before Interest Charges	173,714
Interest Charges	(59,695)
Net Income	$114,019

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

REVENUE BY CLASS OF BUSINESS
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Residential-Service	760,754
- Transportation	13,124
Commercial-Service	147,339
- Transportation	82,692
Industrial- Interruptible	-
- Transportation	2,560
Street and Yard Light Service	4
Off-system Sales and Other	142,969
CIP Rider Revenue	(43,616)
Total Natural Gas Service Revenues	1,105,827

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

OPERATING EXPENSES
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Production Expenses:	
Gas Supply Expenses	$440,225
Gas Production	15,842
Manufactured Gas Production	-
Other Storage	5,139
LPG Expense	-
Total Production Expenses	461,206
Transmission:	
Operation	$8,004
Maintenance	$1,699
Total Transmission	9,704
Distribution:	
Operation	$46,832
Maintenance	$17,076
Total Distribution	63,908
Customer Accounts and Information:	
Customer Accounts	$38,041
Customer Service and Informational	$52,509
Total Customer Accounts and Information	90,550
Sales	4,966
Administrative and General:	
Operation	108,640
Total Administrative and General	108,640
Depreciation	108,727
Taxes other than Income Taxes	69,150
Income taxes:	
Current	21,203
Deferred (Net)	3,293
Total Income Taxes	24,495
Total Gas Operating Expenses	$941,347

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

ADJUSTMENTS - INCREASE OR (DECREASE) - PRESENT RATES
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Test Year Distribution Operating Income	**$164,480**
Wages	(6,523)
Federal and State Income Taxes @ 28.11%	1,833
Payroll Taxes	(499)
Federal and State Income Taxes @ 28.11%	140
Interest Synchronization (Tax Savings)	195
Medical and Fringe Benefits	(3,573)
Federal and State Income Taxes @ 28.11%	1,004
BPU/Rate Counsel Assessments	(501)
Federal and State Income Taxes @ 28.11%	141
BGSS Incentive Margin	(10,783)
Federal and State Income Taxes @ 28.11%	3,031
Rate Case - Outside Services	(272)
Federal and State Income Taxes @ 28.11%	77
Depreciation Annualization	(51,221)
Federal and State Income Taxes @ 28.11%	14,398
SAVEGREEN Margin	(11,153)
Federal and State Income Taxes @ 28.11%	3,135
Real Estate Taxes	(48)
Federal and State Income Taxes @ 28.11%	13
Insurance	(1,053)
Federal and State Income Taxes @ 28.11%	296

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

ADJUSTMENTS - INCREASE OR (DECREASE) - PRESENT RATES
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Commercial Customer Usage	(968)
Federal and State Income Taxes @ 28.11%	272
Revenue Adjustments	(6,080)
Federal and State Income Taxes @ 28.11%	1,709
Regulatory Assets	(2,898)
Federal and State Income Taxes @ 28.11%	815
TSA - Capital	(355)
Federal and State Income Taxes @ 28.11%	35
Total Pro-Forma Adjustments	**(68,832)**
Total Pro-Forma Distribution Operating Income	**$95,648**

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

Exhibit P-4
Schedule AMC - 14
Page 6 of 10

PRO FORMA OPERATING INCOME - PROPOSED RATES
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Operating Income Pro Forma - Present Rates	$	95,648
Adjustment:		
1. Net Increase in Revenues Resulting from proposed Rates		222,600
2. Increase in BPU / RC Assessment and Uncollectible Resulting from Increase Revenue		(1,850)
3. Increase in State Income Taxes		(19,868)
4. Increase in Federal Income Taxes		(42,188)
Total Pro Forma Adjustments		158,694
Operating Income Pro Forma - Proposed Rates	$	254,342

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

OPERATING INCOME, YEAR-END RATE BASE AND RATE OF RETURN
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Present Rates	
Operating Income	$ 95,648
Year-End Rate Base	$3,358,691
Rate of Return	2.85%
Proposed Rates	
Operating Income	$ 254,342
Year-End Rate Base	$3,358,691
Rate of Return	7.57%

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

RATE BASE - ESTIMATED
12 MONTHS ENDING JUNE 30, 2024*
(Thousands)

Plant in Service	$4,139,905
Accumulated Depreciation Reserve	($675,257)
Customer Advances	($2,577)
Net Plant	3,462,071
Gas Supply & LNG Inventory	107,678
Working Capital	
Cash (Lead/Lag)	127,341
Materials and Supplies	20,936
Prepayments	15,604
Net Working Capital	163,881
Net Plant and Working Capital	3,733,630
Deferred Taxes	(240,415)
Excess Deferred Tax	(126,901)
Consolidated Tax Adjustment	(7,624)
Total Rate Base	$3,358,691

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

OPERATING INCOME, AVERAGE NET INVESTMENT RATE BASE AND RATE OF RETURN FOR TEST YEAR ENDING JUNE 30, 2024*

PRO FORMA PRESENT AND PROPOSED RATES
(Thousands)

Present rates	
Operating Income	$95,648
Average Net Investment Rate Base	$3,192,096
Rate of Return	3.00%
Proposed Rates	
Operating Income	$ 254,342
Average Net Investment Rate Base	$3,192,096
Rate of Return	7.97%

* 5 Months Actual and 7 Months Estimated

NEW JERSEY NATURAL GAS COMPANY

AVERAGE NET INVESTMENT RATE BASE
AT JUNE 30, 2024
(Thousands)

Plant in Service	$3,940,889
Accumulated Depreciation Reserve	($621,045)
Customer Advances	($2,603)
Net Plant	3,317,240
Gas Supply Inventory	118,091
Working Capital	
Cash (Lead/Lag)	103,806
Materials and Supplies	19,262
Prepayments	15,452
Net Working Capital	138,520
Net Plant and Working Capital	3,573,851
Deferred Taxes	(374,131)
Consolidated Tax Adjustment	(7,624)
Total Rate Base	$3,192,096

Exhibit P-5

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY OF
HAROLD WALKER, III
GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
MANAGER, FINANCIAL STUDIES

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and address.

A. My name is Harold Walker, III. My business address is 1010 Adams Avenue, Audubon, Pennsylvania, 19403.

Q. By whom are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as Manager, Financial Studies.

Q. What is your educational background and employment experience?

A. My educational background, business experience and qualifications are provided at the end of Exhibit P-5 as Appendix A.

II. SCOPE OF DIRECT TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to recommend appropriate "other" working capital allowances that New Jersey Natural Gas Company ("NJNG" or the "Company") should be afforded an opportunity to earn on as part of its rate base claims for their New Jersey Board of Public Utilities ("BPU") jurisdictional operations. My recommendations are based upon the results of a lead-lag study for NJNG's BPU jurisdictional gas distribution service operations.

Q. Have you prepared an exhibit presenting the results of your studies?

A. Yes. I have prepared 25 Schedules identified as Schedule HW-1 through Schedule HW-25 summarizing the Company's other working capital claim in this proceeding, which schedules were prepared by me or under my direct supervision and control.

III. PRINCIPLES OF WORKING CAPITAL

Q. Would you please explain the ratemaking principles concerning the inclusion of working capital as an element of rate base?

A. Yes. The working capital allowance is a component of rate base. A utility's need for working capital was first recognized in the noted Supreme Court case, *Smyth v. Ames*.[1] Among the many benchmarks established in the case was the "property devoted to public use" doctrine as a basis for fixing rates. The case recognized that among the matters to be considered in determining the value of property used was "the sum required to meet operating expenses."[2] Since that time working capital has generally been recognized as a proper item to be included in the rate base on which a utility is entitled to earn a return.

The rationale for the inclusion of working capital in rate base is to compensate investors for the use of that amount of their funds over and above their investment in plant. Working capital bridges the gap between the time funds are provided by investors to provide service to the customer and the time the revenue requirement is received from those customers as reimbursement for these services.

IV. SUMMARY OF OTHER WORKING CAPITAL CLAIM

Q. What are the components of the Company's working capital claim?

A. NJNG's working capital claim is comprised of materials and supplies, prepayments and "other." My testimony presents the "other" component of the Company's

[1] *Smyth v. Ames*, 169 U.S. 466 (1898), overruled on other grounds by *Fed Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 586 (1942). Specifically, *Fed. Power Comm'n* departed from the holding in *Smyth* that fair market value in cost of service ratemaking must be used and instead concluded that "[t]he Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas."

[2] *Id*. at 547.

working capital claim. The materials and supplies and prepayments elements of NJNG's working capital claim are included in the Direct Testimony of James M. Corcoran. I calculated the "other" component of the Company's working capital through a Lead-Lag Study and a Net Assets and Liabilities Analysis. A summary of NJNG's other working capital requirements is shown on Schedule HW-1.

As shown on Schedule HW-1, the amount of working capital required to finance the recovery of the cost of service is $112,523,000 ($112,522,940 rounded) for NJNG. The amount of working capital required to finance the recovery of the cost of service was developed through a Lead-Lag Study, which is summarized on page 1 Schedule HW-2.

The amount of working capital required to finance the net difference between certain assets and particular liabilities is $14,818,000 ($14,817,746 rounded) for NJNG, shown on Schedule HW-1. The amount of working capital required to finance the net difference between certain assets and particular liabilities was developed through a Net Assets and Liabilities Analysis, which is summarized on Schedule HW-25.

In total, NJNG's other cash working capital requirements are $127,341,000 as shown on Schedule HW-1.

V. EXPLAINING A LEAD-LAG STUDY

Q. What does a lead-lag study measure and how is it measured?

A. The lead-lag study in this testimony measures the level of funding required to operate on a day-to-day basis in providing for the cost of service. This is measured by calculating the net lag between the amount of time elapsed between when a company

provides a service to its customers and when the company receives payments from its customers, and the amount of time elapsed between when a company receives goods and services and when the company pays its suppliers for those goods and services. The difference between these two elapsed periods of time is known as the "net lag."

The net lag is multiplied by the average daily cost of service or revenue requirement to determine the cash working capital. Cash working capital is included in rate base to compensate investors for the use of their funds over and above their investment in plant, and to provide investors with a return on the funds required by a company for daily operations.

Q. What are the components of a lead-lag study?

A. There are two primary elements of a lead-lag analysis, revenue lags and expense leads. The revenue lag is the sum of three distinct components, the service period lag, the billing lag, and the collection lag. The revenue lag is the elapsed time between the delivery of a company's product to its customers and when a company receives payment for the delivery of the product. Investor-provided funds are required to keep a company running during the revenue lag time period, when the revenue stream is temporarily insufficient to finance daily operational needs.

The expense lead is the sum of two distinct factors, the service lead and the payment lead. The expense lead is the elapsed time between when a good or service is provided to a company and when a company pays its supplier for the good or service. During the expense lead time period, cash received from customers may temporarily exceed a company's payments to its suppliers for goods or services, and the excess may be used to repay investor-provided funds. The net difference between

the revenue lag and expense lead denotes a company's cash working capital requirement.

Q. What time period does your lead-lag study encompass?

A. The lead-lag studies in this case analyzed the revenues and the associated cost of service during the 12 months ended September 30, 2023 to derive the appropriate lag (lead) days. The appropriate lag (lead) days were then used to develop the forecasted 12-months ended June 30, 2024 weighted revenue requirement and associated weighted cost of service to calculate the Company's working capital requirements.

Q. What "adjustments" were made in the lead-lag study?

A. Page 2 of Schedule HW-2 shows the adjustments made to NJNG's forecasted revenue requirement/cost of service used in the lead-lag study. I made two adjustments to NJNG's revenue requirement/cost of service used in the lead-lag studies consisting of: (1) Removing uncollectibles from both revenues and expenses; and (2) Adding New Jersey energy sales taxes to both revenues and expenses.

I removed the uncollectibles expense because the lag for uncollectible accounts is part of the calculation of the collection lag as a result of the accounts receivable being reduced when uncollectible accounts are expensed or written off. I added New Jersey energy sales taxes because the Company pays them to the State and must finance their billing, collection and payment even though they are not considered part of the Company's revenue requirement/cost of service. A similar approach has previously been approved by the BPU for other energy utilities.

Q. What data set did you utilize in your lead-lag study?

A. The lead-lag study reflects information provided by the Company. Specifically, Gannett Fleming requested representative data sets from NJNG after developing an understanding of the Company's collections, payment policies, procedures and expense line items' details. Once the requested raw data was provided, data validation was performed by comparing an actual invoice or bill with data from NJNG's accounting systems to ensure accuracy.

The revenue lag data set was based on an accounts receivable analysis of the beginning balance, the monthly charges to this balance as bills were processed and mailed, and the daily receipts for 365 days of the year during the 12 months ended September 30, 2023. The expense lead data set was based on information generated from the Company's central accounts payable system. The expense lead data sets for the 12 months ended September 30, 2023 were analyzed to develop the service beginning and ending dates, the amount purchased, and the date of payment.

Generally speaking, sampling was randomly done for the invoices within each expense and tax category. In instances where there were large differences in the dollar amount of the invoices in a single expense category, sampling was focused on the largest invoices within the expense category. For example, the larger other operations and maintenance ("O&M") expenses accounts were sampled instead of the smaller other O&M expenses accounts. The samples analyzed averaged 88% of the Company's total forecasted weighted cost of service to calculate expense and tax

dollars.[3]

VI. RESULTS OF THE LEAD-LAG STUDY

Q. What are the results of the lead-lag study?

A. Schedule HW-2 is a two-page Schedule which sets forth the results of the lead-lag study, page 1, and the adjustments made to the Company's revenue requirement/cost of service, page 2, used in the lead-lag study. On page 1 of Schedule HW-2, the cash working capital requirement for NJNG is $112,522,940.

Q. Please describe Page 1 of Schedule HW-2.

A. Page 1 of Schedule HW-2 calculates the net lag days and applies the result to the average daily cost of service or revenue requirement. The cash working capital requirement is based on the net difference between the dollar weighted revenue requirement lag days and the dollar weighted cost of service lead days. The weighted lag days for the receipt of the revenue requirement is developed at the top of the schedule, with supporting detail shown in Schedule HW-3. The weighted lead days for the payments of the cost of service is developed on Schedules HW-5 through HW-24 and the schedule references for the weighted lead days for the cost of service line items is shown on Schedule HW-4.

For NJNG, the working capital requirement shown on Page 1 of Schedule HW-2 was calculated by subtracting NJNG's weighted lead days for the cost of service of 20.1 days from the weighted average lag days for the revenue requirement of 57.3 days to determine the net lag days of 37.2. The 37.2 net lag days was

[3] Sampling for the total expense and tax dollars paid totaled 88% and reflected a range of sampling from 13% to 100% of the total line item dollars (or expenses). The least amount of sampling, 13%, occurred for the sub-account line item "other O&M expenses."

multiplied by the average adjusted daily cost of service or revenue requirement of $3,023,883. The result is a cash working capital requirement of $112,522,940 for NJNG.

Q. Please explain the procedures used to determine the revenue requirement lag.

A. Schedule HW-3 of the exhibit summarizes the development of the 57.3 lag days for the Company's revenue requirement. The lag days for revenue requirement are comprised of: service period lag; billing lag; and collection lag. The lag days for NJNG's service period and the billing lag are developed on Page 1 of Schedule HW-3 and the lag days for NJNG's collection lag are developed on Page 2 of Schedule HW-3.

Q. Please explain the procedures used to determine the service period lag days and billing lag days for the revenue requirement.

A. The service period lag is the average time between actual meter readings of 31.4 days based on monthly billing.[4] The average time between meter readings, 31.4 days, is divided by two to produce a midpoint, or service period lag of 15.7 days. A mid-point is used because it is assumed service is provided evenly over the service period.

The billing lag is the time from the meter reading date to the customer billing date. The customer billing date, or the mailing date, is the day when the total billing amount for a cycle is recorded to accounts receivable. The bills are prepared and mailed 5.5 days after meters are read and billings are recorded to accounts receivable. Adding the service period lag to the billing lag produces a combined 21.2 days service period and billing lag (15.7 days + 5.5 days = 21.2 days).

[4] The service period lag and the billing lag are based on an analysis of four months of meter reads and billing for the months of December 2022, February 2023, May 2023, and July 2023.

Q. Please describe the procedure used to calculate the collection lag portion of the revenue lag.

A. The collection lag is the average number of days from the date the bills are posted to accounts receivables to the date payments are received. This was determined by dividing the average monthly accounts receivable balance during the 12 months ended September 30, 2023 by the sum of the daily receipts during the same period. This results in an average collection lag of 36.1 days for NJNG as shown on Page 2 of HW-3.

Q. Please summarize the total revenue lag.

A. The total revenue lag of 57.3 lag days for NJNG is shown on page 1 of Schedule HW-3 and includes 21.2 days service period and billing lag and a collection lag of 36.1 days.

Q. Please explain the revenue adjustment line item shown on Page 1 of Schedule HW-2.

A. The revenue adjustment line item adds back the New Jersey energy sales tax that the Company collects. The New Jersey energy sales tax is included as part of the revenue requirement lag in both revenues and operating expenses. Customers are billed the Energy Sales Tax, known as the Sales and Use Tax ("SUT"), by the Company and the Company remits the charges to the State. The Company is required to remit these dollars to the State in advance of their collection, and the timing difference between the remittance to the State and the collection from customers represents a working capital requirement.

Q. Please explain the calculation of lead days for the cost of service expenses shown on Page 1 of Schedule HW-2.

A. The lead days for NJNG's cost of service expenses shown on Page 1 of Schedule HW-2 are comprised of four major sub-accounts based upon the Company's cost of service. The four major sub-accounts include: operating expenses; income taxes; taxes other than income taxes; and operating income.

For most cost of service expense items shown, the lead days were calculated for each invoice or account based on the midpoints of the service periods to the dates the Company paid the invoices or accounts based on varying levels of sampling of data.[5] The exceptions were depreciation and amortization, deferred taxes and operating income line items.

Schedule HW-4 lists the schedule references for the individual cost of service lead days that were calculated for NJNG. Sampling for the line item cost of service expenses (or dollars) averaged 88%, reflecting a range of sampling from 13% to 100% of the Company's total forecasted weighted cost of service to calculate expense and tax dollars expenses line items (or dollars) being sampled.

Q. How were the lead days determined for the operating expenses sub-account line items shown on Page 1 of Schedule HW-2?

A. For most of the operating expenses sub-account line items shown, the lead days were determined for each invoice or account sampled based on the midpoints of the service periods to the dates the Company paid the invoices or accounts based on varying

[5] As was the case with the revenue service period, a mid-point is used for the service lead because it is assumed service is provided evenly over the service period.

levels of sampling of data. The exceptions were the depreciation and amortization line item, uncollectible accounts expense and regulatory expense.

For the operating expense sub-accounts line items shown on Page 1 of Schedule HW-2, the lead days were determined for each invoice or account sampled based on the midpoints of the service periods to the dates the Company paid the invoices or accounts. As explained previously, sampling was randomly done for the invoices within each expense and tax category.

For example, the weighted average lead days for gas supply costs equal 40.3 days (see Schedule HW-5). The lead days for gas supply costs expense were calculated for each invoice examined based on the midpoints of the service periods to the dates the Company paid the invoices. In total, 100% of the Company's forecasted gas supply costs expenses were sampled. Similar analyses were conducted for salary and wages (see Schedule HW-6), pensions (see Schedule HW-7), PEP (see Schedule HW-8), OPEB (see Schedule HW-9), medical insurance (see Schedule HW-10), dental insurance (see Schedule HW-11), short term disability (see Schedule HW-12), group life, AD&D, and LTD (see Schedule HW-13), flexible spending account (see Schedule HW-14), 401k plans (see Schedule HW-15), and other O&M expenses (see Schedule HW-16).

Within the operating expense sub-accounts line items shown on Page 1 of Schedule HW-2 is the calculation of the weighted average lead days for pensions and benefits reflecting the various benefit plans. NJNG's weighted average lead days for pensions and benefits is 55.4 lead days based on the midpoints of the service periods to the dates the Company paid the invoices or accounts.

For the depreciation and amortization line item, a zero lead has been assigned because accumulated depreciation, the contra account for the depreciation expense, has been deducted from rate base. The accumulated depreciation account balance always includes an uncollected amount of depreciation expense that is equal to the revenue requirement lag days (i.e., 57.3 days). Assigning a zero lead recognizes that investor funding occurred but it has not yet been recovered from customers.

In total, NJNG's operating expenses sub-account line items have a weighted average 29.0 lead days as shown on Page 1 of Schedule HW-2.

Q. How were the lead days determined for the income taxes sub-account line items shown on Page 1 of Schedule HW-2?

A. The lead days for the current federal taxes and current state taxes (CBT) sub-account line items, shown on Page 1 of Schedule HW-2, were calculated based on the midpoint of the tax period to the payment date, weighted by the percent of the payment required. The derivation of the current federal taxes 37.3 lead days is shown on Schedule HW-17 and the derivation of the current state taxes (CBT) negative lead days of -15.3 is shown on Schedule HW-18.

A zero lead has been assigned to deferred taxes because accumulated deferred taxes have been deducted from rate base as a source of cost-free funds. The deferred taxes account balance always includes an uncollected amount of deferred tax expense that is equal to the revenue requirement lag days (i.e., 57.3 days). Therefore, the recorded amount of accumulated deferred taxes deducted from rate base overstates the actual amount of available cost-free capital by an amount equal to the revenue requirement lag days. Assigning a zero lead recognizes that a portion of these cost-

free funds have not been recovered from customers.

In total, NJNG's income taxes sub-account line items have a weighted average lead day of 32.3 as shown on Page 1 of Schedule HW-2.

Q. How were the lead days determined for the taxes other than income sub-account line items shown on Page 1 of Schedule HW-2?

A. The lead days for the taxes other than income taxes sub-account line item shown on Page 1 of Schedule HW-2 were calculated based on the midpoint of the tax liability period to the payment date, weighted by the actual amount paid. The taxes other than income taxes sub-accounts are shown on Schedule HW-19 and are comprised of the tax sub-accounts shown on Schedules HW-20 through HW-23. These taxes include payroll tax (see Schedule HW-20), real estate tax (see Schedule HW-21), New Jersey SUT (see Schedule HW-22), and motor fuel tax (see Schedule HW-23).

As shown on Page 1 of Schedule HW-2, NJNG's taxes other than income taxes sub-account line items have a weighted average 5.6 lead days.

Q. How were the lead days determined for the New Jersey energy sales tax sub-account line items shown on Page 1 of Schedule HW-2?

A. The lead days for the New Jersey energy sales tax sub-account line item shown on Page 1 of Schedule HW-2 were calculated based on the midpoint of the tax liability period to the payment date, weighted by the actual amount paid. The derivation of the New Jersey energy sales tax lead days is shown on Schedule HW-24. As shown on Schedule HW-2, NJNG's New Jersey energy sales tax sub-account line has a weighted average negative lead days of 51.1.

Q. How were the lead days determined for the operating income sub-account line items shown on Page 1 of Schedule HW-2?

A. I assigned a zero lead day to utility operating income, or return on invested capital, because operating income is the property of investors when it is earned. Further, operating income is earned when service is provided. However, when service is provided, the operating income is not collected simultaneously as is evidenced by the existence of the revenue requirement lag days. This situation is remedied by assigning a zero lead day to operating income in recognition that these earnings have not been recovered from customers.[6]

Q. Please summarize your results of the amount of working capital required to finance the recovery of the cost of service based on the lead-lag study shown on Page 1 of Schedule HW-2?

A. As shown on Page 1 of Schedule HW-2, NJNG's working capital requirement was calculated by subtracting NJNG's weighted lead days for the cost of service of 20.1 days from the weighted average lag days for the revenue requirement of 57.3 days to determine the net lag days of 37.2. The 37.2 net lag days was multiplied by the average adjusted daily cost of service or revenue requirement of $3,023,883. The result is a cash working capital requirement of $112,522,940 for NJNG.

[6] *Bluefield Water Works v. Public Service Comm'n*, 262 U.S. 679 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service of the utility to the public are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment." 262 U. S. at 690).

VII. NET ASSETS AND LIABILITIES ANALYSIS

Q. What does a net assets and liabilities analysis measure and how is it measured?

A. Under a net assets and liabilities analysis, certain liabilities are subtracted from particular assets. This difference in the liabilities and the assets is assumed to be the cash working capital. Under a net assets and liabilities analysis, the assets listed require working capital whereas the liabilities listed are sources of working capital.

Q. Please describe the analysis and components of the net assets/liability not recognized in the lead-lag study.

A. Schedule HW-25 provides the details of the net source of Cash Working Capital not considered elsewhere. The listed assets are additional requirements for Working Capital, the liabilities are sources and their net difference, shown on Schedule HW-25, requires Working Capital. NJNG's cash working capital requirement determined through the net assets and liabilities analysis, shown on Schedule HW-25, is $14,817,746. The result of the net assets and liabilities analysis ($14,817,746) is included on Schedule HW-1 Summary and is additional required working capital above the working capital required to finance the recovery of the cost of service.

VIII. CONCLUSION

Q. Does this conclude your Direct Testimony?

A. Yes, it does. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

Professional Qualifications
of
Harold Walker, III
Manager, Financial Studies
Gannett Fleming Valuation and Rate Consultants, LLC.

EDUCATION

Mr. Walker graduated from Pennsylvania State University in 1984 with a Bachelor of Science Degree in Finance. His studies concentrated on securities analysis and portfolio management with an emphasis on economics and quantitative business analysis. He has also completed the regulation and the rate-making process courses presented by the College of Business Administration and Economics Center for Public Utilities at New Mexico State University. Additionally, he has attended programs presented by The Institute of Chartered Financial Analysts (CFA).

Mr. Walker was awarded the professional designation "Certified Rate of Return Analyst" (CRRA) by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience, and the successful completion of a comprehensive examination. He is also a member of the Society of Utility and Regulatory Financial Analysts (SURFA) and has attended numerous financial forums sponsored by the Society. The SURFA forums are recognized by the Association for Investment Management and Research (AIMR) and the National Association of State Boards of Accountancy for continuing education credits.

Mr. Walker also obtained a license as a Municipal Advisor Representative (Series 50) by Municipal Securities Rulemaking Board (MSRB) and Financial Industry Regulatory Authority (FINRA).

BUSINESS EXPERIENCE

Prior to joining Gannett Fleming Valuation and Rate Consultants, LLC., Mr. Walker was employed by AUS Consultants - Utility Services. He held various positions during his eleven years with AUS, concluding his employment there as a Vice President. His duties included providing and supervising financial and economic studies on behalf of investor owned and municipally owned water, wastewater, electric, natural gas distribution and transmission, oil pipeline and telephone utilities as well as resource recovery companies.

In 1996, Mr. Walker joined Gannett Fleming Valuation and Rate Consultants, LLC. In his capacity as Manager, Financial Studies and for the past twenty-five years, he has continuously studied rates of return requirements for regulated firms. In this regard, he supervised the preparation of rate of return studies in connection with his testimony and in the past, for other individuals. He also assisted and/or developed dividend policy studies, nuclear prudence studies, calculated fixed charge rates for avoided costs involving cogeneration projects, financial decision studies for capital budgeting purposes and developed financial models for determining future capital requirements and the effect of those requirements on investors and ratepayers, valued

utility property for acquisition and divestiture, and assisted in the private placement of fixed capital securities for public utilities.

Head, Gannett Fleming GASB 34 Task Force responsible for developing Governmental Accounting Standards Board (GASB) 34 services and educating Gannett Fleming personnel and Gannett Fleming clients on GASB 34 and how it may affect them. The GASB 34 related services include inventory of assets, valuation of assets, salvage estimation, annual depreciation rate determination, estimation of depreciation reserve, asset service life determination, asset condition assessment, condition assessment documentation, maintenance estimate for asset preservation, establishment of condition level index, geographic information system (GIS) and data management services, management discussion and analysis (MD&A) reporting, required supplemental information (RSI) reporting, auditor interface, and GASB 34 compliance review.

In 2004, Mr. Walker was elected to serve on the Board of Directors of SURFA. Previously, he served as an ex officio directors as an advisor to SURFA's existing President. In 2000, Mr. Walker was elected President of SURFA for the 2001-2002 term. Prior to that, he was elected to serve on the Board of Directors of SURFA during the period 1997-1998 and 1999-2000. He also previously served on the Pennsylvania Municipal Authorities Association, Electric Deregulation Committee.

EXPERT TESTIMONY

Mr. Walker has submitted testimony or been deposed on various topics before regulatory commissions and courts in 27 states including: Alaska, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Hampshire, Nevada, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia, and West Virginia. His testimonies covered various subjects including lead-lag studies, fair rate of return, fair market value, the taking of natural resources, benchmarking, appropriate capital structure and fixed capital cost rates, depreciation, purchased water adjustments, synchronization of interest charges for income tax purposes, valuation, cash working capital, financial analyses of investment alternatives, and fair value. The following tabulation provides a listing of the electric power, natural gas distribution, telephone, wastewater, and water service utility cases in which he has been involved as a witness.

Client	Docket No.
Alpena Power Company	U-10020
Armstrong Telephone Company - Northern Division	92-0884-T-42T
Armstrong Telephone Company - Northern Division	95-0571-T-42T
Artesian Water Company, Inc.	90 10
Artesian Water Company, Inc.	06 158
Aqua Illinois Consolidated Water Divisions	

and Consolidated Sewer Divisions	11-0436
Aqua Illinois Hawthorn Woods Wastewater Division	07 0620/07 0621/08 0067
Aqua Illinois Hawthorn Woods Water Division	07 0620/07 0621/08 0067
Aqua Illinois Kankakee Water Division	10-0194
Aqua Illinois Kankakee Water Division	14-0419
Aqua Illinois Vermilion Division	07 0620/07 0621/08 0067
Aqua Illinois Willowbrook Wastewater Division	07 0620/07 0621/08 0067
Aqua Illinois Willowbrook Water Division	07 0620/07 0621/08 0067
Aqua Pennsylvania, Inc	A-2022-3034143
Aqua Pennsylvania Wastewater Inc	A-2016-2580061
Aqua Pennsylvania Wastewater Inc	A-2017-2605434
Aqua Pennsylvania Wastewater Inc	A-2018-3001582
Aqua Pennsylvania Wastewater Inc	A-2019-3008491
Aqua Pennsylvania Wastewater Inc	A-2019-3009052
Aqua Pennsylvania Wastewater Inc	A-2019-3015173
Aqua Pennsylvania Wastewater Inc	A-2021-3024267
Aqua Pennsylvania Wastewater Inc	A-2021-3026132
Aqua Pennsylvania Wastewater Inc	A-2021-3027268
Aqua Pennsylvania Wastewater Inc	A-2023-3041695
Aqua Virginia - Alpha Water Corporation	Pue-2009-00059
Aqua Virginia - Blue Ridge Utility Company, Inc.	Pue-2009-00059
Aqua Virginia - Caroline Utilities, Inc. (Wastewater)	Pue-2009-00059
Aqua Virginia - Caroline Utilities, Inc. (Water)	Pue-2009-00059
Aqua Virginia - Earlysville Forest Water Company	Pue-2009-00059
Aqua Virginia - Heritage Homes of Virginia	Pue-2009-00059
Aqua Virginia - Indian River Water Company	Pue-2009-00059
Aqua Virginia - James River Service Corp.	Pue-2009-00059
Aqua Virginia - Lake Holiday Utilities, Inc. (Wastewater)	Pue-2009-00059
Aqua Virginia - Lake Holiday Utilities, Inc. (Water)	Pue-2009-00059
Aqua Virginia - Lake Monticello Services Co. (Wastewater)	Pue-2009-00059
Aqua Virginia - Lake Monticello Services Co. (Water)	Pue-2009-00059
Aqua Virginia - Lake Shawnee	Pue-2009-00059
Aqua Virginia - Land'or Utility Company (Wastewater)	Pue-2009-00059

Aqua Virginia - Land'or Utility Company (Water)	Pue-2009-00059
Aqua Virginia - Mountainview Water Company, Inc.	Pue-2009-00059
Aqua Virginia - Powhatan Water Works, Inc.	Pue-2009-00059
Aqua Virginia - Rainbow Forest Water Corporation	Pue-2009-00059
Aqua Virginia - Shawnee Land	Pue-2009-00059
Aqua Virginia - Sydnor Water Corporation	Pue-2009-00059
Aqua Virginia - Water Distributors, Inc.	Pue-2009-00059
Atlantic City Sewerage Company	WR21071006
Berkshire Gas Company	18-40
Berkshire Gas Company	22-20
Bermuda Water Company, Inc	W-01812A-22-0256
Borough of Brentwood	A-2021-3024058
Borough of Hanover	R-2009-2106908
Borough of Hanover	R-2012-2311725
Borough of Hanover	R-2014-242830
Borough of Hanover	R-2021-3026116
Borough of Hanover	P-2021-3026854
Borough of Royersford	A-2020-3019634
Butler Area Sewer Authority	A-2020-3019634
Chaparral City Water Company	W 02113a 04 0616
California-American Water Company	CIVCV156413
Connecticut-American Water Company	99-08-32
Connecticut Water Company	06 07 08
Citizens Utilities Company	
Colorado Gas Division	-
Citizens Utilities Company	
Vermont Electric Division	5426
Citizens Utilities Home Water Company	R 901664
Citizens Utilities Water Company	
of Pennsylvania	R 901663
City of Beaver Falls	A-2022-3033138
City of Bethlehem - Bureau of Water	R-00984375
City of Bethlehem - Bureau of Water	R 00072492
City of Bethlehem - Bureau of Water	R-2013-2390244
City of Bethlehem - Bureau of Water	R-2020-3020256
City of Dubois – Bureau of Water	R-2013-2350509
City of Dubois – Bureau of Water	R-2016-2554150
City of Lancaster Sewer Fund	R-00005109
City of Lancaster Sewer Fund	R-00049862

City of Lancaster Sewer Fund	R-2012-2310366
City of Lancaster Sewer Fund	R-2019-3010955
City of Lancaster Sewer Fund	R-2019-3010955
City of Lancaster Water Fund	R-00984567
City of Lancaster Water Fund	R-00016114
City of Lancaster Water Fund	R 00051167
City of Lancaster Water Fund	R-2010-2179103
City of Lancaster Water Fund	R-2014-2418872
City of Lancaster Water Fund	R-2021-3026682
City of Lancaster Water Fund	P-2022-3035591
Coastland Corporation	15-cvs-216
Consumers Pennsylvania Water Company	
Roaring Creek Division	R-00973869
Consumers Pennsylvania Water Company	
Shenango Valley Division	R-00973972
Country Knolls Water Works, Inc.	90 W 0458
East Resources, Inc. - West Virginia Utility	06 0445 G 42T
Elizabethtown Water Company	WR06030257
ENSTAR Natural Gas Company	U-22-081
Falls Water Company, Inc.	FLS-W-23-01
Forest Park, Inc.	19-W-0168 & 19-W-0269
Hampton Water Works Company	DW 99-057
Hidden Valley Utility Services, LP	R-2018-3001306
Hidden Valley Utility Services, LP	R-2018-3001307
Illinois American Water Company	16-0093
Illinois American Water Company	22-0210
Indian Rock Water Company	R-911971
Indiana Natural Gas Corporation	38891
Jamaica Water Supply Company	-
Kane Borough Authority	A-2019-3014248
Kentucky American Water Company, Inc.	2007 00134
Kentucky American Water Company, Inc.	2023-00191
Middlesex Water Company	WR 89030266J
Millcreek Township Water Authority	55 198 Y 00021 11
Missouri-American Water Company	WR 2000-281
Missouri-American Water Company	SR 2000-282
Missouri-American Water Company	WR-2022-0303
Mount Holly Water Company	WR06030257
Nevada Power Company d/b/a NV Energy	20-06003

Nevada Power Company d/b/a NV Energy	23-06007
New Jersey American Water Company	WR 89080702J
New Jersey American Water Company	WR 90090950J
New Jersey American Water Company	WR 03070511
New Jersey American Water Company	WR-06030257
New Jersey American Water Company	WR08010020
New Jersey American Water Company	WR10040260
New Jersey American Water Company	WR11070460
New Jersey American Water Company	WR15010035
New Jersey American Water Company	WR17090985
New Jersey American Water Company	WR19121516
New Jersey American Water Company	WR22010019
New Jersey Natural Gas Company	GR19030420
New Jersey Natural Gas Company	GR21030679
Newtown Artesian Water Company	R-911977
Newtown Artesian Water Company	R-00943157
Newtown Artesian Water Company	R-2009-2117550
Newtown Artesian Water Company	R-2011-2230259
Newtown Artesian Water Company	R-2017-2624240
Newtown Artesian Water Company	R-2019-3006904
North Maine Utilities	14-0396
Northern Indiana Fuel & Light Company	38770
Oklahoma Natural Gas Company	PUD-940000477
Palmetto Utilities, Inc.	2020-281-S
Palmetto Wastewater Reclamation, LLC	2018-82-S
Pennichuck Water Works, Inc.	DW 04 048
Pennichuck Water Works, Inc.	DW 06 073
Pennichuck Water Works, Inc.	DW 08 073
Pennsylvania-American Water Company	A-2023-3039900
Pennsylvania Gas & Water Company (Gas)	R-891261
Pennsylvania Gas & Water Co. (Water)	R 901726
Pennsylvania Gas & Water Co. (Water)	R-911966
Pennsylvania Gas & Water Co. (Water)	R-22404
Pennsylvania Gas & Water Co. (Water)	R-00922482
Pennsylvania Gas & Water Co. (Water)	R-00932667
Philadelphia Gas Works	R-2020-3017206
Philadelphia Gas Works	R-2023-3037933
Public Service Company of North Carolina, Inc.	G-5, Sub 565
Public Service Electric and Gas Company	ER181010029

Public Service Electric and Gas Company	GR18010030
Presque Isle Harbor Water Company	U-9702
Sierra Pacific Power Company d/b/a NV Energy	19-06002
Sierra Pacific Power Company d/b/a NV Energy	22-06014
St. Louis County Water Company	WR-2000-844
Suez Water Delaware, Inc.	19-0615
Suez Water Idaho, Inc.	SUZ-W-20-02
Suez Water New Jersey, Inc.	WR18050593
Suez Water New Jersey, Inc.	WR20110729
Suez Water Owego-Nichols, Inc.	17-W-0528
Suez Water Pennsylvania, Inc.	R-2018-3000834
Suez Water Pennsylvania, Inc.	A-2018-3003519
Suez Water Pennsylvania, Inc.	A-2018-3003517
Suez Water Rhode Island, Inc.	Docket No. 4800
Suez Water Owego-Nichols, Inc.	19-W-0168 & 19-W-0269
Suez Water New York, Inc.	19-W-0168 & 19-W-0269
Suez Westchester, Inc.	19-W-0168 & 19-W-0269
Town of North East Water Fund	9190
Township of Exeter	A-2018-3004933
United Water New Rochelle	W-95-W-1168
United Water Toms River	WR-95050219
Upper Pottsgrove Township	A-2020-3021460
Valley Township (water)	A-2020-3019859
Valley Township (wastewater)	A-2020-3020178
Valley Water Systems, Inc.	06 10 07
Veolia Water Idaho, Inc.	VEO-W-22-02
Veolia Water Delaware, Inc.	23-0598
Veolia Water New York, Inc.	23-W-0111
Virginia American Water Company	PUR-2018-00175
Virginia American Water Company	PUR-2021-00255
Virginia American Water Company	PUR-2023-00194
West Virginia-American Water Company	15-0676-W-42T
West Virginia-American Water Company	15-0675-S-42T
Wilmington Suburban Water Corporation	94-149
York Water Company	R-901813
York Water Company	R-922168
York Water Company	R-943053
York Water Company	R-963619
York Water Company	R-994605

York Water Company	R-00016236
Young Brothers, LLC	2019-0117

TECHNICAL PUBLICATIONS & PRESENTATIONS

Walker, Harold. Panelist "Now is the Time to Maximize Your Utility's Value." Presented at the Pennsylvania Association of Township Supervisors 97th Annual State Convention, April 2019.

Walker, Harold. Panelist "Fair Market Acquisitions Debate." Presented at National Association of Regulatory Utilities Commissioners Winter Policy Summit, February 2019.

Walker, Harold. Panelist "Fair Market Value Legislation." Presented at the National Association of Water Companies Water Summit, October 2018.

Walker, Harold. Panelist "Leveraging Water & Sewer to Address Roads, Schools, and Pension Obligations." Presented at the Maryland Association of Counties 2018 Summer Conference, August 2018.

Walker, Harold. Panelist "Is the Glass Half Full or Half Empty? Valuing Municipal Water Acquisitions." Presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners 23rd Annual Education Conference, June 2018.

Walker, Harold. "Valuation and Inventory of Governmental Assets Under GASB 34." Presented at the Society of Depreciation Professionals 21st Annual Conference, September 2007.

Walker, Harold. "The Paradox of State Regulatory Opinions and Investor Behavior." Presented at the National Association of Water Companies New England Chapter conference, November 2006.

Walker, Harold. "Valuation and Inventory Under GASB 34." Presented at the Government Finance Officers Association South Central Pennsylvania Regional Chapter conference, August 2003.

Walker, Harold. "Valuation and Inventory under GASB 34." Presented at the Government Finance Officers Association Southeastern Pennsylvania Regional Chapter conference, April 2002.

Walker, Harold. "GASB 34 & Your Infrastructure." *The Authority,* August 2001, Volume XXXII, No. 4, pages 10-13.

Walker, Harold. "Managing Risk." Conference Chairperson, presented at the Society of Utility & Regulatory Financial Analysts 33rd Financial Forum, April 2001.

Walker, Harold. "Paying for Your MSW System - Waste Generation Fees." Presented at the Federation of New York Solid Waste Association Solid Waste/Recycling Conference and Trade Show, May 2001.

Walker, Harold. "Statement No. 34 of the Government Accounting Standards Board." Presented at the Pennsylvania Association of Township Supervisors 79th Annual State Convention, April 2001.

Walker, Harold. "Cost of Capital Issues." Presented at the National Association of Water Companies New England Chapter conference, October 2000.

Walker, Harold, Timothy Hartman, and Mark Everett. "Waste Generation Study: Life After Flow Control." Presented at Waste Con 2000, October 1999.

Walker, Harold, and Timothy Hartman. "The Enhancement of Revenues Through a Waste Generation Study." Presented at SWANA's Planning and Management Symposium, July 1999.

NEW JERSEY NATURAL GAS COMPANY
WALL, NEW JERSEY

TO ACCOMPANY THE

DIRECT TESTIMONY

SUPPORTING SCHEDULES

SCHEDULES HW-1 TO HW-25

FOR
LEAD-LAG STUDY
AND NET ASSETS AND LIABILITIES ANALYSIS
FOR DETERMINATION OF OTHER CASH WORKING CAPITAL

JANUARY 2024

Prepared by:

GANNETT FLEMING

NEW JERSEY NATURAL GAS COMPANY

LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

INDEX TO SCHEDULES

NEW JERSEY NATURAL GAS COMPANY
SUMMARY OF OTHER CASH WORKING CAPITAL
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

(THOUSANDS)

	Other Cash Working Capital
Amount Required to Recover Cost of Service	$112,523
Net Assets and Liabilities	14,818
Total Other Cash Working Capital	$127,341

NEW JERSEY NATURAL GAS COMPANY
SUMMARY OF CASH WORKING CAPITAL REQUIREMENTS
BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

	Adjusted Test Year Amount	Lag Days	Weighted Amount
Revenue Requirement	$1,041,555,368	57.3	$59,681,122,586
New Jersey Energy Sales Tax	62,162,082	57.3	3,561,887,299
Total Revenue Requirement	1,103,717,450	57.3	63,243,009,885
Requirements:			
Gas Supply Costs	$534,817,641	40.3	$21,553,150,932
Salary and Wages	78,426,565	7.7	603,884,551
Pension and Benefits:			
Pensions	(1,125,891)	87.0	(97,952,517)
PEP	86,965	(14.1)	(1,226,207)
OPEB	(984,545)	48.7	(47,947,342)
Medical Insurance	11,932,678	71.4	851,993,209
Dental Insurance	861,651	60.0	51,699,060
Short Term Disability	0	76.4	0
Group Life, AD&D, and LTD	847,815	61.5	52,140,623
Flexible Spending Account	0	4.7	0
401K Plans	3,344,135	5.9	19,730,397
Other Fringes	(938,260)	55.4	(51,979,604)
Total Pension and Benefits	14,024,548	55.4	776,457,619
Uncollectibles	0	0.0	0
Other O&M Expenses	109,292,404	14.4	1,573,810,618
Depreciation & Amortization	108,726,997	0.0	0
Subtotal Operating Expenses	845,288,155	29.0	24,507,303,720
Income Taxes:			
Current Federal Taxes	21,506,196	37.3	802,181,111
Current State (CBT)	0	(15.3)	0
Deferred Taxes	3,292,706	0.0	0
Subtotal Income Taxes	24,798,902	32.3	802,181,111
Taxes Other than Income Tax	6,988,279	5.6	39,134,362
New Jersey Energy Sales Tax	62,162,082	(51.1)	(3,176,482,390)
Operating Income	164,480,032	0.0	0
Total Cost of Service Requirement	1,103,717,450	20.1	22,172,136,803
Average Daily Cost of Service Requirement	3,023,883		
Net Lag Days		**37.2**	
Cash Working Capital Requirement			**$112,522,940**

NEW JERSEY NATURAL GAS COMPANY
SUMMARY OF TEST YEAR ADJUSTMENTS
REQUIRED FOR COST OF SERVICE LEAD LAG STUDY
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

	Test Year Amount	Adjustments	Adjusted Test Year Amount
Revenue Requirement	$1,043,664,832	($2,109,464)	$1,041,555,368
New Jersey Energy Sales Tax	0	62,162,082	62,162,082
Total Revenue Requirement	1,043,664,832	60,052,618	1,103,717,450
Requirements:			
Gas Supply Costs	$534,817,641	$0	$534,817,641
Salary and Wages	78,426,565	0	78,426,565
Pension and Benefits:			
Pensions	(1,125,891)	0	(1,125,891)
PEP	86,965	0	86,965
OPEB	(984,545)	0	(984,545)
Medical Insurance	11,932,678	0	11,932,678
Dental Insurance	861,651	0	861,651
Short Term Disability	0	0	0
Group Life, AD&D, and LTD	847,815	0	847,815
Flexible Spending Account	0	0	0
401K Plans	3,344,135	0	3,344,135
Other Fringes	(938,260)	0	(938,260)
Total Pension and Benefits	14,024,548	0	14,024,548
Uncollectibles	2,109,464	(2,109,464)	0
Other O&M Expenses	109,292,404	0	109,292,404
Depreciation & Amortization	108,726,997	0	108,726,997
Subtotal Operating Expenses	847,397,619	(2,109,464)	845,288,155
Income Taxes:			
Current Federal Taxes	21,506,196	0	21,506,196
Current State (CBT)	0	0	0
Deferred Taxes	3,292,706	0	3,292,706
Subtotal Income Taxes	24,798,902	0	24,798,902
Taxes Other than Income Tax	6,988,279	0	6,988,279
New Jersey Energy Sales Tax	0	62,162,082	62,162,082
Operating Income	164,480,032	0	164,480,032
Total Cost of Service Requirement	1,043,664,832	60,052,618	1,103,717,450

NEW JERSEY NATURAL GAS COMPANY
CALCULATION OF TOTAL REVENUE LAG DAYS
BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Service Period Lag Days	15.7
Billing Lag Days	5.5
Collection Lag Days	36.1
Total Revenue Lag Days	57.3

CALCULATION OF SERVICE & BILLING REVENUE LAG DAYS

Months Sampled	Sampled Customer Billings	Average Service Period (days)	Weighted Service Amount
December-22	$125,517,124	16.3	$2,051,893,356
February-23	132,260,149	15.1	1,994,287,988
May-23	62,065,168	15.3	949,942,344
July-23	35,166,266	15.9	560,472,474
Totals	$355,008,706	15.7	$5,556,596,161

Months Sampled	Sampled Customer Billings	Weighted Billing Lag (days)	Weighted Billing Amount
December-22	$125,517,124	5.9	$744,570,772
February-23	132,260,149	5.7	751,906,874
May-23	62,065,168	4.9	301,521,429
July-23	35,166,266	4.3	152,635,489
Totals	$355,008,706	5.5	$1,950,634,564

NEW JERSEY NATURAL GAS COMPANY
CALCULATION OF COLLECTION LAG DAYS
BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Date		NJNG Customer Month End Accounts Receivables Amount
9/30/2022		$78,508,402
10/31/2022		61,967,267
11/30/2022		77,959,309
12/31/2022		147,628,836
1/31/2023		150,530,562
2/28/2023		143,475,157
3/31/2023		142,274,916
4/30/2023		118,407,104
5/31/2023		90,565,428
6/30/2023		72,746,529
7/31/2023		69,597,358
8/31/2023		60,081,718
9/30/2023		55,233,510
13 Month Average A/R		97,613,546
Multiplied By Days, 10/1/22 to 9/30/23	x	365
Sum of Average Daily Balance		35,628,944,234
NJNG Accounts Receivable on 9/30/22	-	78,508,402
Minus NJNG Accounts Receivable on 9/30/23		55,233,510
Change in Accounts Receivables for 12-Months		23,274,892
The Sum of Daily Revenue, 10/1/22 to 9/30/23		964,501,391
Plus Change in A/R for 12-Months	+	23,274,892
The Sum of 12-Months Daily Receipts		987,776,283
Sum of Average Daily Balance		35,628,944,234
Divided By the Sum of Daily 12-Months Receipts	÷	987,776,283
Total Collection Lag Days		36.1

NEW JERSEY NATURAL GAS COMPANY
SUMMARY OF OPERATING EXPENSES AND TAXES LEAD DAYS
BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Description	Schedule Reference	Amount	Weighted Amount	Lead Days
(1)	(2)	(3)	(4)	(5)=(4)/(3)
Operating Expenses & Taxes*				
Gas Supply Costs	Schedule HW-5	838,854,308	33,793,882,745	40.3
Salary and Wages	Schedule HW-6	105,942,132	814,275,531	7.7
Pensions	Schedule HW-7	185,114	16,099,373	87.0
PEP	Schedule HW-8	578,676	-8,178,691	-14.1
OPEB	Schedule HW-9	779,090	37,970,607	48.7
Medical Insurance	Schedule HW-10	28,585,534	2,040,001,232	71.4
Dental Insurance	Schedule HW-11	759,715	45,577,265	60.0
Short Term Disability	Schedule HW-12	744,396	56,835,631	76.4
Group Life, AD&D, and LTD	Schedule HW-13	599,096	36,829,546	61.5
Flexible Spending Account	Schedule HW-14	6,147	28,756	4.7
401K Plans	Schedule HW-15	5,891,458	34,827,338	5.9
Other Fringes	**	**	**	55.4
Other O&M Expenses	Schedule HW-16	14,255,805	205,137,631	14.4
Depreciation & Amortization	***	***	***	0.0
Current Federal Taxes	Schedule HW-17			37.3
Current State (CBT)	Schedule HW-18			-15.3
Deferred Taxes	***	***	***	0.0
Taxes Other than Income Tax	Schedule HW-19	12,267,680	69,191,982	5.6
Payroll Tax	Schedule HW-20	10,227,057	78,605,578	7.7
Real Estate Tax	Schedule HW-21	1,459,647	-29,568,962	-20.3
New Jersey Sales & Use Tax	Schedule HW-22	562,264	19,524,063	34.7
Motor Fuel Tax	Schedule HW-23	18,712	631,304	33.7
New Jersey Energy Sales Tax	Schedule HW-24	55,209,110	-2,821,654,662	-51.1
Operating Income	***	***	***	0.0

* Lead days for expenses are calculated from the mid-point of the service period to the payment date. (See Schedules 5 - 24.)
** Weighted average of pension and benefits
*** Lead days are assumed to be 0.

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR GAS SUPPLY COSTS

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	39.5	$99,094,680.52	$3,914,239,880.54
November-22	40.0	115,884,345.36	4,635,373,814.40
December-22	41.5	74,391,431.36	3,087,244,401.44
January-23	40.0	96,320,373.22	3,852,814,928.80
February-23	42.0	73,649,684.66	3,093,286,755.72
March-23	40.5	52,804,626.96	2,138,587,391.88
April-23	40.0	66,121,917.38	2,644,876,695.20
May-23	39.5	61,082,234.32	2,412,748,255.64
June-23	41.0	58,289,981.28	2,389,889,232.48
July-23	39.5	47,559,856.26	1,878,614,322.27
August-23	40.0	48,253,319.26	1,930,132,770.40
September-23	40.0	45,401,857.40	1,816,074,296.00
Total Gas Supply Costs	40.3	$838,854,307.98	$33,793,882,744.77

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR SALARY AND WAGES

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	6.9	$6,832,211.19	$47,104,914.05
November-22	6.7	10,847,041.06	72,798,314.73
December-22	8.4	18,917,305.50	159,781,572.16
January-23	8.5	8,095,233.07	68,541,470.42
February-23	7.3	6,883,107.24	50,367,489.43
March-23	7.5	6,953,950.61	51,860,494.88
April-23	8.6	6,972,063.13	59,910,292.00
May-23	7.0	9,991,840.01	69,579,555.28
June-23	8.0	7,361,772.20	59,100,881.82
July-23	7.2	7,529,331.73	54,206,335.91
August-23	8.6	8,243,015.08	71,235,607.09
September-23	6.8	7,315,261.51	49,788,603.08
Total Salary and Wages	7.7	$105,942,132.33	$814,275,530.82

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR PENSIONS

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-23	75.5	$56,381.51	$4,257,424.14
March-23	83.0	18,350.12	1,523,059.96
May-23	115.0	14,487.23	1,666,031.45
June-23	106.5	34,495.42	3,673,762.23
July-23	83.6	46,722.33	3,907,654.90
September-23	73.0	14,677.27	1,071,440.71
Total Pensions	87.0	$185,113.88	$16,099,373.38

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR PEP

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	(13.0)	$48,239.25	-$627,110.25
November-22	(14.5)	48,239.25	-699,469.13
December-22	(15.0)	48,239.25	-723,588.75
January-23	(13.0)	47,620.96	-619,072.48
February-23	(13.5)	47,664.42	-643,469.67
March-23	(15.0)	47,642.69	-714,640.35
April-23	(12.5)	47,642.69	-595,533.63
May-23	(15.0)	47,642.69	-714,640.35
June-23	(14.5)	47,642.69	-690,819.01
July-23	(13.0)	47,642.69	-619,354.97
August-23	(15.2)	100,458.94	-1,530,992.87
Total PEP	(14.1)	$578,675.52	-$8,178,691.44

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR OPEB

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
July-23	48.7	$779,090.26	$37,970,606.53
Total OPEB	48.7	$779,090.26	$37,970,606.53

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR MEDICAL INSURANCE

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	8.0	$2,562,787.18	$20,502,297.44
December-22	19.5	2,560,670.65	49,933,077.68
January-23	8.0	2,323,665.61	18,589,324.88
February-23	427.5	4,588,419.91	1,961,366,082.53
March-23	15.0	2,358,135.22	35,372,028.30
April-23	(5.5)	4,642,646.06	-25,357,677.58
June-23	10.5	2,453,792.14	25,764,817.47
July-23	(2.0)	4,727,255.65	-9,462,216.89
August-23	(15.5)	2,368,161.41	-36,706,501.86
Total Medical Insurance	71.4	$28,585,533.83	$2,040,001,231.97

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR DENTAL INSURANCE

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-23	37.5	$227,239.31	$8,521,474.13
May-23	38.5	94,379.80	3,633,622.30
July-23	76.3	438,096.22	33,422,168.49
Total Dental Insurance	60.0	$759,715.33	$45,577,264.91

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR SHORT TERM DISABILITY

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-23	70.3	$216,772.59	$15,234,514.28
May-23	103.7	239,832.11	24,861,274.29
July-23	58.2	287,791.21	16,739,842.28
Total Short Term Disability	76.4	$744,395.91	$56,835,630.84

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR GROUP LIFE, AD&D, AND LTD

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-23	101.0	$66,363.11	$6,702,674.11
February-23	78.5	66,199.94	5,196,695.29
March-23	51.6	128,976.88	6,655,796.82
April-23	18.0	68,151.84	1,226,733.12
May-23	19.5	68,660.93	1,338,888.14
June-23	20.0	69,107.02	1,382,140.40
July-23	108.8	131,636.74	14,326,618.59
Total Group Life, AD&D, and LTD	61.5	$599,096.46	$36,829,546.46

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR FLEXIBLE SPENDING ACCOUNT

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-23	8.0	$697.50	$5,580.00
February-23	8.5	682.00	5,797.00
March-23	0.0	685.10	0.00
April-23	1.5	685.10	1,027.65
May-23	0.0	678.90	0.00
June-23	10.5	685.10	7,193.55
July-23	10.0	678.90	6,789.00
August-23	1.0	678.90	678.90
September-23	2.5	675.80	1,689.50
Total Flexible Spending Account	4.7	$6,147.30	$28,755.60

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR 401K PLANS

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	5.4	$429,077.25	$2,322,931.29
November-22	5.6	579,511.82	3,261,119.66
December-22	5.7	416,736.94	2,361,331.57
January-23	6.8	499,188.46	3,401,804.13
February-23	5.9	458,642.70	2,691,168.21
March-23	6.1	461,256.25	2,801,589.52
April-23	6.2	465,948.42	2,900,007.82
May-23	5.8	652,356.32	3,782,216.56
June-23	5.4	473,742.02	2,578,682.63
July-23	6.0	476,160.06	2,856,022.73
August-23	6.6	507,758.05	3,329,654.67
September-23	5.4	471,080.08	2,540,809.23
Total 401K Plans	5.9	$5,891,458.37	$34,827,338.00

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR OTHER O&M EXPENSES

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	9.3	$1,183,893.11	$11,043,612.67
November-22	35.2	676,961.70	23,831,278.93
December-22	22.4	665,901.25	14,948,742.07
January-23	(14.6)	621,899.31	-9,051,443.17
February-23	18.6	641,798.78	11,908,532.02
March-23	(28.3)	1,503,571.89	-42,605,192.82
April-23	(0.5)	1,095,884.04	-498,796.12
May-23	17.4	1,234,031.49	21,527,342.11
June-23	13.4	1,793,178.11	23,943,408.68
July-23	31.6	2,518,998.14	79,656,724.70
August-23	39.4	1,513,227.78	59,656,987.86
September-23	13.4	806,459.19	10,776,434.21
Total Other O&M Expenses	14.4	$14,255,804.79	$205,137,631.14

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR CURRENT FEDERAL TAXES

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Service Period		Payment	(Lead)/		Weighted
From	To	Date	Lag Days	Amount	Amount
(1)	(2)	(3)	(4)	(5)	(6)
Federal Income Taxes (Current)					
10/1/22	9/30/23	1/15/23	(76.0)	25%	(19.0)
10/1/22	9/30/23	3/15/23	(17.0)	25%	(4.3)
10/1/22	9/30/23	6/15/23	75.0	25%	18.8
10/1/22	9/30/23	9/15/23	167.0	25%	41.8
Total Federal Income Taxes (Current)			37.3	100%	37.3

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR CURRENT STATE (CBT)

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Service Period From (1)	Service Period To (2)	Payment Date (3)	(Lead)/ Lag Days (4)	Amount (5)		Weighted Amount (6)
Current State (CBT)						
10/1/22	9/30/23	1/15/23	(76.0)	25%		(19.0)
10/1/22	9/30/23	3/15/23	(17.0)	50%		(8.5)
10/1/22	9/30/23	5/20/23	49.0	25%	*	12.3
10/1/22	9/30/23	9/15/23	167.0	0%		0.0
Total Current State (CBT)			(15.3)	100%		(15.3)

* The May UTUA payment is credited agains 4th quarter (9/15/23) payment which would be 25% without the UTUA payment

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR TAXES OTHER THAN INCOME TAX

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Expense	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
Total Payroll Tax (see Sch. 20)	7.7	$10,227,057.28	$78,605,577.53
Total Real Estate Tax (see Sch. 21)	(20.3)	1,459,647.24	-29,568,962.36
Total New Jersey Sales & Use Tax (see Sch. 22)	34.7	562,263.83	19,524,062.56
Total Motor Fuel Tax (see Sch. 23)	33.7	18,712.00	631,304.00
Total Taxes Other than Income Tax	5.6	$12,267,680.35	$69,191,981.73

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR PAYROLL TAX

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount *	Weighted Amount
(1)	(2)	(3)	(4)
October-22	6.9	$659,543.22	$4,547,243.32
November-22	6.7	1,047,112.30	7,027,539.62
December-22	8.4	1,826,170.22	15,424,413.84
January-23	8.5	781,468.25	6,616,607.88
February-23	7.3	664,456.44	4,862,194.00
March-23	7.5	671,295.26	5,006,320.34
April-23	8.6	673,043.74	5,783,402.45
May-23	7.0	964,556.01	6,716,818.74
June-23	8.0	710,664.06	5,705,266.54
July-23	7.2	726,839.31	5,232,774.59
August-23	8.6	795,734.29	6,876,684.65
September-23	6.8	706,174.18	4,806,311.56
Total Payroll Tax	7.7	$10,227,057.28	$78,605,577.53

* Includes employee and employer paid tax allocated on gross pay.

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR REAL ESTATE TAX

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
October-22	114.2	$379,535.07	$43,325,515.16
January-23	(164.1)	357,422.21	-58,664,447.88
April-23	(68.2)	357,421.94	-24,371,348.63
July-23	27.4	357,130.12	9,786,978.90
August-23	43.5	8,137.90	354,340.08
Total Real Estate Tax	(20.3)	$1,459,647.24	-$29,568,962.36

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR NEW JERSEY SALES & USE TAX

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
November-22	35.0	42,165.04	1,475,776.40
December-22	34.5	41,403.17	1,428,409.37
January-23	35.0	55,322.33	1,936,281.55
February-23	35.0	$27,030.74	$946,075.90
March-23	33.5	41,862.25	1,402,385.38
April-23	35.0	59,494.49	2,082,307.15
May-23	34.5	65,184.77	2,248,874.57
June-23	35.0	69,394.41	2,428,804.35
July-23	34.5	78,168.30	2,696,806.35
August-23	35.0	46,409.46	1,624,331.10
September-23	35.0	35,828.87	1,254,010.45
Total New Jersey Sales & Use Tax	34.7	$562,263.83	$19,524,062.56

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR MOTOR FUEL TAX

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
February-23	32.0	$4,173.00	$133,536.00
March-23	33.5	3,002.00	100,567.00
April-23	35.0	2,463.00	86,205.00
May-23	33.5	3,346.00	112,091.00
June-23	35.0	2,578.00	90,230.00
July-23	34.5	3,150.00	108,675.00
Total Motor Fuel Tax	33.7	$18,712.00	$631,304.00

NEW JERSEY NATURAL GAS COMPANY

CALCULATION OF LEAD DAYS FOR NEW JERSEY ENERGY SALES TAX

BASED ON LEAD-LAG STUDY FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
February-23	35.0	$5,761,754.30	$201,661,400.50
March-23	33.5	7,937,005.86	265,889,696.31
April-23	34.0	5,235,424.58	178,004,435.72
May-23	(115.5)	31,425,264.42	-3,631,009,498.35
June-23	34.0	2,671,300.20	90,824,206.80
July-23	33.5	2,178,361.11	72,975,097.19
Total New Jersey Energy Sales Tax	(51.1)	$55,209,110.47	-$2,821,654,661.84

NEW JERSEY NATURAL GAS COMPANY
SUMMARY OF NET ASSETS AND LIABILITIES
13-MONTH AVERAGE BALANCE ENDING NOVEMBER 30, 2023

	13-Month Average Balance Ending November 30, 2023
Assets:	
Cash Balances	$5,012,326
Work Orders	504,074
Third Party Damage	1,064,893
NJ Lifeline	103,832
LI Heap	1,083,816
Employees	222,341
Billing In Progress	10,050,328
Account Receivables	507,852
BCBS	2,258,373
Damage Claims	18,731
Prepaid Comm'L Paper Interest	20,155
Prepaid Commitment Fees	151,507
Pension/OBEB Asset	88,792,683
CSV Life Insurance	1,648,606
Total Assets	$111,439,519
Liabilities	
Pension/OPEB Liability	($57,139,005)
Vouchers	(23,046,429)
Undistributed Invoices	(138,246)
Dental Claim Reserve	(49,900)
Account Payables	(724,836)
VIP Life Insurance Deduction	(28,056)
Allstate Supplemental Insurance	(48,564)
Credit Card Processing	(125,420)
Retainage Payable	(73,108)
Customer Deposits	(14,645,948)
Current and Accrued Liabilities	3,569
Supplemental Retirement	(605,831)
Total Liabilities	($96,621,773)
Net Assets/Liability	$14,817,746

Exhibit P-6

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS SCOTTMADDEN, INC. – PARTNER

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

Q. By whom are you employed and in what capacity?

A. I am a Partner at ScottMadden, Inc.

Q. Please summarize your professional experience and educational background.

A. I have offered expert testimony on behalf of investor-owned utilities before over 35 state regulatory commissions in the United States, in addition to the Federal Energy Regulatory Commission, the Alberta Utility Commission, the Canadian Energy Regulator, an American Arbitration Association panel, and the Superior Court of Rhode Island, on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

II. PURPOSE AND SUMMARY

Q. What is the purpose of your Direct Testimony in this proceeding?

A. The purpose of my Direct Testimony is to present evidence on behalf of New Jersey Natural Gas Company ("NJNG" or the "Company") about the appropriate return on common equity ("ROE") and overall Weighted Average Cost of Capital ("WACC") (*i.e.*, overall rate of return) the Company should be given to ensure it the opportunity to earn a return of and on its jurisdictional rate base. I also support the Company's requested capital structure, which is incorporated into my rate of return analysis.

Q. Have you prepared exhibits in support of your recommendation?

A. Yes. I have prepared Exhibits DWD-1 through 9, which were prepared by me or under my direction.

III. SUMMARY OF RECOMMENDATIONS

Q. What is your recommended ROE for NJNG?

A. I recommend the New Jersey Board of Public Utilities (the "Board") authorize the Company the opportunity to earn an ROE within a range of 10.42% and 12.92%. Within

that range, I recommended an ROE of 10.42%. The requested capital structure consists of 44.58% long-term debt at an embedded cost rate of 4.03% and 55.42% common equity at my recommended ROE of 10.42%. The overall rate of return is summarized on page 1 of Exhibit DWD-1 and in Table 1 below:

Table 1: Summary of Overall Rate of Return

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.58%	4.03%	1.80%
Common Equity	55.42%	10.42%	5.77%
Total	100.00%		7.57%

Q. Please summarize your recommended common equity cost rate.

My recommended common equity cost rate of 10.42% is summarized on Exhibit DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to NJNG. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of six natural gas distribution utilities ("Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a proxy group of 45 domestic, non-price regulated companies comparable in total risk

1 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
2 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

to the Utility Proxy Group ("Non-Price Regulated Proxy Group"). The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	10.32%
Risk Premium Model	11.38%
Capital Asset Pricing Model	12.52%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.82%
Indicated Range	10.32% - 12.82%
Credit Risk Adjustment	-0.09%
Flotation Cost Adjustment	0.19%
Recommended Range	10.42% - 12.92%
Recommended Cost of Common Equity	10.42%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 10.32% and 12.82% before any Company-specific adjustments. My Company-specific indicated range of common equity cost rates, adjusted for Company credit risk and flotation costs, which will be discussed in detail below, is between 10.42% and 12.92%.

IV. GENERAL PRINCIPLES

Q. What general principles have you considered in arriving at your recommended common equity cost rate of 10.42%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also

permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. **By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital**.[3]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Board's decision in this proceeding, therefore, should provide the Company opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks, even

[3] *Hope*, 320 U.S. 591 (1944), at 603 (emphasis added).

if the Company determines that an alternative request is appropriate due to market conditions.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, *i.e.*, for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational risk (*i.e.*, business risk) and financing risk (i.e., financial risk) of the Company's New Jersey utility operations on a stand-alone basis.

Q. Within that broad framework, how is the cost of capital estimated in regulatory proceedings?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. Is the authorized return set in regulatory proceedings guaranteed?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the rate-setting process should provide the utility a reasonable opportunity to recover its return of, and return on, its prudently incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

Business Risk

Q. Please define business risk and explain why it is important for determining a fair rate of return.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may

categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to quantify the effect of any individual risk specifically and numerically on investors' required return, *i.e.*, the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to high risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, whereas long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject necessary capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

Financial Risk

Q. Please define financial risk and explain why it is important in determining a fair rate of return.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.,* failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors demand higher returns as compensation for bearing higher financial risk.

Q. Can bond and credit ratings be a proxy for a firm's combined business and financial risks to equity owners (*i.e.*, investment risk)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e*., total risk) faced by bond investors.[4] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

V. NJNG'S OPERATIONS AND THE UTILITY PROXY GROUP

Q. Are you familiar with NJNG's operations?

A. Yes. The Company distributes natural gas to approximately 569,300 residential and commercial customers in the Burlington, Middlesex, Monmouth, Morris, Ocean, and Sussex counties in New Jersey. The Company's operations are not publicly traded as it is

[4] Risk distinctions within S&P Global's ("S&P") bond rating categories are recognized by a plus or minus, *e.g*., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's Investors Services ("Moody's") ratings are distinguished by numerical rating gradations, *e.g*., within the A category, a Moody's rating can be A1, A2 and A3.

a wholly owned subsidiary of New Jersey Resources Corporation, which is traded on the New York Stock Exchange under ticker "NJR".

Q. Why is it necessary to develop a proxy group when estimating the ROE for the Company?

A. It is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for NJNG because the Company is not publicly traded and does not have publicly traded equity securities. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[5]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

[5] The development of the Non-Price Regulated Proxy Group is explained in more detail below.

Q. Please explain how you chose the companies in the Utility Proxy Group.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* ("*Value Line*") (November 24, 2023);

(ii) They have 60% or greater of fiscal year 2022 total operating income derived from, or 60% or greater of fiscal year 2022 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another);

(iv) They have not cut or omitted their common dividends during the five years ended 2022 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following six companies met these criteria: Atmos Energy Corporation, NJR, NiSource Inc., Northwest Natural Gas Company, ONE Gas, Inc., and Spire, Inc. Exhibit DWD-2 contains comparative capitalization and financial statistics for the Utility Proxy Group for the years 2018 to 2022.

Q. Do you believe that a proxy group of six companies is sufficiently large?

A. Yes, I do. My objective in selecting the Utility Proxy Group is to develop a proxy group that is highly representative of the risks and prospects faced by NJNG. Therefore, I

developed and used selection criteria to accomplish that objective. Including additional companies solely for the purpose of increasing the size of the Utility Proxy Group is not reasonable because it would produce results that may be less representative of the risks and prospects faced by NJNG.

VI. CAPITAL STRUCTURE

Q. What is NJNG's requested capital structure?

A. The Company's requested capital structure consists of 44.58% long-term debt and 55.42% common equity, as shown on Exhibit DWD-1. NJNG's requested capital structure is its projected capital structure as of June 30, 2024.

Q. Does NJNG have a separate capital structure that is recognized by investors?

A. Yes. NJNG is a separate corporate entity that has its own capital structure and issues its own debt through the private placement market.

Q. What are the typical sources of capital commonly considered in establishing a utility's capital structure?

A. Common equity and long-term debt are commonly considered in establishing a utility's capital structure because they are the typical sources of capital financing a utility's rate base.

Q. Please explain.

A. Long-lived assets are typically financed with long-lived securities, so that the overall term structure of the utility's long-term liabilities (both debt and equity) closely match the life of the assets being financed. As stated by Brigham and Houston:

> In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term

assets from short-term sources and long-term assets from long-term sources.[6]

Whereas short-term debt has a maturity of one year or less, long-term debt may have maturities of 30 years or longer. Although there are practical financing constraints, such as the need to "stagger" long-term debt maturities, the general objective is to extend the average life of long-term debt. Still, long-term debt has a finite life, which is likely to be less than the life of the assets included in rate base. Common equity, on the other hand, is outstanding into perpetuity. Thus, common equity more accurately matches the life of the going concern of the utility, which is also assumed to operate in perpetuity. Consequently, it is both typical and important for utilities to have significant proportions of common equity in their capital structures.

Q. Why is it important that NJNG's recommended capital structure, consisting of 44.58% long-term debt and 55.42% common equity, be authorized in this proceeding?

A. As a preliminary matter, NJNG's recommended capital structure is comparable to its historical capital structure, and is within a reasonable range from the perspective of the Utility Proxy Group companies.[7] The use of an operating subsidiary's capital structure is consistent with the Federal Energy Regulatory Commission ("FERC") precedent, under which they use the applicant's capital structure, where possible.[8] In particular, the FERC will use the utility operating company's capital structure if it meets three criteria: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital

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6 Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, at 574.

7 *See* Exhibit DWD-2.

8 *See, Transcontinental Gas Pipe Line Corp,* 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

structure within the range of capital structures approved by the commission.[9] NJNG meets all of these criteria.

In order to provide safe, reliable, and affordable service to its customers, NJNG must meet the needs and serve the interests of its various stakeholders, including customers, shareholders, and bondholders. The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong credit ratings, and a supportive regulatory environment so that NJNG has access to capital on reasonable terms in order to make necessary investments.

Safe and reliable service cannot be maintained and necessary investments cannot be made at a reasonable cost if utilities do not have the financial flexibility and strength to access competitive financing markets on reasonable terms. An appropriate capital structure is important not only to ensure long-term financial integrity, it also is critical to enabling access to capital during constrained markets, or when near-term liquidity is needed to fund extraordinary requirements. In that important respect, the capital structure, and the financial strength it engenders, must support both normal circumstances and periods of market uncertainty. The authorization of a capital structure that understates NJNG's actual common equity will weaken the financial condition of its operations and adversely impact NJNG's ability to address expenses and investments, to the detriment of its customers and shareholders.

Consequently, NJNG's recommended capital structure should be used to set rates in this proceeding.

[9] 148 FERC ¶ 61,049, Docket No. EL14-12-000, at 190.

Q. How does NJNG's common equity ratio of 55.42% compare with the common equity ratios maintained by the Utility Proxy Group?

A. NJNG's common equity ratio of 55.42% is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy Group. As shown on Exhibit DWD-2, common equity ratios of the Utility Proxy Group companies ranged from 34.43% to 62.21% for fiscal year 2022.[10]

In addition to comparing NJNG's actual common equity ratio with common equity ratios currently maintained by the Utility Proxy Group, I also compared the Company's actual common equity ratio with the equity ratios maintained by the operating subsidiaries of the Utility Proxy Group companies. As shown on Exhibit DWD-2, common equity ratios of the operating utility subsidiaries of the Utility Proxy Group ranged from 48.85% to 60.24% for fiscal year 2022.

VII. COMMON EQUITY COST RATE MODELS

Q. Is it important that cost of equity models be market based?

A. Yes. A public utility must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those comparable risk companies. When individual investors choose to invest capital among companies of comparable risk, they will choose a company which provides a higher return over a company providing a lower return.

[10] The fiscal year for Atmos Energy Corporation, NJR, and Spire, Inc. is the twelve months ending September 30, 2022, for all other companies in the Utility Proxy Group the fiscal year is the twelve months ending December 31, 2022.

Q. Are your cost of equity models market based?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. Regarding the RPM, the total market risk premium approach uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk, and the Predictive Risk Premium Model ("PRPM") uses monthly market returns in addition to expectations of the risk-free rate. In addition, betas ("β"), which reflect the market/systematic risk component of equity risk premiums, are derived from regression analyses of market prices. The CAPM is market based for many of the same reasons that the RPM is market based (*i.e.*, the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. What analytical approaches did you use to determine the Company's ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I applied to the Utility Proxy Group. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (*i.e.,* the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple

generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

The DCF Model

Q. What is the theoretical basis of the DCF model?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate, *i.e.*, the total common equity return rate expected by investors as shown below:

$$K_e = (D_0 (1+g))/P + g$$

where:
K_e = the required Return on Common Equity;
D_0 = the annualized Dividend Per Share;
P = the current stock price; and
g = the growth rate.

Q. Which version of the DCF model did you use?

A. I used the single-stage constant growth DCF model in my analyses.

Q. Please describe the dividend yield you used in applying the constant growth DCF model.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of November 30, 2023, divided by the average closing market price for the 60 trading days ended November 30, 2023.[11]

[11] *See*, column 1, page 1 of Exhibit DWD-3.

Q. Please explain your adjustment to the dividend yield.

A. Because dividends are paid periodically (*e.g.*, quarterly), as opposed to continuously (*e.g.*, daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Exhibit DWD-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

Q. Please explain the basis for the growth rates you applied to the Utility Proxy Group in your constant growth DCF model.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' ability to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a

better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. Please summarize the constant growth DCF model results.

A. As shown on page 1 of Exhibit DWD-3, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 10.61%, the median result is 10.03%, and the average of the two is 10.32%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. This approach considers all the proxy utilities' results, while mitigating the high and low outliers of those individual results.

The RPM

Q. Please describe the theoretical basis of the RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. Please explain your RPM approach.

A. My RPM approach adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium; (2) an equity risk premium based on the S&P Utilities Index; and (3) an equity risk premium based on authorized ROEs for gas distribution utilities.

Q. Please explain the basis of the expected bond yield of 5.94% applicable to the Utility Proxy Group.

A. The first step in my RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the first quarter of 2025, and *Blue Chip's* long-term projections for 2025 to 2029, and 2030 to 2034. As shown on line 1, page 1 of Exhibit DWD-4, the average expected yield on Moody's Aaa-rated corporate bonds is 5.20%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.74%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield.[12] Adding that recent 0.74% spread to the expected Aaa-rated corporate bond yield of 5.20% results in an expected A2-rated public utility bond yield of 5.94%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2, no other

[12] As shown on line 2 and explained in note 2, page 1 of Exhibit DWD-4.

adjustment is needed to make the A2 prospective bond yield applicable to the A2-rated public utility bond. The results are a 5.94% expected bond yield applicable to the Utility Proxy Group.

Table 3: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[13]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	5.20%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.74%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.94%

To develop the indicated ROE using the total market approach RPM, this prospective bond yield is then added to the average of the three different equity risk premiums described below.

Q. Please explain how the beta-derived equity risk premium is determined.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9 on page 6 of Exhibit DWD-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. How did you derive a market equity risk premium based on long-term historical data?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation

[13] As shown on page 1 of Exhibit DWD-4.

("SBBI") Yearbook 2023 ("SBBI-2023")[14] less the average historical yield on Moody's Aaa/Aa2-rated corporate bonds for the period 1928 to 2022. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.78%, and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa2-rated corporate bonds was 5.96%.[15] As shown on line 1 on page 6 of Exhibit DWD-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.82%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa2 corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI-2023.[16] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

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14 *See,* SBBI-2023 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2022.
15 As explained in note 1, page 7 of Exhibit DWD-4.
16 *See,* SBBI-2023, at 194.

Q. Please explain the derivation of the regression-based market equity risk premium.

A. To derive the regression-based market equity risk premium of 6.90% shown on line 2 of page 6 of Exhibit DWD-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa2-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa2-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

Q. Please explain the derivation of the PRPM equity risk premium.

A. The PRPM, published in the *Journal of Regulatory Economics,*[17] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")".[18] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an

[17] Autoregressive conditional heteroscedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. *The Journal of Regulatory Economics* (December 2011), 40:261-278.

[18] www.nobelprize.org.

estimate of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through November 2023.[19] A generalized form of ARCH, known as GARCH was applied to the historical return data, to produce a predicted GARCH variance series and a GARCH coefficient using Eviews© statistical software. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[20] produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 8.40%.[21]

Q. Please explain the derivation of a projected equity risk premium based on *Value Line* data for your RPM analysis.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4 on page 7 of Exhibit DWD-4. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended December 1, 2023, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.

The average median expected price appreciation is 64%, which translates to a 13.16% annual appreciation, and, when added to the average of *Value Line's* median

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19 Data from January 1928 to December 2022 is from SBBI-2023. Data from January 2023 to September 2023 is from Bloomberg.

20 Annualized Return = (1 + Monthly Return) ^12 - 1.

21 Shown on line 3, page 6 of Exhibit DWD-4.

expected dividend yields of 2.35%, equates to a forecasted annual total return rate on the market of 15.51%. The forecasted Moody's Aaa-rated corporate bond yield of 5.20% is deducted from the total market return of 15.51%, resulting in an equity risk premium of 10.31%, as shown on line 4 of page 6 of Exhibit DWD-4.

Q. Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 14.21%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.20% results in a 9.01% projected equity risk premium.

Q. Please explain the derivation of an equity risk premium based on Bloomberg data.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation identical to the method described above. The expected total return for the S&P 500 is 18.21%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.20% results in a 13.01% projected equity risk premium.

Q. What is your conclusion of a beta-derived equity risk premium for use in your RPM analysis?

A. I gave equal weight to all six equity risk premiums based on each source - historical, *Value Line*, and Bloomberg - in arriving at an 8.91% equity risk premium.

Table 4: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[22]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2022)	5.82%
Regression Analysis on Historical Data	6.90%
PRPM Analysis on Historical Data	8.40%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	10.31%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	9.01%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	13.01%
Average	8.91%

After calculating the average market equity risk premium of 8.91%, I adjusted it by the beta to account for the risk of the Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Exhibit DWD-5, the average of the mean and median beta for the Utility Proxy Group is 0.80. Multiplying the 0.80 average by the market equity risk premium of 8.91% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 7.13%.

Q. How did you derive the equity risk premium based on the S&P Utility Index and Moody's A2-rated public utility bonds?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium

[22] As shown on page 6 of Exhibit DWD-4.

between the S&P Utility Index total returns of 10.63%, and monthly Moody's A2-rated public utility bond yields of 6.44% from 1928 to 2022, to arrive at an equity risk premium of 4.20%.[23] I then used the same historical data to derive an equity risk premium of 4.75% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to November 2023 to arrive at a PRPM-derived equity risk premium of 4.84% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 10.55% and 10.24% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 5.94%[24], which resulted in equity risk premiums of 4.61% and 4.30%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 4.54%.

Table 5: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[25]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2022)	4.20%
Regression Analysis on Historical Data	4.75%
PRPM Analysis on Historical Data	4.84%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	4.61%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	4.30%
Average	4.54%

[23] As shown on line 1, page 10 of Exhibit DWD-4.
[24] Derived on line 3, page 1 of Exhibit DWD-4.
[25] As shown on page 10 of Exhibit DWD-4.

Q. How did you derive an equity risk premium of 4.66% based on authorized ROEs for gas distribution utilities?

A. The equity risk premium of 4.66% shown on line 3 of page 5 of Exhibit DWD-4 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 11 of Exhibit DWD-4, which contains the graphical results of a regression analysis of 829 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through November 30, 2023. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision.

It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[26] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 5.94%. Given the expected A2-rated utility bond yield of 5.94%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.66%, which is shown on line 3 of page 5 of Exhibit DWD-4.

Q. What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. The equity risk premium I applied to the Utility Proxy Group is 5.44%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities

[26] *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33 to 45.

Index, and the authorized return utility equity risk premiums of 7.13%, 4.54%, and 4.66%, respectively.[27]

Q. What is the indicated RPM common equity cost rate based on the total market approach?

A. As shown on line 5 of page 1 of Exhibit DWD-4, I calculated a common equity cost rate of 11.38% for the Utility Proxy Group based on the total market approach RPM.

Table 6: Summary of the Total Market Return Risk Premium Model[28]

Prospective Moody's A2-Rated Utility Bond Applicable to the Utility Proxy Group	5.94%
Prospective Equity Risk Premium	5.44%
Indicated Cost of Common Equity	11.38%

The CAPM

Q. Please explain the theoretical basis of the CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk

[27] As shown on page 5 of Exhibit DWD-4.
[28] As shown on page 1 of Exhibit DWD-4.

of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
R_s = Return rate on the common stock
R_f = Risk-free rate of return
R_m = Return rate on the market as a whole
β = Adjusted beta (volatility of the security relative to the market as a whole)

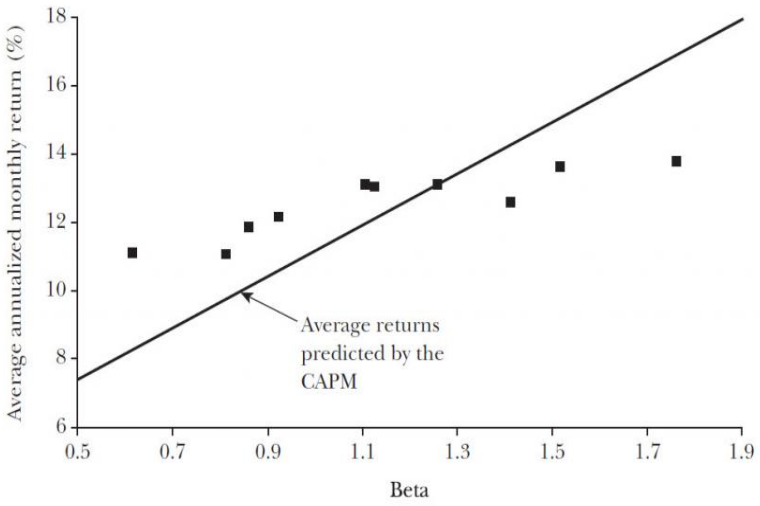
Numerous tests of the CAPM have measured the extent to which security returns and betas are related as predicted by the CAPM, confirming its validity. The Empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[29]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2 below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[30]

[29] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at 223. ("Morin")
[30] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33. ("Fama & French")

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[31]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,(R_M - R_F) + (1-x)\;\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[32]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the

[31] Morin, at 207.
[32] Morin, at 221.

> average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regression tests, like Fama and French (1992).[33]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Lintner CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.[34]

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. What beta coefficients did you use in your CAPM analysis?

A. For the betas in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of the beta to regress to the market mean of 1.00, *Value Line* calculates the beta over a five-year period, while Bloomberg calculates it over a two-year period.

Q. Please describe your selection of a risk-free rate of return.

A. As discussed previously, the risk-free rate adopted for both applications of the RPM and the CAPM is 4.44%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the first calendar quarter of 2025, and long-term projections for the years 2025 to 2029 and 2030 to 2034.

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[33] Fama & French, at 32.
[34] *Ibid.,* at 33.

Q. Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

A. The basis of the market risk premium is explained in detail in note 1 on Exhibit DWD-5. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.00% was deducted from the SBBI-2023 monthly historical total market return of 12.03%, which resulted in an historical market equity risk premium of 7.03%.[35] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI-2023. That regression analysis yielded a market equity risk premium of 7.96%. The PRPM market equity risk premium is 9.38% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through November 2023.

The *Value Line*-derived forecasted total market equity risk premium is determined by deducting the forecasted risk-free rate of 4.44%, discussed above, from the *Value Line* projected total annual market return of 15.51%, resulting in a forecasted total market equity risk premium of 11.07%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 4.44% from the projected total return of the S&P 500 of 14.21%. The resulting market equity risk premium is 9.77%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 4.44% from the projected total return of the S&P 500 of 18.21%. The resulting market equity risk premium is 13.77%. These

[35] SBBI-2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

six measures, when averaged, result in an average total market equity risk premium of 9.83%.

Table 7: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[36]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2022)	7.03%
Regression Analysis on Historical Data	7.96%
PRPM Analysis on Historical Data	9.38%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	11.07%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	9.77%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	13.77%
Average	9.83%

Q. What are the results of your application of the CAPM and ECAPM to the Utility Proxy Group?

A. As shown on page 1 of Exhibit DWD-5, the mean result of my CAPM/ECAPM analyses is 12.49%, the median is 12.55%, and the average of the two is 12.52%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 12.52%.

Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. Why do you also consider a proxy group of domestic, non-price regulated companies?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive

[36] As shown on page 2 of Exhibit DWD-5.

marketplace make an excellent proxy group if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. How did you select non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 45 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;

(iii) Their betas must lie within plus or minus two standard deviations of the average unadjusted betas of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. Have you prepared an exhibit showing the data from which you selected the 45 domestic, non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. Yes. The basis of my selection and both proxy groups' regression statistics are shown in Exhibit DWD-6.

Q. Did you calculate common equity cost rates using the DCF model, RPM, and CAPM for the Non-Price Regulated Proxy Group?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception, however, is in the application of the RPM, where I did not use public utility-specific equity risk premiums.

Page 2 of Exhibit DWD-7 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group is 10.69%.

Pages 3 through 5 of Exhibit DWD-7 contain the data and calculations that support the 13.68% RPM common equity cost rate. As shown on line 1 of page 3 of Exhibit DWD-7, the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the first quarter of 2024, and for the years 2025 to 2029 and 2030 to 2034, is 6.23%.[37] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa1, a downward adjustment of 0.30%[38] to the projected Baa2 corporate bond yield is necessary to reflect the difference in ratings, which results in a projected Baa1 corporate bond yield of 5.93%.

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37 *Blue Chip Financial Forecasts*, December 1, 2023, at 2 and 14.

38 As demonstrated in line 2 and described in note 2 of page 3 of Exhibit DWD-7.

When the beta-adjusted risk premium of 7.75%[39] relative to the Non-Price Regulated Proxy Group is added to the adjusted prospective Baa1-rated corporate bond yield of 5.93%, the indicated RPM common equity cost rate is 13.68%.

Page 6 of Exhibit DWD-7 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 13.13%.

Q. How is the cost rate of common equity based on the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group?

A. As shown on page 1 of Exhibit DWD-7, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is comparable in total risk to the Utility Proxy Group -- are as follows: 10.69% (DCF), 13.68% (RPM), and 13.13% (CAPM). The average of the mean and median of these models is 12.82%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VIII. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. What are the indicated common equity cost rates before adjustments?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates before any relative risk adjustment is between 10.32% and 12.82%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

[39] Derived on page 5 of Exhibit DWD-7.

Based on these common equity cost rate results, I conclude that a common equity cost rate between 10.32% and 12.82% is reasonable and appropriate before any adjustments for relative risk differences between NJNG and the Utility Proxy Group are made.

IX. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Size Adjustment

Q. Does a company's size relative to the Utility Proxy Group companies impact its business risk?

A. Yes. A smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for a utility because, all else being equal, size has a material bearing on risk. Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of

> equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[40]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity, noting:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns that are not captured by the market return and are priced separately from market betas.[41]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[42] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firm stocks have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in the stock market that are higher than those of large firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms.** (emphasis added)[43]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity.

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[40] Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Equity Returns, at 1.

[41] Fama & French, at 38.

[42] Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

[43] Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Q. Is a relative risk adjustment due to NJNG's small size relative to the Utility Proxy Group necessary in this proceeding?

A. No. The Company has similar relative risk to the average company in the Utility Proxy Group because, as shown in Table 8, below and Exhibit DWD-8, NJNG is similar in size to the Utility Proxy Group companies. I measured NJNG's size based on an estimated market capitalization of common equity for NJNG (whose common stock is not publicly traded).

Table 8: Size as Measured by Market Capitalization for NJNG and the Utility Proxy Group

	Market Capitalization*	Times Greater than The Company
	($ Millions)	
New Jersey Natural Gas	$2,732.467	
Utility Proxy Group Median	$3,632.218	1.3x
*From page 1 of Exhibit DWD-8.		

NJNG's estimated market capitalization was $2,732.467 million,[44] compared with the median market capitalization of the Utility Proxy Group of $3,632.218 million, as of November 30, 2023. The Utility Proxy Group's market capitalization is 1.3 times the size of NJNG's estimated market capitalization.

As a result, it is necessary to consider if an upward adjustment to the indicated range of common equity cost rates to reflect NJNG's greater risk due to its smaller relative size is necessary. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2022 period. The average size premium for the Utility Proxy

[44] $2,732.467M = $1,861.354M (requested rate base * requested equity ratio) * 146.8% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Exhibit DWD-8.

Group with a market capitalization of $3,632.218 million falls in the 5th decile, while NJNG's market capitalization of $2,732.467 million also places the Company in the 5th decile. As such, an adjustment to the Company's indicated ROE to reflect its smaller size is not necessary in this proceeding.

Credit Risk Adjustment

Q. Please discuss your proposed credit risk adjustment.

A. The Company's long-term issuer rating is A1 from Moody's, which is slightly less risky than the average long-term issuer ratings for the Utility Proxy Group of A2.[45] Hence, a downward credit risk adjustment is necessary to reflect the lower credit rating, *i.e.,* A1, of the Company relative to the A2 average Moody's bond rating of the Utility Proxy Group.[46]

An indication of the magnitude of the necessary adjustment to reflect the lower credit risk inherent in an A1 bond rating is one-third of a recent three-month average spread between Moody's A2 and Baa2 public utility bond yields of 0.27%, as shown on page 2 of Exhibit DWD-4, or 0.09%.[47]

Flotation Cost Adjustment

Q. What are flotation costs?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include the essential costs of issuance (*e.g.,* market pressure, underwriting fees, and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

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45 Source of Information: S&P Global Market Intelligence. NJNG is not rated by S&P.

46 As shown on page 3 of Exhibit DWD-4.

47 0.09% = 0.27% * (1/3). Moody's does not provide public utility bond yields A1-rated bonds. As such, it was necessary to estimate the difference between A2-rated and A1-rated public utility bonds. Because there are three steps between Baa2 and A2 (Baa2 to Baa1, Baa1 to A3, and A3 to A2) I assumed an adjustment of one-third of the difference between the A2-rated and Baa2-rated public utility bond yield was appropriate to reflect the proxy group's average rating of A2.

Q. Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recovered. Because these costs are real and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[48]

Q. Should flotation costs be recognized only when there was an issuance during the Test Year or there is an imminent Post-Test Year issuance of additional common stock?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to the common equity cost rate, even when there has been neither an issuance during the Test Year nor an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing

[48] Morin, at. 329.

market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested $1.00 (*i.e.*, a return of $0.10), the company needs to earn approximately 10.50% on its invested $0.95 to receive a $0.10 return.

Q. Do the common equity cost rate models you have used already reflect investors' anticipation of flotation costs?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[49] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[50] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. How did you calculate the flotation cost allowance for NJNG?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves,

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[49] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, Thomson/South-Western, 2007, at 342.

[50] Morin, at 337-339.

as well as Morin. Based on the issuance costs shown on page 1 of Exhibit DWD-9, an adjustment of 0.19% is required to reflect the flotation costs applicable to NJNG.

Q. What is the indicated range of common equity cost rates after your company-specific adjustments?

A. Applying the negative 0.09% credit risk adjustment and the 0.19% flotation cost adjustment to the indicated cost of common equity range of 10.32% to 12.82% results in a Company-specific range of common equity cost rates between 10.42% and 12.92%.

X. CONCLUSION

Q. What is your recommended ROE for NJNG?

A. Given the indicated ROE range applicable to the Utility Proxy Group of 10.32% to 12.82%, and the Company-specific ROE range of 10.42% to 12.92%, I conclude that an appropriate ROE for the Company in this proceeding is 10.42%.

Q. In your opinion, is your recommended ROE of 10.42% fair and reasonable to NJNG's shareholders and its customers?

A. Yes, it is.

Q. in your opinion, is NJNG'S proposed capital structure consisting of 44.58% long-term debt and 55.42% common equity fair and reasonable?

A. Yes, it is.

Q. Does this conclude your Direct Testimony?

A. Yes, it does. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

Exhibit P-6
Appendix A
Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

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MANAGEMENT CONSULTANTS

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 15 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 35 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

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MANAGEMENT CONSULTANTS

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure

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MANAGEMENT CONSULTANTS

Exhibit P-6
Appendix A
Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return

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MANAGEMENT CONSULTANTS

Sponsor	Date	Case/Applicant	Docket No.	Subject
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				

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MANAGEMENT CONSULTANTS

Sponsor	Date	Case/Applicant	Docket No.	Subject
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return

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MANAGEMENT CONSULTANTS

Exhibit P-6
Appendix A
Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

New Jersey Natural Gas Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	44.58%	4.03%	(1)	1.80%
Common Equity	55.42%	10.42%	(2)	5.77%
Total	100.00%			7.57%

Notes:
(1) Company-provided.
(2) From page 2 of this Exhibit.

New Jersey Natural Gas Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Distribution Companies
1.	Discounted Cash Flow Model (DCF) (1)	10.32%
2.	Risk Premium Model (RPM) (2)	11.38%
3.	Capital Asset Pricing Model (CAPM) (3)	12.52%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.82%
5.	Indicated Range of Common Equity Cost Rates before Adjustment for Company-specific Risk	10.32% - 12.82%
6.	Credit Risk Adjustment (5)	-0.09%
7.	Flotation Cost Adjustment (6)	0.19%
8.	Recommended Range of Common Equity Cost Rates after Adjustment for Company-specic Risk	10.42% - 12.92%
9.	Recommended Common Equity Cost Rate	10.42%

(2) From page 1 of Exhibit DWD-4.
(3) From page 1 of Exhibit DWD-5.
(4) From page 1 of Exhibit DWD-7.
(5) Company-specific risk adjustment to reflect the Companies' greater lower credit risk due to a higher long-term rating relative to the proxy group as detailed in Mr. D'Ascendis' Direct Testimony.
(6) From page 1 of Exhibit DWD-9.

New Jersey Natural Gas Company
CAPITALIZATION AND FINANCIAL STATISTICS (1)
2018 - 2022, Inclusive

	2022	2021	2020	2019	2018	5 YEAR AVERAGE
			(MILLIONS OF DOLLARS)			
Capitalization Statistics						
Amount of Capital Employed						
Total Permanent Capital	$8,225.462	$7,455.217	$6,855.835	$6,012.401	$5,411.345	
Short-Term Debt	$703.086	$415.467	$333.183	$612.061	$629.275	
Total Capital Employed	$8,928.548	$7,870.684	$7,189.018	$6,624.462	$6,040.620	
Indicated Average Capital Cost Rates (2)						
Total Debt	3.10 %	2.95 %	3.29 %	3.63 %	3.57 %	
Preferred Stock	4.84 %	5.33 %	6.19 %	4.60 %	2.64 %	
Capital Structure Ratios						
Based on Total Permanent Capital:						
Long-Term Debt	49.01 %	50.18 %	50.04 %	46.42 %	46.02 %	48.33 %
Preferred Stock	2.16	2.31	1.78	1.92	1.14	1.86
Common Equity	48.83	47.51	48.18	51.66	52.84	49.81
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Based on Total Capital:						
Total Debt, Including Short-Term Debt	53.55 %	54.26 %	53.51 %	51.06 %	51.14 %	52.70 %
Preferred Stock	1.93	2.18	1.66	1.68	0.99	1.69
Common Equity	44.52	43.56	44.83	47.26	47.87	45.61
Total	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Financial Statistics						
Financial Ratios - Market Based						
Earnings / Price Ratio	5.55 %	5.25 %	3.45 %	3.84 %	4.32 %	4.48 %
Market / Average Book Ratio	184.08	176.32	191.60	224.79	213.85	198.13
Dividend Yield	3.31	3.42	3.09	2.60	2.77	3.04
Dividend Payout Ratio	58.56	60.27	83.22	69.25	54.00	65.06
Rate of Return on Average Book Common Equity	10.54 %	9.85 %	6.75 %	8.68 %	9.55 %	9.08 %
Total Debt / EBITDA (3)	5.05 x	5.10 x	6.03 x	4.96 x	5.01 x	5.23 x
Funds from Operations / Total Debt (4)	14.42 %	11.70 %	12.46 %	14.99 %	24.21 %	15.55 %
Total Debt / Total Capital	53.56 %	54.26 %	53.51 %	51.06 %	51.14 %	52.71 %

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, and are based upon financial statements as originally reported in each year.
(2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.
(3) Total debt relative to EBITDA (Earnings before Interest, Income Taxes, Depreciation and Amortization).
(4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Six Natural Gas Distribution Companies
2018 - 2022, Inclusive

	2022	2021	2020	2019	2018	5 YEAR AVERAGE
Atmos Energy Corporation						
Long-Term Debt	37.96 %	39.35 %	40.02 %	38.03 %	39.15 %	38.90 %
Preferred Stock	-	-	-	-	-	-
Common Equity	62.04	60.65	59.98	61.97	60.85	61.10
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
New Jersey Resources Corporation						
Long-Term Debt	57.77 %	57.81 %	55.35 %	50.11 %	47.89 %	53.79 %
Preferred Stock	-	-	-	-	-	-
Common Equity	42.23	42.19	44.65	49.89	52.11	46.21
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NiSource Inc.						
Long-Term Debt	56.43 %	57.09 %	61.64 %	56.79 %	55.44 %	57.48 %
Preferred Stock	9.14	9.55	5.87	6.35	6.82	7.54
Common Equity	34.43	33.36	32.49	36.86	37.74	34.98
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Northwest Natural Holding Company						
Long-Term Debt	52.70 %	52.12 %	51.81 %	50.43 %	49.12 %	51.24 %
Preferred Stock	-	-	-	-	-	-
Common Equity	47.30	47.88	48.19	49.57	50.88	48.76
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
ONE Gas, Inc.						
Long-Term Debt	37.79 %	41.74 %	41.76 %	37.65 %	38.62 %	39.51 %
Preferred Stock	-	-	-	-	-	-
Common Equity	62.21	58.26	58.24	62.35	61.38	60.49
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Spire Inc.						
Long-Term Debt	51.42 %	52.98 %	49.62 %	45.49 %	45.95 %	49.09 %
Preferred Stock	3.84	4.28	4.83	5.19	-	3.63
Common Equity	44.74	42.74	45.55	49.32	54.05	47.28
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Six Natural Gas Distribution Companies						
Long-Term Debt	49.01 %	50.18 %	50.04 %	46.42 %	46.02 %	48.33 %
Preferred Stock	2.16	2.31	1.78	1.92	1.14	1.86
Common Equity	48.83	47.51	48.18	51.66	52.84	49.81
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

New Jersey Natural Gas Company
Operating Subsidiary Company Capital Structures of the
Proxy Group of Six Natural Gas Distribution Companies

		2022		
Company Name	Parent Company Ticker	Common Equity	Long Term Debt	Total Capital
Atmos Energy Corporation	ATO	53.50%	46.50%	100.00%
New Jersey Natural Gas Company	NJR	55.04%	44.96%	100.00%
Northern Indiana Public Service Company	NI	56.92%	43.08%	100.00%
Northwest Natural Gas Company	NWN	49.70%	50.30%	100.00%
ONE Gas, Inc.	OGS	48.85%	51.15%	100.00%
Spire Alabama Inc.	SR	60.24%	39.76%	100.00%
Spire Missouri Inc.	SR	51.56%	48.44%	100.00%
	Maximum	60.24%	51.15%	
	Minimum	48.85%	39.76%	

Source:
S&P Global Market Intelligence.
Northern Indiana Public Service Company is from FERC financial Report Form Form No. 2 at PDF 14.

New Jersey Natural Gas Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Utility Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Six Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.91 %	7.00 %	7.30 %	7.50 %	7.27 %	3.02 %	10.29 %
New Jersey Resources Corporation	4.00	5.00	6.00	6.00	5.67	4.11	9.78
NiSource Inc.	3.88	9.50	7.20	8.30	8.33	4.04	12.37
Northwest Natural Holding Company	5.10	6.50	3.70	2.80	4.33	5.21	9.54
ONE Gas, Inc.	3.93	6.50	5.00	5.00	5.50	4.04	9.54
Spire Inc.	5.19	8.00	5.60	NA	6.80	5.37	12.17
						Average	10.61 %
						Median	10.03 %
						Average of Mean and Median	10.32 %

Notes:

(1) Indicated dividend at 11/30/2023 divided by the average closing price of the last 60 trading days ending 11/30/2023 for each company.
(2) From pages 2 through 7 of this Exhibit
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.91% x (1+(1/2 x 7.27%)) = 3.02%.
(5) Column 5 + Column 6.

Source of Information: Value Line Investment Survey.
www.zacks.com, Downloaded on 11/30/2023.
www.yahoo.com, Downloaded on 11/30/2023.

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 111.12 | P/E RATIO 17.1 (Trailing: 18.1 Median: 20.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 11/24/23
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 11/10/23
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$94-$159	$127 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+45%)	*12%*
Low	130	(+15%)	*7%*

Institutional Decisions

	4Q2022	1Q2023	2Q2023
to Buy	345	337	314
to Sell	266	258	281
Hld's(000)	132007	131736	136508

	2007	2008	2009	2010	2011	2012
High:	37.3	47.4	58.2	64.8	82.0	93.6
Low:	30.4	34.9	44.2	50.8	60.0	72.5

LEGENDS
36.50 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Percent shares traded: 24, 16, 8

Target Price Range 2026 2027 2028: 200, 160, 100, 80, 60, 50, 40, 30, 20

% TOT. RETURN 10/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.6	-0.7
3 yr.	26.8	33.7
5 yr.	29.6	41.5

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	*28.50*	*30.95*	Revenues per sh [A]	*44.10*
4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	*9.95*	*10.80*	"Cash Flow" per sh	*12.60*
1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	*6.55*	Earnings per sh [AB]	*7.85*
1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	*3.22*	Div'ds Decl'd per sh [C]	*3.90*
4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	*18.70*	*18.70*	Cap'l Spending per sh	*21.50*
22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	*72.35*	*72.75*	Book Value per sh	*79.40*
89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	*150.00*	*155.00*	Common Shs Outst'g [D]	*170.00*
15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7		Avg Ann'l P/E Ratio	*18.5*
.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08		Relative P/E Ratio	*1.05*
4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%		Avg Ann'l Div'd Yield	*2.7%*
3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	*4800*	Revenues ($mill) [A]	*7500*
230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	*985*	Net Profit ($mill)	*1325*
38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	*15.0%*	Income Tax Rate	*25.0%*
5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	*20.5%*	Net Profit Margin	*17.7%*
48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	*38.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	*62.0%*	*60.0%*	Common Equity Ratio	*60.0%*
5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	*17500*	*18800*	Total Capital ($mill)	*22500*
6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	*19600*	*20700*	Net Plant ($mill)	*25000*
5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	*8.0%*	*8.5%*	Return on Shr. Equity	*10.0%*
8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	*8.0%*	*8.5%*	Return on Com Equity	*10.0%*
4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
56%	50%	51%	50%	50%	48%	48%	49%	49%	49%	*49%*	*51%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 6/30/23
Total Debt $6650.1 mill. **Due in 5 Yrs** $2900.0 mill.
LT Debt $6642.6 mill. **LT Interest** $125.0 mill.
(LT interest earned: 9.3x; total interest coverage: 9.3x)
Leases, Uncapitalized Annual rentals $43.1 mill.

Pfd Stock None

Pension Assets-9/22 $479.0 mill.
Oblig. $449.5 mill.
Common Stock 148,462,481 shs.
as of 7/28/23

MARKET CAP: $16.5 billion (Large Cap)

CURRENT POSITION ($MILL.)	2021	2022	6/30/23
Cash Assets	116.7	51.6	56.2
Other	2722.0	2996.1	832.7
Current Assets	2838.7	3047.7	888.9
Accts Payable	423.2	496.0	327.9
Debt Due	2400.5	2386.4	7.5
Other	686.7	720.2	698.9
Current Liab.	3510.4	3602.6	1034.3
Fix. Chg. Cov.	1457%	1238%	1250%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-5.5%	-4.5%	*10.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.0%	9.0%	*7.0%*
Dividends	6.5%	8.5%	*7.5%*
Book Value	9.0%	12.0%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	*1525*	*1700*	*890*	*685*	*4800*

Fiscal Year Ends	EARNINGS PER SHARE [A B E] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	*2.12*	*2.53*	*1.06*	*.84*	*6.55*

Cal-endar	QUARTERLY DIVIDENDS PAID [C] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2022: 63.7%, residential; 28.8%, commercial; 5.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/22 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Profits for Atmos Energy ought to advance, once again, in fiscal 2024 (which began on October 1st). We think that will be brought about partly by the distribution unit, aided by benefits of higher rates and an expanded customer base. Favorable weather would also help, given its effect on consumption levels. The pipeline and storage division stands to have a better showing, too. Though the company's effective income tax rate may climb, full-year earnings per share should grow around 7%, to $6.55, versus fiscal 2023's $6.10 figure. Concerning next year, the bottom line might climb at a similar percentage rate, to $7.00 per share, as operating margins widen further.

Capital spending for fiscal 2024 is expected to be around $2.9 billion. That is near the prior-year figure of $2.8 billion. Like fiscal 2023, a considerable amount of the resources are being utilized to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems. Management adds that it projects total capital expenditures from fiscal 2024 through fiscal 2028 to be roughly $17 billion. A substantial portion of the investments will continue to be deployed to where they are currently. Assuming that finances stay healthy, the company should have little trouble achieving those goals.

Good things appear to be in store over the 3- to 5-year horizon. Atmos Energy ranks as one of the country's largest natural gas-only distributors, with more than three million customers across several states, including Texas, Louisiana, and Mississippi. Also, we believe the pipeline and storage segment has promising overall expansion opportunities, since it operates in one of the most-active drilling regions in the world. The sound balance sheet is another plus.

The quarterly common stock dividend was raised 8.8%, to $0.805 a share. Furthermore, we anticipate additional steady hikes in the distribution out to 2026-2028. The payout ratio over that span ought to be reasonable, around 50% or so.

What about the equity? Capital gains potential over the 18-month span looks worthwhile. But the dividend yield is lower than the average of *Value Line's* Natural Gas Utility Industry.

Frederick L. Harris, III November 24, 2023

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Feb. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. **(D)** In millions. **(E)** Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

NISOURCE INC. NYSE-NI

RECENT PRICE **24.81** | P/E RATIO **14.4** (Trailing: 15.8 Median: 21.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD **4.2%** | **VALUE LINE**

TIMELINESS 1 Raised 11/10/23
SAFETY 3 Lowered 3/19/21
TECHNICAL 3 Raised 11/3/23
BETA .90 (1.00 = Market)

18-Month Target Price Range

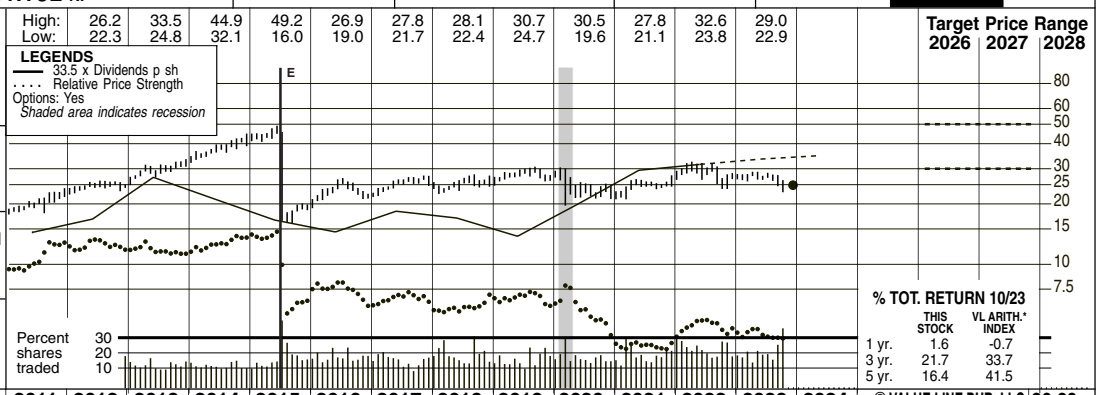
Low-High	Midpoint (% to Mid)
$21-$39	$30 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+100%)	*21%*
Low	30	(+20%)	*9%*

Institutional Decisions

	4Q2022	1Q2023	2Q2023
to Buy	315	301	249
to Sell	214	201	256
Hld's(000)	387502	387698	393166



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	*14.45*	*14.75*	Revenues per sh	*16.50*
3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	*3.60*	*3.80*	"Cash Flow" per sh	*4.25*
1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	*1.60*	*1.70*	Earnings per sh [A]	*2.10*
.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	*1.00*	*1.04*	Div'ds Decl'd per sh [B] ■	*1.20*
2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	*7.95*	*6.55*	Cap'l Spending per sh	*6.75*
18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	*19.45*	*20.25*	Book Value per sh [C]	*19.20*
274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	*415.00*	*420.00*	Common Shs Outst'g [D]	*440.00*
18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.0	19.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.0*
1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.99	11.8			Relative P/E Ratio	*1.05*
4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%			Avg Ann'l Div'd Yield	*3.0%*
5657.3	6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	*6000*	*6200*	Revenues ($mill)	*7250*
490.9	530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	*665*	*715*	Net Profit ($mill)	*925*
34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	--	2.0%	2.3%	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	*57.5%*	*57.5%*	Long-Term Debt Ratio	*55.0%*
43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	*35.0%*	*37.5%*	Common Equity Ratio	*37.5%*
13480	14331	9792.0	10129	11832	12856	13843	14972	16131	17099	*19000*	*20000*	Total Capital ($mill)	*22500*
14365	16017	12112	13068	14360	15543	16912	16620	17882	19843	*22500*	*25000*	Net Plant ($mill)	*27500*
5.2%	5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	*3.5%*	*3.5%*	Return on Total Cap'l	*4.0%*
8.3%	8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.3%	8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	*10.0%*	*9.5%*	Return on Com Equity	*11.0%*
3.1%	3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
62%	61%	NMF	63%	NMF	60%	64%	67%	64%	64%	*63%*	*61%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $13258.0 mill. **Due in 5 Yrs** $2355 mill.
LT Debt $11011.3 mill. **LT Interest** $368 mill.
(Interest cov. earned: 5.8x) (59% of Cap'l)

Leases, Uncapitalized Annual rentals $8.0 mill.
Pension Assets-12/22 $1.4 bill. **Oblig.** $1.4 bill.

Pfd Stock $1547 mill. **Pfd Div'd** $55.1 mill.

Common Stock 413,415,441 shs.
as of 10/24/23
MARKET CAP: $10.3 billion (Large Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	85.2	40.8	56.0
Other	1835.6	2543.5	1759.4
Current Assets	1920.8	2584.3	1815.4
Accts Payable	697.8	899.5	648.2
Debt Due	618.1	1791.9	2246.7
Other	1430.3	1969.1	1500.5
Current Liab.	2746.2	4660.5	4395.4
Fix. Chg. Cov.	250%	255%	260%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1605.5	962.7	902.5	1211.0	4681.7
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	*1916.6*	*6000*
2024	*2000*	*1125*	*1150*	*1925*	*6200*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.76	.13	.09	.34	1.32
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	*.53*	*1.60*
2024	*.85*	*.15*	*.13*	*.57*	*1.70*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.200	.200	.200	.200	.80
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2022: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.1% electric, 2.3% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource has achieved solid operating results thus far in 2023. In the most recent quarter, the public gas and electric utility demonstrated a respectable financial performance during its cyclically low season. The company reported non-GAAP net operating earnings of $84 million or $0.19 per share, a notable increase from $45 million and $0.10 per share in the same quarter last year. This growth can be attributed to strategic investments and improved operational efficiency, despite some challenges, like interest rates, inflation, fluctuating energy prices, and regulatory changes.

NiSource is set to continue its profit-growth trajectory. We are forecasting full-year earnings per share of $1.60 in 2023 and $1.70 in 2024, towards the upper end of management's guidance range of $1.54 to $1.60, and $1.68 to $1.72 in each year, respectively. Our growth outlook is underpinned by the company's focus on increasing efficiency, regulatory compliance, and the ongoing modernization of its energy infrastructure. On that note, ongoing investment in renewable energy generation, with significant solar and wind projects underway, align with industry trends and the management's carbon emissions reductions goals.

We expect sustainable investments will support steady long-term growth. The company expects to invest a projected $16 billion in capital over the next five years, contributing to an estimated rate-base increase of 8% to 10% per year. This supports its goal for a 6% to 8% long-term earnings-per-share growth out to 2028. The shift towards renewable energy, customer-centric investments, and the leveraging of legislative incentives, like the Inflation Reduction Act, position NiSource favorably in the transitioning energy market. However, risks such as regulatory changes, environmental compliance, and the execution of large-scale investments remain. Too, the high interest rate environment may pose a lasting headwind.

NiSource is ranked 1 (Highest) for Timeliness in the year ahead. Too, both the stock's 18-month and 3- to 5-year total capital appreciation potential look appealing on a risk adjusted basis. Conservative accounts may want to have a closer look.

Earl B. Humes *November 24, 2023*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '07, 3¢; '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early February. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '22: $1485.9 million, $3.61/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	55

NEW JERSEY RES. NYSE-NJR

RECENT PRICE **41.18** | P/E RATIO **15.3** (Trailing: 14.2 Median: 17.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **4.0%** | **VALUE LINE**

TIMELINESS 3 Lowered 6/9/23
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Raised 11/24/23
BETA .95 (1.00 = Market)

18-Month Target Price Range

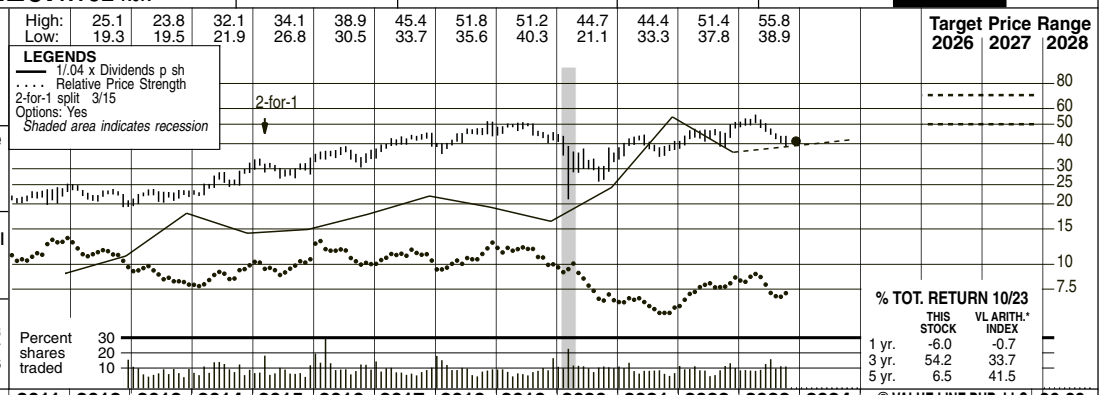
Low-High	Midpoint (% to Mid)
$36-$55	$46 (10%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+70%)	*17%*
Low	50	(+20%)	*9%*

Institutional Decisions

	4Q2022	1Q2023	2Q2023
to Buy	166	157	157
to Sell	115	133	156
Hld's(000)	73958	73728	71570



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	*22.95*	*26.00*	Revenues per sh [A]	*31.85*
1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	*4.25*	*4.45*	"Cash Flow" per sh	*5.20*
.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	*2.70*	*2.80*	Earnings per sh [B]	*3.50*
.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	*1.56*	*1.68*	Div'ds Decl'd per sh [C] ■	*1.95*
.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	*5.15*	*5.05*	Cap'l Spending per sh	*6.25*
7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	*21.70*	*24.20*	Book Value per sh [D]	*27.55*
83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	*98.00*	*100.00*	Common Shs Outst'g [E]	*102.00*
21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98			Relative P/E Ratio	*.95*
3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%			Avg Ann'l Div'd Yield	*4.0%*
3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	*2250*	*2600*	Revenues ($mill) [A]	*3250*
113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	*265*	*280*	Net Profit ($mill)	*355*
25.4%	30.2%	26.3%	15.5%	17.2%	- -	- -	NMF	10.3%	21.4%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	*11.8%*	*10.8%*	Net Profit Margin	*11.0%*
36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	*57.5%*	*56.0%*	Long-Term Debt Ratio	*55.0%*
63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	*42.5%*	*44.0%*	Common Equity Ratio	*45.0%*
1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	*5000*	*5500*	Total Capital ($mill)	*6250*
1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	*5000*	*5200*	Net Plant ($mill)	*5550*
9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	*12.5%*	*11.5%*	Return on Shr. Equity	*12.5%*
12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	*12.5%*	*11.5%*	Return on Com Equity	*12.5%*
5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	*5.5%*	*4.5%*	Retained to Com Eq	*5.5%*
59%	40%	50%	60%	59%	40%	59%	60%	56%	53%	*58%*	*60%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $2873.9 mill. **Due in 5 Yrs** $1049 mill.
LT Debt $2728.7 mill. **LT Interest** $85 mill.
Incl. $7.0 mill. capitalized leases.
(Interest coverage: 5.0x)
Pension Assets-9/22 $484.1 mill.
Oblig. $464.0 mill.

Pfd Stock None

Common Stock 97,561,926 shs.
as of 7/31/23

MARKET CAP: $4.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	4.7	1.1	.5
Other	629.6	755.0	519.9
Current Assets	634.3	756.1	520.4
Accts Payable	429.6	156.6	122.2
Debt Due	450.1	499.1	145.2
Other	171.7	448.5	401.6
Current Liab.	1051.4	1104.2	669.0
Fix. Chg. Cov.	545%	545%	650%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	*618.3*	*2250*
2024	*750*	*850*	*450*	*550*	*2600*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	*.30*	*2.70*
2024	*1.10*	*1.25*	*.10*	*.35*	*2.80*

Calendar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 569,300 cust. at 9/30/22. Fiscal 2022 volume: 144 bill. cu. ft. (23% interruptible, 47% residential, commercial & firm transportation, 30% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.7%. Has 1,288 empls. Off./dir. own less than 1% of common; BlackRock, 14.0%; Vanguard, 11.0% (12/22 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources demonstrated a mixed operating performance in fiscal 2023. (Year ended September 30th). The September period likely saw a year-over-year normalization in revenues and earnings, with the latter likely leveling around $0.30 per share. Good cost-control efforts in the fiscal third quarter helped to float margins in the company's cyclically low season, despite that revenues faltered. Ambitious solar-power developments from the company's Clean Energy Ventures will likely contribute to a less volatile earnings cycle as the segment's operations continue to expand. Earlier in the year, winter storm Elliot helped to lift fiscal first-quarter earnings $0.20 and set the bar high for a solid full-year advance. Also, the addition of new meters throughout the year and resilient regional residential construction helped to support organic growth for the full fiscal year. Our earnings call for $2.70 per share is towards the top of management's guidance range of $2.62 to $2.72, but we think this is achievable given the company's penchant for success in a challenging environment.

We have a cautiously optimistic outlook for the next few years. We look for earnings growth to slow comparatively in 2024, adding only $0.10 from this fiscal year end, equivalent to a $0.30 gain adjusting for normalized weather. The company's next rate case in 2024 will help to drive returns thereafter. The company's 75 megawatts of new solar capacity added in fiscal 2023 will also contribute to generating higher returns in 2024. Meantime, its robust hedging strategy will help to limit volatility from energy prices.

Solid execution and sustainable investments give us confidence in its long-term potential. Projects like the green hydrogen blending facility and significant investments in energy efficiency initiatives position the company to capitalize on emerging opportunities in the green-energy market, while its region's economic strength contributes to overall Safety (2; Above Average) and stability.

Despite the good quality, these shares lack convincing long-term upside potential at the recent quotation. Much of the good outlook is baked into the current price at this juncture.

Earl B. Humes *November 24, 2023*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early February.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2022: $500 million, $5.23/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	60

N.W. NATURAL NYSE-NWN

RECENT PRICE **35.75** | P/E RATIO **12.5** (Trailing: 13.0 Median: 24.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **5.5%** | **VALUE LINE**

TIMELINESS 4 Lowered 11/10/23
SAFETY 3 Lowered 3/19/21
TECHNICAL 3 Raised 11/3/23
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$60	$47 (30%)

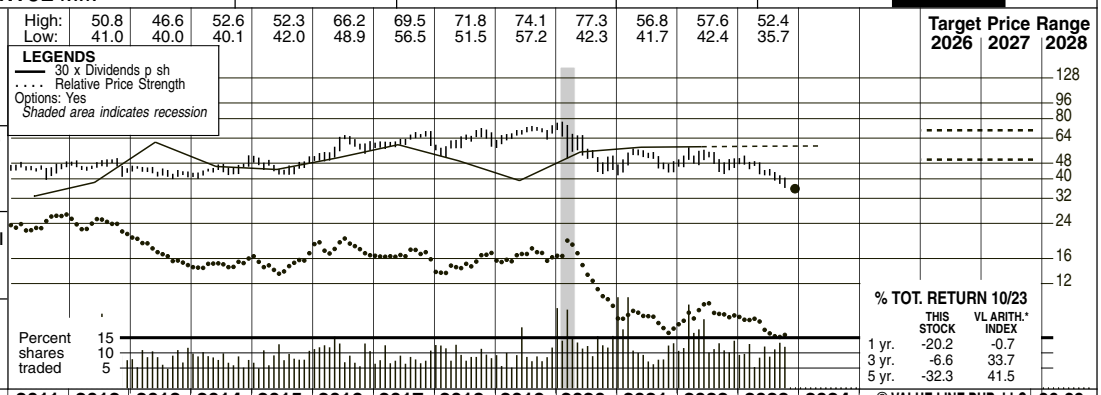
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+95%)	*22%*
Low	50	(+40%)	*13%*

Institutional Decisions

	4Q2022	1Q2023	2Q2023
to Buy	124	115	122
to Sell	90	102	123
Hld's(000)	27135	26729	26926

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
High:	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4								
Low:	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7								
	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	***32.45***	***30.25***	Revenues per sh	***31.25***
	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	***6.15***	***6.40***	"Cash Flow" per sh	***6.10***
	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	***2.65***	***2.80***	Earnings per sh [A]	***3.00***
	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	***1.94***	***1.95***	Div'ds Decl'd per sh [B]■	***1.98***
	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	***9.05***	***7.75***	Cap'l Spending per sh	***7.50***
	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	***31.70***	***32.85***	Book Value per sh [D]	***35.70***
	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	***37.00***	***38.00***	Common Shs Outst'g [C]	***42.00***
	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***20.0***
	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13			Relative P/E Ratio	***1.10***
	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%			Avg Ann'l Div'd Yield	***3.3%***
							758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	***1200***	***1150***	Revenues ($mill)	***1250***
							60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	***100***	***105***	Net Profit ($mill)	***125***
							40.8%	41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	***25.0%***	***25.0%***	Income Tax Rate	***25.0%***
							8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	***8.2%***	***9.1%***	Net Profit Margin	***10.0%***
							47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	***54.0%***	***52.0%***	Long-Term Debt Ratio	***50.0%***
							52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	***46.0%***	***48.0%***	Common Equity Ratio	***50.0%***
							1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	***2550***	***2600***	Total Capital ($mill)	***2750***
							2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	***3250***	***3400***	Net Plant ($mill)	***3750***
							5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	***4.0%***	***4.0%***	Return on Total Cap'l	***4.5%***
							8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	***7.5%***	***8.0%***	Return on Shr. Equity	***9.0%***
							8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	***7.5%***	***8.0%***	Return on Com Equity	***9.0%***
							1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	***2.0%***	***2.5%***	Retained to Com Eq	***3.5%***
							81%	85%	92%	87%	NMF	76%	82%	79%	71%	79%	***72%***	***70%***	All Div'ds to Net Prof	***64%***



CAPITAL STRUCTURE as of 9/30/23
Total Debt $1686.3 mill. **Due in 5 Yrs** $713 mill.
LT Debt $1424.6 mill. **LT Interest** $75 mill.

(Total interest coverage: 1.9x)

Pension Assets-12/22 $300.0 mill.
Oblig. $413.4 mill.

Pfd Stock None

Common Stock 36,778,271 shares
as of 10/26/23

MARKET CAP $1.3 billion (Small Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	18.6	29.3	156.6
Other	418.7	714.9	350.8
Current Assets	437.3	744.2	507.4
Accts Payable	133.5	180.7	99.3
Debt Due	389.8	348.9	261.7
Other	201.5	369.1	229.1
Current Liab.	724.8	898.7	590.1
Fix. Chg. Cov.	335%	320%	275%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-2.5%	- -	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	***358.2***	***1200***
2024	***445***	***220***	***130***	***355***	***1150***

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	***1.26***	***2.65***
2024	***2.10***	***.15***	***d.70***	***1.25***	***2.80***

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,258. BlackRock Inc. owns 17.3% of shares; Vanguard, 12.2%; Off./Dir., .95% (4/23 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural took a step back on its bottom-line progress in the 2023 third quarter. Increased leverage worked against the diversified utilities provider in the period, the company's cyclically low season for its core operations. Losses compared unfavorably to the year prior, as the per-share earnings deficit deepened by $0.09 and missed our target in a similar fashion. Indeed, higher operating and maintenance costs were harmful as the company contends with inflation. Too, a greater interest burden resulted from a roughly $150 million increase in long-term debt over the past year.

We have trimmed our full year 2023 earnings estimate. Our revised call for earnings per share of $2.65 is just five cents below our previous target, and is towards the mid-point of management's earnings guidance range of $2.55 to $2.75. The new target reflects growth of 4.3%, as the strong start to the year buoys the growth outlook. Based on the El Nino year regional weather trends and continued inflationary pressures, we think the fourth quarter may prove to be somewhat underwhelming compared to previous years.

Our growth targets for 2024 remain robust. New rate implementations in Oregon, coupled with consistent customer growth and reduced pension expenses augur well to sustain top- and bottom-line growth in the upcoming year. The broader economic landscape, particularly in Oregon and Washington where the company operates, is showing favorable conditions with unemployment rates staying below the national average. The natural gas utility segment will see heightened utility margins with new rates and more meters.

Long-term prospects appear promising. We like that the company's strategic direction is heavily inclined towards sustainable development and innovation, with a focus on decorbanization and renewable energy. Too, the company's foray into the water utility market shows its ambition to diversify and strengthen both its environmental and overall portfolio.

Though the shares are untimely, long-term recovery potential is wide. The stock price has been facing pressure in the higher interest rate environment, but the long-term potential here is good.

Earl B. Humes *November 24, 2023*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early February.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2022: $149 million, $4.20/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	10

ONE GAS, INC. NYSE-OGS

RECENT PRICE 59.67 | P/E RATIO 14.2 (Trailing: 14.6 Median: NMF) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 4 Lowered 10/6/23
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 10/27/23
BETA .85 (1.00 = Market)

18-Month Target Price Range

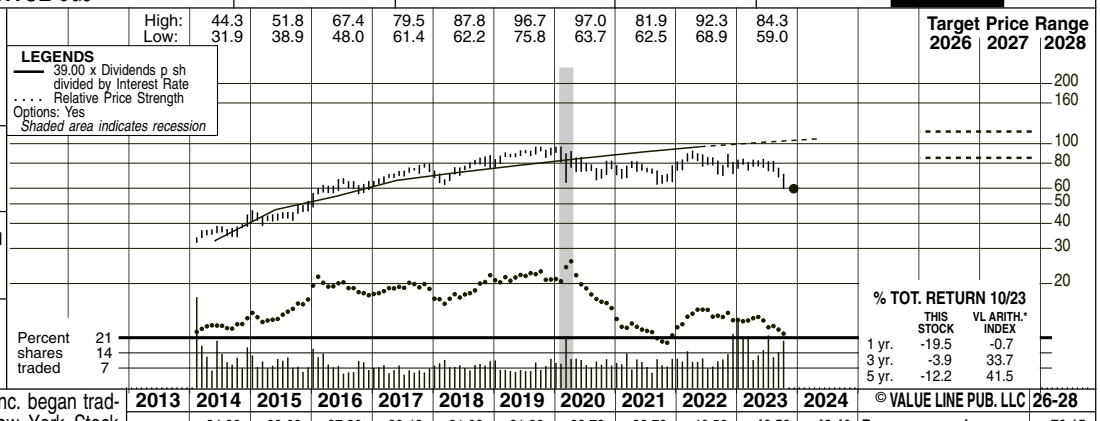
Low-High	Midpoint (% to Mid)
$52-$102	$77 (30%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+95%)	*21%*
Low	85	(+40%)	*13%*

Institutional Decisions

	4Q2022	1Q2023	2Q2023
to Buy	176	157	158
to Sell	132	133	133
Hld's(000)	48298	51917	53044



The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 9/30/23
Total Debt $2990.0 mill. **Due in 5 Yrs** $1250.0 mill.
LT Debt $1862.6 mill. **LT Interest** $115.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x)
Leases, Uncapitalized Annual rentals $6.5 mill.
Pfd Stock None
Pension Assets-12/22 $950.8 mill. **Oblig.** $953.0 mill.
Common Stock 55,454,050 shs.
as of 10/23/23
MARKET CAP: $3.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	8.9	9.7	9.2
Other	2215.7	1207.9	555.2
Current Assets	2224.6	1217.6	564.4
Accts Payable	258.6	360.5	168.6
Debt Due	494.0	572.7	1127.4
Other	227.9	256.2	275.7
Current Liab.	980.5	1189.4	1571.7
Fix. Chg. Cov.	625%	540%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	- -	5.0%	*11.5%*
"Cash Flow"	- -	7.5%	*8.0%*
Earnings	- -	8.0%	*6.5%*
Dividends	- -	10.0%	*5.5%*
Book Value	- -	4.0%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	*814*	*2580*
2024	*1050*	*420*	*395*	*820*	*2685*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.72	.48	.39	1.09	3.68
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	*1.23*	*4.10*
2024	*1.89*	*.63*	*.52*	*1.26*	*4.30*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
	- -	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	*46.50*	*48.40*	Revenues per sh	*70.15*
	- -	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	*9.10*	*10.15*	"Cash Flow" per sh	*12.20*
	- -	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	*4.10*	*4.30*	Earnings per sh A	*5.60*
	- -	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	*2.60*	*2.72*	Div'ds Decl'd per sh B■	*3.15*
	- -	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	*11.75*	*11.95*	Cap'l Spending per sh	*12.50*
	- -	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	*47.05*	*49.55*	Book Value per sh	*64.45*
	- -	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	*55.50*	*55.50*	Common Shs Outst'g C	*57.00*
	- -	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	- -	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.03	1.16			Relative P/E Ratio	*1.00*
	- -	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%			Avg Ann'l Div'd Yield	*3.2%*
	- -	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	*2580*	*2685*	Revenues ($mill)	*4000*
	- -	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	*230*	*240*	Net Profit ($mill)	*320*
	- -	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	*15.5%*	*16.0%*	Income Tax Rate	*21.0%*
	- -	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	*8.9%*	*8.9%*	Net Profit Margin	*8.0%*
	- -	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	*42.0%*	*45.0%*	Long-Term Debt Ratio	*51.0%*
	- -	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	39.0%	49.3%	*58.0%*	*55.0%*	Common Equity Ratio	*49.0%*
	- -	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	*4500*	*5000*	Total Capital ($mill)	*7500*
	- -	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	*6050*	*6425*	Net Plant ($mill)	*7550*
	- -	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	*6.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
	- -	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*9.0%*	*8.5%*	Return on Shr. Equity	*8.5%*
	- -	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*9.0%*	*8.5%*	Return on Com Equity	*8.5%*
	- -	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	*3.5%*	*3.0%*	Retained to Com Eq	*4.0%*
	- -	40%	53%	52%	55%	56%	56%	58%	60%	60%	*63%*	*63%*	All Div'ds to Net Prof	*56%*

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 165 Bcf of natural gas supply in 2022, compared to 164 Bcf in 2021. Total volumes delivered by customer (fiscal 2022): transportation, 57.3%; residential, 31.2%; commercial & industrial, 10.8%; other, .7%. ONE Gas has around 3,600 employees. BlackRock owns 12.6% of common stock; The Vanguard Group, 11.5%; State Street Corporation, 11.5%; officers and directors, 1.5% (4/23 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. appears to be en route to an unspectacular year. During the first nine months, earnings per share of $2.87 were just one penny above last year's $2.86 total. That was traced, to some extent, from a 12.5% rise in total operating expenses, which especially reflected increased depreciation & amortization and operations & maintenance costs. Too, interest expense jumped. The number of diluted shares outstanding was a bit higher, as well. But the company's results were aided partly by benefits from new rates. Also, the effective income tax rate decreased. Nonetheless, since we expect another uninspiring performance in the fourth quarter, full-year profits may be around $4.10 per share. That would be only two cents more than 2022's $4.08 tally. Regarding 2024, though, the bottom line stands to advance at a 5% rate, to $4.30 per share, based to a certain degree on our assumption of further growth of the customer base.

This year's capital expenditures, including asset removal costs, are anticipated to be around $725 million. (That would be some 10% higher than the 2022 figure of $656.5 million.) Nearly 70% of the budget is devoted to system integrity and pipeline replacement projects. It's worth stating that the energy firm projects total spending to be about $3.6 billion ($650 million—$750 million annually) between 2023 and 2027, with roughly the same percentage of funds allocated to where they are currently. These goals seem achievable assuming, of course, that finances remain in healthy condition.

ONE Gas shares have surrendered roughly 20% of their value since our last full-page report in late August. We believe that movement is attributable, in part, to ONE Gas' lackluster results to date. Moreover, the equity is pegged to trail the market in the year ahead (Timeliness rank 4: Below Average).

But there are some silver linings here. Among them is the stock's appealing 18-month capital appreciation potential. Upside possibilities out to 2026-2028 are worthwhile, too. The dividend yield is another feature. Consider, also, the 2 (Above Average) Safety rank and high Price Stability score of 90 out of 100.

Frederick L. Harris, III November 24, 2023

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Feb. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	100

SPIRE INC. NYSE-SR

RECENT PRICE **57.23** | P/E RATIO **12.6** (Trailing: 13.3 Median: 19.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **5.2%** | **VALUE LINE**

TIMELINESS 4 Raised 10/13/23
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Lowered 9/29/23
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$48-$88	$68 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+85%)	*20%*
Low	75	(+30%)	*11%*

Institutional Decisions

	4Q2022	1Q2023	2Q2023
to Buy	146	128	142
to Sell	122	132	138
Hld's(000)	45462	45090	46098

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
High:	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8								
Low:	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8								
	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	*51.05*	*53.40*	Revenues per sh [A]	*63.65*
	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	*9.10*	*9.60*	"Cash Flow" per sh	*11.10*
	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	*4.30*	*4.50*	Earnings per sh [A B]	*5.50*
	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	*3.00*	Div'ds Decl'd per sh [C ■]	*3.45*
	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	*13.35*	*12.85*	Cap'l Spending per sh	*12.35*
	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	*52.30*	*58.10*	Book Value per sh [D]	*67.10*
	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	*52.50*	*53.00*	Common Shs Outst'g [E]	*55.00*
	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	*15.5*		Avg Ann'l P/E Ratio	*16.5*
	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	*.89*		Relative P/E Ratio	*.90*
	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%		Avg Ann'l Div'd Yield	*3.8%*
							1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	*2680*	*2830*	Revenues ($mill) [A]	*3500*
							52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	*226*	*240*	Net Profit ($mill)	*300*
							25.0%	27.6%	31.2%	32.5%	32.4%	NMF	15.7%	12.3%	20.1%	21.1%	*18.5%*	*19.0%*	Income Tax Rate	*25.0%*
							5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	*8.4%*	*8.5%*	Net Profit Margin	*8.6%*
							46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	*55.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
							53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	*41.0%*	*44.0%*	Common Equity Ratio	*45.0%*
							1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	*6700*	*7000*	Total Capital ($mill)	*8200*
							1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	*5750*	*6050*	Net Plant ($mill)	*7100*
							3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
							5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.0%*
							5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	*8.0%*	*8.0%*	Return on Com Equity	*8.0%*
							1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
							81%	73%	58%	59%	60%	51%	66%	NMF	54%	71%	*73%*	*72%*	All Div'ds to Net Prof	*68%*

LEGENDS
26.50 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2026 2027 2028

% TOT. RETURN 10/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-16.7	-0.7
3 yr.	12.1	33.7
5 yr.	-7.7	41.5

CAPITAL STRUCTURE as of 6/30/23
Total Debt $4517.5 mill. **Due in 5 Yrs**$2775.0 mill.
LT Debt $3553.3 mill. **LT Interest** $200.0 mill.
(Total interest coverage: 3.3x)

Leases, Uncapitalized Annual rentals $9.0 mill.
Pension Assets-9/22 $625.9 mill.
Oblig. $882.8 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 52,603,138 shs.
as of 7/31/23

MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	6/30/23
Cash Assets	4.3	6.5	5.3
Other	1312.2	1585.5	855.9
Current Assets	1316.5	1592.0	861.2
Accts Payable	409.9	617.4	196.3
Debt Due	727.8	1318.7	964.2
Other	470.6	417.5	369.9
Current Liab.	1608.3	2353.6	1530.4
Fix. Chg. Cov.	448%	393%	410%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	-5.0%	1.0%	*8.0%*
"Cash Flow"	5.5%	4.0%	*6.5%*
Earnings	2.5%	1.0%	*8.0%*
Dividends	5.0%	6.0%	*5.0%*
Book Value	6.5%	4.0%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)[A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	*324.1*	*2680*
2024	*790*	*1270*	*430*	*340*	*2830*

Fiscal Year Ends	EARNINGS PER SHARE [A B F] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	*d.21*	*4.30*
2024	*1.40*	*3.45*	*d.11*	*d.24*	*4.50*

Calendar	QUARTERLY DIVIDENDS PAID [C ■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2022: 3.2 bill. Revenue mix for regulated operations: residential, 73%; commercial and industrial, 17%; transportation, 6%; other, 4%. Officers and directors own 2.9% of common shares; American Century Companies, 14.9% (12/22 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

A new CEO was appointed at Spire on October 1st. Suzanne Sitherwood retired after serving since 2012. Her replacement, Steve Lindsey, has assumed several leadership roles since joining the team in 2012. Before then, he worked 23 years at the natural gas utility unit of AGL Resources (acquired by Southern Company in 2016), where he held some key executive positions. All things considered, we believe the company is in capable hands.

A partial earnings rebound was likely in fiscal 2023, which concluded September 30th. (Please be aware that fourth-quarter numbers were not available when this report went to press.) Recall that through the first nine months, share net of $4.51 was 8% above the previous year's $4.18 figure. This was made possible partly by the Gas Marketing division, as favorable market conditions enabled it to optimize storage and transportation positions. Moreover, the performance of the Midstream unit enjoyed better results from the Spire Storage West segment. Elsewhere, profits for the Gas Utility operation were about flat. The company did post a wider per-share deficit in the June period, which reflected, among other factors, a decrease in revenues and higher interest expense. Still, if there were no major setbacks in the fourth quarter, full-year earnings per share might have recovered nearly 10%, to $4.30, relative to the fiscal 2022 total of $3.95. Concerning the new year, the bottom line stands to advance around 5%, to $4.50 a share, assuming that operating margins widen further.

Finances are in healthy shape. When the third quarter ended, cash and equivalents were $5.3 million. What's more, there was $1.3 billion available via a revolving credit facility maturing in July, 2027. Too, long-term debt sat at a manageable 55% of total capital, and short-term borrowings were not a big hurdle. So, Spire ought to continue to meet its obligations with little trouble.

These shares, though untimely, ought to be of interest to some investors. The dividend yield compares nicely to those of other equities in *Value Line's* Natural Gas Utility group. Furthermore, capital appreciation potential over the 18-month period and out to 2026-2028 looks worthwhile.

Frederick L. Harris, III November 24, 2023

(A) Fiscal year ends Sept. 30th. **(B)** Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late Jan. **(C)** Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '22: $1,171.6 mill., $22.32/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

New Jersey Natural Gas Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Distribution Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.20 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.74
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.94 %
4.	Equity Risk Premium (3)	5.44
5.	Risk Premium Derived Common Equity Cost Rate	11.38 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 8 and 9 of this Exhibit).

(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.74% from page 2 of this Exhibit.

(3) From page 5 of this Exhibit.

New Jersey Natural Gas Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Nov-2023	5.28 %	6.05 %	6.29 %
Oct-2023	5.61	6.34	6.61
Sep-2023	5.13	5.86	6.15
Average	5.34 %	6.08 %	6.35 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.74 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.27 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services.

New Jersey Natural Gas Company
Comparison of Long-Term Issuer Ratings for the
Utility Proxy Group

Proxy Group of Six Natural Gas Distribution Companies	Moody's Long-Term Issuer Rating November 2023		Standard & Poor's Long-Term Issuer Rating November 2023	
	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Spire Inc.	A1/A2	5.5	A-	7.0
Average	A2	6.4	A-	6.8
New Jersey Natural Gas Company	A1	5.0	NR	- -

Notes:
(1) Ratings are the average of each company's utility operating subsidiaries.

(2) From page 4 of this Exhibit.

Source Information: Moody's Investors Services.
Standard & Poor's Global Utilities Rating Services.

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

New Jersey Natural Gas Company
Judgment of Equity Risk Premium for the
Utility Proxy Group

Line No.		Proxy Group of Six Natural Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	7.13 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	4.54
3.	Predicted Equity Risk Premium Based on Regression Analysis of 829 Fully-Litigated Natural Gas Distribution Cases (3)	4.66
4.	Average equity risk premium	5.44 %

Notes: (1) From page 6 of this Exhibit.
(2) From page 10 of this Exhibit.
(3) From page 11 of this Exhibit.

New Jersey Natural Gas Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Utility Proxy Group

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Distribution Companies
1.	Kroll Equity Risk Premium (1)	5.82 %
2.	Regression on Kroll Risk Premium Data (2)	6.90
3.	Kroll Equity Risk Premium based on PRPM (3)	8.40
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	10.31
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.01
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	13.01
7.	Conclusion of Equity Risk Premium	8.91 %
8.	Adjusted Beta (7)	0.80
9.	Forecasted Equity Risk Premium	7.13 %

Notes provided on page 7 of this Exhibit.

New Jersey Natural Gas Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Utility Proxy Group

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2023 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2022.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa rated corporate bond yields from 1928-2022 referenced in note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The SBBI equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between SBBI large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through November 2023.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.20% (from page 2 of this Exhibit) from the projected 3-5 year total annual market return of 15.51% (described fully in note 1 on page 2 of Exhibit DWD-5).

(5) Using data from Value Line for the S&P 500, an expected total return of 14.21% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.20% results in an expected equity risk premium of 9.01%.

(6) Using data from Bloomberg for the S&P 500, an expected total return of 18.21% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.20% results in an expected equity risk premium of 13.01%.

(7) Average of mean and median beta from page 1 of Exhibit DWD-5.

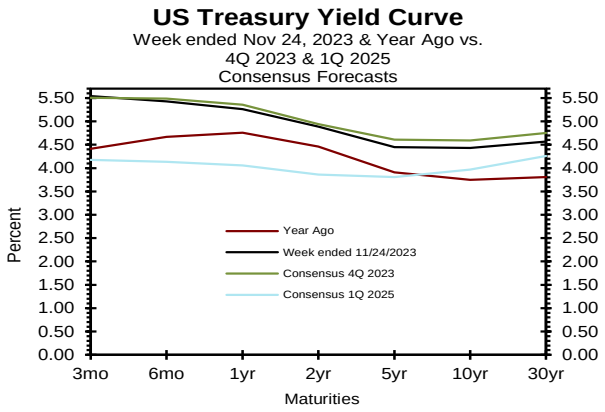
Sources of Information:

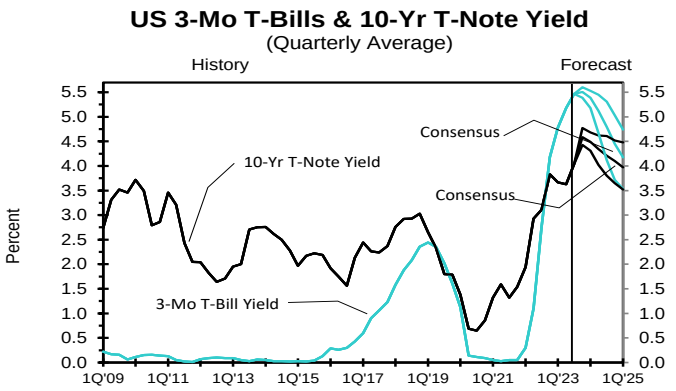
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts December 1, 2023
Bloomberg Professional Services.

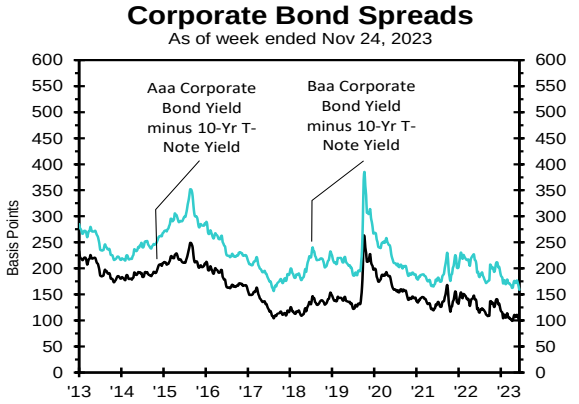
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

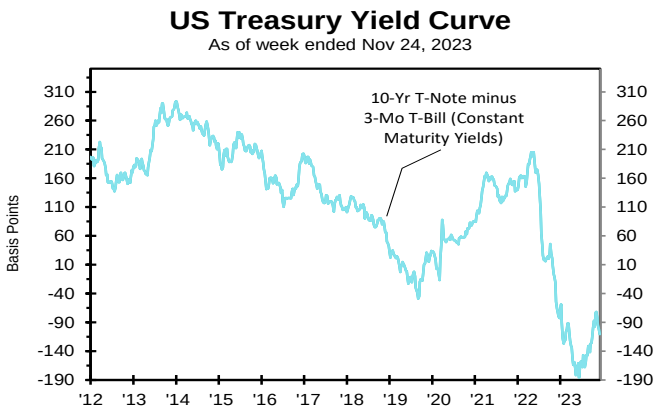
	History				History				Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov 24	Nov 17	Nov 10	Nov 3	Oct	Sep	Aug	3Q 2023	2023	2024	2024	2024	2024	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.26	**5.4**	**5.4**	**5.2**	**4.9**	**4.6**	**4.2**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.43	**8.5**	**8.5**	**8.3**	**8.1**	**7.7**	**7.4**
SOFR	5.31	5.32	5.32	5.33	5.31	5.31	5.30	5.23	**5.4**	**5.3**	**5.2**	**4.9**	**4.6**	**4.3**
Commercial Paper, 1-mo.	5.33	5.34	5.32	5.33	5.33	5.31	5.30	5.26	**5.4**	**5.4**	**5.1**	**4.9**	**4.5**	**4.2**
Treasury bill, 3-mo.	5.54	5.52	5.54	5.57	5.60	5.56	5.56	5.54	**5.5**	**5.4**	**5.1**	**4.8**	**4.5**	**4.2**
Treasury bill, 6-mo.	5.43	5.41	5.46	5.51	5.57	5.51	5.54	5.53	**5.5**	**5.3**	**5.1**	**4.7**	**4.4**	**4.1**
Treasury bill, 1 yr.	5.26	5.27	5.35	5.38	5.42	5.44	5.37	5.39	**5.4**	**5.2**	**4.9**	**4.6**	**4.3**	**4.1**
Treasury note, 2 yr.	4.89	4.89	4.97	4.97	5.07	5.02	4.90	4.92	**4.9**	**4.8**	**4.5**	**4.2**	**4.0**	**3.9**
Treasury note, 5 yr.	4.45	4.50	4.59	4.69	4.77	4.49	4.31	4.31	**4.6**	**4.5**	**4.3**	**4.1**	**4.0**	**3.8**
Treasury note, 10 yr.	4.43	4.50	4.59	4.75	4.80	4.38	4.17	4.15	**4.6**	**4.5**	**4.3**	**4.2**	**4.1**	**4.0**
Treasury note, 30 yr.	4.57	4.65	4.75	4.93	4.95	4.47	4.28	4.24	**4.8**	**4.7**	**4.5**	**4.5**	**4.4**	**4.3**
Corporate Aaa bond	5.41	5.53	5.66	5.86	5.87	5.38	5.25	5.20	**5.5**	**5.5**	**5.3**	**5.3**	**5.1**	**5.0**
Corporate Baa bond	6.02	6.17	6.31	6.52	6.53	6.03	5.90	5.86	**6.4**	**6.4**	**6.4**	**6.3**	**6.2**	**6.1**
State & Local bonds	4.45	4.55	4.67	4.90	4.88	4.54	4.39	4.38	**4.6**	**4.7**	**4.6**	**4.6**	**4.5**	**4.4**
Home mortgage rate	7.29	7.44	7.50	7.76	7.62	7.20	7.07	7.04	**7.4**	**7.3**	**7.1**	**6.9**	**6.7**	**6.5**
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2021	2022	2022	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025
Fed's AFE $ Index	106.9	108.3	113.5	118.8	119.8	115.5	114.6	115.1	**116.6**	**116.3**	**115.9**	**115.9**	**115.7**	**115.7**
Real GDP	7.0	-2.0	-0.6	2.7	2.6	2.2	2.1	5.2	**1.2**	**0.7**	**0.3**	**0.6**	**1.2**	**1.7**
GDP Price Index	7.0	8.5	9.1	4.4	3.9	3.9	1.7	3.6	**2.7**	**2.4**	**2.3**	**2.2**	**2.2**	**2.2**
Consumer Price Index	8.8	9.2	9.7	5.5	4.2	3.8	2.7	3.6	**2.9**	**2.5**	**2.3**	**2.5**	**2.3**	**2.2**
PCE Price Index	6.8	7.7	7.2	4.7	4.1	4.2	2.5	2.8	**2.6**	**2.4**	**2.2**	**2.3**	**2.2**	**2.1**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2029 and averages for the five-year periods 2025-2029 and 2030-2034. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2025	2026	2027	2028	2029	2025-2029	2030-2034
1. Federal Funds Rate	**CONSENSUS**	**3.8**	**3.2**	**3.1**	**3.0**	**3.0**	**3.2**	**3.0**
	Top 10 Average	4.3	3.6	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	3.3	2.7	2.6	2.6	2.5	2.7	2.5
2. Prime Rate	**CONSENSUS**	**6.9**	**6.3**	**6.2**	**6.2**	**6.2**	**6.3**	**6.1**
	Top 10 Average	7.3	6.7	6.7	6.6	6.6	6.8	6.6
	Bottom 10 Average	6.5	5.9	5.7	5.7	5.7	5.9	5.6
3. SOFR	**CONSENSUS**	**3.8**	**3.2**	**3.1**	**3.1**	**3.1**	**3.3**	**3.0**
	Top 10 Average	4.1	3.6	3.5	3.5	3.4	3.6	3.4
	Bottom 10 Average	3.4	2.9	2.7	2.7	2.6	2.9	2.6
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.7**	**3.2**	**3.2**	**3.2**	**3.1**	**3.3**	**3.1**
	Top 10 Average	3.9	3.5	3.4	3.4	3.4	3.5	3.4
	Bottom 10 Average	3.5	2.9	2.8	2.8	2.8	3.0	2.7
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.7**	**3.2**	**3.1**	**3.0**	**3.0**	**3.2**	**3.0**
	Top 10 Average	4.1	3.6	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	3.2	2.7	2.6	2.5	2.5	2.7	2.4
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.7**	**3.3**	**3.2**	**3.2**	**3.1**	**3.3**	**3.1**
	Top 10 Average	4.1	3.7	3.6	3.6	3.6	3.7	3.6
	Bottom 10 Average	3.4	2.9	2.8	2.7	2.7	2.9	2.7
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.7**	**3.4**	**3.3**	**3.3**	**3.2**	**3.4**	**3.2**
	Top 10 Average	4.1	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.3	3.0	2.9	2.8	2.8	3.0	2.8
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.7**	**3.5**	**3.4**	**3.4**	**3.4**	**3.5**	**3.4**
	Top 10 Average	4.1	3.9	3.9	3.9	3.9	3.9	3.9
	Bottom 10 Average	3.3	3.1	3.0	2.9	2.9	3.0	2.9
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
	Top 10 Average	4.1	4.1	4.2	4.2	4.3	4.2	4.3
	Bottom 10 Average	3.3	3.2	3.2	3.1	3.1	3.2	3.1
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.3	4.4	4.5	4.5	4.5	4.4	4.5
	Bottom 10 Average	3.5	3.3	3.3	3.3	3.3	3.3	3.3
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.5	4.6	4.7	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.6	3.6	3.6	3.6	3.7	3.6
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.0**	**4.9**	**4.9**	**5.0**	**5.0**	**4.9**	**5.0**
	Top 10 Average	5.3	5.3	5.4	5.5	5.5	5.4	5.5
	Bottom 10 Average	4.6	4.5	4.5	4.5	4.5	4.5	4.4
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**	**6.0**
	Top 10 Average	6.4	6.4	6.5	6.6	6.6	6.5	6.6
	Bottom 10 Average	5.7	5.5	5.5	5.6	5.6	5.6	5.6
14. State & Local Bonds Yield	**CONSENSUS**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
	Top 10 Average	4.6	4.7	4.7	4.8	4.8	4.7	4.9
	Bottom 10 Average	4.0	3.8	3.9	3.9	3.8	3.9	3.8
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**	**5.8**
	Top 10 Average	6.6	6.4	6.4	6.5	6.5	6.5	6.5
	Bottom 10 Average	5.7	5.5	5.4	5.3	5.2	5.4	5.2
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**114.1**	**113.0**	**113.1**	**113.2**	**112.8**	**113.2**	**112.3**
	Top 10 Average	116.0	115.5	115.9	116.5	116.2	116.0	115.7
	Bottom 10 Average	111.8	110.4	110.1	109.6	109.1	110.2	108.5
		Year-Over-Year, % Change					Five-Year Averages	
		2025	2026	2027	2028	2029	2025-2029	2030-2034
B. Real GDP	**CONSENSUS**	**1.6**	**2.1**	**2.1**	**2.0**	**2.0**	**1.9**	**2.0**
	Top 10 Average	2.1	2.4	2.4	2.3	2.3	2.3	2.3
	Bottom 10 Average	1.1	1.8	1.8	1.7	1.7	1.6	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.5	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.5	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.3	2.3	2.2	2.2	2.2	2.2	2.3
	Bottom 10 Average	2.0	2.0	1.9	1.9	2.0	1.9	2.0

New Jersey Natural Gas Company
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	Implied Equity Risk Premium
1.	Historical Equity Risk Premium	4.20 %
2.	Regression of Historical Equity Risk Premium (2)	4.75
3.	Forecasted Equity Risk Premium Based on PRPM (3)	4.84
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	4.61
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	4.30
6.	Average Equity Risk Premium (6)	4.54 %

Notes:

(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2022. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2022 referenced in note 1 above.

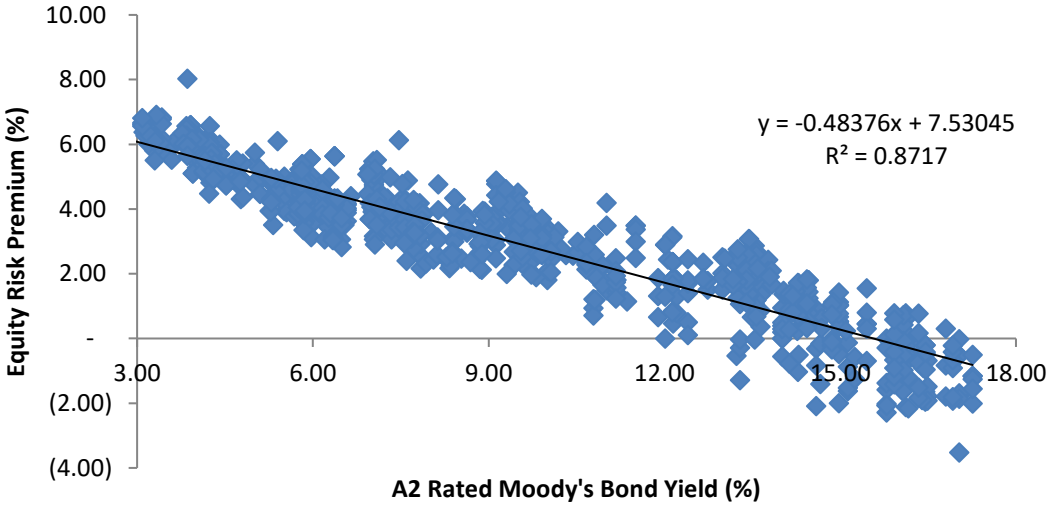
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - November 2023.

(4) Using data from Value Line for the S&P Utilities Index, an expected return of 10.55% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.94%, calculated on line 3 of page 1 of this Exhibit results in an equity risk premium of 4.61%. (10.55% - 5.94% = 4.61%)

(5) Using data from Bloomberg Services for the S&P Utilities Index, an expected return of 10.24% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.94%, calculated on line 3 of page 1 of this Exhibit results in an equity risk premium of 4.30%. (10.24% - 5.94% = 4.3%)

(6) Average of lines 1 through 5.

New Jersey Natural Gas Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Gas Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5304 %	-0.48376	5.94 %	4.66 %

Notes:

(1) From line 3 of page 1 of this Exhibit.

Source of Information: Regulatory Research Associates.

New Jersey Natural Gas Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.85	0.75	0.80	9.83 %	4.44 %	12.30 %	12.79 %	12.55 %
New Jersey Resources Corporation	0.95	0.74	0.85	9.83	4.44	12.79	13.16	12.98
NiSource Inc.	0.90	0.76	0.83	9.83	4.44	12.60	13.02	12.81
Northwest Natural Holding Company	0.85	0.63	0.74	9.83	4.44	11.71	12.35	12.03
ONE Gas, Inc.	0.85	0.64	0.74	9.83	4.44	11.71	12.35	12.03
Spire Inc.	0.85	0.74	0.80	9.83	4.44	12.30	12.79	12.55
Mean			0.79			12.24 %	12.75 %	12.49 %
Median			0.80			12.30 %	12.79 %	12.55 %
Average of Mean and Median			0.80			12.27 %	12.77 %	12.52 %

Notes on page 2 of this Exhibit.

New Jersey Natural Gas Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Kroll, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Kroll Arithmetic Mean MRP (1926-2022)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2022:	12.03	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.00	
MRP based on Kroll Historical Data:	7.03	%

Measure 2: Application of a Regression Analysis to Kroll Historical Data
(1926-2022) 7.96 %

Measure 3: Application of the PRPM to Kroll Historical Data:
(January 1926 - November 2023) 9.38 %

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP Thirteen weeks ending December 1, 2023.

Total projected return on the market 3-5 years hence*:	15.51	%
Projected Risk-Free Rate (see note 2):	4.44	
MRP based on Value Line Summary & Index:	11.07	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	14.21	%
Projected Risk-Free Rate (see note 2):	4.44	
MRP based on Value Line data	9.77	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	18.21	%
Projected Risk-Free Rate (see note 2):	4.44	
MRP based on Bloomberg data	13.77	%
Average of Value Line, Kroll, and Bloomberg MRP:	9.83	%

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 9 and 10 of Exhibit DWD-4) The projection of the risk-free rate is illustrated below:

Fourth Quarter 2023	4.80	%
First Quarter 2024	4.70	
Second Quarter 2024	4.50	
Third Quarter 2024	4.50	
Fourth Quarter 2024	4.40	
First Quarter 2025	4.30	
2025-2029	4.10	
2030-2034	4.20	
	4.44	%

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index.
Blue Chip Financial Forecasts December 1, 2023
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Bloomberg Professional Services.

New Jersey Natural Gas Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the Utility Proxy Group was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.62 - 0.88 and residual standard error of the regression range of 2.7505 - 3.2805 of the proxy group of six natural gas distribution companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1325. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1325 = \frac{3.0155}{\sqrt{518}} = \frac{3.0155}{22.7596}$$

Source of Information: Value Line Proprietary Database, September 2023.
Value Line Investment Survey (Standard Edition).

New Jersey Natural Gas Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.73	2.8787	0.0631
New Jersey Resources Corporation	0.95	0.89	3.0804	0.0675
NiSource Inc.	0.90	0.79	2.5133	0.0551
Northwest Natural Holding Company	0.80	0.68	3.3472	0.0734
ONE Gas, Inc.	0.80	0.67	3.1776	0.0697
Spire Inc.	0.85	0.71	3.0960	0.0679
Average	0.86	0.75	3.0155	0.0661
Beta Range (+/- 2 std. Devs. of Beta)	0.62	0.88		
2 std. Devs. of Beta	0.13			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.7505	3.2805		
Std. dev. of the Res. Std. Err.	0.1325			
2 std. devs. of the Res. Std. Err.	0.2650			

Source of Information: Value Line Proprietary Database, September 2023.

New Jersey Natural Gas Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Utility Proxy Group

Proxy Group of Fourty-Five Non-Price Regulated Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Abbott Labs.	0.90	0.81	2.9745	0.0652
AbbVie Inc.	0.85	0.72	3.2219	0.0706
Agilent Technologies	0.95	0.86	2.8574	0.0626
Air Products & Chem.	0.90	0.83	3.0038	0.0658
Alphabet Inc.	0.90	0.81	3.1147	0.0683
Altria Group	0.85	0.76	2.9954	0.0657
Cencora	0.80	0.68	3.0538	0.0669
Assurant Inc.	0.90	0.81	3.0499	0.0669
AutoZone Inc.	0.95	0.86	3.2654	0.0716
Booz Allen Hamilton	0.85	0.75	3.2504	0.0713
Bristol-Myers Squibb	0.80	0.68	2.8609	0.0627
Broadridge Fin'l	0.90	0.80	2.8555	0.0626
CSW Industrials	0.90	0.79	3.2750	0.0718
CACI Int'l	0.90	0.81	3.0710	0.0673
Casey's Gen'l Stores	0.90	0.79	3.1672	0.0694
Chemed Corp.	0.80	0.63	2.9085	0.0638
Cisco Systems	0.90	0.79	2.7938	0.0612
Danaher Corp.	0.90	0.80	2.8299	0.0620
Exponent, Inc.	0.95	0.87	3.2549	0.0714
Fastenal Co.	0.90	0.82	2.9347	0.0643
Franklin Electric	0.90	0.83	2.9710	0.0651
Henry (Jack) & Assoc	0.85	0.75	3.2091	0.0703
L3Harris Technologie	0.90	0.82	3.2076	0.0733
Landstar System	0.80	0.66	2.8876	0.0633
Lockheed Martin	0.90	0.81	2.9631	0.0650
MSC Industrial Direc	0.90	0.84	2.9342	0.0643
McCormick & Co.	0.80	0.64	3.1480	0.0690
McKesson Corp.	0.85	0.74	3.1864	0.0698
Microsoft Corp.	0.90	0.82	2.8641	0.0628
Monster Beverage	0.85	0.71	2.7537	0.0604
O'Reilly Automotive	0.90	0.83	3.0180	0.0662
OSI Systems	0.90	0.80	3.2046	0.0702
Oracle Corp.	0.85	0.72	3.0184	0.0662
Pfizer, Inc.	0.80	0.68	3.0820	0.0676
RLI Corp.	0.80	0.64	3.0314	0.0665
Selective Ins. Group	0.85	0.75	3.1048	0.0681
Service Corp. Int'l	0.95	0.85	3.2077	0.0703
Smith (A.O.)	0.90	0.79	3.0812	0.0675
Texas Instruments	0.85	0.77	2.7821	0.0610
Thermo Fisher Sci.	0.90	0.78	2.8552	0.0626
UniFirst Corp.	0.90	0.81	3.0649	0.0672
Universal Corp.	0.80	0.64	3.1943	0.0700
VeriSign Inc.	0.90	0.84	2.9384	0.0644
Waters Corp.	0.95	0.85	3.1619	0.0693
Watsco, Inc.	0.90	0.78	3.1138	0.0683
Average	0.88	0.77	3.0383	0.0667
Proxy Group of Six Natural Gas Distribution Companies	0.86	0.75	3.0155	0.0661

Source of Information: Value Line Proprietary Database, September 2023.

New Jersey Natural Gas Company
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Utility Proxy Group

Principal Methods		Proxy Group of Fourty-Five Non-Price Regulated Companies	
Discounted Cash Flow Model (DCF) (1)		10.69	%
Risk Premium Model (RPM) (2)		13.68	
Capital Asset Pricing Model (CAPM) (3)		13.13	
	Mean	12.50	%
	Median	13.13	%
	Average of Mean and Median	12.82	%

Notes:
(1) From page 2 of this Exhibit.
(2) From page 3 of this Exhibit.
(3) From page 6 of this Exhibit.

New Jersey Natural Gas Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Utility Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	
Proxy Group of Fourty-Five Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS (1)	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (2)	
Abbott Labs.	2.09 %	4.50 %	9.00 %	-2.00 %	6.75 %	2.16 %	8.91 %	
AbbVie Inc.	4.26	2.00	5.00	-3.83	3.50	4.33	7.83	
Agilent Technologies	0.84	13.50	8.00	7.70	9.73	0.88	10.61	
Air Products & Chem.	2.48	10.50	11.30	10.02	10.61	2.61	13.22	
Alphabet Inc.	-	13.00	16.60	17.70	15.77	-	NA	
Altria Group	9.36	6.00	3.00	2.24	3.75	9.54	13.29	
Cencora	1.08	9.00	8.90	8.70	8.87	1.13	10.00	
Assurant Inc.	1.90	10.50	14.60	14.60	13.23	2.03	15.26	
AutoZone Inc.	-	13.00	12.70	9.05	11.58	-	NA	
Booz Allen Hamilton	1.57	8.00	12.00	12.00	10.67	1.65	12.32	
Bristol-Myers Squibb	4.15	NA	4.10	-0.22	4.10	4.24	8.34	
Broadridge Fin'l	1.77	9.50	NA	11.80	10.65	1.86	12.51	
CSW Industrials	0.43	8.00	16.00	12.00	12.00	0.46	12.46	
CACI Int'l	-	7.00	9.50	6.70	7.73	-	NA	
Casey's Gen'l Stores	0.63	8.50	10.20	11.13	9.94	0.66	10.60	
Chemed Corp.	0.30	6.50	8.90	10.00	8.47	0.31	8.78	
Cisco Systems	2.96	8.50	6.20	5.83	6.84	3.06	9.90	
Danaher Corp.	0.51	11.00	12.00	-1.27	11.50	0.54	12.04	
Exponent, Inc.	1.26	9.00	NA	15.00	12.00	1.34	13.34	
Fastenal Co.	2.64	6.50	9.00	6.33	7.28	2.74	10.02	
Franklin Electric	1.01	10.50	12.00	13.40	11.97	1.07	13.04	
Henry (Jack) & Assoc	1.40	6.50	8.00	7.10	7.20	1.45	8.65	
L3Harris Technologie	2.57	16.00	3.60	1.14	6.91	2.66	9.57	
Landstar System	0.75	1.00	NA	12.00	6.50	0.77	7.27	
Lockheed Martin	2.90	7.00	8.60	11.33	8.98	3.03	12.01	
MSC Industrial Direc	3.40	5.00	NA	9.12	7.06	3.52	10.58	
McCormick & Co.	2.46	4.50	7.10	8.10	6.57	2.54	9.11	
McKesson Corp.	0.55	9.00	10.50	9.70	9.73	0.58	10.31	
Microsoft Corp.	0.88	11.50	13.50	14.01	13.00	0.94	13.94	
Monster Beverage	-	11.00	22.00	22.64	18.55	-	NA	
O'Reilly Automotive	-	11.00	13.30	11.50	11.93	-	NA	
OSI Systems	-	10.50	11.00	8.00	9.83	-	NA	
Oracle Corp.	1.45	10.00	8.80	9.85	9.55	1.52	11.07	
Pfizer, Inc.	5.16	2.00	10.00	-11.24	6.00	5.31	11.31	
RLI Corp.	0.80	13.00	NA	9.80	11.40	0.85	12.25	
Selective Ins. Group	1.36	15.00	23.80	23.80	20.87	1.50	22.37	(3)
Service Corp. Int'l	2.01	5.00	7.20	12.00	8.07	2.09	10.16	
Smith (A.O.)	1.83	9.50	9.00	8.00	8.83	1.91	10.74	
Texas Instruments	3.38	3.00	9.00	10.00	7.33	3.50	10.83	
Thermo Fisher Sci.	0.29	9.50	7.70	2.10	6.43	0.30	6.73	
UniFirst Corp.	0.79	9.00	NA	8.50	8.75	0.82	9.57	
Universal Corp.	6.56	18.00	NA	NA	18.00	7.15	25.15	(3)
VeriSign Inc.	-	13.00	NA	8.00	10.50	-	NA	
Waters Corp.	-	10.00	3.90	3.51	5.80	-	NA	
Watsco, Inc.	2.65	12.00	6.70	4.42	7.71	2.75	10.46	
						Mean	10.77 %	
	NA= Not Available							
	NMF = Non-Meaningful Figure					Median	10.60 %	
					Average of Mean and Median		10.69 %	

Notes:

(1) Average of columns 2 through 4 excluding negative growth rates.

(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of November 30, 2023. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:
Value Line Investment Survey.
www.zacks.com, Downloaded on 11/30/2023.
www.yahoo.com, Downloaded on 11/30/2023.

New Jersey Natural Gas Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fourty-Five Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.23 %
2	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.30)
3	Adjusted Prospective Bond Yield	5.93
4.	Equity Risk Premium (3)	7.75
5.	Risk Premium Derived Common Equity Cost Rate	13.68 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated December 1, 2023 (see pages 8 and 9 of Exhibit DWD-4). The estimates are detailed below.

Fourth Quarter 2023	6.40 %
First Quarter 2024	6.40
Second Quarter 2024	6.40
Third Quarter 2024	6.30
Fourth Quarter 2024	6.20
First Quarter 2025	6.10
2025-2029	6.00
2030-2034	6.00
Average	6.23 %

(2) The average yield spread of Baa rated corporate bonds over A corporate bonds for the three months ending November 2023 . To reflect the A3 average rating of the Natural Gas Non-Utility proxy groups, the prosepctive yield on Baa1 corporate bonds must be adjusted by 2/3 of the spread between A and Baa corporate bond yields as shown below:

	A Corp. Bond Yield	Baa Corp. Bond Yield	Spread
Nov-23	5.87 %	6.29 %	0.42 %
Oct-23	6.18	6.63	0.45
Sep-23	5.70	6.16	0.46
		Average yield spread	0.44
		2/3 of spread	0.30

(3) From page 5 of this Exhibit.

New Jersey Natural Gas Company
Comparison of Long-Term Issuer Ratings for the
Utility Proxy Group

Proxy Group of Fourty-Five Non-Price Regulated Companies	Moody's Long-Term Issuer Rating November 2023		Standard & Poor's Long-Term Issuer Rating November 2023	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Abbott Labs.	Aa3	4.0	AA-	4.0
AbbVie Inc.	A3	7.0	A-	7.0
Agilent Technologies	Baa1	8.0	BBB+	8.0
Air Products & Chem.	A2	6.0	A	6.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group	A3	7.0	BBB	9.0
Cencora	Baa2	9.0	BBB+	8.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	NA	--	NA	--
Bristol-Myers Squibb	A2	6.0	A+	5.0
Broadridge Fin'l	Baa2	9.0	BBB	9.0
CSW Industrials	NA	--	NA	--
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Chemed Corp.	WR	--	NR	--
Cisco Systems	A1	5.0	AA-	4.0
Danaher Corp.	A3	7.0	A-	7.0
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
Franklin Electric	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
L3Harris Technologie	Baa2	9.0	BBB	9.0
Landstar System	NA	--	NA	--
Lockheed Martin	A2	6.0	A-	7.0
MSC Industrial Direc	NA	--	NA	--
McCormick & Co.	Baa2	9.0	BBB	9.0
McKesson Corp.	Baa1	8.0	BBB+	8.0
Microsoft Corp.	Aaa	1.0	AAA	1.0
Monster Beverage	NA	--	NA	--
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	NA	--	NA	--
Oracle Corp.	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A1	5.0	A+	5.0
RLI Corp.	WR	--	BBB	9.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Smith (A.O.)	NA	--	NA	--
Texas Instruments	Aa3	4.0	A+	5.0
Thermo Fisher Sci.	A3	7.0	A-	7.0
UniFirst Corp.	NA	--	NA	--
Universal Corp.	WR	--	BBB-	10.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Average	A3	7.2	A-	7.4
New Jersey Natural Gas Company	A1	5.0	NR	--

Notes:
(1) From page 4 of Exhibit DWD-4.

Source of Information:
Bloomberg Professional Services.

New Jersey Natural Gas Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Utility Proxy Group

Line No.	Equity Risk Premium Measure	Proxy Group of Fourty-Five Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	5.82 %
2.	Regression on Kroll Risk Premium Data (2)	6.90
3.	Kroll Equity Risk Premium based on PRPM (3)	8.40
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	10.31
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.01
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	13.01
7.	Conclusion of Equity Risk Premium	8.91 %
8.	Adjusted Beta (7)	0.87
9.	Forecasted Equity Risk Premium	7.75 %

Notes:

(1) From note 1 of page 7 of Exhibit DWD-4.
(2) From note 2 of page 7 of Exhibit DWD-4.
(3) From note 3 of page 7 of Exhibit DWD-4.
(4) From note 4 of page 7 of Exhibit DWD-4.
(5) From note 5 of page 7 of Exhibit DWD-4.
(6) From note 6 of page 7 of Exhibit DWD-4.
(7) Average of mean and median beta from page 6 of this Exhibit.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts December 1, 2023
Bloomberg Professional Services.

New Jersey Natural Gas Company
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Utility Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	
Proxy Group of Fourty-Five Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)	
Abbott Labs.	0.90	0.83	0.87	9.83 %	4.44 %	12.99 %	13.31 %	13.15 %	
AbbVie Inc.	0.85	0.64	0.74	9.83	4.44	11.71	12.35	12.03	
Agilent Technologies	0.95	1.07	1.01	9.83	4.44	14.37	14.34	14.36	
Air Products & Chem.	0.90	0.87	0.88	9.83	4.44	13.09	13.38	13.24	
Alphabet Inc.	0.90	1.14	1.02	9.83	4.44	14.47	14.42	14.44	
Altria Group	0.85	0.62	0.73	9.83	4.44	11.62	12.28	11.95	
Cencora	0.85	0.69	0.77	9.83	4.44	12.01	12.57	12.29	
Assurant Inc.	0.90	0.77	0.83	9.83	4.44	12.60	13.02	12.81	
AutoZone Inc.	0.95	0.85	0.90	9.83	4.44	13.29	13.53	13.41	
Booz Allen Hamilton	0.85	0.83	0.84	9.83	4.44	12.70	13.09	12.89	
Bristol-Myers Squibb	0.80	0.54	0.67	9.83	4.44	11.03	11.84	11.43 (4)	
Broadridge Fin'l	0.90	1.02	0.96	9.83	4.44	13.88	13.97	13.93	
CSW Industrials	0.90	0.73	0.82	9.83	4.44	12.50	12.94	12.72	
CACI Int'l	0.90	0.77	0.84	9.83	4.44	12.70	13.09	12.89	
Casey's Gen'l Stores	0.90	0.75	0.82	9.83	4.44	12.50	12.94	12.72	
Chemed Corp.	0.80	0.61	0.70	9.83	4.44	11.32	12.06	11.69	
Cisco Systems	0.90	0.84	0.87	9.83	4.44	12.99	13.31	13.15	
Danaher Corp.	0.90	1.06	0.98	9.83	4.44	14.07	14.12	14.10	
Exponent, Inc.	0.95	0.99	0.97	9.83	4.44	13.97	14.05	14.01	
Fastenal Co.	0.90	0.95	0.93	9.83	4.44	13.58	13.75	13.67	
Franklin Electric	0.90	0.92	0.91	9.83	4.44	13.38	13.61	13.50	
Henry (Jack) & Assoc	0.85	0.81	0.83	9.83	4.44	12.60	13.02	12.81	
L3Harris Technologie	0.90	0.84	0.87	9.83	4.44	12.99	13.31	13.15	
Landstar System	0.80	0.83	0.81	9.83	4.44	12.40	12.87	12.64	
Lockheed Martin	0.90	0.65	0.78	9.83	4.44	12.11	12.65	12.38	
MSC Industrial Direc	0.90	0.87	0.89	9.83	4.44	13.19	13.46	13.32	
McCormick & Co.	0.80	0.72	0.76	9.83	4.44	11.91	12.50	12.21	
McKesson Corp.	0.90	0.62	0.76	9.83	4.44	11.91	12.50	12.21	
Microsoft Corp.	0.90	1.10	1.00	9.83	4.44	14.27	14.27	14.27	
Monster Beverage	0.85	0.73	0.79	9.83	4.44	12.21	12.72	12.46	
O'Reilly Automotive	0.90	0.80	0.85	9.83	4.44	12.79	13.16	12.98	
OSI Systems	0.90	0.90	0.90	9.83	4.44	13.29	13.53	13.41	
Oracle Corp.	0.85	1.06	0.95	9.83	4.44	13.78	13.90	13.84	
Pfizer, Inc.	0.80	0.70	0.75	9.83	4.44	11.81	12.43	12.12	
RLI Corp.	0.80	0.70	0.75	9.83	4.44	11.81	12.43	12.12	
Selective Ins. Group	0.85	0.63	0.74	9.83	4.44	11.71	12.35	12.03	
Service Corp. Int'l	0.95	0.81	0.88	9.83	4.44	13.09	13.38	13.24	
Smith (A.O.)	0.90	1.03	0.96	9.83	4.44	13.88	13.97	13.93	
Texas Instruments	0.85	1.00	0.92	9.83	4.44	13.48	13.68	13.58	
Thermo Fisher Sci.	0.90	0.97	0.94	9.83	4.44	13.68	13.83	13.75	
UniFirst Corp.	0.90	0.79	0.85	9.83	4.44	12.79	13.16	12.98	
Universal Corp.	0.80	0.65	0.73	9.83	4.44	11.62	12.28	11.95	
VeriSign Inc.	0.90	1.08	0.99	9.83	4.44	14.17	14.20	14.18	
Waters Corp.	0.95	0.98	0.96	9.83	4.44	13.88	13.97	13.93	
Watsco, Inc.	0.90	1.09	0.99	9.83	4.44	14.17	14.20	14.18	
		Mean	0.86			12.90 %	13.24 %	13.11 %	
		Median	0.87			12.99 %	13.31 %	13.15 %	
		Average of Mean and Median	0.87			12.95 %	13.28 %	13.13 %	

Notes:
(1) From note 1 of page 2 of Exhibit DWD-5.
(2) From note 2 of page 2 of Exhibit DWD-5.
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

New Jersey Natural Gas Company
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on November 30, 2023 (1) (millions)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
a.	New Jersey Natural Gas Company - based on the Utility Proxy Group	$ 2,732.467		5	0.93%	
b.	Proxy Group of Six Natural Gas Distribution Companies	$ 3,632.218	1.3 x	5	0.93%	0.00%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 31,549.077	$ 2,203,381.286	-0.26%
	2	12,372.885	31,316.513	0.45%
	3	5,918.981	12,323.854	0.57%
	4	3,770.176	5,916.017	0.58%
	5	2,365.425	3,769.877	0.93%
	6	1,389.851	2,365.076	1.16%
	7	789.019	1,389.118	1.37%
	8	377.076	782.383	1.18%
	9	218.389	373.879	2.15%
Smallest	10	2.015	218.227	4.83%

*From 2023 Kroll Cost of Capital Navigator

Notes:

(1) From page 2 of this Exhibit.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.00% in Column [4], Line No. 2 is derived as follows 0.00% = 0.93% - 0.93%.

New Jersey Natural Gas Company
Market Capitalization of New Jersey Natural Gas Company and the
Utility Proxy Group

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2022 (millions)	[2] Book Value per Share at Fiscal Year End 2022 (1)	[3] Total Common Equity at Fiscal Year End 2022 (millions)	[4] Closing Stock Market Price on November 30, 2023	[5] Market-to-Book Ratio on November 30, 2023 (2)	[6] Market Capitalization on November 30, 2023 (3) (millions)
New Jersey Natural Gas Company		NA	NA	1,861.354 (4)	NA		
Based upon Proxy Group of Six Natural Gas Distribution Companies						146.8 (5)	$ 2,732.467 (6)
Proxy Group of Six Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	140.897	$ 66.85	$ 9,419.09	$ 113.81	170.2 %	$ 16,035.442
New Jersey Resources Corporation	NYSE	96.250	$ 18.88	$ 1,817.21	$ 42.20	223.5	4,061.74
NiSource Inc.	NYSE	412.143	$ 14.14	$ 5,828.80	$ 25.64	181.3	10,567.34
Northwest Natural Holding Company	NYSE	35.525	$ 33.09	$ 1,175.44	$ 36.62	110.7	1,300.93
ONE Gas, Inc.	NYSE	55.350	$ 46.69	$ 2,584.43	$ 57.63	123.4	3,189.82
Spire Inc.	NYSE	52.495	$ 53.69	$ 2,818.50	$ 61.01	113.6	3,202.69
Median		75.800	$ 39.890	$ 2,701.463	$ 49.915	146.8 %	$ 3,632.218

NA= Not Available

Notes:
(1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of New Jersey Natural Gas Company on November 30, 2023 is assumed to be equal to the market-to-book ratio of on November 30, 2023 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2022 Annual Forms 10K.
Finance.Yahoo.com.
Bloomberg Professional Services.

New Jersey Natural Gas Company
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Date of Offering (1)	Transaction	Shares Issued (2)	Average Offering Price per Share (2)	Underwriting Discount (2)	Total Offering Expense per Share (2)	Net Proceeds per Share (3)	Total Flotation Costs (4)	Gross Equity Issue before Costs (5)	Net Proceeds (6)	Flotation Cost Percentage (7)
9/9/2013	NJR	571,303	$42.44	$0.424	$0.336	$41.680	$ 434,461	$ 24,246,099	$ 23,811,638	1.792%
12/13/2014*	NJR	344,289	$58.68	$0.587	$0.456	$57.637	$ 359,118	$ 20,202,879	$ 19,843,761	1.778%
12/8/2017	NJR	553,715	$41.45	$0.309	$0.289	$40.852	$ 331,048	$ 22,951,487	$ 22,620,439	1.442%
5/31/2018	NJR	460,384	$41.53	$0.328	$0.291	$40.912	$ 284,623	$ 19,119,748	$ 18,835,125	1.489%
11/20/2018	NJR	168,163	$47.93	$0.360	$0.214	$47.359	$ 96,455	$ 8,060,557	$ 7,964,102	1.197%
3/17/2019	NJR	338,952	$49.49	$0.371	$0.221	$48.901	$ 200,744	$ 16,775,814	$ 16,575,069	1.197%
5/8/2019	NJR	304,654	$49.61	$0.372	$0.266	$48.971	$ 194,362	$ 15,113,580	$ 14,919,219	1.286%
5/15/2019	NJR	369,005	$49.15	$0.370	$0.220	$48.563	$ 217,532	$ 18,137,636	$ 17,920,104	1.199%
12/4/2019	NJR	5,700,000	$41.25	$1.238	$1.421	$38.591	$ 15,153,750	$ 235,125,000	$ 219,971,250	6.445%
12/8/2022	NJR	368,240	$49.26	$0.369	$0.220	$48.670	$ 217,028	$ 18,139,370	$ 17,922,342	1.196%
5/17/2023	NJR	256,738	$49.09	$0.368	$0.219	$48.502	$ 150,781	$ 12,603,007	$ 12,452,226	1.196%
6/5/2023	NJR	262,252	$48.03	$0.360	$0.214	$47.453	$ 150,713	$ 12,595,334	$ 12,444,621	1.197%
							$ 17,790,614	$ 423,070,510	$ 405,279,896	4.205%

Flotation Cost Adjustment

	[10]	[11]	[12]	[13]	[14]	[15]
	Average Dividend Yield (8)	Average Projected EPS Growth Rate (8)	Adjusted Dividend Yield (9)	Average DCF Cost Rate Unadjusted for Flotation (10)	DCF Cost Rate Adjusted for Flotation (11)	Flotation Cost Adjustment (12)
Proxy Group of Six Natural Gas Distribution Companies	4.17 %	6.32 %	4.30 %	10.62 %	10.81 %	0.19 %

Notes:
(1) Transactions prior to NJR's common stock split 2-for-1 effective on March 4, 2015.
(2) Company Provided
(3) Column [2] - Column [3] - Column [4].
(4) (Column [2] - Column [5]) x Column [1].
(5) Column [1] x Column [2].
(6) Column [1] x Column [5].
(7) Column [6] / Column [7].
(8) From page 1 of Exhibit DWD-3.
(9) Column [10] x (1 + 0.5 x (Column [11] / 100)).
(10) Column [11] + Column [12].
(11) (Column [12] / (1 - Column [9])) + Column [11].
(12) Column [14] - Column [13].

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

PREPARED DIRECT TESTIMONY OF RONALD E. WHITE, PH.D. ON BEHALF OF NEW JERSEY NATURAL GAS

I. INTRODUCTION AND QUALIFICATION

Q. PLEASE STATE YOUR NAME, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Ronald E. White. I serve as President of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908. A summary of my education, relevant employment experience and other professional qualifications is provided in Appendix REW–1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by New Jersey Natural Gas Company ("NJNG" or "Company") to conduct a fiscal 2024 depreciation study ("F2024 Study") for gas properties owned and operated by NJNG. The purpose of my testimony is to describe and sponsor the study conducted by Foster Associates.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I sponsor Exhibit REW–1, a document titled "Fiscal 2024 Depreciation Rate Study." This exhibit was prepared by me or under my direction and supervision.

IV. SUMMARY

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR NJNG IN THE F2024 STUDY.

A. Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended for NJNG in the F2024 Study.

Function	Accrual Rates			F2024 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Storage	1.77%	1.86%	0.09%	$ 1,518,051	$ 1,585,925	$ 67,874
Transmission	2.47%	2.54%	0.07%	15,860,281	16,319,409	459,128
Distribution	2.66%	3.85%	1.19%	74,564,546	107,648,492	33,083,946
General	4.87%	6.58%	1.71%	14,172,028	19,267,739	5,095,711
Total	2.79%	3.79%	1.00%	$106,114,906	$144,821,565	$ 38,706,659

Table 1. Depreciation Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.79 percent. Depreciation expense is currently accrued at rates that composite to 2.79 percent. The recommended change in the composite depreciation rate is an increase of 1.00 percentage points. The proposed F2024 expense increase of $38,706,659 includes amortization of a $428,775,396 reserve deficiency. The remaining portion of the increase is attributable to adjusted service lives and net salvage parameters.

V. Development of Depreciation Rates

Q. PLEASE EXPLAIN THE GOAL OF DEPRECIATION ACCOUNTING AND WHY DEPRECIATION STUDIES ARE CONDUCTED PERIODICALLY.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential (or future economic benefit) of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other noncash expenses) or cash inflows attributable to the use of that asset alone. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all property units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected

distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent such cost–based regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of an accounting measurement of earnings. While a continuation of such practices may not comport with the goals of depreciation accounting, achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon authorized levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation can be a significant source of internally generated funds used to finance plant replacements, new capacity additions or other cash expenditures. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL ACTIVITIES UNDERTAKEN IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about future forces of retirement to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience and service life indications are considered descriptive of the future.

An estimate of net salvage associated with future retirements is most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may produce different amounts of net salvage than realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the estimated projection–life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive study will also include an analysis of the adequacy (or inadequacy) of recorded depreciation reserves. The purpose of such an analysis is to compare current recorded reserve balances with balances required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between a required (or theoretical) reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is

not taken to extinguish such reserve imbalances.

Although reserve records are typically maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise when depreciation rates are negotiated in settlements that shift the timing of depreciation expense to future accounting periods. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute or rebalance recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and net salvage rates. A redistribution of recorded reserves will realign reserve balances for each primary account consistent with revised estimates of net salvage and service–life statistics and establish a baseline against which future reserve comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are entered into a formulation of accrual rates using a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Figure 1 below.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Figure 1. Elements of a Depreciation System

The above elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

VI. F2024 DEPRECIATION RATE STUDY

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY NJNG.

A. Depreciation rates currently used by NJNG were approved by the New Jersey Board of Public Utilities (BPU) pursuant to a Stipulation of Settlement in Docket No. GR21030679 (Order dated November 24, 2021). Parties to the 2021 settlement agreed to maintain a composite depreciation rate of 2.78 percent composed of an investment rate of 1.89 percent and a net salvage rate of 0.89 percent.[1] Settled depreciation rates in Docket No. GR21030679 were derived by retaining all accrual rates approved and adopted in a settlement of Docket No. GR19030420 (Order dated November 13, 2019), with the exception of modified net salvage accrual rates for three plant accounts described in Exhibit REW–1, Table 1.

Q. DID NJNG PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE F2024 DEPRECIATION STUDY?

A. Yes. The database used in the F2024 Study was assembled by appending transactions over the period October 1, 2020 through September 30, 2023 to the database used in conducting the F2021 Study. Reserve transactions recorded over the period fiscal 1972–2023 were used in the analysis of future net salvage rates.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR NJNG PLANT AND EQUIPMENT?

A. Yes. As discussed in Exhibit REW–1, full mortality plant accounts were analyzed using a technique in which first, second and third–degree polynomials were fitted to a set of observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. Observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indica-

[1] A composite rate of 3.47 percent composed of an investment rate of 2.09 percent and a net salvage rate of 1.38 percent was recommended in the F2021 Depreciation Rate Study based on September 30, 2020 plant and depreciation reserve balances.

tions derived from the statistical analyses were blended with expectations about the future to obtain an appropriate projection life and curve for each plant category. Plant accounts classified in storage and processing and transmission structures were treated as life–span categories in the F2024 Study.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS IN THE F2024 STUDY?

A. Yes. A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the F2024 Study to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates.

However, at the request of NJNG, future net salvage rates for transmission and distribution mains and distribution services were tempered to produce a Company composite accrual rate of approximately 3.80 percent. The tempered composite accrual rate was requested to mitigate an otherwise study–supported composite rate exceeding 10 percent. Table 2 below provides a comparison of study–supported (*i.e.*, untempered) future net salvage rates with the tempered rates used to derive the requested reduction in the composite depreciation rate.

Account Description	Untempered	Tempered
A	B	C
TRANSMISSION PLANT		
367.00 Mains	-310%	-70%
DISTRIBUTION PLANT		
376.00 Mains - Steel	-650%	-70%
376.26 Mains - Plastic	-575%	-60%
380.01 Services - Steel	-425%	-70%
380.21 Services - Plastic	-240%	-60%

Table 2. Future Net Salvage Rates

Average net salvage rates were estimated using direct dollar weighting of historical retirements with historical net salvage rates, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rates. The computation of estimated average net salvage rates is shown in Exhibit REW–1, Statement E.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Exhibit REW–1, Statement C provides a comparison of the computed, recorded and rebalanced reserves at September 30, 2023. The recorded reserve was $677,224,903 or 17.7 percent of the depreciable plant investment. The corresponding computed reserve is $1,106,000,299 or 29.0 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $428,775,396 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates recommended in the F2024 Study.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES?

A. Yes. A redistribution of recorded reserves is again considered appropriate for NJNG. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the F2024 Study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of recorded reserves for depreciable plant categories was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves to the function total calculated reserve. The sum of redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before redistribution. Depreciation reserves for amortizable categories were redistributed by setting recorded reserves for the amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the general function.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED FOR NJNG.

A. Current depreciation rates were developed and approved for each primary account using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM USED BY NJNG?

A. No. Depreciation rates recommended in the F2024 Study were developed using the currently approved system. It is the opinion of Foster Associates that this system will remain appropriate for NJNG, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

RONALD E. WHITE, PH.D.

EDUCATION

1961 – 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated with the Service Life of Industrial Property

EMPLOYMENT

2015 – Present: Foster Associates Consultants, LLC, President

2007 – 2015 Foster Associates, Inc., Chairman

1996 – 2007 Foster Associates, Inc., Executive Vice President

1988 – 1996 Foster Associates, Inc., Senior Vice President

1979 – 1988 Foster Associates, Inc., Vice President

1978 – 1979 Northern States Power Company, Assistant Treasurer

1974 – 1978 Northern States Power Company, Manager, Corporate Economics

1972 – 1974 Northern States Power Company, Corporate Economist

1970 – 1972 Iowa State University, Graduate Student and Instructor

1968 – 1970 Northern States Power Company, Valuation Engineer

1965 – 1968 Iowa State University, Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem with AFDC is …, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

- Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.
- Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.
- Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.
- Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.
- Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.
- Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.
- Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.
- Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–16–0036, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–19–0236, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–22–0144, Arizona Public Service Company; rebuttal testimony to Staff advocated treatment of net salvage accrual rates.

- Arizona Corporation Commission, Docket No. E–04204A–22–0251, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–12–0126, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–15–0322, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–19–0028, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–15–0142, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.
- California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.
- California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.
- California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.
- California Public Utilities Commission. Application No. A.16–09–001 Southern California Edison; testimony regarding estimation of service lives and net salvage rates.
- Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.
- State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.
- Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.
- Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.
- Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

- Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1115, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1137, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1162, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.
- Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.
- Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.
- Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

- Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.
- Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.
- Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.
- Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.
- Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.
- Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.
- Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.
- Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.
- Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.
- Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.
- Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.
- Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.
- Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.
- Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.
- Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.
- Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

- Kansas Corporation Commission, Docket No. 23-EKCE-775-RTS, Evergy Kansas Central, Evergy Kansas South and Evergy Kansas Metro; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 16-KGSG-491-RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 18-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.
- Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.
- Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 18–KGSG–560–RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.
- Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9424, Delmarva Power and Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9481, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

- Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 15–155, Massachusetts Electric Company/Nantucket Electric Company; testimony supporting proposed depreciation rates.
- Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.
- Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.
- Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.
- Michigan Public Service Commission, Case No. U–18150, DTE Electric Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.
- Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates
- Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.
- Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.
- Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.
- Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.
- Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.
- Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

- Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.
- Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.
- Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.
- Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.
- Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.
- Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.
- Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.
- Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.
- Montana Public Service Commission, Docket No. D2018.2.12, NorthWestern Energy –Montana; testimony supporting proposed depreciation rates.
- Montana Public Service Commission, Docket No. D2022.07.078, NorthWestern Energy – Montana; testimony supporting proposed depreciation rates.
- Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.
- Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.
- Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.
- New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.
- New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Public Utilities, Docket No. GR87060552, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Public Utilities, Docket No. GR21030679, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Public Utilities, Docket No. GR19030420, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony supporting depreciation rates.

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- New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.
- New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.
- North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.
- North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.
- North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.
- North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Oklahoma Corporation Commission, Cause No. PUD 202100063, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
- Oklahoma Corporation Commission, Cause No. PUD 201500213, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
- Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
- Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.
- Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.
- Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.
- Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.
- Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

- Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.
- Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.
- Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.
- Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.
- Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.
- Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.
- Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.
- South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.
- South Dakota Public Utilities Commission, Docket No. EL14–106, NorthWestern Energy; testimony supporting revised depreciation rates.
- Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.
- Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.
- The Railroad Commission of Texas, GUD Docket No. 9896, Texas Gas Service, testimony supporting recommended depreciation rates.

- The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10488, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10506, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10656, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10526, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10928, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 14399, Texas Gas Service, testimony supporting recommended depreciation rates.
- State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.
- State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.
- Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

OTHER CONSULTING ENGAGEMENTS

Arbitrator in a Technical Dispute relating to classification of Capital Budget expenditures.

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

FACULTY

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

PROFESSIONAL ASSOCIATIONS

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee).

MODERATOR

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

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The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

SPEAKER

Depreciation Training Seminar, Kansas Gas Service, October 2018.

Depreciation Workshop, Oklahoma Corporation Commission, Public Utility Division, March 2015.

Depreciation Workshop, ONE Gas, Inc. January 2015.

Depreciation Training Seminar, Florida Public Service Commission, March 2013.

Depreciation and Obsolescence (Isness and Oughtness), Ninety–Fifth Annual Arizona Tax Conference, August 2012.

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation? American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

HONORS AND AWARDS

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

December 2023

Fiscal 2024 Depreciation Rate Study

New Jersey Natural Gas

foster associates

CONTENTS

DISTRIBUTION

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a fiscal 2024 depreciation study ("F2024 Study") conducted by Foster Associates Consultants, LLC (Foster Associates) for gas plant owned and operated by New Jersey Natural Gas Company (NJNG). Work on the study began in August 2023 and progressed through December, at which time the project was completed.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by NJNG were approved by the New Jersey Board of Public Utilities (BPU) pursuant to a Stipulation of Settlement in Docket No. GR21030679 (Order dated November 24, 2021). Parties to the 2021 settlement agreed to maintain a composite depreciation rate of 2.78 percent composed of an investment rate of 1.89 percent and a net salvage rate of 0.89 percent.[1] Settled depreciation rates in Docket No. GR21030679 were derived by retaining all accrual rates approved and adopted in a settlement of Docket No. GR19030420 (Order dated November 13, 2019), with the exception of modified net salvage accrual rates shown in Table 1 below.

Account Description	2019 Settlement			2021 Settlement		
	Invest.	Net Sal.	Total	Invest.	Net Sal.	Total
A	B	C	D=B	E	F	G=E+F
TRANSMISSION PLANT						
367.00 Mains	1.49%	0.88%	2.37%	1.46%	0.88%	2.34%
DISTRIBUTION PLANT						
378.00 Meas, and Reg.Sta. Equip.	1.53%	0.91%	2.44%	1.50%	0.94%	2.44%
380.21 Services - Plastic	1.57%	0.92%	2.49%	1.48%	0.94%	2.42%

Table 1. Modified Net Salvage Accrual Rates

[1] A composite rate of 3.47 percent composed of an investment rate of 2.09 percent and a net salvage rate of 1.38 percent was recommended in the F2021 Depreciation Rate Study based on September 30, 2020 plant and depreciation reserve balances.

The principal findings and recommendations of the F2024 Depreciation Rate Study are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of recorded, computed, and redistributed depreciation reserves. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, and average remaining life.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data.
- Reconciliation of data to the official records of the Company.
- Discussions with NJNG plant accounting and operations personnel.
- Estimation of projection lives and retirement dispersion patterns.
- Analysis of gross salvage and cost of removal.
- Analysis and redistribution of recorded depreciation reserves.
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, NJNG is currently using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique. This system was proposed and adopted in a 1987 study to more nearly achieve the goals of depreciation accounting. Prior to the 1987 study, NJNG had been using a system composed of the straight–line method, broad group procedure and remaining–life technique. Additionally, a composite accrual rate was used for each function *(i.e.,* Production, Storage, Transmission, Distribution and General) and a single depreciation reserve was maintained for all plant

categories. Accrual rates were developed for each primary account in the 1987 study and the recorded depreciation reserve was disaggregated into primary account reserves.

Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is "retired" (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Realized net salvage for amortizable accounts is netted against current–year vintage additions.

Depreciation theory provides that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure and remaining–life technique, It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

PROPOSED DEPRECIATION RATES

Table 2 below provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation rates recommended in the F2024 Study.

	Accrual Rates			F2024 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Storage	1.77%	1.86%	0.09%	$ 1,518,051	$ 1,585,925	$ 67,874
Transmission	2.47%	2.54%	0.07%	15,860,281	16,319,409	459,128
Distribution	2.66%	3.85%	1.19%	74,564,546	107,648,492	33,083,946
General	4.87%	6.58%	1.71%	14,172,028	19,267,739	5,095,711
Total	2.79%	3.79%	1.00%	$106,114,906	$144,821,565	$38,706,659

Table 2. Depreciation Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.79 percent. Depreciation expense is currently accrued at rates that composite to 2.79 percent. The recommended change in the composite depreciation rate is an increase of 1.00 percentage points.

The proposed F2024 expense increase of $38,706,659 includes amortization of a $428,775,396 reserve deficiency. The remaining portion of the increase is attributable to adjusted service lives and net salvage parameters.

Of the 31 property accounts included in the F2024 Study, Foster Associates is recommending rate reductions for 7 accounts, rate increases for 20 accounts and no change for 4 accounts.

COMPANY PROFILE

GENERAL

New Jersey Natural Gas (NJNG) is the principal subsidiary of New Jersey Resources (NJR), a New Jersey corporation formed in 1982 pursuant to a corporate reorganization. NJR subsidiaries and businesses include:

1. NJNG, a local natural gas distribution company;
2. NJR Clean Energy Ventures, an affiliate engaged in unregulated capital investments in clean energy projects, including commercial and residential solar projects and onshore wind investments.
3. NJR Energy Services, an affiliate that maintains and transacts around a portfolio of physical assets consisting of natural gas storage and transportation contracts;
4. NJR Retail Holdings, an affiliate that consolidates NJR's unregulated retail operations including heating, ventilation and cooling service repair and contract services;
5. NJR Capital Services, an affiliate that consolidates NJR's unregulated energy–related and real estate investments; and
6. NJR Services, an unregulated company that provides shared administrative services including corporate communications, financial and administrative, internal audit, legal, human resources and technology for NJR and all subsidiaries of NJR.

GAS UTILITY OPERATIONS

NJNG provides regulated natural gas service to approximately 576,000 customers. Its service territory encompasses 1,516 square miles, covering 110 municipalities with an estimated population of 1.5 million people.

NJNG added 8,800 and 7,808 new in fiscal 2023 and 2022, respectively. NJNG's new customer annual growth rate of approximately 1.9 percent is expected to continue with projected additions in the range of approximately 32,000 to 34,000 new customers over the next three fiscal years. This anticipated customer growth represents approximately $8.5 million in new annual utility gross margin, as calculated under NJNG's Conservation Incentive Program Tariff.

GAS UTILITY PROPERTIES

As of September 30, 2023, NJNG owned approximately 7,334 miles of distribution main, 7,768 miles of service main, 251 miles of transmission main and 595,225 meters. Mains are primarily located under public roads. Where mains are located under private property, NJNG has obtained easements for the owners of record.

Additionally, NJNG owns and operates two LNG storage plants in Stafford Township, Ocean County, and Howell Township, Monmouth County. The two

LNG plants have an aggregate estimated maximum capacity of 170,000 Dths per day and 1 Bcf of total capacity. These facilities are used for peaking natural gas supply and for emergencies. NJNG Liquefaction facility is also located on the Howell Township property and allows NJNG to convert natural gas into LNG to fill NJNG's existing LNG storage tanks.

NJNG owns five service centers located in Rockaway Township, Morris County; Atlantic Highlands, and Wall Township, Monmouth County; and Lakewood and Stafford Township, Ocean County. These service centers house storerooms, garages, gas distribution and administrative offices. NJNG leases a customer service office in Asbury Park, Monmouth County. These customer service offices support customer contact, marketing, economic development and other functions. NJNG also owns its headquarters and customer service facilities in Wall Township and a training facility in Howell Township, Monmouth County, to support the technical training of its employees.

GAS SUPPLY

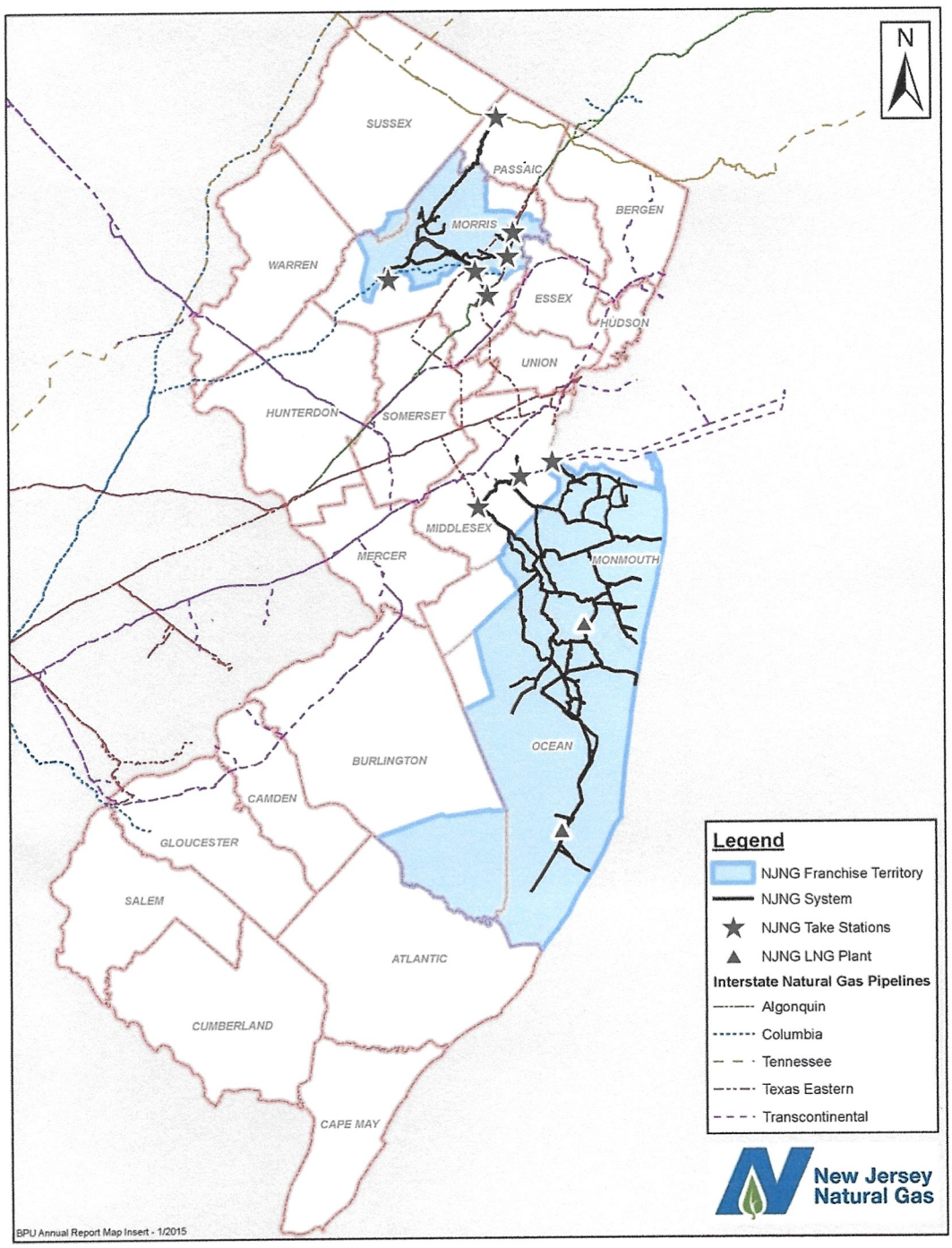
NJNG's gas supply portfolio consists of long–term (over seven months), winter–term (for the five winter months) and short–term contracts. In fiscal 2023, NJNG purchased gas from approximately 58 suppliers under contract ranging from one day to seven months and purchased over 10 percent of its natural gas from two suppliers.

In order to take delivery of firm natural gas supplies, NJNG maintains agreements for firm transportation and storage capacity with several interstate pipeline companies. NJNG receives natural gas at 11 city gate stations located in Burlington, Middlesex, Morris and Passaic counties in New Jersey.

SERVICE TERRITORY

NJNG's service territory covers New Jersey's Monmouth and Ocean counties and parts of Burlington, Morris, Middlesex, and Sussex counties. It is primarily suburban, highlighted by approximately 100 miles of New Jersey seacoast. It is in close proximity to New York City, Philadelphia and the metropolitan areas of northern New Jersey and is accessible through a network of major roadways and mass transportation.

SERVICE AREA MAP



STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and the adequacy of depreciation accruals and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation rates used by NJNG for its gas operations. The proposed rates are subject to approval by the New Jersey Board of Public Utilities.

SCOPE

Steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the F2024 Study for NJNG included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage–year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary

reports are created in a format reconcilable to a company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by NJNG provides aged transactions for all plant accounts.

Service–life studies conducted in the F2024 Study were based upon plant accounting transactions recorded over the fiscal period 1961–2023. Data used in the study were assembled and coded by NJNG plant accounting personnel. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity used in conducting the depreciation study.

The database for NJNG was initially constructed for a fiscal 1993 study with accrual rates based on September 30, 1992 plant and depreciation reserve balances. The database for the 1993 study was constructed from a reverse calculation of historical arrangements over the period 1961-1991 for each plant account. Age distributions of plant exposed to retirement at the beginning of each activity year were obtained by adding (or subtracting) transaction amounts to the coded age distributions of surviving plant at September 30, 1991. Plant additions for each activity year and age distributions of surviving plant at the beginning of 1961 were subsequently coded and added to the database. Coded age distributions of surviving plant at the end of fiscal 1991 were subsequently removed from the database. The conversion of the database from a reverse construction of the historical arrangement to a forward construction was made to facilitate appending fiscal 1992 and subsequent activity–year transactions to the data without removing or adjusting prior coded transactions.

The database used in the current study was assembled by appending transactions over the period October 1, 2020 through September 30, 2023 to the database used in conducting the F2021 Study[2]. Reserve transactions recorded over the period fiscal 1972–2023 were used in the analysis of future net salvage rates.

The accuracy and completeness of the assembled data base was examined for fiscal activity years 2021 through 2023 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. The ac-

[2] Fiscal–year reporting of plant activity was adopted by NJNG in 1988 coincident with the conversion from a manual fixed asset accounting system to a McCormick & Dodge mechanized system. The M&D system was replaced in 1993 by a JD Edwards system that was replaced in 2003 by Information Intellect's IntelliPlant system. Fixed asset accounting is currently maintained in a PowerPlan system installed in 2008 and initialized with September 2008 age distributions.

curacy of activity years prior to fiscal 2023 was verified in conducting the fiscal 2021 and prior studies.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

Analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the F2024 Study.

An actuarial life analysis program designed and developed by Foster Associates was used in the F2024 Study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally contains the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in the F2024 Study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ra-

tio—called a "retirement ratio"—is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the F2024 Study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. Observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

The set of computer programs used in the NJNG study provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined for a "retirement era" which restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides both tabular and graphics output and algorithms for calculating de-

preciation rates and accruals.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method with interim retirements described by an appropriate survivor curve. Plant accounts classified in storage and processing and transmission structures were treated as life–span categories in the F2024 Study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a basis for estimating future salvage and cost of removal. However, consideration should be given to events that may cause deviations from net salvage realized in the past. Factors that should be considered include the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

Five–year moving averages of the ratio of realized salvage, reimbursements and cost of removal to the associated retirements were used in the F2024 Study to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates.

However, at the request of NJNG, future net salvage rates for transmission and distribution mains and distribution services were tempered to produce a Company composite accrual rate of approximately 3.80 percent. The tempered composite

accrual rate was requested to mitigate an otherwise study–supported composite rate exceeding 10 percent. Table 3 below provides a comparison of study–supported (*i.e.*, untempered) future net salvage rates with the tempered rates used to derive the requested reduction in the composite depreciation rate.

Account Description	Untempered	Tempered
A	B	C
TRANSMISSION PLANT		
367.00 Mains	-310%	-70%
DISTRIBUTION PLANT		
376.00 Mains - Steel	-650%	-70%
376.26 Mains - Plastic	-575%	-60%
380.01 Services - Steel	-425%	-70%
380.21 Services - Plastic	-240%	-60%

Table 2. Future Net Salvage Rates

Average net salvage rates were estimated using direct dollar weighting of historical retirements with historical net salvage rates, and future retirements (*i.e.*, surviving plant) with the proposed tempered future net salvage rates. The computation of the estimated average net salvage rates is shown in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to gradually extinguish the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of plant units still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant currently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that

will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or anticipated changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for NJNG. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of recorded reserves for depreciable plant categories was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves to the function total calculated reserve. The sum of redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before redistribution. Depreciation reserves for amortizable categories were redistributed by setting recorded reserves for the amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the general function.

Statement C provides a comparison of the computed, recorded and rebalanced reserves at September 30, 2023. The recorded reserve was $677,224,903 or 17.7 percent of the depreciable plant investment. The corresponding computed reserve is $1,106,000,299 or 29.0 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $428,775,396 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates recommended in this study.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the F2024 Study were developed using the currently approved system composed of the straight–line method, vintage group procedure and remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for NJNG, provided depreciation studies are conducted periodically and parameters are adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories. Depreciation rates shown in Statement A (Column G) are the reciprocal of the reported amortization periods.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage statistics recommended for NJNG. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized F2024 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category on September 30, 2023.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates (Column D) shown on Statement A. These are the effective rates used by the NJNG for the mix of investments recorded on September 30, 2023. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates (Column G) shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

The above formulation of a remaining–life accrual rate is equivalent to the sum of a whole–life rate and an amortization of reserve imbalances over the estimated remaining life of a plant category. The equivalent formulation is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

NEW JERSEY NATURAL GAS

Statement A

Comparison of Current and Proposed Accrual Rates
Filed: VG Procedure / RL Technique
Settled VG Procedure / RL Technique

Account Description	Current (at 9/30/2023)			Proposed (at 9/30/2023)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STORAGE AND PROCESSING PLANT						
361.00 Structures and Improvements	1.31%	0.12%	1.43%	1.47%	0.14%	1.61%
362.00 Gas Holders	0.94%	0.38%	1.32%	1.06%	0.43%	1.49%
363.20 Vaporizing Equipment	2.30%	-1.14%	1.16%	2.32%	-1.15%	1.17%
363.30 Compressor Equipment	1.85%	0.09%	1.94%	1.89%	0.09%	1.98%
363.40 Measuring and Regulating Equipment	2.64%	0.14%	2.78%	2.60%	0.13%	2.73%
363.50 Other Equipment	-3.93%	-0.21%	-4.14%	-2.16%	-0.12%	-2.28%
363.52 Other Equipment - Hydrogen	3.70%		3.70%	2.83%	0.14%	2.97%
Total Storage and Processing Plant	1.92%	-0.15%	1.77%	1.99%	-0.13%	1.86%
TRANSMISSION PLANT						
366.00 Structures and Improvements	3.13%	0.30%	3.43%	2.84%	0.28%	3.12%
367.00 Mains	1.46%	0.88%	2.34%	1.44%	1.02%	2.46%
369.00 Measuring and Regulating Equipment	2.03%	1.52%	3.55%	2.00%	1.21%	3.21%
Total Transmission Plant	1.52%	0.95%	2.47%	1.50%	1.04%	2.54%
DISTRIBUTION PLANT						
375.01 Structures and Improvements	1.77%	0.07%	1.84%	1.57%	0.07%	1.64%
376.00 Mains - Steel	1.49%	1.34%	2.83%	1.65%	1.35%	3.00%
376.26 Mains - Plastic	1.50%	0.94%	2.44%	2.02%	1.24%	3.26%
378.00 Meas. and Reg. Station Equip. - General	3.22%	2.49%	5.71%	2.62%	1.99%	4.61%
380.01 Services - Steel	1.60%	0.79%	2.39%	2.23%	2.52%	4.75%
380.21 Services - Plastic	1.48%	0.94%	2.42%	3.11%	1.97%	5.08%
381.00 Meters	3.16%	0.07%	3.23%	3.45%	0.04%	3.49%
382.00 Meter Installations	2.96%	1.55%	4.51%	3.12%	1.76%	4.88%
385.00 Meas. and Reg. Equipment - Industrial	3.42%	0.35%	3.77%	2.61%	0.27%	2.88%
387.00 Other Equipment	7.87%	1.15%	9.02%	8.50%	1.27%	9.77%
Total Distribution Plant	1.66%	1.00%	2.66%	2.40%	1.45%	3.85%
GENERAL PLANT						
Depreciable						
390.02 Structures and Improvements	2.48%	-1.00%	1.48%	3.27%	-0.06%	3.21%
392.00 Transportation Equipment	4.57%	-1.48%	3.09%	6.91%	-0.86%	6.05%
396.00 Power Operated Equipment	0.19%		0.19%	3.40%		3.40%
Total Depreciable	3.12%	-1.14%	1.98%	4.44%	-0.32%	4.12%
Amortizable						
391.01 Furniture, Fixtures and Equipment	3.95%		3.95%	← 25 Year Amortization →		4.00%
391.02 Information Systems	8.93%		8.93%	← 10 Year Amortization →		10.00%
391.03 Data Handling Equipment	5.57%		5.57%	← 10 Year Amortization →		10.00%
391.04 Computer Software	8.10%		8.10%	← 10 Year Amortization →		10.00%
393.00 Stores Equipment	2.86%		2.86%	← 35 Year Amortization →		2.86%
394.00 Tools, Shop and Garage Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%
395.00 Laboratory Equipment	2.86%		2.86%	← 35 Year Amortization →		2.86%
397.00 Communication Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%
Total Amortizable	7.64%		7.64%	8.92%		8.92%
Total General Plant	5.43%	-0.56%	4.87%	6.73%	-0.15%	6.58%
TOTAL UTILITY	1.94%	0.85%	2.79%	2.57%	1.22%	3.79%

NEW JERSEY NATURAL GAS

Comparison of Current and Proposed Accruals
Filed: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	09/30/23 Investment	Current F2024 Annualized Accrual Investment	Net Salvage	Total	Proposed F2024 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STORAGE AND PROCESSING PLANT								
361.00 Structures and Improvements	$ 3,610,916	$ 47,303	$ 4,333	$ 51,636	$ 53,080	$ 5,055	$ 58,135	$ 6,499
362.00 Gas Holders	10,544,240	99,116	40,068	139,184	111,769	45,340	157,109	17,925
363.20 Vaporizing Equipment	18,758,628	431,448	(213,848)	217,600	435,200	(215,724)	219,476	1,876
363.30 Compressor Equipment	3,377,445	62,483	3,040	65,523	63,834	3,040	66,874	1,351
363.40 Measuring and Regulating Equipment	38,229,174	1,009,250	53,521	1,062,771	993,959	49,698	1,043,657	(19,114)
363.50 Other Equipment	5,335,098	(209,669)	(11,204)	(220,873)	(115,238)	(6,402)	(121,640)	99,233
363.52 Other Equipment - Hydrogen	5,465,138	202,210		202,210	154,663	7,651	162,314	(39,896)
Total Storage and Processing Plant	$ 85,320,639	$ 1,642,141	$ (124,090)	$ 1,518,051	$ 1,697,267	$ (111,342)	$ 1,585,925	$ 67,874
TRANSMISSION PLANT								
366.00 Structures and Improvements	$ 930,111	$ 29,112	$ 2,790	$ 31,902	$ 26,415	$ 2,604	$ 29,019	$ (2,883)
367.00 Mains	574,802,600	8,392,118	5,058,263	13,450,381	8,277,157	5,862,987	14,140,144	689,763
369.00 Measuring and Regulating Equipment	66,985,855	1,359,813	1,018,185	2,377,998	1,339,717	810,529	2,150,246	(227,752)
Total Transmission Plant	$ 642,718,566	$ 9,781,043	$ 6,079,238	$ 15,860,281	$ 9,643,289	$ 6,676,120	$ 16,319,409	$ 459,128
DISTRIBUTION PLANT								
375.01 Structures and Improvements	$ 41,980,661	$ 743,058	$ 29,386	$ 772,444	$ 659,096	$ 29,386	$ 688,482	$ (83,962)
376.00 Mains - Steel	451,067,003	6,720,898	6,044,298	12,765,196	7,442,606	6,089,405	13,532,011	766,815
376.26 Mains - Plastic	1,152,280,864	17,284,213	10,831,440	28,115,653	23,276,073	14,288,283	37,564,356	9,448,703
378.00 Meas. and Reg. Station Equip. - General	43,158,363	1,389,699	1,074,643	2,464,342	1,130,749	858,851	1,989,600	(474,742)
380.01 Services - Steel	36,543,597	584,698	288,694	873,392	814,922	920,899	1,735,821	862,429
380.21 Services - Plastic	823,009,291	12,180,538	7,736,287	19,916,825	25,595,589	16,213,283	41,808,872	21,892,047
381.00 Meters	116,024,431	3,666,372	81,217	3,747,589	4,002,843	46,410	4,049,253	301,664
382.00 Meter Installations	122,574,330	3,628,200	1,899,902	5,528,102	3,824,319	2,157,308	5,981,627	453,525
385.00 Meas. and Reg. Equipment - Industrial	9,490,230	324,566	33,216	357,782	247,695	25,624	273,319	(84,463)
387.00 Other Equipment	257,438	20,260	2,961	23,221	21,882	3,269	25,151	1,930
Total Distribution Plant	$ 2,796,386,208	$ 46,542,502	$ 28,022,044	$ 74,564,546	$ 67,015,774	$ 40,632,718	$ 107,648,492	$ 33,083,946
GENERAL PLANT								
Depreciable								
390.02 Structures and Improvements	$ 95,346,335	$ 2,364,589	$ (953,463)	$ 1,411,126	$ 3,117,825	$ (57,208)	$ 3,060,617	$ 1,649,491
392.00 Transportation Equipment	45,900,208	2,097,640	(679,323)	1,418,317	3,171,704	(394,742)	2,776,962	1,358,645
396.00 Power Operated Equipment	2,042,857	3,881		3,881	69,457		69,457	65,576
Total Depreciable	$ 143,289,400	$ 4,466,110	$ (1,632,786)	$ 2,833,324	$ 6,358,986	$ (451,950)	$ 5,907,036	$ 3,073,712
Amortizable								
391.01 Furniture, Fixtures and Equipment	$ 4,179,353	$ 165,084	$ -	$ 165,084	$ 167,174	$ -	$ 167,174	$ 2,090
391.02 Information Systems	31,545,396	2,817,004		2,817,004	3,154,540		3,154,540	337,536
391.03 Data Handling Equipment	1,172,788	65,324		65,324	117,279		117,279	51,955
391.04 Computer Software	85,811,446	6,950,727		6,950,727	8,581,145		8,581,145	1,630,418
393.00 Stores Equipment	232,386	6,646		6,646	6,646		6,646	
394.00 Tools, Shop and Garage Equipment	26,035,485	1,301,774		1,301,774	1,301,774		1,301,774	
395.00 Laboratory Equipment	258,817	7,402		7,402	7,402		7,402	
397.00 Communication Equipment	494,852	24,743		24,743	24,743		24,743	
Total Amortizable	$ 149,730,523	$ 11,338,704	$ -	$ 11,338,704	$ 13,360,703	$ -	$ 13,360,703	$ 2,021,999
Total General Plant	$ 293,019,923	$ 15,804,814	$ (1,632,786)	$ 14,172,028	$ 19,719,689	$ (451,950)	$ 19,267,739	$ 5,095,711
TOTAL UTILITY	$ 3,817,445,336	$ 73,770,500	$ 32,344,406	$ 106,114,906	$ 98,076,019	$ 46,745,546	$ 144,821,565	$ 38,706,659

NEW JERSEY NATURAL GAS
Depreciation Reserve Summary
Vintage Group Procedure
September 30, 2023

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STORAGE AND PROCESSING PLANT							
361.00 Structures and Improvements	$ 3,610,916	$ 2,209,320	61.18%	$ 1,282,688	35.52%	$ 1,538,671	42.61%
362.00 Gas Holders	10,544,240	12,799,139	121.39%	6,852,578	64.99%	8,220,134	77.96%
363.20 Vaporizing Equipment	18,758,628	9,343,012	49.81%	4,271,641	22.77%	5,124,124	27.32%
363.30 Compressor Equipment	3,377,445	1,762,776	52.19%	2,081,430	61.63%	2,496,817	73.93%
363.40 Measuring and Regulating Equipment	38,229,174	7,587,724	19.85%	11,573,041	30.27%	13,882,651	36.31%
363.50 Other Equipment	5,335,098	3,627,807	68.00%	5,112,724	95.83%	6,133,060	114.96%
363.52 Other Equipment - Hydrogen	5,465,138	360,690	6.60%	245,931	4.50%	295,011	5.40%
Total Storage and Processing Plant	$ 85,320,639	$ 37,690,469	44.18%	$ 31,420,033	36.83%	$ 37,690,469	44.18%
TRANSMISSION PLANT							
366.00 Structures and Improvements	$ 930,111	$ 847,760	91.15%	$ 755,526	81.23%	$ 722,412	77.67%
367.00 Mains	574,802,600	114,706,957	19.96%	126,174,339	21.95%	120,644,357	20.99%
369.00 Measuring and Regulating Equipment	66,985,855	21,991,371	32.83%	16,920,932	25.26%	16,179,320	24.15%
Total Transmission Plant	$ 642,718,566	$ 137,546,089	21.40%	$ 143,850,797	22.38%	$ 137,546,089	21.40%
DISTRIBUTION PLANT							
375.01 Structures and Improvements	$ 41,980,661	$ 12,182,436	29.02%	$ 7,454,673	17.76%	$3,598,998	8.57%
376.00 Mains - Steel	451,067,003	(4,201,499)	-0.93%	83,922,803	18.61%	40,516,603	8.98%
376.26 Mains - Plastic	1,152,280,864	235,481,180	20.44%	300,344,867	26.07%	145,001,756	12.58%
378.00 Meas. and Reg. Station Equip. - General	43,158,363	16,877,572	39.11%	11,198,395	25.95%	5,406,408	12.53%
380.01 Services - Steel	36,543,597	(75,865,225)	-207.60%	1,230,632	3.37%	594,130	1.63%
380.21 Services - Plastic	823,009,291	192,951,219	23.44%	379,106,924	46.06%	183,026,832	22.24%
381.00 Meters	116,024,431	19,173,717	16.53%	26,122,434	22.51%	12,611,498	10.87%
382.00 Meter Installations	122,574,330	9,846,741	8.03%	34,997,170	28.55%	16,896,081	13.78%
385.00 Meas. and Reg. Equipment - Industrial	9,490,230	1,437,140	15.14%	1,017,026	10.72%	491,004	5.17%
387.00 Other Equipment	257,438	356,723	138.57%	200,283	77.80%	96,694	37.56%
Total Distribution Plant	$ 2,796,386,208	$ 408,240,003	14.60%	$ 845,595,206	30.24%	$ 408,240,003	14.60%

NEW JERSEY NATURAL GAS
Depreciation Reserve Summary
Vintage Group Procedure
September 30, 2023

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
GENERAL PLANT							
Depreciable							
390.02 Structures and Improvements	$ 95,346,335	$ 9,270,403	9.72%	$ 6,226,707	6.53%	$ 8,377,607	8.79%
392.00 Transportation Equipment	45,900,208	16,001,901	34.86%	18,147,358	39.54%	24,416,023	53.19%
396.00 Power Operated Equipment	2,042,857	412,476	20.19%	563,105	27.56%	757,620	37.09%
Total Depreciable	$ 143,289,400	$ 25,684,780	17.93%	$ 24,937,171	17.40%	$ 33,551,250	23.42%
Amortizable							
391.01 Furniture, Fixtures and Equipment	$ 4,179,353	$ (2,873,577)	-68.76%	$ 695,978	16.65%	$ 695,978	16.65%
391.02 Information Systems	31,545,396	14,437,743	45.77%	15,540,073	49.26%	15,540,073	49.26%
391.03 Data Handling Equipment	1,172,788	1,616,630	137.84%	1,096,717	93.51%	1,096,717	93.51%
391.04 Computer Software	85,811,446	47,251,862	55.06%	33,009,821	38.47%	33,009,821	38.47%
393.00 Stores Equipment	232,386	172,143	74.08%	196,549	84.58%	196,549	84.58%
394.00 Tools, Shop and Garage Equipment	26,035,485	6,285,466	24.14%	9,067,524	34.83%	9,067,524	34.83%
395.00 Laboratory Equipment	258,817	484,658	187.26%	203,144	78.49%	203,144	78.49%
397.00 Communication Equipment	494,852	688,638	139.16%	387,286	78.26%	387,286	78.26%
Total Amortizable	$ 149,730,523	$ 68,063,562	45.46%	$ 60,197,092	40.20%	$ 60,197,092	40.20%
Total General Plant	$ 293,019,923	$ 93,748,342	31.99%	$ 85,134,263	29.05%	$ 93,748,342	31.99%
TOTAL UTILITY	$ 3,817,445,336	$ 677,224,903	17.74%	$ 1,106,000,299	28.97%	$ 677,224,903	17.74%

NEW JERSEY NATURAL GAS
Depreciation Reserve Components
Redistributed Reserve
September 30, 2023

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Rebalanced Reserve Amount	Total Rebalanced Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STORAGE AND PROCESSING PLANT							
361.00 Structures and Improvements	$ 3,610,916	$ 1,388,089	38.44%	$ 150,583	4.17%	$ 1,538,671	42.61%
362.00 Gas Holders	10,544,240	5,886,016	55.82%	2,334,119	22.14%	8,220,134	77.96%
363.20 Vaporizing Equipment	18,758,628	10,345,501	55.15%	(5,221,378)	-27.83%	5,124,124	27.32%
363.30 Compressor Equipment	3,377,445	2,376,326	70.36%	120,491	3.57%	2,496,817	73.93%
363.40 Measuring and Regulating Equipment	38,229,174	13,252,626	34.67%	630,025	1.65%	13,882,651	36.31%
363.50 Other Equipment	5,335,098	5,838,336	109.43%	294,724	5.52%	6,133,060	114.96%
363.52 Other Equipment - Hydrogen	5,465,138	280,963	5.14%	14,048	0.26%	295,011	5.40%
Total Storage and Processing Plant	$ 85,320,639	$ 39,367,856	46.14%	$ (1,677,387)	-1.97%	$ 37,690,469	44.18%
TRANSMISSION PLANT							
366.00 Structures and Improvements	$ 930,111	$ 656,315	70.56%	$ 66,098	7.11%	$ 722,412	77.67%
367.00 Mains	574,802,600	75,153,649	13.07%	45,490,708	7.91%	120,644,357	20.99%
369.00 Measuring and Regulating Equipment	66,985,855	10,347,025	15.45%	5,832,294	8.71%	16,179,320	24.15%
Total Transmission Plant	$ 642,718,566	$ 86,156,989	13.41%	$ 51,389,100	8.00%	$ 137,546,089	21.40%
DISTRIBUTION PLANT							
375.01 Structures and Improvements	$ 41,980,661	$ 3,282,027	7.82%	$ 316,971	0.76%	$ 3,598,998	8.57%
376.00 Mains - Steel	451,067,003	50,921,345	11.29%	(10,404,742)	-2.31%	40,516,603	8.98%
376.26 Mains - Plastic	1,152,280,864	98,635,282	8.56%	46,366,474	4.02%	145,001,756	12.58%
378.00 Meas. and Reg. Station Equip. - General	43,158,363	3,388,479	7.85%	2,017,929	4.68%	5,406,408	12.53%
380.01 Services - Steel	36,543,597	7,660,189	20.96%	(7,066,059)	-19.34%	594,130	1.63%
380.21 Services - Plastic	823,009,291	128,345,639	15.59%	54,681,193	6.64%	183,026,832	22.24%
381.00 Meters	116,024,431	13,875,671	11.96%	(1,264,173)	-1.09%	12,611,498	10.87%
382.00 Meter Installations	122,574,330	15,960,267	13.02%	935,814	0.76%	16,896,081	13.78%
385.00 Meas. and Reg. Equipment - Industrial	9,490,230	450,123	4.74%	40,881	0.43%	491,004	5.17%
387.00 Other Equipment	257,438	83,976	32.62%	12,717	4.94%	96,694	37.56%
Total Distribution Plant	$ 2,796,386,208	$ 322,602,998	11.54%	$ 85,637,006	3.06%	$ 408,240,003	14.60%

NEW JERSEY NATURAL GAS
Depreciation Reserve Components
Redistributed Reserve
September 30, 2023

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Rebalanced Reserve Amount	Total Rebalanced Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
GENERAL PLANT							
Depreciable							
390.02 Structures and Improvements	$ 95,346,335	$ 6,675,111	7.00%	$ 1,702,496	1.79%	$ 8,377,607	8.79%
392.00 Transportation Equipment	45,900,208	23,991,768	52.27%	424,255	0.92%	24,416,023	53.19%
396.00 Power Operated Equipment	2,042,857	757,620	37.09%			757,620	37.09%
Total Depreciable	$ 143,289,400	$ 31,424,499	21.93%	$ 2,126,751	1.48%	$ 33,551,250	23.42%
Amortizable							
391.01 Furniture, Fixtures and Equipment	$ 4,179,353	$ 695,978	16.65%	$ -		$ 695,978	16.65%
391.02 Information Systems	31,545,396	15,540,073	49.26%			15,540,073	49.26%
391.03 Data Handling Equipment	1,172,788	1,096,717	93.51%			1,096,717	93.51%
391.04 Computer Software	85,811,446	33,009,821	38.47%			33,009,821	38.47%
393.00 Stores Equipment	232,386	196,549	84.58%			196,549	84.58%
394.00 Tools, Shop and Garage Equipment	26,035,485	9,067,524	34.83%			9,067,524	34.83%
395.00 Laboratory Equipment	258,817	203,144	78.49%			203,144	78.49%
397.00 Communication Equipment	494,852	387,286	78.26%			387,286	78.26%
Total Amortizable	$ 149,730,523	$ 60,197,092	40.20%	$ -		$ 60,197,092	40.20%
Total General Plant	$ 293,019,923	$ 91,621,591	31.27%	$ 2,126,751	0.73%	$ 93,748,342	31.99%
TOTAL UTILITY	$ 3,817,445,336	$ 539,749,433	14.14%	$ 137,475,469	3.60%	$ 677,224,903	17.74%

NEW JERSEY NATURAL GAS
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STORAGE AND PROCESSING PLANT									
361.00 Structures and Improvements	$ 3,764,718	$ 153,802	$ 3,610,916		-10.0%	$ -	$ (361,092)	$ (361,092)	-9.6%
362.00 Gas Holders	11,665,038	1,120,798	10,544,240	-42.9%	-40.0%	(480,822)	(4,217,696)	(4,698,518)	-40.3%
363.20 Vaporizing Equipment	18,894,060	135,432	18,758,628		50.0%		9,379,314	9,379,314	49.6%
363.30 Compressor Equipment	3,433,327	55,882	3,377,445		-5.0%		(168,872)	(168,872)	-4.9%
363.40 Measuring and Regulating Equipment	38,346,296	117,122	38,229,174	-46.7%	-5.0%	(54,696)	(1,911,459)	(1,966,155)	-5.1%
363.50 Other Equipment	5,945,230	610,132	5,335,098		-5.0%		(266,755)	(266,755)	-4.5%
363.52 Other Equipment - Hydrogen	5,465,138		5,465,138		-5.0%		(273,257)	(273,257)	-5.0%
Total Storage and Processing Plant	$ 87,513,807	$ 2,193,168	$ 85,320,639	-24.4%	2.6%	$ (535,518)	$ 2,180,184	$ 1,644,665	1.9%
TRANSMISSION PLANT									
366.00 Structures and Improvements	$ 948,644	$ 18,533	$ 930,111		-10.0%	$ -	$ (93,011)	$ (93,011)	-9.8%
367.00 Mains	580,259,325	5,456,725	574,802,600	-229.5%	-70.0%	(12,523,184)	(402,361,820)	(414,885,004)	-71.5%
369.00 Measuring and Regulating Equipment	73,181,952	6,196,097	66,985,855	-68.6%	-60.0%	(4,250,523)	(40,191,513)	(44,442,036)	-60.7%
Total Transmission Plant	$ 654,389,921	$ 11,671,355	$ 642,718,566	-143.7%	-68.9%	$ (16,773,706)	$ (442,646,344)	$ (459,420,051)	-70.2%
DISTRIBUTION PLANT									
375.01 Structures and Improvements	$ 43,418,677	$ 1,438,016	$ 41,980,661	21.9%	-5.0%	$ 314,926	$ (2,099,033)	$ (1,784,108)	-4.1%
376.00 Mains - Steel	480,549,268	29,482,265	451,067,003	-519.8%	-70.0%	(153,248,813)	(315,746,902)	(468,995,716)	-97.6%
376.26 Mains - Plastic	1,159,124,382	6,843,518	1,152,280,864	-526.7%	-60.0%	(36,044,809)	(691,368,518)	(727,413,328)	-62.8%
378.00 Meas. and Reg. Station Equip. - General	53,614,454	10,456,091	43,158,363	-90.4%	-75.0%	(9,452,306)	(32,368,772)	(41,821,079)	-78.0%
380.01 Services - Steel	63,024,772	26,481,175	36,543,597	-366.3%	-70.0%	(97,000,544)	(25,580,518)	(122,581,062)	-194.5%
380.21 Services - Plastic	864,379,115	41,369,824	823,009,291	-233.2%	-60.0%	(96,474,430)	(493,805,575)	(590,280,004)	-68.3%
381.00 Meters	141,252,548	25,228,117	116,024,431	-16.8%		(4,238,324)		(4,238,324)	-3.0%
382.00 Meter Installations	144,786,337	22,212,007	122,574,330	-156.2%	-50.0%	(34,695,155)	(61,287,165)	(95,982,320)	-66.3%
385.00 Meas. and Reg. Equipment - Industrial	9,586,303	96,073	9,490,230	-15.5%	-10.0%	(14,891)	(949,023)	(963,914)	-10.1%
387.00 Other Equipment	591,869	334,431	257,438	-14.4%	-15.0%	(48,158)	(38,616)	(86,774)	-14.7%
Total Distribution Plant	$ 2,960,327,725	$ 163,941,517	$ 2,796,386,208	-262.8%	-58.0%	$ (430,902,505)	$ (1,623,244,122)	$ (2,054,146,627)	-69.4%
GENERAL PLANT									
Depreciable									
390.02 Structures and Improvements	$ 97,640,115	$ 2,293,780	$ 95,346,335	60.6%		$ 1,390,031	$ -	$ 1,390,031	1.4%
392.00 Transportation Equipment	66,168,305	20,268,097	45,900,208	19.0%	5.0%	3,850,938	2,295,010	6,145,949	9.3%
396.00 Power Operated Equipment	2,049,756	6,899	2,042,857						
Total Depreciable	$ 165,858,176	$ 22,568,776	$ 143,289,400	23.2%	1.6%	$ 5,240,969	$ 2,295,010	$ 7,535,980	4.5%
Amortizable									
391.01 Furniture, Fixtures and Equipment	$ 12,977,833	$ 8,798,480	$ 4,179,353			$ -	$ -	$ -	
391.02 Information Systems	47,537,944	15,992,548	31,545,396						
391.03 Data Handling Equipment	3,186,439	2,013,651	1,172,788						
391.04 Computer Software	123,940,822	38,129,376	85,811,446						
393.00 Stores Equipment	315,258	82,872	232,386						
394.00 Tools, Shop and Garage Equipment	34,120,826	8,085,341	26,035,485						
395.00 Laboratory Equipment	327,665	68,848	258,817						
397.00 Communication Equipment	3,075,670	2,580,818	494,852						
Total Amortizable	$ 225,482,457	$ 75,751,934	$ 149,730,523			$ -	$ -	$ -	
Total General Plant	$ 391,340,633	$ 98,320,710	$ 293,019,923	5.3%	0.8%	$ 5,240,969	$ 2,295,010	$ 7,535,980	1.9%
TOTAL UTILITY	$ 4,093,572,086	$ 276,126,750	$ 3,817,445,336	-160.4%	-54.0%	$ (442,970,761)	$ (2,061,415,272)	$ (2,504,386,033)	-61.2%

NEW JERSEY NATURAL GAS
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current (at 9/30/2023) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed (at 9/30/2023) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STORAGE AND PROCESSING PLANT												
361.00 Structures and Improvements	2068	200-SC	64.53	46.27	-9.5	-10.0	2068	200-SC	61.63	41.88	-9.6	-10.0
362.00 Gas Holders	2068	200-SC	77.90	46.13	-40.3	-40.0	2068	200-SC	78.07	41.74	-40.3	-40.0
363.20 Vaporizing Equipment	2068	35-R5	35.22	23.61	49.6	50.0	2068	35-R5	35.78	19.33	49.6	50.0
363.30 Compressor Equipment	2068	35-R5	35.73	19.06	-4.9	-5.0	2068	35-R5	38.02	15.72	-4.9	-5.0
363.40 Measuring and Regulating Equipment	2068	35-R5	35.13	29.61	-5.1	-5.0	2068	35-R5	35.33	25.12	-5.1	-5.0
363.50 Other Equipment	2068	35-R5	35.13	29.61	-5.1	-5.0	2068	35-R5	49.81	4.37	-4.5	-5.0
363.52 Other Equipment - Hydrogen	2068	35-R5	37.50	5.09	-4.5	-5.0	2068	35-R5	35.00	33.50	-5.0	-5.0
Total Storage and Processing Plant									39.65	24.40	1.9	2.6
TRANSMISSION PLANT												
366.00 Structures and Improvements	2034	200-SC	39.18	15.18	-9.8	-10.0	2034	200-SC	39.50	10.35	-9.8	-10.0
367.00 Mains							70.00	R3	70.06	60.48	-71.5	-70.0
369.00 Measuring and Regulating Equipment	50.00	L0	50.24	43.51	-74.5	-75.0	50.00	L0	50.45	42.30	-60.7	-60.0
Total Transmission Plant									67.26	57.83	-70.2	-68.9
DISTRIBUTION PLANT												
375.01 Structures and Improvements	65.00	L1.5	65.39	46.76	-3.0	-5.0	70.00	S1	70.09	58.74	-4.1	-5.0
376.00 Mains - Steel	77.00	S1.5	77.09	55.88	-87.6	-93.0	70.00	S2	70.05	53.67	-97.6	-70.0
376.26 Mains - Plastic							55.00	R4	54.99	45.24	-62.8	-60.0
378.00 Meas. and Reg. Station Equip. - General	35.00	L0.5	35.23	26.13	-78.8	-75.0	42.00	L0	42.06	35.22	-78.0	-75.0
380.01 Services - Steel	70.00	L0	72.26	51.31	-38.7	-60.0	60.00	R0.5	62.60	35.42	-194.5	-70.0
380.21 Services - Plastic							40.00	R4	40.06	27.12	-68.3	-60.0
381.00 Meters	35.00	L2	35.07	27.40	-3.8		34.00	S1	33.91	25.51	-3.0	
382.00 Meter Installations	38.00	L1.5	38.22	28.54	-54.4	-50.0	38.00	L1.5	38.19	27.89	-66.3	-50.0
385.00 Meas. and Reg. Equipment - Industrial	40.00	L2	41.92	19.78	-10.4	-10.0	40.00	L2	40.41	36.44	-10.1	-10.0
387.00 Other Equipment	15.00	L0	19.07	8.33	-14.1	-15.0	15.00	L0	24.45	7.93	-14.7	-15.0
Total Distribution Plant									49.04	37.32	-69.4	-58.0

NEW JERSEY NATURAL GAS
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current (at 9/30/2023) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed (at 9/30/2023) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
GENERAL PLANT												
Depreciable												
390.02 Structures and Improvements	30.00	SC	29.18	25.11	10.9		30.00	SC	29.98	28.42	1.4	
392.00 Transportation Equipment	12.00	L1	12.04	9.52	14.6	10.0	11.00	L1.5	11.30	6.91	9.3	5.0
396.00 Power Operated Equipment	25.00	S4	25.53	16.36			25.00	S4	25.54	18.50		
Total Depreciable									19.57	16.38	4.5	1.6
Amortizable												
391.01 Furniture, Fixtures and Equipment	25.00	SQ	25.00	17.33			25.00	SQ	25.00	20.84		
391.02 Information Systems	10.00	SQ	10.00	5.23			10.00	SQ	10.00	5.94		
391.03 Data Handling Equipment	10.00	SQ	10.00	3.54	0.1		10.00	SQ	10.00	1.92		
391.04 Computer Software	10.00	SQ	10.00	4.24			10.00	SQ	10.00	7.14		
393.00 Stores Equipment	35.00	SQ	35.00	10.39			35.00	SQ	35.00	5.45		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	16.05			20.00	SQ	20.00	13.07		
395.00 Laboratory Equipment	35.00	SQ	35.00	12.53			35.00	SQ	35.00	7.53		
397.00 Communication Equipment	20.00	SQ	20.00	4.78			20.00	SQ	20.00	7.86		
Total Amortizable									11.21	7.56		
Total General Plant									14.17	10.68	1.9	0.8
TOTAL UTILITY									42.69	33.04	-61.2	-54.0

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the F2024 depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 378.00 – Measuring and Regulating Station Equipment – General. Supporting schedules for all other plant accounts are contained in the study work papers. Supporting schedules developed in the NJNG study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Net Salvage History.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column C) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

Table 4 below provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 4. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

Computed proportions surviving (Column D) for unaged data are derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Ac-

tivity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. Negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between observed proportions surviving and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa

dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – NET SALVAGE HISTORY

An Unadjusted Net Salvage History contains recorded activity–year retirements, salvage, cost of removal and other depreciation reserve activity appropriately recognized in the computation of average net salvage rates. This schedule provides a moving–average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving–average analysis of the components of unadjusted net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

An Adjusted Net Salvage History contains recorded activity–year total retirements, salvage, cost of removal and other depreciation reserve activity appropriately adjusted in the estimation of future net salvage rates. The moving–average adjusted net salvage analysis and component analysis are displayed in columns corresponding to an unadjusted net salvage analysis.

Schedule A
Page 1 of 3

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant
Account: 378.00 Meas. and Reg. Sta. Equip. - General

Dispersion: 42 - L0
Procedure: Vintage Group

Generation Arrangement

	September 30, 2023				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2023	0.5	942,147	42.00	41.57	0.9897	1.0000	932,443	22,432
2022	1.5	792,841	42.01	40.79	0.9711	1.0000	769,913	18,875
2021	2.5	5,322,022	42.02	40.08	0.9539	1.0000	5,076,878	126,668
2020	3.5	609,797	42.03	39.42	0.9378	1.0000	571,883	14,507
2019	4.5	11,849,474	42.06	38.80	0.9225	1.0000	10,930,942	281,741
2018	5.5	2,243,138	42.04	38.21	0.9088	1.0000	2,038,610	53,358
2017	6.5	960,961	42.15	37.64	0.8931	1.0000	858,270	22,801
2016	7.5	1,004,015	42.16	37.10	0.8799	1.0000	883,415	23,812
2015	8.5	267,728	42.28	36.58	0.8653	1.0000	231,656	6,333
2014	9.5	1,991,728	42.08	36.08	0.8573	1.0000	1,707,489	47,330
2013	10.5	910,622	42.28	35.59	0.8417	1.0000	766,516	21,537
2012	11.5	354,687	42.56	35.12	0.8251	1.0000	292,656	8,333
2011	12.5	543,933	42.17	34.66	0.8219	1.0000	447,040	12,897
2010	13.5	111,612	40.97	34.22	0.8352	1.0000	93,220	2,724
2009	14.5	211,627	41.71	33.78	0.8099	1.0000	171,403	5,074
2008	15.5	442,288	40.92	33.36	0.8153	1.0000	360,586	10,809
2007	16.5	497,607	41.43	32.94	0.7952	1.0000	395,683	12,011
2006	17.5	461,555	41.89	32.54	0.7768	1.0000	358,548	11,019
2005	18.5	730,573	41.42	32.14	0.7760	1.0000	566,931	17,639
2004	19.5	1,146,357	43.34	31.75	0.7326	1.0000	839,864	26,452
2003	20.5	1,517,636	43.49	31.37	0.7212	1.0000	1,094,461	34,894
2002	21.5	378,653	42.53	30.98	0.7286	1.0000	275,878	8,904
2001	22.5	716,501	40.73	30.61	0.7514	1.0000	538,406	17,589
2000	23.5	873,796	41.11	30.24	0.7356	1.0000	642,790	21,257
1999	24.5	347,973	36.49	29.87	0.8187	1.0000	284,882	9,537
1998	25.5	616,767	42.11	29.51	0.7008	1.0000	432,201	14,646
1997	26.5	1,086,617	43.65	29.15	0.6679	1.0000	725,773	24,895
1996	27.5	62,367	40.73	28.80	0.7072	1.0000	44,104	1,531
1995	28.5	318,316	45.46	28.45	0.6258	1.0000	199,207	7,002
1994	29.5	327,996	40.27	28.11	0.6979	1.0000	228,902	8,144
1993	30.5	258,395	40.27	27.77	0.6895	1.0000	178,160	6,417
1992	31.5	292,854	44.99	27.43	0.6097	1.0000	178,553	6,510
1991	32.5	560,857	46.31	27.10	0.5851	1.0000	328,166	12,111
1990	33.5	758,999	42.75	26.77	0.6262	1.0000	475,251	17,755
1989	34.5	586,843	39.70	26.44	0.6661	1.0000	390,881	14,782
1988	35.5	547,182	42.39	26.12	0.6162	1.0000	337,164	12,907
1987	36.5	692,912	42.44	25.80	0.6080	1.0000	421,305	16,327

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant
Account: 378.00 Meas. and Reg. Sta. Equip. - General

Dispersion: 42 - L0
Procedure: Vintage Group

Generation Arrangement

	September 30, 2023				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1986	37.5	674,658	44.45	25.49	0.5735	1.0000	386,944	15,179
1985	38.5	340,656	38.15	25.18	0.6600	1.0000	224,833	8,928
1984	39.5	23,421	39.88	24.88	0.6237	1.0000	14,608	587
1983	40.5	55,105	36.93	24.57	0.6654	1.0000	36,667	1,492
1982	41.5	129,986	40.05	24.27	0.6061	1.0000	78,783	3,246
1981	42.5	37,505	36.19	23.98	0.6625	1.0000	24,846	1,036
1980	43.5	29,123	35.82	23.69	0.6612	1.0000	19,257	813
1979	44.5	34,296	36.00	23.40	0.6499	1.0000	22,289	953
1978	45.5	17,456	31.18	23.11	0.7412	1.0000	12,938	560
1977	46.5	76,717	38.19	22.83	0.5977	1.0000	45,856	2,009
1976	47.5	48,276	37.26	22.55	0.6051	1.0000	29,213	1,296
1975	48.5	44,784	41.60	22.27	0.5354	1.0000	23,977	1,077
1974	49.5	7,259	36.79	22.00	0.5980	1.0000	4,341	197
1973	50.5	25,213	40.51	21.73	0.5364	1.0000	13,524	622
1972	51.5	48,143	36.34	21.46	0.5906	1.0000	28,433	1,325
1971	52.5	22,932	35.10	21.20	0.6039	1.0000	13,849	653
1970	53.5	41,157	45.90	20.93	0.4561	1.0000	18,771	897
1969	54.5	16,992	37.08	20.68	0.5576	1.0000	9,475	458
1968	55.5	15,674	41.00	20.42	0.4980	1.0000	7,806	382
1967	56.5	6,265	38.80	20.17	0.5198	1.0000	3,256	161
1966	57.5	8,678	38.67	19.91	0.5150	1.0000	4,469	224
1965	58.5	10,933	44.82	19.67	0.4388	1.0000	4,798	244
1964	59.5	9,461	42.25	19.42	0.4597	1.0000	4,349	224
1963	60.5	13,621	44.76	19.18	0.4285	1.0000	5,836	304
1962	61.5	8,353	38.70	18.94	0.4894	1.0000	4,088	216
1961	62.5	1,343	33.41	18.70	0.5598	1.0000	752	40
1960	63.5	8,520	40.35	18.46	0.4576	1.0000	3,899	211
1959	64.5	17,165	45.47	18.23	0.4010	1.0000	6,883	378
1958	65.5	12,098	45.67	18.00	0.3942	1.0000	4,768	265
1957	66.5	3,836	43.47	17.77	0.4088	1.0000	1,568	88
1956	67.5	5,441	44.55	17.55	0.3938	1.0000	2,143	122
1955	68.5	941	43.53	17.32	0.3980	1.0000	374	22
1954	69.5	7,074	47.73	17.10	0.3583	1.0000	2,534	148
1953	70.5	2,474	61.53	16.88	0.2744	1.0000	679	40
1952	71.5	600	47.46	16.66	0.3511	1.0000	211	13
1951	72.5	305	30.77	16.45	0.5345	1.0000	163	10
1950	73.5	1,681	43.84	16.24	0.3703	1.0000	622	38

Schedule A
Page 3 of 3

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant
Account: 378.00 Meas. and Reg. Sta. Equip. - General

Dispersion: 42 - L0
Procedure: Vintage Group

Generation Arrangement

	September 30, 2023				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1949	74.5	897	43.10	16.02	0.3718	1.0000	333	21
1943	80.5	555	66.99	14.80	0.2209	1.0000	123	8
1939	84.5	313	42.31	14.02	0.3313	1.0000	104	7
1938	85.5	1,919	86.23	13.83	0.1604	1.0000	308	22
1937	86.5	665	80.16	13.64	0.1701	1.0000	113	8
1934	89.5	340	56.08	13.08	0.2333	1.0000	79	6
1932	91.5	412	70.35	12.72	0.1808	1.0000	75	6
1931	92.5	1,370	54.70	12.54	0.2292	1.0000	314	25
1930	93.5	649	56.83	12.36	0.2174	1.0000	141	11
1927	96.5	1,714	70.21	11.83	0.1685	1.0000	289	24
1926	97.5	554	61.71	11.66	0.1890	1.0000	105	9
1925	98.5	1,458	66.38	11.49	0.1731	1.0000	252	22
Total	12.9	$43,158,363	42.06	35.22	0.8374	1.0000	$36,140,071	$1,026,190

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Age Distribution

Vintage	Age as of 09/30/2023	Derived Additions	1961 Opening Balance	Experience to 09/30/2023		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2023	0.5	942,147		942,147	1.0000	0.5000
2022	1.5	792,841		792,841	1.0000	1.5000
2021	2.5	5,322,022		5,322,022	1.0000	2.5000
2020	3.5	609,797		609,797	1.0000	3.5000
2019	4.5	11,863,612		11,849,474	0.9988	4.4970
2018	5.5	2,334,113		2,243,138	0.9610	5.4415
2017	6.5	960,961		960,961	1.0000	6.5000
2016	7.5	1,010,148		1,004,015	0.9939	7.4605
2015	8.5	267,728		267,728	1.0000	8.5000
2014	9.5	2,093,682		1,991,728	0.9513	9.2239
2013	10.5	964,607		910,622	0.9440	10.3272
2012	11.5	354,687		354,687	1.0000	11.5000
2011	12.5	604,941		543,933	0.8992	11.9889
2010	13.5	150,822		111,612	0.7400	11.6455
2009	14.5	276,582		211,627	0.7652	13.2384
2008	15.5	579,516		442,288	0.7632	13.2815
2007	16.5	622,866		497,607	0.7989	14.6162
2006	17.5	588,367		461,555	0.7845	15.8795
2005	18.5	1,180,488		730,573	0.6189	16.2027
2004	19.5	1,293,215		1,146,357	0.8864	18.8985
2003	20.5	1,669,552		1,517,636	0.9090	19.8163
2002	21.5	497,794		378,653	0.7607	19.5990
2001	22.5	1,094,686		716,501	0.6545	18.5383
2000	23.5	1,374,889		873,796	0.6355	19.6276
1999	24.5	901,879		347,973	0.3858	15.7125
1998	25.5	915,735		616,767	0.6735	22.0251
1997	26.5	1,352,084		1,086,617	0.8037	24.2334
1996	27.5	173,074		62,367	0.3603	21.9697
1995	28.5	388,495		318,316	0.8194	27.3505
1994	29.5	568,448		327,996	0.5770	22.7912
1993	30.5	538,531		258,395	0.4798	23.4021
1992	31.5	425,816		292,854	0.6877	28.7206
1991	32.5	715,931		560,857	0.7834	30.6280
1990	33.5	1,282,174		758,999	0.5920	27.6396
1989	34.5	1,229,282		586,843	0.4774	25.1473
1988	35.5	919,859		547,182	0.5949	28.3845
1987	36.5	1,186,446		692,912	0.5840	28.9610
1986	37.5	1,003,865		674,658	0.6721	31.4817

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Age Distribution

Vintage	Age as of 09/30/2023	Derived Additions	1961 Opening Balance	Experience to 09/30/2023		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1985	38.5	792,394		340,656	0.4299	25.6912
1984	39.5	649,728		23,421	0.0360	27.9077
1983	40.5	240,243		55,105	0.2294	25.4296
1982	41.5	296,468		129,986	0.4384	29.0108
1981	42.5	151,118		37,505	0.2482	25.6036
1980	43.5	82,213		29,123	0.3542	25.6645
1979	44.5	164,991		34,296	0.2079	26.2669
1978	45.5	125,226		17,456	0.1394	21.8564
1977	46.5	280,132		76,717	0.2739	29.2643
1976	47.5	172,085		48,276	0.2805	28.7203
1975	48.5	194,194		44,784	0.2306	33.4295
1974	49.5	25,693		7,259	0.2825	28.9798
1973	50.5	57,750		25,213	0.4366	33.0475
1972	51.5	260,419		48,143	0.1849	29.2164
1971	52.5	125,722		22,932	0.1824	28.3023
1970	53.5	104,809		41,157	0.3927	39.4181
1969	54.5	75,169		16,992	0.2260	30.9034
1968	55.5	56,651		15,674	0.2767	35.1166
1967	56.5	52,218		6,265	0.1200	33.1969
1966	57.5	42,763		8,678	0.2029	33.3456
1965	58.5	70,174		10,933	0.1558	39.7527
1964	59.5	35,689		9,461	0.2651	37.4355
1963	60.5	44,587		13,621	0.3055	40.1925
1962	61.5	30,745		8,353	0.2717	34.3640
1961	62.5	23,383		1,343	0.0574	29.2953
1960	63.5		36,262	8,520	0.2350	36.4526
1959	64.5		54,642	17,165	0.3141	41.7797
1958	65.5		40,386	12,098	0.2996	42.1800
1957	66.5		14,711	3,836	0.2608	40.1719
1956	67.5		21,024	5,441	0.2588	41.4333
1955	68.5		9,161	941	0.1027	40.5828
1954	69.5		36,007	7,074	0.1964	44.9504
1953	70.5		56,724	2,474	0.0436	58.9055
1952	71.5		6,554	600	0.0916	44.9945
1951	72.5		12,225	305	0.0249	28.4483
1950	73.5		16,672	1,681	0.1008	41.6572
1949	74.5		5,713	897	0.1570	41.0424
1948	75.5		5,642		0.0000	31.9661

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Age Distribution

Vintage	Age as of 09/30/2023	Derived Additions	1961 Opening Balance	Experience to 09/30/2023		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1947	76.5		3,032		0.0000	27.4825
1946	77.5		639		0.0000	59.0000
1945	78.5		922		0.0000	30.3124
1944	79.5		4,202		0.0000	42.9099
1943	80.5		838	555	0.6623	65.6022
1942	81.5		3,518		0.0000	38.8961
1941	82.5		1,749		0.0000	43.3955
1940	83.5		1,196		0.0000	35.5171
1939	84.5		1,041	313	0.3005	41.2600
1938	85.5		2,034	1,919	0.9433	85.2448
1937	86.5		774	665	0.8592	79.2481
1936	87.5		75		0.0000	36.0000
1935	88.5		337		0.0000	31.3234
1934	89.5		838	340	0.4060	55.3477
1932	91.5		3,721	412	0.1108	69.7256
1931	92.5		9,282	1,370	0.1476	54.1229
1930	93.5		6,327	649	0.1026	56.2999
1929	94.5		4,145		0.0000	56.0379
1928	95.5		6,795		0.0000	57.1096
1927	96.5		8,833	1,714	0.1940	69.7940
1926	97.5		4,180	554	0.1325	61.3282
1925	98.5		15,860	1,458	0.0919	66.0286
1924	99.5		922		0.0000	71.9458
1923	100.5		2,731		0.0000	50.9253
1922	101.5		1,342		0.0000	71.4471
1920	103.5		168		0.0000	75.0000
1919	104.5		1,039		0.0000	52.0000
1916	107.5		314		0.0000	63.3563
1912	111.5		593		0.0000	60.0000
1910	113.5		481		0.0000	91.7030
1909	114.5		296		0.0000	63.0000
1908	115.5		781		0.0000	92.9259
1905	118.5		2,097		0.0000	60.6371
1902	121.5		257		0.0000	95.0000
1901	122.5		1,126		0.0000	92.0000
Total	12.9	$53,206,244	$408,210	$43,158,363	0.8050	

Schedule C
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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1967	458,127	47,223	5,973		499,377
1968	499,377	29,978	2,078		527,277
1969	527,277	30,528	12,755		545,050
1970	545,050	62,994	5,346		602,698
1971	602,698	118,101	14,739		706,060
1972	706,060	307,902	43,178		970,784
1973	970,784	39,068	11,961		997,891
1974	997,891	44,291	5,375	(684)	1,036,123
1975	1,036,123	196,221	22,847		1,209,497
1976	1,209,497	188,869	19,267		1,379,099
1977	1,379,099	326,885	24,893		1,681,091
1978	1,681,091	127,831	4,372		1,804,550
1979	1,804,550	202,189	24,932		1,981,807
1980	1,981,807	106,143	19,482		2,068,468
1981	2,068,468	111,281	8,174		2,171,575
1982	2,171,575	205,672	31,264		2,345,983
1983	2,345,983	353,909	496,228	899	2,204,563
1984	2,204,563	108,228	4,031		2,308,760
1985	2,308,760	374,322	50,510		2,632,572
1986	2,632,572	337,684	36,693		2,933,563
1987	2,933,563	784,076	34,108		3,683,531
1988	3,683,531	627,273	77,651	(24,342)	4,208,811
1989	4,208,811	1,213,448	65,535		5,356,724
1990	5,356,724	856,470	35,409		6,177,785
1991	6,177,785	715,931	92,563	2,615,627	9,416,780
1992	9,416,780	425,816	153,798	765,017	10,453,815
1993	10,453,815	538,531	393,199		10,599,147
1994	10,599,147	568,448	42,610		11,124,985
1995	11,124,985	388,372	160,794		11,352,563
1996	11,352,563	173,074	187,545		11,338,092
1997	11,338,092	1,352,084	15,633		12,674,543
1998	12,674,543	915,735	232,284		13,357,994
1999	13,357,994	901,879	24,487		14,235,387
2000	14,235,387	1,374,889	326,306		15,283,970
2001	15,283,970	1,094,686	389,622		15,989,034
2002	15,989,034	497,794	30,371		16,456,457
2003	16,456,457	1,669,552	121,232		18,004,777
2004	18,004,777	1,293,215	407,026		18,890,966
2005	18,890,966	1,180,488	371,546		19,699,908
2006	19,699,908	588,367	289,720		19,998,555

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2007	19,998,555	622,866	756,668		19,864,753
2008	19,864,753	579,516	463,186		19,981,084
2009	19,981,084	276,582	64,751		20,192,914
2010	20,192,914	150,822	275,655		20,068,081
2011	20,068,081	604,941	154,374		20,518,648
2012	20,518,648	354,687	100,925		20,772,410
2013	20,772,410	964,607	1,031,597		20,705,420
2014	20,705,420	2,093,682	667,664		22,131,439
2015	22,131,439	267,728	734,917		21,664,251
2016	21,664,251	1,010,148	510,346		22,164,053
2017	22,164,053	10,123,908	175,361	(9,162,948)	22,949,653
2018	22,949,653	2,334,113	264,989		25,018,777
2019	25,018,777	11,863,612	455,310		36,427,079
2020	36,427,079	609,797	97,248		36,939,628
2021	36,939,628	5,322,022	520,920		41,740,730
2022	41,740,730	792,841	208,199		42,325,372
2023	42,325,372	942,147	109,156		43,158,363

Schedule C
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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1967	459,694	48,688	6,301		502,080
1968	502,080	32,505	2,465		532,120
1969	532,120	29,900	12,755		549,265
1970	549,265	63,591	5,346		607,510
1971	607,510	126,075	14,739		718,846
1972	718,846	296,959	43,178		972,627
1973	972,627	38,686	11,961		999,352
1974	999,352	43,607	5,375	(684)	1,036,900
1975	1,036,900	194,763	22,847		1,208,816
1976	1,208,816	188,740	18,796		1,378,761
1977	1,378,761	327,573	25,364		1,680,969
1978	1,680,969	128,619	4,372		1,805,217
1979	1,805,217	202,299	24,932		1,982,583
1980	1,982,583	106,143	19,482		2,069,244
1981	2,069,244	110,067	8,174		2,171,137
1982	2,171,137	206,887	31,264		2,346,760
1983	2,346,760	353,909	33,800	(462,428)	2,204,441
1984	2,204,441	108,227	4,031		2,308,637
1985	2,308,637	374,322	49,607		2,633,352
1986	2,633,352	334,787	36,693		2,931,446
1987	2,931,446	784,076	34,108		3,681,414
1988	3,681,414	590,812	67,064		4,205,162
1989	4,205,162	1,231,963	66,438		5,370,687
1990	5,370,687	842,385	35,409		6,177,662
1991	6,177,662	715,931	92,563	2,615,627	9,416,657
1992	9,416,657	425,816	153,798	765,017	10,453,693
1993	10,453,693	538,531	393,199		10,599,025
1994	10,599,025	568,448	42,610		11,124,862
1995	11,124,862	388,495	160,794		11,352,563
1996	11,352,563	173,074	187,545		11,338,092
1997	11,338,092	1,352,084	15,633		12,674,543
1998	12,674,543	915,735	232,284		13,357,994
1999	13,357,994	901,879	24,487		14,235,387
2000	14,235,387	1,374,889	326,306		15,283,970
2001	15,283,970	1,094,686	389,622		15,989,034
2002	15,989,034	497,794	30,371		16,456,457
2003	16,456,457	1,669,552	121,232		18,004,777
2004	18,004,777	1,293,215	407,026		18,890,967
2005	18,890,967	1,180,488	371,546		19,699,908
2006	19,699,908	588,367	289,720		19,998,555

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2007	19,998,555	622,866	756,668		19,864,753
2008	19,864,753	579,516	463,186		19,981,084
2009	19,981,084	276,582	64,751		20,192,914
2010	20,192,914	150,822	275,655		20,068,081
2011	20,068,081	604,941	154,374		20,518,648
2012	20,518,648	354,687	100,925		20,772,410
2013	20,772,410	964,607	1,031,597		20,705,420
2014	20,705,420	2,093,682	667,664		22,131,439
2015	22,131,439	267,728	734,917		21,664,251
2016	21,664,251	1,010,148	510,346		22,164,053
2017	22,164,053	10,123,908	175,361	(9,162,948)	22,949,653
2018	22,949,653	2,334,113	264,989		25,018,777
2019	25,018,777	11,863,612	455,310		36,427,079
2020	36,427,079	609,797	97,248		36,939,628
2021	36,939,628	5,322,022	520,920		41,740,730
2022	41,740,730	792,841	208,199		42,325,372
2023	42,325,372	942,147	109,156		43,158,363

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

T-Cut: None
Placement Band: 1910-2023
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1967-1971	2.5	39.0	L0	11.51	71.6	O4 *	10.78	38.7	O2 *	10.19
1968-1972	1.0	26.9	L0	6.35	32.7	O3 *	4.22	26.1	L0 *	4.35
1969-1973	0.9	26.3	L0	5.53	29.3	O2 *	3.45	25.6	L0 *	3.77
1970-1974	1.1	28.2	L0.5	5.46	29.0	L0.5 *	3.25	27.5	L0.5 *	4.18
1971-1975	0.0	27.0	L0.5	4.05	27.2	L0.5 *	2.60	26.7	L0 *	3.64
1972-1976	0.6	28.0	L0.5	5.29	29.0	L0.5 *	3.74	27.5	L0	4.36
1973-1977	20.8	39.7	O2	5.26	67.4	O4 *	3.31	38.3	L0	4.23
1974-1978	27.2	45.2	L0	6.06	84.3	O4 *	3.92	44.8	L0	3.32
1975-1979	45.5	41.3	L0	13.16	77.9	O4 *	10.35	42.8	O2	8.81
1976-1980	47.8	44.2	L0	12.68	85.9	O4 *	8.75	47.3	L0 *	5.84
1977-1981	52.5	50.9	L0	11.17	101.0	O4 *	6.34	56.0	SC *	3.51
1978-1982	50.6	50.2	L0	11.15	99.9	O4 *	5.74	55.2	SC *	3.16
1979-1983	34.0	42.3	L0	8.09	77.6	O4 *	4.22	43.9	SC *	4.42
1980-1984	43.4	51.0	L0	7.50	94.5	O4 *	3.48	51.4	SC *	4.46
1981-1985	38.9	46.6	L0	8.58	80.5	O4 *	6.20	47.2	SC	5.60
1982-1986	27.6	42.1	L0	5.63	66.5	O4 *	3.57	43.5	SC	4.80
1983-1987	28.5	46.0	O2	4.49	73.6	O4 *	3.66	46.5	SC	5.18
1984-1988	46.8	46.5	O2	13.91	89.0	O4 *	8.66	50.0	SC	5.90
1985-1989	23.4	37.5	O2	10.03	70.1	O4 *	6.75	44.2	SC *	5.18
1986-1990	27.0	39.8	L0	9.93	76.3	O4 *	4.05	46.7	SC *	4.91
1987-1991	33.9	41.7	L0	11.24	85.2	O4 *	2.84	50.3	SC *	6.60
1988-1992	17.5	33.0	L0.5	9.91	53.4	O4 *	3.88	37.7	O3 *	2.87
1989-1993	6.6	27.3	L0.5	4.19	32.9	O3 *	2.36	33.0	O3 *	2.46
1990-1994	10.4	30.3	L0.5	5.32	38.7	O3 *	2.82	39.0	O3 *	3.00
1991-1995	2.9	29.5	L0.5	4.54	35.4	O2 *	2.86	35.7	O2 *	2.97
1992-1996	0.0	29.2	L0.5	5.27	34.1	L0.5 *	3.94	30.3	L0.5 *	3.35
1993-1997	7.2	34.4	L0.5	3.97	40.3	O2 *	2.22	38.0	L0 *	2.22
1994-1998	8.5	38.0	L1	5.10	58.7	O4 *	5.00	42.0	L0 *	4.47
1995-1999	11.3	40.3	L1	5.66	60.9	O4 *	4.14	44.6	L0 *	3.56
1996-2000	17.3	41.2	L0.5	7.01	43.5	L0 *	5.80	56.8	O4 *	5.20
1997-2001	14.7	34.3	L1	9.52	40.9	O2 *	7.17	43.0	O3 *	6.60
1998-2002	16.5	35.8	L1	9.92	43.7	O2 *	7.36	46.7	O3 *	6.53
1999-2003	25.7	40.7	L0.5	12.33	45.6	L0 *	10.09	54.8	O4 *	8.82
2000-2004	21.0	36.4	L0.5	10.60	48.0	O3 *	6.97	51.2	O4 *	6.27
2001-2005	14.1	35.9	L0.5	7.71	52.7	O4 *	4.46	53.6	O4 *	3.66
2002-2006	21.0	40.4	L0.5	9.45	74.2	O4 *	3.53	74.3	O4 *	3.61
2003-2007	16.1	32.5	L0	9.58	58.6	O4 *	3.21	45.1	O3 *	3.19
2004-2008	5.8	29.8	L0	4.09	45.8	O4 *	3.84	35.7	O3	3.46

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

T-Cut: None
Placement Band: 1910-2023
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2009	9.0	33.5	L0	5.70	53.9	O4 *	4.45	44.1	O3	4.03
2006-2010	16.6	35.2	L0	10.03	64.1	O4 *	3.97	47.2	O3 *	3.71
2007-2011	26.1	39.1	L0	13.37	71.5	O4 *	3.19	53.2	O3	2.58
2008-2012	21.2	48.7	L0.5	8.87	72.5	O4 *	2.67	76.0	O4 *	2.82
2009-2013	13.5	36.6	L1.5*	12.41	44.6	L0.5 *	9.94	45.0	L1.5 *	9.64
2010-2014	8.9	33.1	L1.5*	8.57	38.1	L1 *	6.80	38.5	L1.5 *	6.60
2011-2015	0.0	30.7	L0.5	7.68	38.3	O2 *	5.06	38.2	O2 *	5.04
2012-2016	0.0	29.0	L0.5	4.67	36.4	O2 *	2.75	36.5	O2 *	2.76
2013-2017	0.0	28.9	L0	2.92	34.3	O2 *	2.11	31.4	L0	1.80
2014-2018	0.0	36.2	O2	4.32	35.0	O2	3.59	36.9	L0	5.18
2015-2019	0.0	38.9	L0	4.70	37.5	L0	3.85	39.4	SC	4.84
2016-2020	0.0	47.4	L0.5	7.00	44.1	S0	4.47	44.8	R0.5 *	3.90
2017-2021	0.6	48.4	L0.5	6.92	45.8	S0	5.47	45.5	R0.5 *	3.97
2018-2022	1.0	51.5	L0.5	7.82	49.8	L1	6.68	47.5	R0.5 *	4.39
2019-2023	2.3	56.2	L0.5	6.42	108.2	O3 *	20.12	55.5	R0.5 *	8.06

Schedule D
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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

T-Cut: None
Placement Band: 1910-2023
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1967-2023	0.0	39.1	L0.5	4.18	58.2	O4 *	5.70	42.1	L0 *	2.15
1969-2023	0.0	39.1	L0.5	4.18	58.2	O4 *	5.69	42.1	L0 *	2.15
1971-2023	0.0	39.1	L0.5	4.17	58.0	O4 *	5.65	42.1	L0 *	2.14
1973-2023	0.0	39.2	L0.5	4.29	58.6	O4 *	5.81	42.3	L0 *	2.17
1975-2023	0.0	39.2	L0.5	4.30	58.6	O4 *	5.81	42.3	L0 *	2.17
1977-2023	0.0	39.2	L0.5	4.30	58.6	O4 *	5.81	42.3	L0 *	2.18
1979-2023	0.0	39.2	L0.5	4.28	58.4	O4 *	5.75	42.3	L0 *	2.18
1981-2023	0.0	39.1	L0.5	4.26	58.2	O4 *	5.67	42.2	L0 *	2.16
1983-2023	0.0	39.1	L0.5	4.24	58.0	O4 *	5.62	42.2	L0 *	2.16
1985-2023	0.0	39.1	L0.5	4.27	57.9	O4 *	5.61	42.2	L0 *	2.16
1987-2023	0.0	39.1	L0.5	4.30	57.9	O4 *	5.60	42.2	L0 *	2.16
1989-2023	0.0	39.1	L0.5	4.26	57.5	O4 *	5.52	42.2	L0 *	2.18
1991-2023	0.0	39.1	L0.5	4.13	57.2	O4 *	5.58	42.1	L0 *	2.36
1993-2023	0.0	39.3	L0.5	3.99	56.9	O4 *	5.60	42.2	L0 *	2.55
1995-2023	0.0	39.6	L0.5	4.20	58.0	O4 *	6.11	42.6	L0 *	2.86
1997-2023	0.0	39.8	L0.5	4.20	58.1	O4 *	5.87	42.8	L0 *	2.78
1999-2023	0.0	39.7	L0.5	4.10	58.0	O4 *	5.96	42.7	L0 *	2.86
2001-2023	0.0	39.6	L0.5	4.11	59.3	O4 *	6.40	42.7	L0 *	2.99
2003-2023	0.0	39.9	L0.5	3.89	58.8	O4 *	6.38	42.8	L0 *	3.10
2005-2023	0.0	39.9	L0.5	3.79	58.5	O4 *	6.52	42.6	L0 *	3.27
2007-2023	0.0	40.3	L0.5	3.51	57.0	O4 *	6.03	42.7	L0 *	3.22
2009-2023	0.0	42.3	L0.5	3.72	56.5	O3 *	5.55	44.2	L0 *	3.26
2011-2023	0.0	41.6	L0.5	3.43	53.0	O3 *	5.16	43.1	L0 *	3.05
2013-2023	0.0	39.9	L0.5	3.45	52.8	O3 *	5.54	41.4	L0 *	2.97
2015-2023	0.0	48.3	L0.5	5.65	60.3	O3 *	9.08	47.4	SC *	5.82
2017-2023	0.6	55.0	L0.5	8.73	51.4	S0	5.84	49.9	R1 *	4.02
2019-2023	2.3	56.2	L0.5	6.42	108.2	O3 *	20.12	55.5	R0.5 *	8.06
2021-2023	0.0	59.5	L0.5	10.01	118.4	SC *	24.87	58.8	R0.5 *	11.55
2023-2023	0.0	74.8	L1.5*	17.52	67.9	S1 *	13.80	65.6	S1 *	12.58

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

T-Cut: None
Placement Band: 1910-2023
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1967-1968	15.9	45.6	L1	21.17	81.8	O4 *	18.13	90.9	O4 *	17.39
1967-1970	33.4	44.4	L0	9.65	86.3	O4 *	5.10	85.7	O4 *	4.48
1967-1972	1.0	27.9	L0.5	7.40	34.2	O3 *	4.87	27.0	L0 *	5.25
1967-1974	1.6	30.8	L0.5	7.62	38.1	O3 *	4.99	29.7	L0 *	5.66
1967-1976	3.2	31.5	L0	5.83	41.5	O3 *	3.78	30.8	L0 *	4.32
1967-1978	6.2	34.2	L0	4.85	49.3	O4 *	3.19	33.9	L0	2.99
1967-1980	9.3	35.4	L0	3.84	56.2	O4 *	3.49	36.1	O2 *	2.37
1967-1982	13.6	37.8	L0	3.65	62.3	O4 *	3.25	43.7	O3	2.49
1967-1984	17.1	39.0	L0.5	3.68	63.5	O4 *	2.63	42.2	O2	1.80
1967-1986	20.5	38.7	L0	4.79	62.6	O4 *	2.50	39.8	L0	2.36
1967-1988	24.4	39.4	L0	6.27	67.6	O4 *	2.96	41.1	O2	3.14
1967-1990	19.9	39.1	L0	5.46	68.2	O4 *	2.82	41.4	O2	2.13
1967-1992	18.8	36.3	L0.5	7.49	61.1	O4 *	2.57	40.0	O2 *	1.97
1967-1994	15.3	33.8	L0.5	6.41	51.9	O4 *	1.74	51.7	O4 *	1.69
1967-1996	7.9	33.5	L0.5	5.11	50.3	O4 *	2.87	36.2	O2 *	1.45
1967-1998	11.5	34.7	L0.5	6.18	52.0	O4 *	2.12	46.2	O3 *	1.68
1967-2000	13.5	36.2	L0.5	6.47	51.0	O4 *	2.26	53.7	O4 *	2.46
1967-2002	13.5	35.6	L0.5	7.06	50.7	O4 *	2.44	52.7	O4 *	2.53
1967-2004	15.1	36.5	L0.5	7.60	53.5	O4 *	2.38	55.5	O4 *	2.40
1967-2006	14.4	36.0	L0.5	7.90	54.8	O4 *	2.08	55.7	O4 *	2.32
1967-2008	11.7	34.0	L0.5	6.97	50.1	O4 *	1.73	50.6	O4 *	1.98
1967-2010	14.1	35.8	L0.5	8.17	56.4	O4 *	1.93	56.6	O4 *	2.12
1967-2012	14.6	38.3	L0.5	8.45	62.3	O4 *	2.38	62.1	O4 *	2.28
1967-2014	8.8	34.0	L0.5	6.92	44.9	O3 *	3.39	46.4	O3 *	3.26
1967-2016	0.0	33.8	L0.5	6.90	48.2	O4 *	2.41	48.7	O4 *	2.57
1967-2018	0.0	35.2	L0.5	3.76	42.4	O2 *	2.87	37.7	L0	2.23
1967-2020	0.0	36.6	L0.5	3.87	46.8	O3 *	3.32	39.1	L0	1.97
1967-2022	0.0	37.9	L0.5	4.10	54.5	O4 *	4.99	40.9	L0 *	2.06
1967-2023	0.0	39.1	L0.5	4.18	58.2	O4 *	5.70	42.1	L0 *	2.15

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

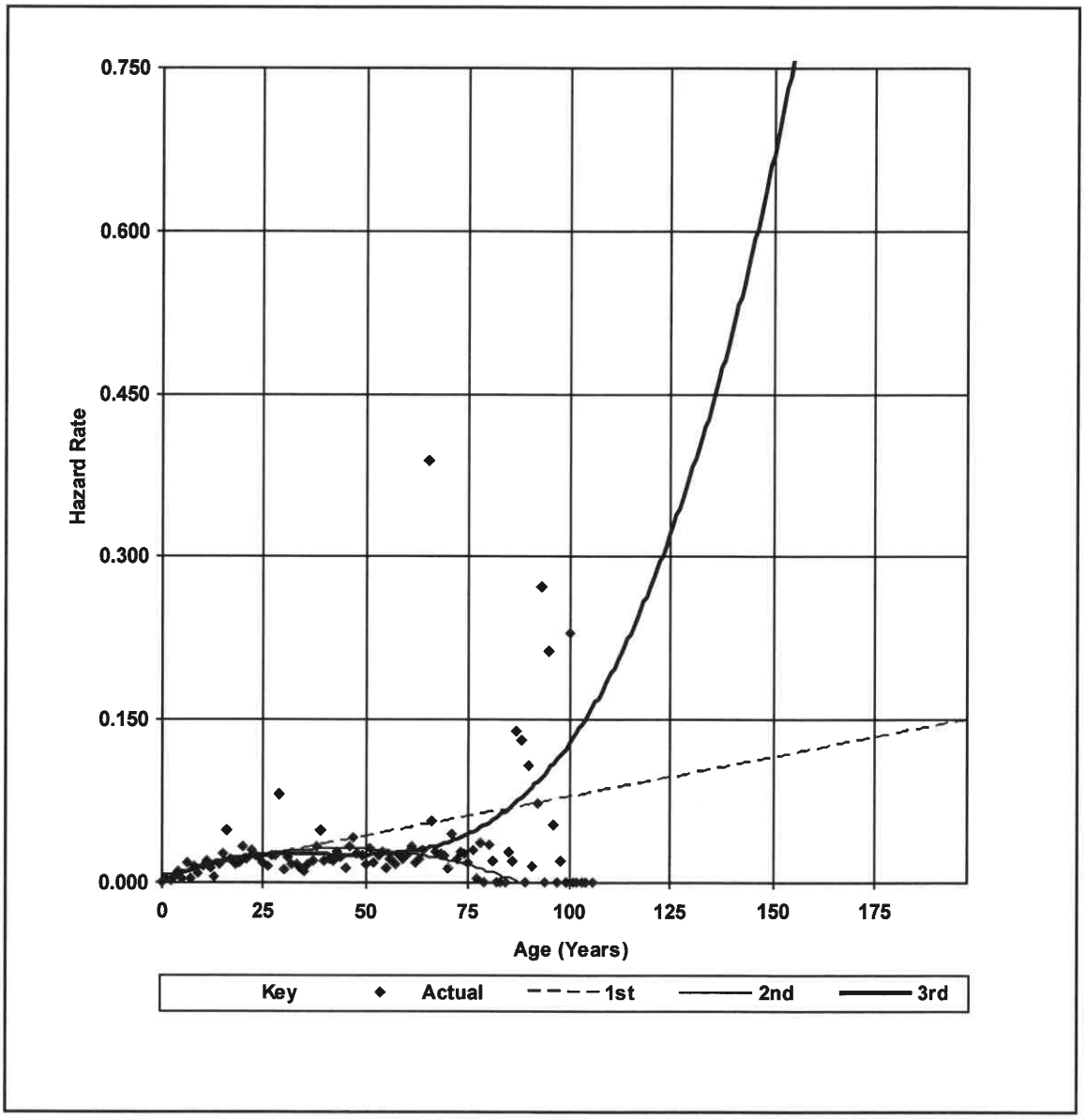
T-Cut: None

Placement Band: 1910-2023 Observation Band: 1966-2023

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Functions 1st: 39.1-L0.5 2nd: 58.2-O4 3rd: 42.1-L0



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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

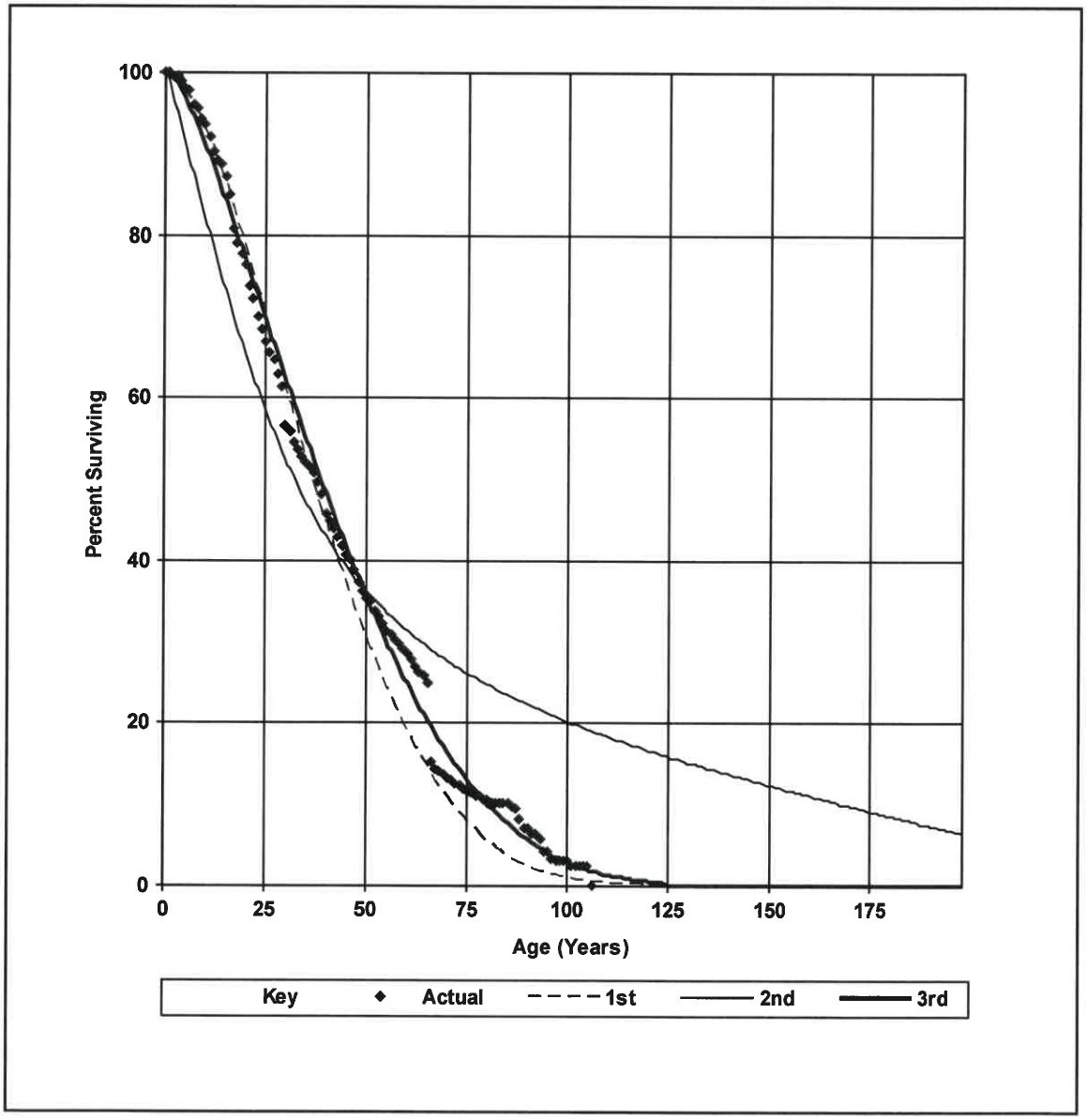
T-Cut: None

Placement Band: 1910-2023 Observation Band: 1967-2023

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions 1st: 39.1-L0.5 2nd: 58.2-O4 3rd: 42.1-L0



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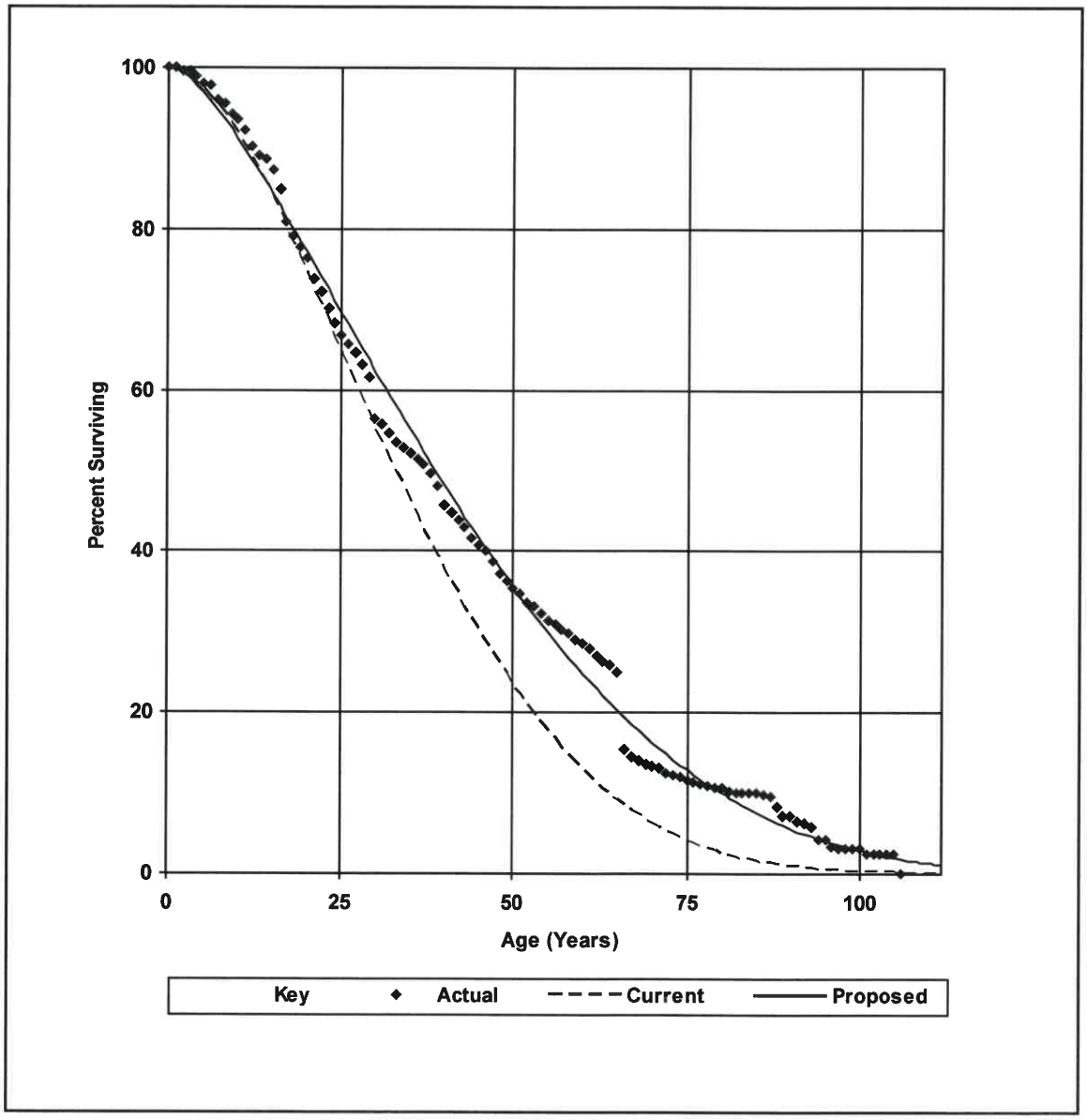
NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

T-Cut: None
Placement Band: 1910-2023
Observation Band: 1967-2023

Projection Life Curves **Current: 35.0-L0.5** **Proposed: 42.0-L0**



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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1972	43,178	11,650	27.0		28,670	66.4		(17,020)	-39.4	
1973	11,961	285	2.4		7,643	63.9		(7,358)	-61.5	
1974	5,375		0.0		8,410	156.5		(8,410)	-156.5	
1975	22,847		0.0		17,422	76.3		(17,422)	-76.3	
1976	19,267		0.0	11.6	30,636	159.0	90.4	(30,636)	-159.0	-78.8
1977	24,893		0.0	0.3	27,844	111.9	109.0	(27,844)	-111.9	-108.7
1978	4,372		0.0	0.0	12,335	282.1	125.9	(12,335)	-282.1	-125.9
1979	24,932		0.0	0.0	42,588	170.8	135.8	(42,588)	-170.8	-135.8
1980	19,482		0.0	0.0	8,014	41.1	130.6	(8,014)	-41.1	-130.6
1981	8,174		0.0	0.0	24	0.3	110.9	(24)	-0.3	-110.9
1982	31,264	3,200	10.2	3.6	13,506	43.2	86.7	(10,306)	-33.0	-83.0
1983	496,228		0.0	0.6	32,086	6.5	16.6	(32,086)	-6.5	-16.0
1984	4,031		0.0	0.6	3,010	74.7	10.1	(3,010)	-74.7	-9.6
1985	50,510		0.0	0.5	35,974	71.2	14.3	(35,974)	-71.2	-13.8
1986	36,693		0.0	0.5	25,476	69.4	17.8	(25,476)	-69.4	-17.3
1987	34,108		0.0	0.0	12,722	37.3	17.6	(12,722)	-37.3	-17.6
1988	77,651		0.0	0.0	23,694	30.5	49.7	(23,694)	-30.5	-49.7
1989	65,535		0.0	0.0	58,037	88.6	58.9	(58,037)	-88.6	-58.9
1990	35,409		0.0	0.0	30,875	87.2	60.5	(30,875)	-87.2	-60.5
1991	92,563		0.0	0.0	65,207	70.4	62.4	(65,207)	-70.4	-62.4
1992	153,798		0.0	0.0	99,472	64.7	65.3	(99,472)	-64.7	-65.3
1993	393,199		0.0	0.0	100,986	25.7	47.9	(100,986)	-25.7	-47.9
1994	42,610		0.0	0.0	29,454	69.1	45.4	(29,454)	-69.1	-45.4
1995	160,794		0.0	0.0	178,122	110.8	56.1	(178,122)	-110.8	-56.1
1996	187,545		0.0	0.0	154,580	82.4	60.0	(154,580)	-82.4	-60.0
1997	15,633		0.0	0.0	33,628	215.1	62.1	(33,628)	-215.1	-62.1
1998	232,284		0.0	0.0	440,523	189.6	130.9	(440,523)	-189.6	-130.9
1999	24,487		0.0	0.0	109,275	446.3	147.6	(109,275)	-446.3	-147.6
2000	326,306		0.0	0.0	370,736	113.6	141.0	(370,736)	-113.6	-141.0
2001	389,622		0.0	0.0	975,389	250.3	195.2	(975,389)	-250.3	-195.2
2002	30,371		0.0	0.0	94,468	311.0	198.4	(94,468)	-311.0	-198.4
2003	121,232		0.0	0.0	500,372	412.7	229.8	(500,372)	-412.7	-229.8
2004	407,026		0.0	0.0	391,924	96.3	183.0	(391,924)	-96.3	-183.0
2005	371,546		0.0	0.0	327,492	88.1	173.5	(327,492)	-88.1	-173.5
2006	289,720		0.0	0.0	256,919	88.7	128.8	(256,919)	-88.7	-128.8
2007	756,668		0.0	0.0	163,188	21.6	84.3	(163,188)	-21.6	-84.3
2008	463,186		0.0	0.0	476,238	102.8	70.6	(476,238)	-102.8	-70.6
2009	64,751		0.0	0.0	31,962	49.4	64.5	(31,962)	-49.4	-64.5
2010	275,655		0.0	0.0	199,358	72.3	61.0	(199,358)	-72.3	-61.0
2011	154,374		0.0	0.0	203,563	131.9	62.7	(203,563)	-131.9	-62.7
2012	100,925		0.0	0.0	202,300	200.4	105.1	(202,300)	-200.4	-105.1

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NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2013	1,031,597		0.0	0.0	475,115	46.1	68.4	(475,115)	-46.1	-68.4
2014	667,664		0.0	0.0	844,621	126.5	86.3	(844,621)	-126.5	-86.3
2015	734,917		0.0	0.0	246,958	33.6	73.3	(246,958)	-33.6	-73.3
2016	510,346		0.0	0.0	510,203	100.0	74.8	(510,203)	-100.0	-74.8
2017	175,361		0.0	0.0	194,341	110.8	72.8	(194,341)	-110.8	-72.8
2018	264,989		0.0	0.0	363,582	137.2	91.8	(363,582)	-137.2	-91.8
2019	455,310		0.0	0.0	407,700	89.5	80.5	(407,700)	-89.5	-80.5
2020	97,248		0.0	0.0	171,933	176.8	109.6	(171,933)	-176.8	-109.6
2021	520,920		0.0	0.0	248,490	47.7	91.6	(248,490)	-47.7	-91.6
2022	208,199		0.0	0.0	286,073	137.4	95.5	(286,073)	-137.4	-95.5
2023	109,156		0.0	0.0	248,544	227.7	98.0	(248,544)	-227.7	-98.0
Total	10,845,909	15,135	0.1		9,821,679	90.6		(9,806,544)	-90.4	

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1972	43,178	11,650	27.0		28,670	66.4		(17,020)	-39.4	
1973	11,961	285	2.4		7,643	63.9		(7,358)	-61.5	
1974	5,375		0.0		8,410	156.5		(8,410)	-156.5	
1975	22,847		0.0		17,422	76.3		(17,422)	-76.3	
1976	18,796		0.0	11.7	30,636	163.0	90.8	(30,636)	-163.0	-79.1
1977	25,364		0.0	0.3	27,844	109.8	109.0	(27,844)	-109.8	-108.7
1978	4,372		0.0	0.0	12,335	282.1	125.9	(12,335)	-282.1	-125.9
1979	24,932		0.0	0.0	42,588	170.8	135.8	(42,588)	-170.8	-135.8
1980	19,482		0.0	0.0	8,014	41.1	130.6	(8,014)	-41.1	-130.6
1981	8,174		0.0	0.0	24	0.3	110.3	(24)	-0.3	-110.3
1982	31,264	3,200	10.2	3.6	13,506	43.2	86.7	(10,306)	-33.0	-83.0
1983	33,800		0.0	2.7	32,086	94.9	81.8	(32,086)	-94.9	-79.1
1984	4,031		0.0	3.3	3,010	74.7	58.5	(3,010)	-74.7	-55.2
1985	49,607		0.0	2.5	35,974	72.5	66.7	(35,974)	-72.5	-64.2
1986	36,693		0.0	2.1	25,476	69.4	70.8	(25,476)	-69.4	-68.8
1987	34,108		0.0	0.0	12,722	37.3	69.1	(12,722)	-37.3	-69.1
1988	67,064		0.0	0.0	23,694	35.3	52.7	(23,694)	-35.3	-52.7
1989	66,438		0.0	0.0	58,037	87.4	61.4	(58,037)	-87.4	-61.4
1990	35,409		0.0	0.0	30,875	87.2	62.9	(30,875)	-87.2	-62.9
1991	92,563		0.0	0.0	65,207	70.4	64.5	(65,207)	-70.4	-64.5
1992	153,798		0.0	0.0	99,472	64.7	66.8	(99,472)	-64.7	-66.8
1993	393,199		0.0	0.0	100,986	25.7	47.8	(100,986)	-25.7	-47.8
1994	42,610		0.0	0.0	29,454	69.1	45.4	(29,454)	-69.1	-45.4
1995	160,794		0.0	0.0	178,122	110.8	56.1	(178,122)	-110.8	-56.1
1996	187,545		0.0	0.0	154,580	82.4	60.0	(154,580)	-82.4	-60.0
1997	15,633		0.0	0.0	33,628	215.1	62.1	(33,628)	-215.1	-62.1
1998	232,284		0.0	0.0	440,523	189.6	130.9	(440,523)	-189.6	-130.9
1999	24,487		0.0	0.0	109,275	446.3	147.6	(109,275)	-446.3	-147.6
2000	326,306		0.0	0.0	370,736	113.6	141.0	(370,736)	-113.6	-141.0
2001	389,622		0.0	0.0	975,389	250.3	195.2	(975,389)	-250.3	-195.2
2002	30,371		0.0	0.0	94,468	311.0	198.4	(94,468)	-311.0	-198.4
2003	121,232		0.0	0.0	500,372	412.7	229.8	(500,372)	-412.7	-229.8
2004	407,026		0.0	0.0	391,924	96.3	183.0	(391,924)	-96.3	-183.0
2005	371,546		0.0	0.0	327,492	88.1	173.5	(327,492)	-88.1	-173.5
2006	289,720		0.0	0.0	256,919	88.7	128.8	(256,919)	-88.7	-128.8
2007	756,668		0.0	0.0	163,188	21.6	84.3	(163,188)	-21.6	-84.3
2008	463,186		0.0	0.0	476,238	102.8	70.6	(476,238)	-102.8	-70.6
2009	64,751		0.0	0.0	31,962	49.4	64.5	(31,962)	-49.4	-64.5
2010	275,655		0.0	0.0	199,358	72.3	61.0	(199,358)	-72.3	-61.0
2011	154,374		0.0	0.0	203,563	131.9	62.7	(203,563)	-131.9	-62.7
2012	100,925		0.0	0.0	202,300	200.4	105.1	(202,300)	-200.4	-105.1

NEW JERSEY NATURAL GAS COMPANY

Distribution Plant

Account: 378.00 Meas. and Reg. Sta. Equip. - General

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H.	I=C-F	J=I/B	K
2013	1,031,597		0.0	0.0	475,115	46.1	68.4	(475,115)	-46.1	-68.4
2014	667,664		0.0	0.0	844,621	126.5	86.3	(844,621)	-126.5	-86.3
2015	734,917		0.0	0.0	246,958	33.6	73.3	(246,958)	-33.6	-73.3
2016	510,346		0.0	0.0	510,203	100.0	74.8	(510,203)	-100.0	-74.8
2017	175,361		0.0	0.0	194,341	110.8	72.8	(194,341)	-110.8	-72.8
2018	264,989		0.0	0.0	363,582	137.2	91.8	(363,582)	-137.2	-91.8
2019	455,310		0.0	0.0	407,700	89.5	80.5	(407,700)	-89.5	-80.5
2020	97,248		0.0	0.0	171,933	176.8	109.6	(171,933)	-176.8	-109.6
2021	520,920		0.0	0.0	248,490	47.7	91.6	(248,490)	-47.7	-91.6
2022	208,199		0.0	0.0	286,073	137.4	95.5	(286,073)	-137.4	-95.5
2023	109,156		0.0	0.0	248,544	227.7	98.0	(248,544)	-227.7	-98.0
Total	10,372,894	15,135	0.1		9,821,679	94.7		(9,806,544)	-94.5	

Exhibit P-8

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY
OF
DANIEL P. YARDLEY
YARDLEY ASSOCIATES – PRINCIPAL

I. INTRODUCTION AND BACKGROUND

Q. Please state your name, affiliation and business address.

A. My name is Daniel P. Yardley. I am Principal, Yardley Associates and my business address is 2409 Providence Hills Drive, Matthews, North Carolina 28105.

Q. On whose behalf are you testifying?

A. I am testifying on behalf New Jersey Natural Gas Company ("NJNG" or the "Company").

Q. Please provide a brief outline of your professional and educational background.

A. I have been employed as a consultant to the natural gas industry for the past 30 years. During this period, I have directed or participated in numerous consulting assignments on behalf of local distribution companies ("LDCs"). A number of these assignments involved the development of gas distribution company cost allocation, pricing, service unbundling, revenue decoupling and other tariff analyses. In addition to this work, I have performed interstate pipeline cost of service and rate design analyses, gas supply planning analyses, and financial evaluation analyses. I received a Bachelor of Science Degree in Electrical Engineering from the Massachusetts Institute of Technology in 1988.

Q. Have you previously testified before the New Jersey Board of Public Utilities ("BPU") and other regulatory bodies concerning rate and regulatory matters?

A. Yes. I have testified before the BPU on various ratemaking and regulatory matters including: rate unbundling, cost allocation, rate design, revenue decoupling, cost recovery

mechanisms and tariff design. My testimony in various proceedings has been presented on behalf of NJNG, Elizabethtown Gas Company, and South Jersey Gas Company. I have also testified in proceedings before several other state public utility commissions and before the Federal Energy Regulatory Commission and the Canada Energy Regulator on a variety of rate and regulatory topics. A summary of my previous expert testimony is provided as Attachment A to my Direct Testimony.

Q. What is the purpose of your Direct Testimony?

A. I have been asked by NJNG to evaluate the manner in which it recovers its base distribution revenue requirements from customers and to propose changes that are consistent with the nature of the services that it provides as well as important rate design objectives. In this regard, my Direct Testimony addresses two topics. First, I will review the Company's Conservation Incentive Program ("CIP") and discuss the foundation it provides for NJNG's base rates. Second, I will support the derivation of specific rates and charges for distribution services that fairly apportion the Company's proposed revenue requirement among customer classes. The new charges are based on appropriate rate design considerations including the results of an allocated cost of service study ("ACOSS") performed in a consistent manner with other elements of the Company's filing.

Q. Please summarize your findings.

A. The three principal conclusions of my Direct Testimony are as follows:

(1) **Existing monthly fixed customer charges for the majority of NJNG's customers are substantially below cost-based levels:** The customer charges for residential customers are less than 20 percent of corresponding customer-related costs. Similarly, customer charges for small general service customers are less than 50 percent of customer-related costs. The below-cost customer charges result in intra-class subsidies as substantial customer-related costs are recovered through volumetric charges applied to customer use. This shifts a disproportionate share of customer-related costs to larger use customers within a class.

(2) **Class-differentiated base revenue changes are appropriate based upon the results of the ACOSS:** The results of the ACOSS demonstrate that the earned rates of return for service to residential and small general service customers are below the rates of return for all other classes of customers. Applying a larger proportion of the revenue increase to these rate classes is reasonable, as it promotes fairness among the base rates for the various customers that NJNG serves.

(3) **The proposed class-specific base revenue requirements reasonably apportion the Company's proposed revenue increase among rate classes:** By applying a larger proportion of the revenue increase to rate classes with below-average rates of return, the proposed class-specific revenue requirements promote fairness. At the same time, no revenue decreases are proposed for rate classes that reflect above-average rates of return in order to balance fairness with rate moderation concerns.

Q. Are you sponsoring any exhibits that accompany your Direct Testimony?

A. Yes. I am sponsoring the following three exhibits, which were prepared by me or under my direct supervision and control and which will be explained later in my Direct Testimony:

Schedule DPY-1:	ACOSS;
Schedule DPY-2:	Allocation of Proposed Revenue Adjustments to Customer Classes; and
Schedule DPY-3:	Existing and Proposed Rates and Revenues.

II. THE COMPANY'S CIP

Q. How does NJNG's CIP benefit customers?

A. A fundamental tenet of the CIP Tariff, which was first approved by the BPU in 2006, is alignment of the financial interests of NJNG with those of its customers with respect to reductions in total energy costs to customers. In particular, the base revenue impacts of any customer savings from energy efficiency and conservation do not contribute negatively to the Company's financial performance. The CIP Tariff mitigates fixed cost recovery concerns that would otherwise be present when customers reduce consumption. Customers that lower their consumption realize substantial savings as gas supply commodity costs are avoided altogether. The CIP and other similar programs adopted in other jurisdictions are

recognized as supporting important local and national policy goals to lower energy use and reduce the associated environmental impacts.

Q. Please comment on the relationship between NJNG's CIP and the appropriate rate design in this proceeding.

A. The CIP represents an appropriate means of separating NJNG's margin revenue recoveries from customer usage. The CIP is essential to aligning the interests of NJNG and its customers with respect to energy consumption. Removing the link between throughput and margins through the CIP allows NJNG to fully support increased energy efficiency and conservation, encouraging customers to reduce their gas bills and lower the environmental impacts of their gas consumption.

Moreover, the CIP is layered over the existing rate design, which provides important flexibility in terms of the design of base rates. While increases to fixed charges are appropriate, the CIP enables the ongoing recovery of a portion of fixed costs through variable charges and is an integral component of NJNG's overall rate structure.

III. NJNG DISTRIBUTION SERVICE CLASSIFICATIONS AND RATE DESIGN

Q. Please describe the specific rate design goals for NJNG that guided the development of the rate design you are recommending.

A. The rate design approach I am recommending seeks to achieve the following five goals:

(1) Fairness – Fairness is accomplished through pricing services based on the underlying cost. Fairness is important in many respects including: (i) between the Company and its customers, (ii) across rate classes served by NJNG, and (iii) among customers taking service under a common service classification.

(2) **Not Discriminatory** – Avoiding undue discrimination requires rates that do not grant an unreasonable preference or subject an unreasonable disadvantage to any customer or group of customers.

(3) **Rate Moderation** – Moderation allows for the implementation of price changes over time to ensure that customers are not exposed to dramatic price changes all at once.

(4) **Revenue Stability** – Revenue stability means that NJNG's base rate revenues are more predictable in view of future uncertainties. As customer usage patterns have become less certain, improved revenue stability through rate design takes on greater importance as a way of mitigating the increased risks to customers and the Company associated with such unpredictable consumption patterns.

(5) **Energy Efficiency** – Energy efficiency as a goal is the promotion of consumption decisions that support the efficient use of natural gas.

Q. Please describe the Company's existing service classifications.

A. NJNG's existing service classifications are segregated by sector, nature of service (firm or interruptible), customer size and by end-use in some cases. Over 98 percent of the Company's customers are served under either the Residential Service ("RS") or General Service Small ("GSS") service classifications. These service classifications provide service to small customers, with average annual use of approximately 950 therms for the RS service classification and 1,260 therms for the GSS service classification. The RS and GSS service classifications provide customers with the opportunity to purchase gas supply from NJNG by paying the applicable Basic Gas Supply Service ("BGSS") rate or from a

third-party supplier. The price paid for distribution service is not affected by a customer's choice of its gas supplier.

General service customers whose annual use is greater than or equal to 5,000 therms take service under the General Service Large ("GSL") service classification. The GSL service classification provides customers with the option of purchasing BGSS or third-party gas supply, similar to the RS and GSS service classifications. Larger customers also have the option of taking service under the Firm Transportation ("FT") service classification, which incorporates daily balancing requirements that are more stringent than for the GSL service classification. The FT service classification is utilized by some of the Company's largest customers. The average annual consumption for GSL customers is approximately 18,000 therms and over 100,000 therms for FT customers.

NJNG also provides firm service under service classifications applicable to specific end-uses. Customers utilizing fuel cells, microturbines or other distributed generation technologies are eligible to take service pursuant to either NJNG's Distributed Generation Residential ("DGR") or Distributed Generation Commercial ("DGC") service classifications. Customers refueling natural gas vehicles or operating natural gas vehicle refueling stations are eligible to take service pursuant to either NJNG's Natural Gas Vehicle ("NGV") or Compressed Natural Gas ("CNG") service classifications.

Large customers that do not require firm service may elect to be served pursuant to the Interruptible Service ("IS") classification. IS customers are required to curtail gas service when required by the Company. In order to qualify for IS service, customers must have a minimum connected load of 150 therms per hour.

Q. Does NJNG provide service to any off-tariff customers?

A. Yes. A limited number of large electric generation customers receive service under long-term contracts rather than the Company's tariff. Each contract service customer committed to pay rates over a multi-year period that result in an appropriate revenue stream to support the Company's associated investment in facilities to provide service. The rates and charges under each long-term contract reflect the unique attributes of the specific customer, including the nature of the load and investment requirements. All off-tariff services are approved by the BPU before service to the customer begins.

Q. What rates and charges are incorporated into the RS and GSS service classifications?

A. The existing rate design for these service classifications is similar and includes two types of margin rate charges that are intended to recover NJNG's non-gas revenue requirements or cost of service: a fixed monthly customer charge and a volumetric charge or charges applicable to monthly volumes. Fixed monthly customer charges are applied per customer per month and volumetric charges are applied to each customer's monthly usage. Under this rate structure, all customers pay a minimum monthly amount to NJNG equal to the fixed customer charge, regardless of their monthly usage. The rate design also results in customers paying higher amounts as their consumption increases due to the per-therm volumetric charge. The volumetric charge is considered a variable charge because all of the associated revenues are linked to customer usage or throughput.

For RS service, the current fixed monthly customer charge is $10.32 and the corresponding volumetric charge is $0.5791 per therm. The monthly fixed charge for GSS service is $39.39 and the corresponding volumetric charge is $0.5059 per therm. GSS customers that utilize natural gas for air conditioning and pool heating pay a discounted

volumetric charge of $0.1096 per therm during the summer months of May through September. All NJNG retail charges included in my Direct Testimony exclude the New Jersey Sales and Use Tax ("SUT"). The SUT rate of 6.625 percent applies to all of NJNG's retail charges and is included in the rates in the Company's proposed Tariff, attached to the Direct Testimony of Tina M. Trebino as Schedule TMT-1.

Q. Please describe the rates incorporated in NJNG's larger customer service classifications, GSL and FT.

A. The margin rates applicable to the GSL and FT service classifications incorporate a demand charge in addition to a monthly fixed charge and volumetric charges. The demand charge is an important means of recovering fixed peak-related costs from customers in an equitable manner. The margin rates for the GSL rate class are a monthly fixed charge of $97.54 and a monthly demand charge of $3.2000 per therm of highest monthly average daily usage ("HMAD"). A volumetric charge of $0.3216 per therm applies to all use, except for air conditioning and pool heating use by customers, which reflects a volumetric charge of $0.1096 per therm during the summer months of May through September. The margin rates for the FT rate class are a monthly fixed charge of $328.25 and a monthly demand charge of $2.3447 per therm of maximum daily demand and a volumetric charge of $0.0818 per therm.

Q. Please describe the rates for NJNG's distributed generation service classifications.

A. DGR customers pay the same monthly customer charge as RS customers of $10.32. In addition, DGR customers pay a seasonally-differentiated volumetric charge of $0.1685 per therm during the winter months of November through April and $0.1185 per therm during the summer months of May through October. Presently, there are no customers on the

DGR service classification. DGC customers pay a monthly customer charge of $97.54 and a monthly demand charge of $2.2040 per therm of peak demand. Additionally, DGC customers pay a seasonally-differentiated volumetric charge of $0.0726 per therm during the winter and $0.0420 per therm during the summer.

Q. Please describe the existing rates and service for NJNG's natural gas vehicle service classifications.

A. The Company has two service classifications for natural gas vehicle refueling. First, the CNG service classification provided for the construction of Company-owned stations operated by customers at customer locations and includes firm service for compressed natural gas delivery service at the three stations constructed. The CNG service classification reflects a monthly charge of $97.54 and a volumetric charge of $0.2734 per therm. The CNG service classification also incorporates a charge of $0.2000 per therm to offset the costs of providing compression. Second, the NGV service classification includes service for fueling natural gas vehicles at Company-owned and -operated re-fueling facilities and at customer-owned and -operated re-fueling facilities. The NGV service classification reflects the same monthly charge of $97.54 and volumetric charge of $0.2734 per therm as the CNG service classification.

Q. Please describe the rates for NJNG's interruptible services.

A. The existing monthly charge for IS service is $537.38 and volumetric charge is $0.0494 per therm. Any customer that does not have alternate fuel capability pays a higher volumetric charge equal to $0.2753 per therm. IS customers have the option of requesting the Company to purchase a gas supply on their behalf pursuant to rate schedule IGS. NJNG

is under no obligation to provide IGS service and would only do so to the extent that it is able to secure a gas supply at a price that offers net benefits to firm customers.

IV. THE ACOSS AND THE ALTERNATIVE ACOSS

Q. Did you perform an ACOSS to support your rate design recommendations?

A. Yes. I believe that an ACOSS provides an important means of assessing the reasonableness of existing prices and to guide the development of price changes. In particular, the ACOSS that I performed for NJNG examines all of the Company's common costs reflected in its base rate petition, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. The ACOSS is an important tool because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, thereby establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the revenue requirements among all of NJNG's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and volumetric components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

Q. Please describe the general costing methodology that is incorporated in the NJNG ACOSS.

A. The most significant consideration in the development of an ACOSS is the methodological approach to allocating fixed demand costs. Various approaches may be employed to allocate fixed demand costs, including ones that are based on system design, system utilization, or a blending of system design and system utilization. The ACOSS performed for NJNG reflects a system design approach to the allocation of fixed demand costs that closely follows principles of cost causation. A full description of the NJNG ACOSS and detailed results are presented in Schedule DPY-1.

Q. Please summarize the results of the ACOSS.

A. The primary results from the ACOSS are the rate of return by class and the unit customer and demand-related costs. The results of the ACOSS indicate that the rate of return for the residential heating and residential non-heating classes are below the system average as confirmed by a unitized return below 1.0. The rate of return for all other classes is above the system-average, to varying degrees, indicating that these other classes are subsidizing the prices for residential customers. A summary of the rate of return by class is provided in Table 1.

Table 1 – ACOSS – Rate of Return by Class

	Rate of Return	Unitized
Residential Heating	0.8%	0.3
Residential Non-Heating	(6.0%)	(2.1)
GSS	5.6%	2.0
GSL	24.7%	8.7
FT	10.8%	3.8
DGC	15.7%	5.5
NGV / CNG	73.3%	25.7
Overall	2.8%	1.0

With respect to unit costs, the ACOSS indicates that the system-wide average customer cost is $74 per month, and the cost generally varies with the size of the customer. The lowest average customer cost of $72 per month is indicated for the residential non-heating class and the highest is $262 per month for the FT class. A comparison of existing customer costs to customer-related costs is presented in Table 2.

Table 2 – Comparison of Existing Customer Charges and Customer-Related Costs

	Existing Customer Charge	Customer-Related Cost	Difference
Residential Heating	$10.32	$73.06	$62.74
Residential Non-Heating	$10.32	$72.30	$61.98
GSS	$39.39	$79.36	$39.97
GSL	$97.54	$149.03	$51.49
FT	$328.25	$243.18	($85.07)
DGC	$97.54	$176.12	$78.58
NGV / CNG	$97.54	$262.24	$164.70

The significant variance between monthly customer-related costs and customer charges is taken into consideration when designing the intra-class rate design.

Q. Did you perform an alternative ACOSS?

A. Yes, I performed an alternative ACOSS related to the classification and allocation of distribution mains costs among NJNG's customer classes. NJNG's investment in distribution mains is the single largest plant investment on its books and represents approximately 42 percent of net plant investment. It is appropriate to allocate a portion of the costs of distribution mains among classes based on the number of customers for each class, recognizing that distribution mains are designed to deliver supplies in reasonable proximity to customers in order to minimize the length of pipe used to serve all customers in an overall efficient fashion. The primary ACOSS reflects this system design criterion

by means of the minimum size mains study. Prior to determining the appropriate allocation of the proposed change in base revenue requirements, I performed an alternative ACOSS that does not allocate any portion of distribution mains costs based on the number of customers in each class. The results of the alternative ACOSS are presented in Table 3.

Table 3 – Alternative ACOSS – Rate of Return by Class

	Rate of Return	Unitized
Residential Heating	1.1%	0.4
Residential Non-Heating	(7.3%)	(2.6)
GSS	5.2%	1.8
GSL	13.8%	4.8
FT	3.8%	1.3
DGC	6.4%	2.3
NGV / CNG	40.9%	14.4
Overall	2.8%	1.0

V. RATE RECOMMENDATIONS

Q. What steps did you employ to develop the specific rates you are proposing?

A. First, I determined the class-by-class revenue requirements, which reflect the results of the ACOSS and other rate design principles. Next, I evaluated the existing level of customer charges and proposed increases that take into account the customer-related costs for each class. Last, I established the appropriate variable distribution rates to recover the remaining portion of class revenue requirements.

Q. How did you develop the class-by-class revenue requirements to be reflected in new base rates?

A. I determined the proportion of the overall base revenue increase that should be recovered from each class taking into consideration the results of the ACOSS and other rate design considerations, including the need for rate moderation. The ACOSS and the alternative

ACOSS both indicate that two rate classes would require a base rate decrease in order to bring their rates of return in line with the overall rate of return requested by the Company of 7.57%. These are the GSL and NGV rate classes. The DGC rate class is above the overall rate of return for the primary ACOSS and just under this level for the alternate ACOSS. Similarly, the FT rate class shows a rate of return under the primary ACOSS above the proposed overall rate of return. While the rate of return for the FT class under the alternate ACOSS is lower, it is approximately equal to the proposed overall rate of return on average for the two ACOSSs. However, I am not proposing to lower rates for any class of customers in order to mitigate the base revenue increase that remaining classes bear.

In order to establish the proportion of revenue increase assigned to each customer class, I segregated rate classes into two groups based on the ACOSS results. The first group is comprised of rate classes whose existing rates under the primary ACOSS already produce a unitized return that is above the requested return of 7.57% without any revenue increase. Since the rates of return for these rate classes are already somewhat above the requested return, I am proposing an increase that is three-fourths of the overall base revenue change, which mitigates the increase to the other rate classes. I am proposing to apply the average base revenue increase to the IS rate class in order to increase the net benefit these customers provide to firm customers. I am proposing to allocate the remaining revenue increase to the RS and GSS rate classes. The proposed revenue allocation mitigates the increases to the RS and GSS rate classes by increasing the rates of other classes by more than the levels indicated under the ACOSS studies. The resulting base revenues by rate class for proposed rates are reflected in Schedule DPY-2, Column (D).

Q. Why is the level of the customer charge important?

A. The level of the customer charge is important for a variety of reasons that relate to the Company's rate design goals I described earlier. First, the customer charge provides customers with an important price signal concerning the impact of connecting to NJNG's distribution system. Second, recovering customer-related costs through customer charges contributes to intra-class fairness. To the extent that a portion of customer-related costs are recovered through volumetric charges, intra-class subsidies will be created as larger use customers pay a disproportionate share of customer-related costs. Within the residential class, the level of the customer charge affects the price signal to existing non-heating customers contemplating a conversion to natural gas heating. Third, the customer charge provides revenue stability as fixed costs that are incurred to serve customers are recovered through a fixed charge.

Q. Please describe your proposed changes to the Company's monthly customer charges as well as any applicable demand charges.

A. I am proposing changes to the customer charges applicable to all service classifications. While it is desirable to recover a greater proportion of the class revenue requirement increase through the customer charge, I am limiting the increase to the RS customer charge in order to reduce the impacts to smaller residential heating customers and residential non-heating customers. For the RS class, the proposed customer charge is $14.07 per month. A sizeable increase is needed to bring the charge closer to the cost-based level indicated by the ACOSS and to address the very low rate of return for residential non-heating customers. The higher RS customer charge reduces the increases needed to volumetric charges in order to recover the class-specific revenue requirements. Even with the increase

to the RS customer charge, 83% of the target revenue requirements of the class are recovered through the volumetric charge under the proposed RS rates.

I am proposing to increase the customer charge for the GSS class to $53.93, for the GSL class to $133.65, and for the FT class to $445.49. For the GSL and FT rate classes, I am proposing to increase the monthly demand charge to $4.2204 and $3.517, respectively. For the DGC rate class, I am proposing to increase the monthly customer charge to $133.65 and the monthly demand charge to $3.0481 per therm. I am proposing to increase the customer charge for the IS class to $679.95 per month. These increases to fixed customer and demand charges are also supported by the results of the ACOSS and reduce the required increase to volumetric charges to yield class margin revenues.

Q. Please explain the changes you recommend to the rates and terms of service for the NGV and CNG rate classes.

A. The distribution service and underlying costs of serving customers on these two classes is comparable given both are designed to meet natural gas vehicle refueling needs. For instance, unlike the majority of the Company's customers, vehicle refueling is not subject to weather variances. Therefore, I am recommending that the rates for distribution service for both the NGV and CNG service classifications be increased to $0.3675 per therm. The remaining distinction between the NGV and CNG service classifications is that the CNG service will continue to be subject to an additional charge attributable to the cost of providing compression. I am proposing to increase the charge for compression applicable to CNG service customers to $0.4127 per therm.

Q. Please explain the changes you are proposing to the rates and charges for the Electric Generation Service ("EGS") rate class.

A. There are presently no customers taking service pursuant to the EGS tariff. All large electric generation customers are presently served under special contracts approved by the BPU on a case-by-case basis. Since there are no customers presently taking the tariff rate for EGS service, I am proposing to increase the existing EGS rates by the average base revenue increase requested by the Company. In addition, I am proposing a new rate for limited firm service for this customer classification.

Q. What rate are you proposing for the limited firm EGS service?

A. Pursuant to the BPU's Order in Docket No. GW22050359, the Company was directed to consider the need for a separate tariff rate for large electric generators. This requirement resulted from the New Jersey Division of Rate Counsel's ("Rate Counsel") recommendation that NJNG consider offering a summer firm service that may be suitable for electric generators. I am recommending a different monthly demand charge applicable to electric generation customers that desire firm service for the off-peak period from May 15th through September 15th. The recommended off-peak demand charge for this period is $0.6253 per therm, which is one-third of the proposed rate for prospective year-round firm EGS tariff service. Off-peak firm EGS customers would also pay the same monthly customer charge and volumetric charge as year-round firm EGS customers.

Q. Have you prepared a summary of the proposed rate changes?

A. Yes. The existing and proposed rates and resulting revenues for each class are presented in Schedule DPY-3. In addition to the proposed fixed customer and demand charges noted

earlier, Schedule DPY-3 indicates the volumetric charges for each rate class necessary to yield the target base revenues by class.

The rates and revenues shown in columns (f) and (g) of Schedule DPY-3 reflect the proposed revenue allocation among rate classes. Schedule DPY-3 also provides a proof of revenues demonstrating that the proposed charges yield the requested revenue requirements based on the Company's forecasts of sales and customers.

Q. Please comment on the impact of the proposed rate changes on NJNG's recovery of its overall costs of providing service to customers.

A. The estimated return on rate base investment by class at existing and proposed rates is provided in Table 4 below.

Table 4 – ACOSS – Estimated Return on Rate Base Investment

Service Classification	Existing Rates	Proposed Rates
Residential Heating	0.8%	5.0%
Residential Non-Heating	(6.0%)	(5.2%)
GSS	5.6%	12.0%
GSL	24.7%	34.9%
FT	10.8%	15.6%
DGC	15.7%	22.1%
NGV / CNG	73.3%	102.2%
Overall	2.8%	7.6%

While the proposed rates do not entirely eliminate existing subsidies, improvement in intra-class revenue responsibility is achieved through the increases to fixed charges. In my view, the proposed rates in this proceeding result from a fair and reasonable rate design approach given revenue changes applied in recent base rate proceedings and the continuation of NJNG's CIP.

Q. Did you examine the impact of the proposed rate changes on the rate of return by class under the alternative ACOSS as well?

A. Yes. Table 5 below provides the estimated rates of return by class based upon the alternative ACOSS.

Table 5 – Alternative ACOSS – Estimated Return on Rate Base Investment

Service Classification	Existing Rates	Proposed Rates
Residential Heating	1.1%	5.7%
Residential Non-Heating	(7.3%)	(4.7%)
GSS	5.2%	11.1%
GSL	13.8%	19.3%
FT	3.8%	5.5%
DGC	6.4%	8.9%
NGV / CNG	40.9%	57.0%
Overall	2.8%	7.5%

VI. CONCLUSION

Q. Does this conclude your Direct Testimony?

A. Yes, it does. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

NEW JERSEY NATURAL GAS COMPANY
ALLOCATED COST OF SERVICE STUDY

I. PURPOSE AND GUIDING PRINCIPLES

New Jersey Natural Gas Company ("NJNG") is proposing to change existing rates in connection with a proposed increase in base rate revenue requirements. An allocated cost of service study ("ACOSS") assesses the reasonableness of existing prices, and guides the development of price changes. In particular, the ACOSS examines all of a utility's common costs, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. An ACOSS is necessary to determine the cost responsibility for each customer class because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the base rate increase among all of NJNG's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and commodity components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

The primary principle that guides the ACOSS process is that of cost causation. Each step in the development of the ACOSS is consistent with the factors that drive or contribute to the incurrence of costs on the NJNG system. For example, the principle of cost causation requires that the costs

incurred by the Company for billing be apportioned to classes on the basis of the number of bills issued or customers in each class.

II. SPECIFICATION OF NJNG ACOSS

A. Overview

The ACOSS follows a three-part process, which consists of the functionalization, classification and allocation of NJNG's total cost of service. First, cost functionalization involves the segregation of costs into categories based on the function that each cost is incurred to provide. In the ACOSS, the functions are production, transmission, storage and distribution – the direct functions associated with costs incurred by the Company. Second, cost classification further separates costs according to the primary cost causative forces exhibited on NJNG's system. The cost classifications used in the ACOSS relate to fixed costs required to serve peak requirements (demand-related), fixed costs associated with providing customers with access to and active status on the system (customer-related), and variable costs associated with system throughput (commodity-related). Finally, cost allocation takes each classification of cost for each function and apportions that cost to each of the Company's customer classes. Cost allocation utilizes a variety of factors to apportion the various types of costs among classes in a manner that is consistent with principles of cost responsibility.

B. Customer Classes

The ACOSS includes eight customer classes, which are: Residential Heating, Residential Non-Heating, General Service Small ("GSS"), General Service Large ("GSL"), Firm Transportation ("FT"), Distributed Generation Commercial ("DGC") and Natural Gas Vehicle ("CNG / "NGV").

The Residential Heating and Residential Non-Heating customers are served under the same rate schedule, Residential Service ("RS"); however, the two types of customers are studied separately to guide the design of the customer and delivery rates that apply to RS customers. This approach provides for the evaluation of the cost of serving subsets of customers with disparate characteristics served under a common rate schedule. Residential Non-Heating customers are much smaller than Residential Heating customers and also have a much higher load factor, both of which have important implications for designing rates that are revealed by separating the groups in the ACOSS.

B. Data Sources

The primary data sources fall in two general categories: data related to the establishment of the total cost of service, and data used as the basis for allocating the total cost of service among customer classes. The total cost of service or revenue requirement data utilized in the ACOSS are taken from schedules supporting NJNG's base rate application in this proceeding. The Company's forecasts of sales, customers and revenues by class supporting the application as adjusted for pro forma changes are used as allocation bases for several categories of costs. The remaining allocation data are derived from special studies of facility or operating costs. All of the data utilized in the ACOSS correspond to a common time period of July 2023 through June 2024. This is NJNG's test year, which is the period for which rates are to be determined.

C. Cost Functionalization

The functionalization of costs refers to the segregation of costs among the primary functions provided by gas utilities to their retail customers. The chart of accounts prescribed by the New Jersey Board of Public Utilities separates the majority of costs into the following four functions:

- *Production:* The production function includes costs associated with the upstream commodity gas supply, interstate pipeline transportation capacity necessary to deliver the supply to NJNG's system, and upstream storage facilities. Additionally, the costs of any production facilities and the administrative costs associated with procuring natural gas and transportation are categorized as production-related.

- *Storage:* The storage function includes costs associated with on-system facilities that are able to receive injected supplies or delivered liquid natural gas for later withdrawals.

- *Transmission:* The transmission function includes costs associated with large diameter, high pressure facilities that deliver gas to smaller distribution facilities. Transmission facilities include transmission mains and compressors.

- *Distribution:* The distribution function includes costs associated with delivering supplies within areas that are close in proximity to gas loads, such as distribution mains. The costs associated with connecting customers to the distribution system are also considered distribution-related, which include

costs associated with services, meters and regulators.

The majority of NJNG's non-gas supply costs are associated with the distribution function. Costs that do not directly fall into one of these primary functions, such as administrative and general expenses, are functionalized on the same basis as other related costs.

D. Cost Classification

Classification is the apportionment of costs among demand, customer and commodity categories. Each of NJNG's rate base and expense accounts is classified consistent with the manner in which the associated costs are incurred. Costs that are associated with serving peak requirements on the system are classified as demand-related, e.g., costs associated with transmission accounts. Costs that are associated with providing customers access to and active status on the distribution system are classified as customer-related. Customer-related costs are incurred regardless of the amount of gas a customer consumes in any given period and include the costs of services, meters and regulators, and meter reading and billing expenses. Costs that are associated with the quantity of gas purchased or transported are classified as commodity-related. Examples of commodity-related costs are purchased gas costs. Demand and customer-related costs are considered fixed, while commodity-related costs are variable. Some categories of costs vary with more than one of the classifications described previously.

Lastly, some categories of costs are appropriately classified based on how other related costs are classified. For example, distribution operations supervision and engineering expenses are classified based on the classification of all other distribution operations accounts.

The classification of distribution mains reflects the distinct cost causative factors that drive the Company's investments in these facilities. The first factor is the coincident peak demand on the system. Distribution mains are designed to deliver the maximum quantities that are required during a peak period from NJNG's transmission pipelines or interstate pipeline interconnects to the interconnection with each individual customer service. The second factor is the number of customers on the system. Distribution mains are also designed to deliver supplies in reasonable proximity to customers in order to minimize the length of pipe used to serve all customers in an overall efficient fashion.

The breakdown of distribution mains investment costs between the demand and

customer-related components is determined through a minimum-size study. The premise underlying this study is that the size of distribution main installed in a given location is most affected by the peak load that will be served by the main, and that the length of distribution main is most affected by the number of customers that are served. The validity of this premise is supported by the system design criteria taken into consideration by the Company's distribution engineering staff.

The minimum size study evaluates the cost of replacing the existing distribution mains of the system under two different sets of assumptions. The first determines the cost of replacing existing distribution mains with the same type, diameter and lengths of pipe as is currently installed. The second determines the replacement cost assuming that the entire system is replaced with two-inch diameter plastic pipe, which is the smallest, least-expensive size and type of pipe presently being installed. The customer component of distribution mains is equal to the ratio of the replacement cost using the smallest size pipe to the replacement cost using the installed sizes of pipe. Based on the results of this study, 69.9% of NJNG's distribution mains investment is classified as customer-related.

E. Cost Allocation

Cost allocation is the apportionment of individual elements of the Company's classified cost of service among rate classes based on each class' responsibility for the cost being incurred. Cost allocation follows cost causation principles and requires the development of numerous allocation factors that reflect the different types of costs included in NJNG's overall revenue requirements. Considerable effort is required to yield the set of allocation factors underlying the ACOSS.

The ACOSS follows system-design criteria in order to allocate costs on the basis of cost causation. The demand allocator used in the ACOSS is the coincident design day demand factor. Under this method, the allocation of demand costs reflects the manner in which the Company designs, plans and constructs its system to satisfy firm demands. Off-peak loads do not increase the Company's demand-related investments, and therefore, are not factored into the demand allocator in a system-design ACOSS.

The other allocation factors used in the ACOSS may be grouped into three categories as follows: (i) class summary statistics reflected in the base rate filing, such as the number of customers and throughput by class; (ii) special studies that examine the

costs associated with a specific type of investment or expense; and (iii) internal allocation factors, which are composite factors determined on the basis of how related cost items are allocated. All of the various factors must be developed assuming a consistent time period for the ACOSS to be accurate.

Seven special studies were performed related to significant capital investment and operations and maintenance ("O&M") expense accounts. The studies are as follows:

- *Meter Investment Study:* The meter investment study establishes the aggregate investment in meters and associated regulators based on the type and replacement cost of various meters installed to serve each class.
- *Meter Installation Investment Study:* The meter investment study establishes the aggregate investment in meter installations based on the type and replacement cost of various meters installed to serve each class.
- *Service Investment Study:* NJNG's investment in distribution services is the largest investment on its books after the Company's investment in mains. The services investment study establishes the aggregate investment in services based on the type and length of various services installed to serve each class.
- *Cash Working Capital Study:* The cash working capital study examines the components of NJNG's proposed cash working capital allowance. A composite allocator is derived from the allocation of each component within the ACOSS.
- *Customer Deposits Study:* The customer deposits study assesses the customer deposits by rate class.
- *Labor Expense Study:* A study of the Company's payroll expense examines components of the Company's payroll costs. The labor study is used as the basis for allocating costs that vary with direct payroll costs, such as pensions and benefits costs.
- *Write-offs Study:* The write-offs study examines historical write-offs by customer class.

Together, these special studies are utilized to allocate a substantial portion of the Company's total revenue requirements to customer classes.

Gas costs recovered through Basic Gas Supply Service ("BGSS") charges and costs recovered through other tariff riders represent a significant proportion of the Company's overall O&M expense. Costs

associated with the BGSS and other tariff riders are allocated among NJNG's rate classes on the basis of the associated rider revenues. The Company does not necessarily incur all gas costs on this basis as a portion of gas costs result from fixed interstate pipeline demand charges. However, given that all customers are allowed to choose an alternate gas supplier, it is important that the application of the ACOSS results to the design of distribution prices not be affected by variances in the allocation of gas costs among sales service classifications.

III. RESULTS

Detailed ACOSS results are provided in Schedule DPY-1, Attachment I. The first two pages of the attached results provide an income statement by class at existing and proposed rates, respectively. Pages three, four and five contain summaries of allocated rate base, O&M expense and total revenue requirements by classification and rate class. Lastly, page six provides a detailed analysis of the components of monthly customer-related costs.

The ACOSS demonstrates that the rates of return at present rates for the Residential Heating, Residential Non-Heating and General Service Small customers are less than the proposed rate of return of 7.57%. The rates of return for the General Service Large, Firm Transportation, Distributed Generation and Natural Gas Vehicle classes are above the system-average rate of return. These results indicate the class-differentiated increases in base revenue requirements are appropriate.

Monthly customer costs are derived from the costs that are classified as customer-related and the apportionment of these costs to NJNG's various customer classes. The system-wide average monthly customer cost is $74, and the cost generally varies with the size of the customer. The lowest average customer cost of $72 per month is associated with serving the Residential Non-Heating class.

Schedule DPY-1
Attachment 1
Page 1

New Jersey Natural Gas Company
Income and Rate of Return at Present Rates

	Total System	Residential Heating	Residential Non-Heating	General Service GSS	General Service GSL	Firm Transportation	Distributed Generation	CNG / NGV
REVENUES								
Margin Revenues	$ 497,030,276	$ 360,740,690	$ 3,528,147	$ 36,045,424	$ 88,258,679	$ 6,619,498	$ 1,232,347	$ 605,491
Other Revenues	579,812,701	468,102,884	4,248,160	33,654,969	67,236,825	5,184,724	802,019	583,120
Total	**$ 1,076,842,978**	**$ 828,843,574**	**$ 7,776,307**	**$ 69,700,394**	**$ 155,495,504**	**$ 11,804,222**	**$ 2,034,366**	**$ 1,188,611**
OPERATING EXPENSES								
Operations and Maintenance	$ 750,395,087	$614,329,196	$7,635,088	$44,000,901	$76,588,254	$6,270,928	$957,668	$613,052
Depreciation and Amortization	162,969,478	137,937,840	3,100,612	10,035,199	10,317,148	1,353,543	202,132	23,004
Taxes Other Than Income Taxes	70,198,452	56,801,212	519,212	4,056,692	8,066,967	590,968	91,302	72,099
Total	**$ 983,563,017**	**$ 809,068,248**	**$ 11,254,912**	**$ 58,092,792**	**$ 94,972,370**	**$ 8,215,440**	**$ 1,251,102**	**$ 708,155**
OPERATING INCOME BEFORE TAXES	**$ 93,279,960**	**$ 19,775,327**	**$ (3,478,605)**	**$ 11,607,602**	**$ 60,523,134**	**$ 3,588,782**	**$ 783,264**	**$ 480,456**
INCOME TAXES								
Federal Income Taxes	$ (2,580,313)	$ (2,157,794)	$ (44,098)	$ (159,848)	$ (188,561)	$ (25,661)	$ (3,847)	$ (504)
State Income Taxes	(3,312,177)	(2,769,817)	(56,606)	(205,187)	(242,043)	(32,939)	(4,938)	(647)
Deferred Income Taxes	3,292,706	2,753,534	56,273	203,981	240,621	32,746	4,909	643
Total	**$ (2,599,785)**	**$ (2,174,077)**	**$ (44,431)**	**$ (161,055)**	**$ (189,984)**	**$ (25,855)**	**$ (3,876)**	**$ (508)**
RATEMAKING ADJUSTMENTS	**$ (231,821)**	**($200,035)**	**($4,801)**	**($13,800)**	**($11,510)**	**($1,428)**	**($222)**	**($25)**
NET INCOME	**$ 95,647,924**	**$ 21,749,368**	**$ (3,438,975)**	**$ 11,754,857**	**$ 60,701,608**	**$ 3,613,209**	**$ 786,918**	**$ 480,939**
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADJUSTED NET INCOME	**$ 95,647,924**	**$ 21,749,368**	**$ (3,438,975)**	**$ 11,754,857**	**$ 60,701,608**	**$ 3,613,209**	**$ 786,918**	**$ 480,939**
RATE BASE	**$ 3,358,690,866**	**$2,808,714,350**	**$57,400,741**	**$208,068,251**	**$245,442,585**	**$33,401,887**	**$5,007,112**	**$655,940**
RATE OF RETURN AT PRESENT RATE	**2.85%**	**0.77%**	**-5.99%**	**5.65%**	**24.73%**	**10.82%**	**15.72%**	**73.32%**

Schedule DPY-1
Attachment 1
Page 2

New Jersey Natural Gas Company
Income and Rate of Return at Proposed Rates

	Total System	Residential Heating	Residential Non-Heating	General Service GSS	General Service GSL	Firm Transportation	Distributed Generation	CNG / NGV
REVENUES								
Margin Revenues	$ 719,234,205	$ 531,911,072	$ 5,040,105	$ 53,133,807	$ 117,855,402	$ 8,839,657	$ 1,645,587	$ 808,573
BGSS and Rider Revenues	580,206,349	468,432,073	4,254,887	33,679,356	67,265,591	5,188,639	802,606	583,197
Total	**$ 1,299,440,554**	**$ 1,000,343,145**	**$ 9,294,993**	**$ 86,813,163**	**$ 185,120,994**	**$ 14,028,296**	**$ 2,448,193**	**$ 1,391,770**
OPERATING EXPENSES								
Operations and Maintenance	$ 751,658,898	$615,304,581	$7,643,225	$44,080,262	$76,771,909	$6,284,411	$960,013	$614,496
Depreciation and Amortization	162,969,478	137,937,840	3,100,612	10,035,199	10,317,148	1,353,543	202,132	23,004
Taxes Other Than Income Taxes	70,784,511	57,291,306	529,228	4,092,998	8,109,795	596,797	92,176	72,213
Total	**$ 985,412,887**	**$ 810,533,727**	**$ 11,273,064**	**$ 58,208,459**	**$ 95,198,852**	**$ 8,234,751**	**$ 1,254,321**	**$ 709,713**
OPERATING INCOME BEFORE TAXES	**$ 314,027,667**	**$ 189,809,418**	**$ (1,978,072)**	**$ 28,604,704**	**$ 89,922,142**	**$ 5,793,545**	**$ 1,193,873**	**$ 682,056**
INCOME TAXES								
Federal Income Taxes	$ 39,608,049	$ 33,122,339	$ 676,910	$ 2,453,687	$ 2,894,432	$ 393,899	$ 59,047	$ 7,735
State Income Taxes	16,555,341	13,844,449	282,934	1,025,590	1,209,812	164,641	24,681	3,233
Deferred Income Taxes	3,292,706	2,753,534	56,273	203,981	240,621	32,746	4,909	643
Total	**$ 59,456,095**	**$ 49,720,321**	**$ 1,016,117**	**$ 3,683,258**	**$ 4,344,865**	**$ 591,286**	**$ 88,637**	**$ 11,612**
RATEMAKING ADJUSTMENTS	**$ (231,821)**	**($200,035)**	**($4,801)**	**($13,800)**	**($11,510)**	**($1,428)**	**($222)**	**($25)**
NET INCOME	**$ 254,339,750**	**$ 139,889,062**	**$ (2,998,990)**	**$ 24,907,646**	**$ 85,565,767**	**$ 5,200,831**	**$ 1,105,014**	**$ 670,420**
RATE BASE	**$ 3,358,690,866**	**$2,808,714,350**	**$57,400,741**	**$208,068,251**	**$245,442,585**	**$33,401,887**	**$5,007,112**	**$655,940**
RATE OF RETURN AT PROPOSED RA	**7.57%**	**4.98%**	**-5.22%**	**11.97%**	**34.86%**	**15.57%**	**22.07%**	**102.21%**

New Jersey Natural Gas Company
Rate Base

	Total System	Residential Heating	Residential Non-Heating	General Service GSS	General Service GSL	Firm Transportation	Distributed Generation	CNG / NGV
I. PLANT IN SERVICE								
Demand	$ 1,391,778,455	$ 1,019,529,612	$ 3,237,469	$93,061,636	$228,047,128	$41,032,840	$6,203,600	$666,170
Customer	2,747,696,773	2,439,071,965	68,631,494	163,728,513	73,737,330	2,212,791	259,887	54,792
Commodity	429,662	344,774	2,436	24,655	52,950	3,769	586	491
	$ 4,139,904,890	$3,458,946,351	$71,871,400	$256,814,804	$301,837,409	$43,249,399	$6,464,074	$721,453
II. ACCUMULATED RESERVE FOR DEPRECIATION								
Demand	$ 257,058,992	$ 188,305,254	$ 597,953	$17,188,320	$42,119,926	$7,578,704	$1,145,796	$123,040
Customer	418,129,945	370,108,831	10,403,540	25,186,970	11,982,727	399,100	39,749	9,028
Commodity	68,086	54,634	386	3,907	8,391	597	93	78
	$ 675,257,023	$558,468,719	$11,001,878	$42,379,197	$54,111,044	$7,978,401	$1,185,637	$132,147
III. NET PLANT IN SERVICE								
Demand	$ 1,134,719,462	$ 831,224,359	$ 2,639,517	$75,873,316	$185,927,202	$33,454,136	$5,057,804	$543,129
Customer	2,329,566,829	2,068,963,134	58,227,955	138,541,543	61,754,603	1,813,691	220,139	45,764
Commodity	361,576	290,139	2,050	20,748	44,560	3,172	494	413
	$ 3,464,647,867	$2,900,477,632	$60,869,522	$214,435,607	$247,726,365	$35,270,998	$5,278,436	$589,307
IV. RATE BASE ADDITIONS								
Demand	$ 164,420,580	$ 134,012,910	$ 1,046,470	$10,296,112	$17,674,675	$1,111,005	$176,493	$102,915
Customer	107,121,810	89,367,567	1,905,775	6,831,644	8,061,769	794,168	119,062	41,825
Commodity	16,643	13,570	225	1,053	1,609	153	23	11
	$ 271,559,033	$223,394,046	$2,952,470	$17,128,809	$25,738,053	$1,905,326	$295,579	$144,751
V. RATE BASE DEDUCTIONS								
Demand	$ (131,268,479)	$ (97,435,879)	$ (374,365)	($8,737,456)	($20,640,845)	($3,485,401)	($528,125)	($66,408)
Customer	(246,209,339)	(217,690,803)	(6,046,657)	(14,756,495)	(7,376,295)	(288,698)	(38,725)	(11,667)
Commodity	(38,216)	(30,646)	(230)	(2,214)	(4,693)	(338)	(53)	(43)
	$ (377,516,035)	($315,157,328)	($6,421,251)	($23,496,165)	($28,021,833)	($3,774,437)	($566,903)	($78,118)
VI. TOTAL RATE BASE								
Demand	**$ 1,167,871,563**	**$ 867,801,390**	**$ 3,311,622**	**$77,431,972**	**$182,961,032**	**$31,079,739**	**$4,706,172**	**$579,636**
Customer	**2,190,479,299**	**1,940,639,898**	**54,087,073**	**130,616,692**	**62,440,078**	**2,319,162**	**300,475**	**75,922**
Commodity	**340,003**	**273,063**	**2,045**	**19,588**	**41,476**	**2,987**	**464**	**381**
	$ 3,358,690,866	**$2,808,714,350**	**$57,400,741**	**$208,068,251**	**$245,442,585**	**$33,401,887**	**$5,007,112**	**$655,940**

New Jersey Natural Gas Company
O&M Expense

	Total System	Residential Heating	Residential Non-Heating	General Service GSS	General Service GSL	Firm Transportation	Distributed Generation	CNG / NGV
I. PRODUCTION EXPENSE								
Demand	$ 256,782	$ 188,102	$ 597	$17,170	$42,075	$7,571	$1,145	$123
Customer	-	-	-	-	-	-	-	-
Commodity	455,826,811	365,768,892	2,584,854	26,156,363	56,174,919	3,998,496	622,201	521,086
	$ 456,083,593	$365,956,994	$2,585,451	$26,173,533	$56,216,993	$4,006,067	$623,346	$521,209
II. STORAGE EXPENSE								
Demand	$ 5,233,579	$ 3,833,786	$ 12,174	$ 349,945	$ 857,542	$ 154,300	$ 23,328	$ 2,505
Customer	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-
	$ 5,233,579	$3,833,786	$12,174	$349,945	$857,542	$154,300	$23,328	$2,505
III. TRANSMISSION EXPENSE								
Demand	$ 10,034,006	$ 7,350,272	$ 23,340	$ 670,927	$ 1,644,110	$ 295,829	$ 44,725	$ 4,803
Customer	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-
	$ 10,034,006	$7,350,272	$23,340	$670,927	$1,644,110	$295,829	$44,725	$4,803
IV. DISTRIBUTION EXPENSE								
Demand	$ 16,368,675	$ 11,990,645	$ 38,075	$1,094,497	$2,682,070	$482,592	$72,961	$7,835
Customer	50,522,752	44,428,450	1,239,624	3,136,767	1,645,566	66,280	4,792	1,273
Commodity	-	-	-	-	-	-	-	-
	$ 66,891,427	$56,419,095	$1,277,699	$4,231,264	$4,327,636	$548,871	$77,753	$9,108
V. CUSTOMER ACCOUNTS EXPENSE								
Demand	$ 1,172,943	$ 905,255	$ 7,552	$ 73,655	$ 170,450	$ 12,514	$ 2,176	$ 1,340
Customer	39,695,911	35,608,601	970,964	2,237,512	835,350	34,753	5,893	2,837
Commodity	341	264	2	21	50	4	1	0
	$ 40,869,195	$36,514,120	$978,518	$2,311,189	$1,005,850	$47,271	$8,070	$4,177
VI. CUSTOMER SERVICE AND SALES EXPENSE								
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	5,983,231	5,411,135	152,677	334,996	82,282	1,800	289	52
Commodity	51,788,670	41,556,758	293,678	2,971,750	6,382,302	454,288	70,691	59,203
	$ 57,771,901	$ 46,967,893	$ 446,354	$ 3,306,746	$ 6,464,584	$ 456,089	$ 70,980	$ 59,255
VII. ADMINISTRATIVE AND GENERAL EXPENSE								
Demand	$ 23,736,467	$ 17,431,747	$ 57,339	$1,584,795	$3,859,298	$687,835	$104,017	$11,435
Customer	90,932,284	80,745,258	2,261,745	5,445,755	2,382,779	87,217	7,648	1,883
Commodity	106,446	85,417	604	6,108	13,117	934	145	122
	$ 114,775,197	$98,262,422	$2,319,688	$7,036,658	$6,255,193	$775,985	$111,810	$13,440
VIII. TOTAL O&M EXPENSE								
Demand	**$ 56,802,451**	**$ 41,699,807**	**$ 139,077**	**$ 3,790,989**	**$ 9,255,546**	**$ 1,640,640**	**$ 248,352**	**$ 28,041**
Customer	**187,134,178**	**166,193,444**	**4,625,010**	**11,155,030**	**4,945,977**	**190,050**	**18,622**	**6,045**
Commodity	**507,722,269**	**407,411,330**	**2,879,138**	**29,134,243**	**62,570,387**	**4,453,722**	**693,038**	**580,411**
	$ 751,658,898	**$ 615,304,581**	**$ 7,643,225**	**$ 44,080,262**	**$ 76,771,909**	**$ 6,284,411**	**$ 960,013**	**$ 614,496**

New Jersey Natural Gas Company
Total Revenue Requirements

	Total System	Residential Heating	Residential Non-Heating	General Service GSS	General Service GSL	Firm Transportation	Distributed Generation	CNG / NGV
I. O&M EXPENSE								
Demand	$ 56,802,451	$ 41,699,807	$ 139,077	$ 3,790,989	$ 9,255,546	$ 1,640,640	$ 248,352	$ 28,041
Customer	187,134,178	166,193,444	4,625,010	11,155,030	4,945,977	190,050	18,622	6,045
Commodity	507,722,269	407,411,330	2,879,138	29,134,243	62,570,387	4,453,722	693,038	580,411
	$ 751,658,898	$ 615,304,581	$ 7,643,225	$ 44,080,262	$ 76,771,909	$ 6,284,411	$ 960,013	$ 614,496
II. DEPRECIATION								
Demand	$ 42,725,545	$ 31,308,734	$ 99,902	$ 2,856,283	$ 6,993,414	$ 1,256,736	$ 190,008	$ 20,468
Customer	120,212,046	106,603,519	3,000,529	7,177,086	3,319,804	96,528	12,081	2,499
Commodity	31,887	25,587	181	1,830	3,929	280	44	36
	$ 162,969,478	$ 137,937,840	$ 3,100,612	$ 10,035,199	$ 10,317,148	$ 1,353,543	$ 202,132	$ 23,004
III. TAXES OTHER THAN INCOME								
Demand	$ 1,418,046	$ 1,037,079	$ 3,217	$ 94,909	$ 233,507	$ 42,269	$ 6,389	$ 676
Customer	6,901,087	6,130,162	171,789	413,686	178,215	6,584	522	129
Commodity	62,465,379	50,124,064	354,222	3,584,403	7,698,072	547,944	85,265	71,408
	$ 70,784,511	$57,291,306	$529,228	$4,092,998	$8,109,795	$596,797	$92,176	$72,213
IV. DEFERRED INCOME TAXES								
Demand	$ 1,144,927	$ 850,752	$ 3,247	$ 75,911	$ 179,367	$ 30,469	$ 4,614	$ 568
Customer	2,147,445	1,902,514	53,024	128,051	61,213	2,274	295	74
Commodity	333	268	2	19	41	3	0	0
	$ 3,292,706	$2,753,534	$56,273	$203,981	$240,621	$32,746	$4,909	$643
V. RATEMAKING ADJUSTMENTS								
Demand	$ 45,972	$ 33,676	$ 107	$ 3,074	$ 7,533	$ 1,355	$ 205	$ 22
Customer	185,849	166,359	4,694	10,726	3,977	73	17	3
Commodity	-	-	-	-	-	-	-	-
	$ 231,821	$200,035	$4,801	$13,800	$11,510	$1,428	$222	$25
VI. RETURN								
Demand	$ 87,902,023	$ 65,316,684	$ 249,255	$ 5,828,061	$ 13,770,902	$ 2,339,274	$ 354,219	$ 43,627
Customer	164,870,495	146,065,868	4,070,964	9,831,108	4,699,668	174,556	22,616	5,714
Commodity	25,591	20,553	154	1,474	3,122	225	35	29
	$ 252,798,109	$211,403,105	$4,320,373	$15,660,644	$18,473,692	$2,514,055	$376,870	$49,371
VII. INCOME TAXES								
Demand	$ 19,528,926	$ 14,511,210	$ 55,376	$ 1,294,803	$ 3,059,440	$ 519,709	$ 78,696	$ 9,693
Customer	36,628,778	32,451,011	904,434	2,184,147	1,044,111	38,781	5,024	1,270
Commodity	5,685	4,566	34	328	694	50	8	6
	$ 56,163,390	$46,966,787	$959,844	$3,479,278	$4,104,244	$558,540	$83,728	$10,969
VIII. TOTAL REVENUE REQUIREMENTS								
Demand	**$ 209,567,890**	**$ 154,757,942**	**$ 550,181**	**$ 13,944,029**	**$ 33,499,709**	**$ 5,830,452**	**$ 882,483**	**$ 103,095**
Customer	**518,079,878**	**459,512,878**	**12,830,444**	**30,899,834**	**14,252,967**	**508,845**	**59,176**	**15,734**
Commodity	**570,251,145**	**457,586,369**	**3,233,731**	**32,722,297**	**70,276,244**	**5,002,223**	**778,390**	**651,891**
	$ 1,297,898,913	**$1,071,857,188**	**$16,614,356**	**$77,566,160**	**$118,028,919**	**$11,341,520**	**$1,720,049**	**$770,720**

New Jersey Natural Gas Company
Monthly Customer Cost Detail

	Total System	Residential Heating	Residential Non-Heating	General Service GSS	General Service GSL	Firm Transportation	Distributed Generation	CNG / NGV
I. AVERAGE CUSTOMER COSTS				24.73				
Customer-Related Revenue Req.	$ 518,079,878	$ 459,512,878	$ 12,830,444	$ 30,899,834	$ 14,252,967	$ 508,845	$ 59,176	$ 15,734
Average Customers	579,520	524,108	14,788	32,447	7,970	174	28	5
Average Monthly Customer Cost	**$ 74.50**	**$ 73.06**	**$ 72.30**	**$ 79.36**	**$ 149.03**	**$ 243.18**	**$ 176.12**	**$ 262.24**
II. MONTHLY CUSTOMER COST DETAIL								
O&M Expense								
Mains and Services Expense	$ 2.11	$ 2.09	$ 2.09	$ 2.19	$ 3.46	$ 2.85	$ 4.25	$ 3.92
Meter & Regulator Expense	0.66	0.55	0.50	1.11	5.95	15.99	3.31	8.17
Meter Reading Expense	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Customer Records and Collections	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Uncollectible Accounts	0.32	0.27	0.08	0.35	3.34	11.22	12.15	41.89
All Other O&M	19.08	18.77	18.65	20.25	34.22	56.03	30.98	42.04
Total O&M	$ 26.91	$ 26.42	$ 26.06	$ 28.65	$ 51.72	$ 90.83	$ 55.42	$ 100.75
Depreciation								
Mains	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54	$ 5.54
Services	6.52	6.36	6.36	6.99	15.05	11.16	20.00	17.93
Meters and Meter Installations	1.51	1.40	1.39	1.90	6.85	16.88	3.96	9.05
Regulators	-	-	-	-	-	-	-	-
All Other Depreciation	3.71	3.64	3.61	3.99	7.27	12.56	6.45	9.13
Total Depreciation	$ 17.29	$ 16.95	$ 16.91	$ 18.43	$ 34.71	$ 46.13	$ 35.95	$ 41.65
Taxes Other Than Income Taxes	$ 0.99	$ 0.97	$ 0.97	$ 1.06	$ 1.86	$ 3.15	$ 1.55	$ 2.15
Deferred Income Taxes	$ 0.31	$ 0.30	$ 0.30	$ 0.33	$ 0.64	$ 1.09	$ 0.88	$ 1.24
Ratemaking Adjustments	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.04	$ 0.03	$ 0.05	$ 0.05
Rate Base-Related (Return and Income Taxes)								
Mains	$ 13.61	$ 13.61	$ 13.61	$ 13.61	$ 13.61	$ 13.61	$ 13.61	$ 13.61
Services	10.25	10.01	10.01	11.00	23.67	17.54	31.45	28.19
Meters and Meter Installations	2.59	2.37	2.33	3.40	13.23	33.27	7.58	17.64
Regulators	0.01	0.01	0.01	0.02	0.11	0.30	0.06	0.15
All Other Rate Base-Related	2.52	2.39	2.09	2.83	9.45	37.24	29.56	56.81
Total Rate Base-Related	$ 28.98	$ 28.38	$ 28.04	$ 30.86	$ 60.06	$ 101.96	$ 82.26	$ 116.40
Total Average Monthly Customer Cost	**$ 74.50**	**$ 73.06**	**$ 72.30**	**$ 79.36**	**$ 149.03**	**$ 243.18**	**$ 176.12**	**$ 262.24**

New Jersey Natural Gas Company
Allocation of Proposed Revenue Adjustments to Base Rates
(In Thousands of Dollars)

Description	Current Base Revenue	Allocation of Proposed Revenue Adjustment	Proposed Base Revenues
(A)	(B)	(C)	(D) = (B) + (C)
Rate Schedule:			
Residential Service	364,269	172,689	536,958
General Service - Small	36,045	17,088	53,134
General Service - Large	88,259	29,593	117,852
Firm Transportation Service	6,619	2,220	8,839
Distributed Generation Service - Commercial	1,232	413	1,646
Electric Generation Service	-	-	-
NGV / CNG Service	605	203	809
Interruptible Transportation	880	394	1,274
Total	497,911	222,600	720,511

New Jersey Natural Gas Company
Base Rates and Revenues at Present and Proposed Rates

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			RS		**RS**	
Residential Service						
Customer Charge	6,466,751	Bills	$ 10.32	$ 66,736,874	$ 14.07	$ 90,987,191
Volumetric Charge	513,783,394	Therms	0.5791	297,531,964	0.8680	445,963,986
						-
Total Base Revenues				**$ 364,268,837**		**$ 536,951,177**
			GSS		**GSS**	
General Service Small (less than 5,000 Annual Therms)						
Customer Charge	389,362	Bills	$ 39.39	$ 15,336,958	$ 53.93	$ 20,998,277
Volumetric Charge	40,918,572	Therms	0.5059	20,700,705	0.7851	32,125,171
Volumetric Charge - A/C	70,811	Therms	0.1096	7,761	0.1463	10,360
Total Base Revenues				**$ 36,045,424**		**$ 53,133,807**

New Jersey Natural Gas Company
Base Rates and Revenues at Present and Proposed Rates

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			GSL		**GSL**	
General Service Large (5,000 + Annual Therms)						
Customer Charge	95,636	Bills	$ 97.54	$ 9,328,321	$ 133.65	$ 12,781,731
Demand Charge	10,368,454	Therms	3.2000	33,179,054	4.2204	43,759,025
Volumetric Charge	142,221,644	Therms	0.3216	45,738,481	0.4310	61,297,528
Volumetric Charge - A/C	117,002	Therms	0.1096	12,823	0.1463	17,117
Total Base Revenues				**$ 88,258,679**		**$ 117,855,402**
			FT		**FT**	
Firm Transportation Service*						
Customer Charge	2,092	Bills	$ 328.25	$ 686,840	$ 445.49	$ 932,157
Demand Charge	1,872,696	Therms	2.3447	4,390,911	3.5170	6,586,273
Volumetric Charge	18,847,757	Therms	0.0818	1,541,747	0.0701	1,321,228
Total Base Revenues				**$ 6,619,498**		**$ 8,839,657**

New Jersey Natural Gas Company
Base Rates and Revenues at Present and Proposed Rates

Component (a)	Amount (b)	Units (c)	Present Rates Rate (d)	Present Rates Revenue (e)	Proposed Rates Rate (f)	Proposed Rates Revenue (g)
			DGC		DGC	
Distributed Generation - Commercial*						
Customer Charge	336	Bills	$ 97.54	$ 32,773	$ 133.65	$ 44,906
Demand Charge	398,132	Therms	2.2040	877,483	3.0481	1,213,546
Volumetric Charge - Winter	2,895,401	Therms	0.0726	210,206	0.0843	244,082
Volumetric Charge - Summer	2,663,921	Therms	0.0420	111,885	0.0537	143,053
Total Base Revenues				**$ 1,232,347**		**$ 1,645,587**
			EGS		EGS	
Electric Generation Service						
Customer Charge	0	Bills	$ 877.26	$ -	$ 914.42	$ -
Demand Charge - Year-Round F	0	Therms	1.5132	-	1.8757	-
Demand Charge - Off-Peak Firm	0	Therms		-	0.6253	-
Volumetric Charge	0	Therms	0.0047	-	0.0094	-
Total Base Revenues				**$ -**		**$ -**

New Jersey Natural Gas Company
Base Rates and Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates		Proposed Rates	
			Rate	Revenue	Rate	Revenue
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Natural Gas Vehicle / Compressed Natural Gas Service			NGV / CNG		NGV / CNG	
Customer Charge	60	Bills	$ 97.54	$ 5,852	$ 133.65	$ 8,019
Volumetric Charge	1,551,585	Therms	0.2734	424,203	0.3675	570,208
CNG Charge	877,177	Therms	0.2000	175,435	0.2626	230,347
Total Base Revenues				**$ 605,491**		**$ 808,573**
Interruptible Service			Interruptible		Interruptible	
Customer Charge	300	Bills	$ 537.38	$ 161,214	$ 679.95	$ 203,985
Volumetric Charge - with Alterna	14,559,205	Therms	0.0494	719,225	0.0735	1,070,102
Volumetric Charge - without Alte	0	Therms	0.2753	-	0.4127	-
Total Base Revenues				**$ 880,439**		**$ 1,274,087**

New Jersey Natural Gas Company
Base Rates and Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates		Proposed Rates	
			Rate	Revenue	Rate	Revenue
(a)	(b)	(c)	(d)	(e)	(f)	(g)
TOTAL SYSTEM BASE DISTRIBUTION REVENUES				**$ 497,910,715**		**$ 720,508,291**

Increase	**222,597,576**
TARGET Increase	**222,600,066**
Difference	**($2,489)**

Exhibit P-9

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY OF TINA M. TREBINO
DIRECTOR, RATES AND TARIFF

I. INTRODUCTION

Q. Please state your name, affiliation and business address.

A. My name is Tina M. Trebino and I am Director, Rates and Tariff for New Jersey Natural Gas Company (the "Company" or "NJNG"). My business address is 1415 Wyckoff Road, Wall, New Jersey 07719.

Q. Please describe your education and business experience.

A. I received a Bachelor of Science degree in Accounting with a minor in Mathematics from the University of Richmond in 1993. Furthermore, I am a Certified Public Accountant licensed in the Commonwealth of Virginia.

I was employed by the Virginia State Corporation Commission as an auditor within the Public Utility Accounting Department from July 1993 to May 1996.

In May 1996, I accepted a position as a Rate and Regulatory Analyst with NJNG in the Energy Services Department and held that position until January 1997 when I assumed the responsibilities as a Gas Planning Analyst, also in the Energy Services Department. In July 2002, I accepted the position of Senior Regulatory Affairs Analyst in the Regulatory Affairs Department of NJNG. In January 2007, I was promoted to Manager, Regulatory Affairs and in July 2014, I was promoted to my current position of Director, Rates and Tariff.

Q. What are your responsibilities as Director of Rates and Tariff?

A. I am responsible for preparing and supporting Company rate and tariff matters submitted to the New Jersey Board of Public Utilities (the "Board" or "BPU"). I am also involved in the daily operations of the Regulatory Affairs Department including rates, tariffs, U.S. Securities and Exchange Commission ("SEC") reporting and related matters.

Q. Have you previously testified in regulatory proceedings?

A. Yes. In addition to supporting and testifying in regulatory proceedings during my tenure with the Virginia State Corporation Commission, I have filed testimony on behalf of NJNG in several prior rate proceedings.

Q. What are your responsibilities with respect to this proceeding?

A. By way of this Direct Testimony, I am addressing changes to the Company's Tariff other than the rate charges for service, which are being sponsored and supported by the Direct Testimony of Daniel P. Yardley, Exhibit P-8. Additionally, I will address changes to the Company's Balancing Charge and customer-related impacts from those changes.

I am supporting the following schedules appended to my Direct Testimony, which were prepared under my direction and/or control: Schedule TMT-1, a clean version of the proposed Tariff, New Jersey Natural Gas Company Tariff – BPU No. 12 Gas; Schedule TMT-2, which is the proposed Tariff with red-lined changes to NJNG's current Tariff; and Schedule TMT-3, a summary of the substantive proposed tariff changes; Schedule TMT-4, reflecting changes to the Balancing Charge; and Schedule TMT-5, which shows the impact to customers from the (i) rate changes proposed by Company Witness Daniel Yardley in his Direct Testimony, and (ii) change to the Balancing Charge.

Q. What changes to the Tariff is the Company proposing in this proceeding?

A. The Company proposes to modify a number of Tariff sheets within this base rate case proceeding. Many of these changes represent minor changes in language to reflect current operations and/or to provide clarifications and necessary updates. Schedule TMT-3 includes a summary of the substantive changes. The proposed changes to the Tariff addressed in my Direct Testimony and the impact of the rates proposed by Mr. Yardley are presented in the following sections:

II. Standard Terms and Conditions

III. Electric Generation Service ("EGS")

IV. Third Party Supplier ("TPS") Requirements

V. Riders

VI. Balancing Charge

VII. Impact on Customers.

II. STANDARD TERMS AND CONDITIONS

Q. Please describe the proposed changes to the standard terms and conditions of the Company's Tariff.

A. I have highlighted the proposed changes below:

Paragraph 8.7 Equal Payment Plan (Sheet No. 28)[1]

- The Company proposes a new paragraph in Section 8 Meter Reading and Billing to describe the Equal Payment Plan available to customers.

[1] Sheet numbers refer to the Tariff Sheet numbers in Schedule TMT-1.

Paragraph 8.9 Payment Obligation (Sheet No. 28)

- The Company proposes to update Paragraph 8.9 to reflect New Jersey Administration Code ("N.J.A.C.") requirements implemented since the Company's last rate case. The Company follows these N.J.A.C. requirements and is simply proposing to update the Tariff language to be consistent with changes made. In accordance with N.J.A.C. 14:3-3A.3, the Company is changing the bill payment due date from within at least fifteen (15) days from the date the bill is sent to within at least twenty (20) days. Also in accordance with N.J.A.C. 14:3-3A.3, the Company is revising the number of days before the Company can serve a notice of discontinuance from the expiration of the 15-day payment period to the expiration of the 20-day payment period. Additionally, in accordance with N.J.A.C. 14:3-3A.2, the Company is changing the minimum arrearage for discontinuance of service for nonpayment from $100.00 to $200.00.

Paragraph 9.2 Customer Acts or Omissions (Sheet No. 30)

- The Company proposes to update the N.J.A.C. reference in Paragraph 9.2(a) to N.J.A.C. 14:3-3A.2 to match the reference included in N.J.A.C. 14:3-3A.1(a)3.

III. ELECTRIC GENERATION SERVICE

Q. Please describe the proposed changes to Service Classification EGS?

A. EGS currently offers Year-Round firm service available throughout the year. Pursuant to the BPU's Order, in *I/M/O The Waiver Request Of New Jersey Natural Gas Company To File A Petition For A Review Of The Original Service Agreement And First Amendment Between New Jersey Natural Gas And Essential Power OPP, LLC*, Docket No. GW22050359, Order (dated July 12, 2023), the Company was directed to evaluate the need to create a separate tariff for large electric generators and include testimony addressing this

issue in its next base rate case. Having conducted the required evaluation, the Company is now proposing the addition of Off-Peak firm service available May 15 through September 15 and an associated demand charge as described in the Direct Testimony of Mr. Yardley. (See Tariff, Sheet No. 69).

IV. THIRD PARTY SUPPLIER REQUIREMENTS

Q. Please describe the Company's proposed modifications to Service Classification TPS.

A. The Company proposes the following changes to Service Classification TPS:

FT, DGC-FT, CNG, NGV Commercial, and IS Service (Sheet No. 90)

- A TPS is to use its best efforts to achieve a balance between its deliveries and its aggregate FT, DGC-FT, CNG, NGV Commercial, and IS Service customer requirements. Currently, if the TPS' account is out of balance by more than 30 percent, the TPS may be required, upon two (2) business days' notice from the Company, to initiate corrective action within the following five (5) day period. The Company proposes to change the numbers of days for a TPS to initiate corrective action from five (5) days to three (3) days to require the TPS to address the issue in a timelier manner.

RS, GSS, GSL, DGC Balancing, and NGV Residential (Sheet No. 91)

- Currently, for non-Force Majeure reasons, if the sum of the cumulative imbalances for a TPS' RS, GSS, GSL, DGC Balancing, and NGV Residential customers for the time period which the Company has not received payment are under-deliveries that exceed three (3) times the required Daily Delivery Volume, the Company will notify the TPS. Additionally, if such under-deliveries exceed five (5) times the required Daily Delivery Volume, the TPS will have four (4) business days to post and maintain additional cash deposit or letter of credit. The Company is proposing

changes to the time requirements in order to address the TPS' under-delivery issue in a timelier manner. Specifically, the Company proposes changing the amount of a TPS' cumulative under-delivery imbalance that warrants the Company to notify the TPS from exceed 3 times the required Daily Delivery Volume to be at least three (3) times the required Daily Delivery Volume and changing the amount of a TPS' cumulative under-delivery imbalance that requires the TPS to post and maintain a deposit or letter of credit from exceed five (5) times the required Daily Delivery Volume to be at least five (5) times the required Daily Delivery Volume.

Unauthorized Use Charge (Sheet No. 96)

- The Company proposes modifying the Unauthorized Use Charge description to clarify the determination of the charge and be consistent with the language for the Delivery Shortfall Charge (Sheet No. 96).

Nominations (Sheet No. 98)

- The Nominations section describes the information to be included in the TPS' nominations. The Company proposes to delete "the name of the supplier" from the description of the required information as it is not a required field in NJNG's Electronic Bulletin Board ("EBB").

Payment (Sheet No. 98)

- The Company proposes additional language in the Payment section to clarify that the Company may net all amounts due or owed by the TPS and the Company in the TPS bills.

V. RIDERS

Q. Please describe the Company's proposed modifications to the rider section of the Tariff.

A. The Company proposes the inclusion of a new Rider "C" to define the Societal Benefits Charge ("SBC") and its components. Additionally, the Company proposes to reorder its existing Riders so that the SBC-related Riders follow the new Rider C. Additional changes to Rider "H" (current Rider "D") Infrastructure Investment Program ("IIP") and Rider "I" Conservation Incentive Program ("CIP") are discussed below.

Q. Please describe the Company's proposed modifications to the IIP in the Tariff.

A. Rider "H" has been modified to include a description of the IIP Earning Test (Sheet No. 175).

Q. Please describe the Company's proposed modifications to the CIP in the Tariff.

A. Rider "I" has been modified to update the baseline use per customer for each class based on test year billing determinants, the margin factors based on the proposed base rates, and the large customer adjustment based on the GSL baseline use per customer (Sheet Nos. 177-178). Degree days and weather consumption factors for the calculation of the CIP weather component have also been updated (Sheet No. 179). Additionally, the return on equity test calculation description has been revised to be similar to the IIP Earnings Test (Sheet No. 180).

VI. BALANCING CHARGE

Q. Is the Company proposing a change to its Balancing Charge rate?

A. Yes. The Balancing Charge has two components: (1) carrying charges on inventory costs, and (2) pipeline demand charges. In accordance with the Board's Order, dated October 3, 2008, in BPU Docket No. GR07110889, the Balancing Charge related to inventory is to be updated in a base rate case and the pipeline demand charges component is to be updated in the Company's annual BGSS filings. Pursuant to the Board's Order, dated November 17, 2021 and issued in connection with the Company's last base rate case, BPU Docket Nos. GR21030679 and GR21030680, the Balancing Charge related to inventory was to remain fixed until new rates become effective in the Company's next base rate case, *i.e.*, this proceeding.

In Schedule TMT-4, I have updated the Company's pre-tax Balancing Charge related to inventory for test year inventory balances and the Company's proposed pre-tax rate of return of 9.83 percent (as included in Exhibit P-3, Schedule JMC-3). As shown on Schedule TMT-4, the Company's pre-tax Balancing Charge related to inventory for test year inventory balances is $0.0014 per therm, a $0.0005 per therm increase from the current pre-tax Balancing Charge related to inventory of $0.0009. During the course of this proceeding, the inventory component will be updated to reflect 12 months of actual balances and both the inventory and demand charge components will be updated to include the volumes from the Company's 2025 BGSS filing to be submitted by June 1, 2024 ("2025 BGSS filing"). The demand charge component of the Balancing Charge will also include updated demand charges from the 2025 BGSS filing.

VII. IMPACT ON CUSTOMERS

Q. What is the impact of the proposed rates to customer bills?

A. The impact of the rates proposed in Schedule DPY-3 and the Balancing Charge are included in Schedule TMT-5. The rates result in an overall increase of approximately 23.4 percent, or $34.85 per month, for a typical residential heating sales customer using 100 therms of natural gas per month. The overall impact to a residential non-heating sales customer using 25 therms of natural gas per month is an increase of approximately 26.5 percent, or $11.71 per month. The overall impact to a GSS sales customer using 100 therms of natural gas per month is an increase of approximately 26.8 percent, or $45.32 per month. The total bill for GSL sales customers will increase by approximately 16.3 percent, or $283.18 per month, for a customer using 1,200 therms of natural gas each month.

VIII. CONCLUSION

Q. Does this conclude your Direct Testimony at this time?

A. Yes, it does. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.

NJNG TARIFF - BPU NO. 12 - GAS

NEW JERSEY NATURAL GAS COMPANY

TARIFF

FOR GAS SERVICE

BPU No. 12 - Gas

APPLICABLE IN

All service areas of the Company
located in parts of
Middlesex, Monmouth, Ocean, Morris, Sussex and Burlington Counties

ISSUED BY: Mark G. Kahrer
Senior Vice President
Wall, New Jersey

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas ***Original Sheet No. 2***

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 4*

LIST OF COMMUNITIES SERVED

BURLINGTON COUNTY

Bass River Township
Washington Township

MIDDLESEX COUNTY

Old Bridge Township (*)
Sayreville (*)

MONMOUTH COUNTY

Aberdeen Township
Allenhurst Borough
Asbury Park, City of
Atlantic Highlands Borough
Avon-By-The-Sea Borough
Belmar Borough
Bradley Beach Borough
Brielle Borough
Colts Neck Township
Deal Borough
Eatontown Borough
Englishtown Borough
Fair Haven Borough
Farmingdale Borough
Freehold Borough
Freehold Township
Hazlet Township
Highlands Borough
Holmdel Township
Howell Township
Interlaken Borough
Keansburg Borough
Keyport Borough
Lake Como Borough
Little Silver Borough
Loch Arbour Village
Long Branch, City of
Manalapan Township
Manasquan Borough
Marlboro Township
Matawan Borough
Middletown Township
Monmouth Beach Borough
Neptune City Borough
Neptune Township
Oceanport Borough
Ocean Township
Red Bank Borough
Rumson Borough
Sea Bright Borough
Sea Girt Borough
Shrewsbury Borough
Shrewsbury Township
Spring Lake Borough
Spring Lake Heights Borough
Tinton Falls Borough
Union Beach Borough
Wall Township
West Long Branch Borough

MORRIS COUNTY

Boonton, Town of
Boonton Township
Denville Township
Dover, Town of
Jefferson Township
Kinnelon Borough
Lincoln Park Borough
Mine Hill Township
Montville Township
Mountain Lakes Borough
Mount Arlington Borough
Mount Olive Township (*)
Netcong Borough
Parsippany-Troy Hills Township (*)
Randolph Township
Rockaway Borough
Rockaway Township
Roxbury Township
Washington Township (*)
Wharton Borough
Victory Gardens Borough

OCEAN COUNTY

Barnegat Light Borough
Barnegat Township
Bay Head Borough
Beach Haven Borough
Beachwood Borough
Berkeley Township
Brick Township
Dover Township
Eagleswood Township
Harvey Cedars Borough
Island Heights Borough
Jackson Township
Lacey Township
Lakehurst Borough
Lakewood Township
Lavallette Borough
Little Egg Harbor Township
Long Beach Township
Manchester Township
Mantoloking Borough
Ocean Gate Borough
Ocean Township
Pine Beach Borough
Point Pleasant Borough
Point Pleasant Beach Borough
Seaside Heights Borough
Seaside Park Borough
Ship Bottom Borough
South Toms River Borough
Stafford Township
Surf City Borough
Toms River Township
Tuckerton Borough

SUSSEX COUNTY

Byram Township (*)
Hopatcong Borough
Stanhope Borough

(*) Partial Franchise

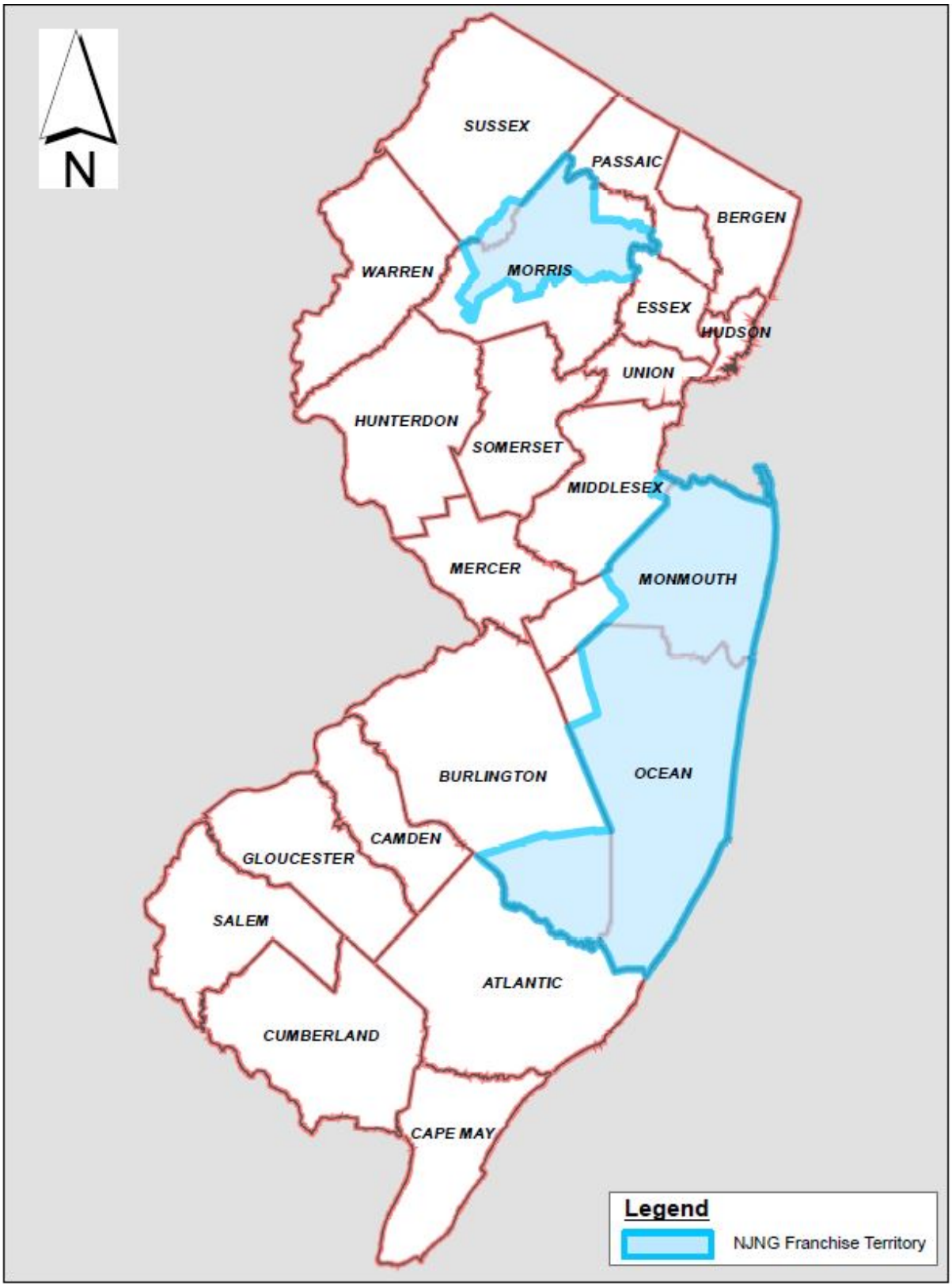
Date of Issue:
Issued by: *Mark G. Kahrer, Senior Vice President*
Wall, NJ 07719

Effective for service rendered on and after March 1, 2024

Filed pursuant to Order of the Board of Public Utilities entered in Docket No.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 5*



Date of Issue:
Issued by: *Mark G. Kahrer, Senior Vice President*
Wall, NJ 07719

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Filed pursuant to Order of the Board of Public Utilities entered in Docket No.

STANDARD TERMS AND CONDITIONS - INDEX

STANDARD TERMS AND CONDITIONS – INDEX (continued)

STANDARD TERMS AND CONDITIONS

DEFINITIONS

A. "*Board*" means the Board of Public Utilities of the state of New Jersey. Customers can contact the Board Division of Customer Assistance by calling 1-609-341-9188 or 1-800-624-0241 and at their website, www.nj.gov/bpu/.

B. "*Company*" means New Jersey Natural Gas Company, or any legal successor.

C. "*Customer*" means a person that is an end user, a customer of record, or both, as these terms are defined in this section.

D. *"Customer of record"* means the person that applies for utility service and is identified in the account records of a public utility as the person responsible for payment of the public utility bill. A customer may or may not be an end user, as defined herein.

E. *"End user"* means a person who receives, uses, or consumes gas service. An end user may or may not be a customer of record, as defined in this section.

F. "*Month*" is used for billing purposes to designate a period of 26 to 34 days.

G. "*Year*" is used to designate a period of twelve consecutive "months".

H. "*MCF*" is used to designate one thousand (1,000) cubic feet of gas.

I. "*BTU*" (British Thermal Unit) is used to designate the amount of heat required to raise the temperature of one (1) pound of water @ 60°Fahrenheit, 1° Fahrenheit.

J. "*Therm*" is used to designate a unit of heating value equivalent to 100,000 BTUs.

K. "*FERC*" means the Federal Energy Regulatory Commission.

L. "*Tampering*" means the unauthorized connecting, disconnecting, or causing to be connected or disconnected, or in any other manner interfering with the operation of the Company's meters, pipes, conduits, other equipment or attachments, or as otherwise provided by this Tariff (see Sections 6.6, 6.13, and 6.15).

M. *"Point of Delivery"* shall be that point where the Company delivers metered gas (outlet of Company gas meter) to the Customer's installation unless otherwise specified in the service agreement. The gas supplied by Company becomes the property of the Customer at the Point of Delivery.

STANDARD TERMS AND CONDITIONS

DEFINITIONS (continued)

N. *"Customer Equipment"* shall mean all appliances, piping, vents, connectors, valves, fittings or any other gas utilization or distribution equipment at or on the Customer's side of the Point of Delivery with the exception of Company owned facilities, e.g., Compressed Natural Gas ("CNG") re-fueling facilities. Customer Equipment also includes equipment leased by the Customer from third parties.

O. *"Gas Service"* shall mean the provision of gas service to customers. The gas provided shall be a service and shall not constitute goods for any purpose.

Main and Service Extension Related Terms

P. **"***Extension***"** means the construction or installation of plant and/or facilities by the Company to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. This term includes all plant and/or facilities for transmission and/or distribution, whether located overhead or underground, on a public street or right of way, or on a private property or private right of way, including the pipe, conduit or other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An extension begins at the existing infrastructure and ends at the meter, inclusive of the meter;

Q. **"***Distribution Revenue***"** means total annual revenue, inclusive of related Sales and Use Tax collected from a Customer, less the Basic Gas Supply Service and Balancing charges, inclusive of related Sales and Use Tax, assessed in accordance with the Tariff.

R. **"***Applicant***"** means a person that has applied to the appropriate regulated entity, as defined at N.J.A.C. 14:3-1 for construction of an extension, as defined at N.J.A.C. 14:3-8.2 and above.

S. **"***Cost***"** means, with respect to the cost of construction of an extension, actual and/or site-specific unitized expenses incurred for materials and labor (including both internal and external labor) employed in the actual design, construction, and/or installation of the extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the Company and shall include all costs inclusive of upgrades to existing infrastructure.

STANDARD TERMS & CONDITIONS

1. GENERAL

1.1 INTRODUCTION

These Standard Terms and Conditions, filed as part of the Tariff of New Jersey Natural Gas Company (referred to as "the Company" or "Company"), set forth the terms and conditions under which service is rendered and will be supplied. They govern all classes of service, to the extent applicable, and are made a part of all agreements for the supply of gas service, unless specifically modified by the terms of a particular service classification, or by special terms written in and made a part of a contract for service.

Failure by the Company to enforce any provisions, terms or conditions set forth in this Tariff shall not be deemed a waiver of such provisions, terms or conditions.

1.2 APPLICATION OF TARIFF

This Tariff applies to all persons, partnerships, corporations or others herein designated as Customers who are lawfully receiving gas service from the Company, under the prescribed service classification whether service is based upon contract, agreement, or accepted signed application. If any terms and conditions contained in this Tariff are in conflict with the New Jersey Administrative Code, the New Jersey Administrative Code shall prevail. The Tariff will not be construed to be in conflict with the New Jersey Administrative Code if the Tariff provides for a more liberal treatment of Customers than that provided for in the New Jersey Administrative Code.

1.3 FILING AND POSTING OF TARIFF

A copy of this Tariff is filed with the Board of Public Utilities (referred to as "the Board" or "Board"), of the state of New Jersey. Copies are posted and open for inspection at the offices of the Company and on the Company's website at https://www.njng.com/regulatory/tariff.aspx.

1.4 REVISION OF TARIFF

This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the rules of procedure determined by the Board.

1.5 STATEMENTS BY AGENTS

No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto, and the Company shall not be bound thereby.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE

2.1 APPLICATION FOR SERVICE

Application for gas service may be made in person at any customer service office of the Company, by mail, by telephone, by the Company's website at https://www.njng.com/, or by electronic mail, where available. The applicant shall state, at the time of making application for service, the conditions under which service will be required, and may be required to sign an agreement covering special circumstances for the supply of gas service. The applicant also may be required to supply proof of identification, in accordance with N.J.A.C. 14:3-3.2(e) and (h), as may be amended or superseded.

2.2 ACCOUNT OPENING CHARGE

The applicant shall be required to pay a $15.00 account opening charge each time service is turned on at a new or existing location. However, the Company may waive the account opening fee if a field visit is not required to establish service.

2.3 SERVICE INFORMATION FROM COMPANY

Upon receipt of application from the prospective Customer, the Company will advise the Customer of the type and character of gas service which will be furnished, the point at which service will be delivered and the location to be provided for the Company's metering and regulating equipment.

All customers shall be given a copy of the "Customer Bill of Rights" approved by the Board, effective at the time of service initiation. The copy shall be presented no later than at the time of the issuance of the customer's first bill or 30 days after the initiation of service, whichever is later.

2.4 FORM OF APPLICATION

Standard applications or agreements to supply gas service shall be in accordance with the particular service classification. The Company, in its sole discretion, reserves the right to require contributions toward the investment required for such service and to establish such minimum charges and facilities charges as may be appropriate.

Additionally, the Company may require a special service agreement and/or charge when: 1) large or special investment is necessary to supply service, 2) special facilities are required to serve a Customer, or 3) the hourly capacity of the Company's facilities, necessary to serve the Customer's demand, may be out of proportion with the monthly or annual use of gas service for occasional, intermittent, or low load factor purposes.

When a Customer signs a main and/or service extension agreement, and subsequently does not install any or all of the indicated equipment within a reasonable time, not to exceed six (6) months, or does not purchase the volumes of gas included in the service agreement, the Company reserves the right to charge the Customer for the full cost of providing the main and/or service.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE (continued)

2.5 SELECTION OF SERVICE CLASSIFICATION

Upon the request of a Customer, the Company will assist in the selection of the available rate most desirable to the Customer. Any advice given by the Company will be based on the Customer's oral or written statements as to the class of service desired and the manner in which it is intended to be used. However, by giving such advice, the Company assumes no responsibility related to the customer selection for class of service.

2.6 CHANGE OF SERVICE CLASSIFICATION

Within three months after service has begun, a Customer may request in writing to change the service classification or provision within a service classification under which they are billed. Subsequent to initial selection of a service classification, a Customer may request in writing a change to the service classification or provision within a service classification under which they are billed if their character or use of gas service has changed. Any change in schedule, if permitted, will be applicable to the next regular billing subsequent to such notification by the Customer.

2.7 DEPOSIT AND GUARANTEE

Before the Company renders service, a deposit or other guarantee satisfactory to the Company may be required as security for the payment of future and final bills from any new or existing Customer who has not established credit with the Company. A deposit also may be required from a Customer whose credit has become impaired. A new Customer, who provides the Company with a letter of reference from another utility or source acceptable to the Company, may have the deposit waived. The deposit shall be in accordance with the provisions set forth in N.J.A.C. 14:3-3.4, as may be amended or superseded.

If a Customer's service has been terminated for non-payment of bills, the Company may not condition restoration of service on payment of the deposit, unless the deposit has been included on prior bills, or notice has been provided to the Customer.

2.8 AMOUNT OF GUARANTEE DEPOSIT

The Company may require a deposit to guarantee payments of bills equivalent to the estimated gross bill for natural gas service for any single billing period plus an additional billing period.

2.9 INTEREST ON GUARANTEE DEPOSIT

The Company will credit simple interest at the applicable interest rate established annually by the Board on customer deposits provided such amount remains on deposit for not less than three (3) consecutive months.

Interest shall be payable annually and/or when the deposit is refunded or applied in accordance with N.J.A.C. 14:3-3.5, as may be amended or superseded.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE (continued)

2.10 RETURN OF GUARANTEE DEPOSIT

The Company shall review residential Customer accounts at least once every year and non-residential Customer accounts at least once every two years. If the review indicates that a Customer has established good credit, the Company will apply the deposit, plus any interest, to the outstanding balance on the Customer's account and will send a refund check to the Customer for any amount over and above the outstanding balance. Upon termination of service, the Customer will receive the balance of the deposit, plus interest, less any unpaid charges in accordance with N.J.A.C. 14:3-3.5, as may be amended or superseded.

2.11 PERMITS

The Customer shall obtain or cause to be obtained all legally-required permits and/or certificates necessary to give the Company or its representatives access to the Customer's equipment and to enable its mains to be connected with the Customer's equipment. If the Company makes application for any permits and/or certificates, the Customer will be required to pay the application fee/charge, if any. The Company shall not be obliged to furnish service unless and until such permits and/or certificates have been delivered to the Company.

When the Customer is not the owner of the premises or the owner of the property lying between the premises and the Company's mains, the Customer may be required to obtain from the proper owner(s) the necessary consent to install and maintain all necessary equipment to supply gas at the Customer's premises.

2.12 TEMPORARY SERVICE

Temporary service is available, for a limited period, to any Customer who can be served from the Company's existing lines or facilities, when and where the Company is permitted to provide such service. The Customer shall pay the total cost of connecting and disconnecting the gas service, including any piping, metering equipment, or other facilities that may be necessary. The Company may require an advance payment covering the estimated cost of construction or gas supplied, or both.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE (continued)

2.13 SERVICE TO FORMER CUSTOMERS

Service will not be supplied by the Company to former Customers until such time as any and all amounts or outstanding balances owed to the Company for previous service have been paid or otherwise discharged in accordance with N.J.A.C. 14:3-3A.9, as may be amended or superseded. Customers qualifying for Winter Termination Protection who have a prior outstanding balance due from their existing service location may have service restored upon the establishment of satisfactory payment arrangements. The Company may refuse to initiate service, or may discontinue service after proper notice and in accordance with N.J.A.C. 14:3-3A.2, as may be amended or superseded, to a residential applicant, or a member of the household then indebted to the Company for services provided by the Company at any location, if the Company reasonably determines that substantially the same household occupies the premises to be or being served. The Company may refuse to initiate service or may discontinue service after proper notice and in accordance with N.J.A.C. 14:3-3A.2, as may be amended or superseded, to a commercial applicant, or an officer, director, general or limited partner, business associate, or other agent, of an entity then indebted to the Company for services provided by the Company at any location, if the Company has reason to believe that substantially the same entity occupies the premises to be or being served.

STANDARD TERMS & CONDITIONS

3. CHARACTERISTICS OF SERVICE

3.1 GENERAL

Gas service supplied by the Company in the entire territory served shall be straight natural gas, or any mixture of straight natural gas and substitute gas. The volume of gas to be delivered shall be measured in accordance with the published recommendation of the American Gas Association, as amended or superseded from time to time.

The basic unit of volume or one standard cubic foot shall be one cubic foot of gas at a temperature of 60° Fahrenheit (F) and an absolute pressure of 14.73 pounds per square inch. The average atmospheric pressure shall be assumed to be 14.73 pounds per square inch irrespective of variations in atmospheric pressure from time to time. The volume of gas measured, other than at the standard temperature and/or pressure shall be adjusted in accordance with Boyle's Law for measuring gas at varying pressures and the Charles Law for measuring gas at varying temperatures.

3.2 SINGLE POINT OF DELIVERY

The Company will furnish, install and maintain a single meter for each service classification under which a Customer receives service unless, in the sole and final judgment of the Company, the volume of the Customer's requirements, economic considerations, conditions on its distribution system, or other reasons make it desirable to install additional meters.

3.3 CONTINUITY OF SERVICE

The Company will use reasonable diligence to provide a regular and uninterrupted supply of service, but should the supply be suspended, curtailed or discontinued by the Company for any of the reasons set forth in Section 9 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective or fail by reason of any Act of God, accident, strike, legal process, governmental interference, or other cause whatsoever beyond its control, the Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, defect, interruption, curtailment, deficiency or failure.

3.4 UNUSUAL CONDITIONS

The Company reserves the right to place limitations on the amount and character of gas service it will supply; to refuse service to new Customers or existing Customers for additional load if unable to obtain sufficient supply for such service; to reject applications for service or additional service where such service is not available, or where such service might affect the supply of gas to other Customers; or for other good and sufficient reasons subject to the orders or rules of the Board.

STANDARD TERMS & CONDITIONS

4. GAS DISTRIBUTION MAIN AND SERVICE EXTENSIONS

4.1 GENERAL PROVISIONS

The Company will construct, own, and maintain gas mains located on streets and highways and on rights-of-way acquired by the Company. The formulae for the extension of utility service set forth below shall not serve to prevent the parties hereto from exercising their rights under the N.J.S.A. 48:2-27 and the applicable New Jersey Administrative Code provisions.

Where it is necessary to provide additional facilities to serve the requirements of either existing customers or new applicants, the Company may require a deposit or a contribution in aid of construction according to the conditions specified below. The Company, in its sole discretion, will determine the appropriate amount of such deposit or contribution in aid of construction. The Extension cost for which the Company receives a deposit or a non-refundable contribution shall include the tax consequences incurred by the Company.

4.2 RESIDENTIAL AND FIRM COMMERCIAL CUSTOMER - MAIN EXTENSION AND SERVICE LINE CONNECTION

The Company will install facilities and make gas main extensions and service line connections to serve individual permanent residential customers and firm commercial customers without alternate fuel capacity and taking service under service classifications included in Rider "I" Conservation Incentive Program (CIP) free of charge where the Extension Cost does not exceed ten (10) times the annual distribution revenue at the baseline usage per customer volume for the Customer's respective CIP group and subject to the terms described in Paragraph 5.2. For residential customers, the Extension Cost shall not include the cost of the meter.

An applicant shall be required to provide an Extension Cost Deposit or a non-refundable contribution in aid of construction for the value of any Extension Cost that is greater than ten (10) times the annual distribution revenue at the baseline usage per customer volume for the Customer's respective CIP group. If the Company accepts an application for an extension of a residential customer, the Company may furnish and place, at no cost to the Customer, up to 200 feet of normal residential facilities. The Company shall waive a required deposit of $3,000 or less.

For customers taking service under firm service classifications not included in Rider "I" CIP, the Company will install facilities and make gas main extensions and service line connections to serve individual customers without alternate fuel capacity free of charge where the Extension Cost does not exceed ten (10) times the estimated annual distribution revenue, unless otherwise specified in the service classification. An applicant shall be required to provide an Extension Cost Deposit or a non-refundable contribution in aid of construction for the value of any Extension Cost that is greater than ten (10) times the estimated annual distribution revenue and subject to the terms described in Paragraph 5.2; however, the Company shall waive a required deposit of $3,000 or less.

STANDARD TERMS & CONDITIONS

4. GAS DISTRIBUTION MAIN AND SERVICE EXTENSIONS (continued)

The Extension Cost Deposit, as defined above, shall remain, without interest, in the possession of the Company unless additional customers connect to the particular extension. At such time there will be refunded to the depositor, the annual baseline distribution revenue value for the additional connecting Customer based upon the ratio in effect when the deposit was made. Once a portion of the deposit has been refunded to the applicant, the calculation shall only be reviewed for subsequent additional customers connecting to the particular extension. No further calculation shall be performed when accumulated refunds are equal to the sum deposited and in no event shall refunds exceed the initial deposit.

All deposits not returned to the applicant within a period of ten (10) years after the Company first makes gas service available shall remain the property of the Company with no further obligation of refund. The Company and applicant may agree upon a satisfactory revenue guarantee in lieu of a deposit or contribution.

Where it is necessary to provide additional facilities to serve increased requirements of an existing Customer, the Company reserves the right to require the Customer to provide a non-refundable contribution in aid of construction or a deposit in an amount equal to the cost of such additional facilities. The deposit amount may be subject to refund as outlined earlier in this section except that refunds shall be a function of the incremental distribution revenue generated by the increased requirements over a predetermined base.

STANDARD TERMS & CONDITIONS

4. GAS DISTRIBUTION MAIN AND SERVICE EXTENSIONS (continued)

4.3 LAND DEVELOPMENT - MAIN EXTENSION AND SERVICE LINE CONNECTIONS

Where applications for extensions into newly developed tracts of land are made by individuals, partnerships, or corporations interested in the development and sale of land but not as ultimate residents, the Company shall require a deposit from the applicant covering the entire cost of installing the necessary mains, services and common distribution facilities to serve the tracts. However, if an individual, partnership, or corporation has contracted sales to ultimate residents, the Company may waive a required deposit for the value of any Extension Cost that is less than or equal to ten (10) times the annual distribution revenue at the baseline usage per customer volume for the ultimate residents' respective CIP group.

Such deposits are to be returned to the depositor, without interest, if during a ten-year period from the date of the original deposit, when and as new services abutting on such mains are completed, the prospective Customer's gas equipment is installed, and the dwellings are occupied by bona-fide owners or responsible tenants who have entered into an agreement for use of gas service. Upon such completion and occupation, there shall be returned to the depositor an amount equal to the product of residential customer ratio in effect in Paragraph 4.2 when the deposit was made and the annual baseline distribution revenue for each of the dwellings as described above but not in excess of the amount deposited. In no event shall more than the original deposit be returned to the depositor. All deposits not returned to the applicant within a period of ten (10) years after the Company first made gas service available to the tract of land shall remain the property of the Company with no further obligation of refund. The Company may agree upon a satisfactory revenue guarantee in lieu of a deposit or contribution.

4.4 ALTERNATE FUEL CUSTOMER - MAIN EXTENSION

The Company reserves the right to require any alternate fuel customer to make a non-refundable contribution in aid of construction of an amount equal to the entire cost of the new facilities required to provide service. Where it is necessary to provide additional facilities to serve the increased requirements of any existing Customer, the Company reserves the right to require the Customer to provide a non-refundable contribution in aid of construction in an amount equal to the cost of such additional facilities and shall include the tax consequences incurred by the Company.

The Company is under no obligation to refund any of the contribution but the Company reserves the right in its sole judgment to do so where economics and revenue conditions warrant said action. In lieu of a contribution, the Company may agree upon a satisfactory revenue guarantee.

STANDARD TERMS & CONDITIONS

5. SERVICE LINE CONNECTIONS

5.1 GENERAL PROVISIONS

Gas service will normally be supplied to each premise through a single service line, except where, in the judgment of the Company, it is deemed desirable to install more than one service line. The Company may also choose to install multiple meters on one service line providing service to several premises. If more than one service line is installed for the convenience of the Customer, each location will be considered as a separate Customer.

5.2 FIRM CUSTOMERS

The Company shall furnish and place, a service line in accordance with the terms described in Paragraph 4.2 above, measured at right angles from the nearest curb line to Customer's building, at the point of service entrance designated by the Company. Should the Customer request a service entrance at a location other than that designated by the Company, the Customer shall pay any additional cost associated with said change in point of service entrance and shall include the tax consequences incurred by the Company.

5.3 ALTERNATE FUEL CUSTOMERS

The Company shall provide a service line connection at the Customer's expense.

5.4 CHANGE IN EXISTING INSTALLATIONS

Any change in the existing service line, which may include installation of an Excess Flow Valve, and/or metering facilities requested by the Customer and approved by the Company shall be made at the Customer's expense and shall include the tax consequences incurred by the Company. If the change in the service line or metering facilities is to serve increased usage requirements, deposits or contributions in aid of construction shall be administered in accordance with Section 4 of these Standard Terms and Conditions.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT

6.1 GENERAL

A suitable meter or meters will be installed, owned and maintained by the Company for the purpose of measuring the quantity of gas service delivered to the Customer. The type and make of metering equipment will be in accordance with the Company's specification which, from time to time, may be changed or altered. It is the sole obligation of the Company to furnish meters that provide adequate and accurate records for billing purposes in accordance with N.J.A.C. 14:3-4.1, as may be amended or superseded.
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6.2 METER LOCATION

The Customer shall provide on the premises, at a location satisfactory to the Company, proper space for metering and associated equipment. The meter location shall be kept free and clear of obstructions so that properly authorized representatives of the Company may gain easy access to the meter location for the purpose of operating valves, reading meters, or emergencies in accordance with N.J.A.C. 14:3-4.2, as may be amended or superseded.
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6.3 CHANGE OF METER LOCATION

Any change requested by the Customer in the point of location of the meter or service facilities, if approved by the Company, shall be made at the expense of the Customer and shall include the tax consequences incurred by the Company.

6.4 CUSTOMER'S RESPONSIBILITY

The Customer shall be responsible for the protection and safekeeping of the equipment and facilities of the Company while it is on the Customer's premises. The Customer shall permit access to the Company's equipment to duly authorized representatives of the Company or duly authorized governmental officials.

6.5 ACCESS TO CUSTOMER'S PREMISES

Properly identified and authorized representatives of the Company shall have free access to the Customer's premises at all reasonable times for the purpose of reading meters, for inspection and repairs, for investigation of emergencies or hazardous conditions, for removal of the Company's property or for any other purposes incident to the supply of gas service, in accordance with N.J.A.C. 14:3-3.6, as may be amended or superseded. The Customer is requested to contact the Company immediately if a question arises regarding the authority or credentials of any person claiming to represent the Company.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.6 AUTHORIZATION TO TURN ON GAS

No person other than a duly authorized employee or representative of the Company shall turn gas service on or into any new system of piping or into any old system of piping from which the use of gas has been discontinued. Disconnections, reconnections, or meter removals performed by persons other than authorized Company personnel are prohibited and shall constitute Tampering.

6.7 UNAUTHORIZED USE

The use of service in excess of 30 days without the Company's express authorization may be terminated by the Company without notice. The use of natural gas service, without notice to the Company, shall render the user liable for any amount reasonably determined by the Company to be due for gas service supplied to the premises since the last meter reading recorded and billed by the Company.

6.8 OWNERSHIP AND REMOVAL

All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove its equipment from the premises of the Customer at any time after termination of service.

6.9 PAYMENT FOR REPAIRS OR LOSS

The Customer shall pay the Company for any necessary repairs for damage to or any loss of the Company's property located on the Customer's premises, and for the reconnection of service interrupted by such damage or loss, when the damage or loss is caused by negligence or willful misconduct on the part of Customer, or the Customer's family members, employees or agents, or by the failure of the Customer or foregoing persons to comply with the Standard Terms and Conditions and applicable service classifications under which service is furnished. The reconnection charge shall be $45.00 per Customer interruption. This charge will be waived when the appropriate Company personnel are on site at the time of the repair and able to reconnect the Customer safely.

6.10 REMOTE METER READING EQUIPMENT

The Company, in its sole discretion and as a condition of service, may install at the Company's expense a remote meter reading device, e.g., an Automated Meter Reading (AMR) device, to monitor a Customer's gas consumption. When such device requires attachment to services including, but not limited to, telephone utilities, electric utilities, or a data plan, the Customer shall provide suitable connections.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company. The Customer may reimburse the Company for the remote meter reading device expense, either in a lump sum payment or over a twelve-month period with the prime interest rate used to calculate carrying costs. All equipment remains the sole property of the Company.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.11 SUB-METERING

Sub-metering, the practice in which the customer of record buys gas from the company and resells it through some metering device to tenants at a profit, is not permitted in any form. Gas service supplied by the Company shall not be resold by the Customer to others except where the Customer is another publicly regulated gas utility company, or where the natural gas is used for conversion to compressed natural gas, or when check-metering as defined below is being used by the Customer.

6.12 CHECK-METERING

Check-metering is defined as the practice in which a Customer, through the use of a gas check meter, monitors or evaluates his own consumption or the consumption of a tenant for accountability or conservation purposes.

Gas check meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a utility-owned meter. Gas check meters provide the Customer the means to apportion among the end users the cost of gas service being supplied through the Company meter.

Check-metering is permitted in new or existing buildings or premises where the basic characteristic of service is industrial or commercial. Check-metering is not permitted in new or existing buildings or premises where the basic characteristic of service is residential, except for condominiums or cooperative housing, or where such buildings or premises are publicly financed or government owned or are charitable in nature, or where the gas use is restricted to cooking gas. Check-metering is not permitted for space heating in residential premises subject to the exceptions set forth above.

If the Customer charges the tenant for usage incurred by the tenant, reasonable administrative expenses may be included, but such charges shall not exceed the amount the Company would charge if the tenant was served and billed directly by the Company.

Prior to the installation of any gas check metering devices, the Customer is required to contact the Company in order to ascertain whether the affected premises are located within a utilization pressure area of the Company's distribution system and whether or not the installation of a check metering device will cause any significant pressure drop within the affected premises.

All gas-consuming devices in any tenant unit must be metered through a single gas check-meter.

The ownership of all check-metering devices is that of the Customer, along with all incidents in connection with said ownership, including accuracy of the meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of check-metering devices shall be borne by the Customer.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.13 TAMPERING & OTHER DECEPTIVE PRACTICES

When it is established that Tampering has occurred and the Customer has caused or knowingly benefited from such Tampering, the Customer shall be required to bear all of the costs incurred by the Company including, but not limited to, the following: (a) investigations, (b) inspections, (c) costs related to administrative, civil or criminal proceedings, (d) attorneys' fees, (e) installation of any protective equipment deemed necessary by the Company, and (f) actual costs of damage to equipment.

Furthermore, when Tampering with Company facilities results in incorrect measurement, correctly measured service used without Company authorization or the omission of measurement of the service supplied, and the Customer has benefited from such Tampering, the Customer shall pay for such service as the Company may estimate from available information, to have been used on the premises.

If persons other than the Customer are identified as beneficiaries of service obtained at the Customer's premises by Tampering, or have created or contributed to the Tampering, the Company shall elect to hold such persons liable for all of the aforesaid costs incurred and the value of service (metered or unmetered) received. A "beneficiary" is any person who benefits from such Tampering.

The foregoing remedies against the Customer and other beneficiaries arising from Tampering shall also apply to gas service obtained by fraudulent means, imposture, theft of identity, impersonation, theft of service, theft by deception or other unlawful methods.

6.14 DIVERSION OF SERVICE

Diversion is an unauthorized connection to pipes by which the gas service registers on the Customer's meter, even if such service is being used by other than the Customer of record without his or her knowledge or cooperation. When a Customer alleges, or it is established, that service has been diverted outside of the Customer's premises, the Customer shall not be required to pay for such service without his or her consent. The definitions, procedures, investigations and determination of N.J.A.C. 14:3-7.8, as may be amended or superseded, shall apply.

6.15 SEALING OF METERS AND LOCKING DEVICES

For safety purposes, it is the practice of the Company to seal meters and regulators, and to install locking devices when needed. Removal of seals or locking devices by persons other than authorized Company personnel is prohibited and shall constitute Tampering.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.16 INABILITY TO ACCESS CUSTOMER LOCATION

If a Customer has requested that the Company perform work related to the installation of a meter set on Customer property and the Company is unable to complete that work due to the Customer not being available at the scheduled time or the required work not being completed by the Customer and/or contractor, the Customer shall be charged $45.00.

STANDARD TERMS AND CONDITIONS

7. CUSTOMER'S INSTALLATION

7.1 INSTALLATION RULES

Customer's appliances, piping, and installation shall be made and maintained in accordance with the standards of the Fuel Gas Subcode of the Uniform Construction Code set forth in N.J.A.C. 5:23-3.22 as may be amended or superseded and such other regulations as may be determined from time to time by any governmental agency having jurisdiction over the Customer's installations.

7.2 ADEQUACY AND SAFETY OF INSTALLATION

The Company shall not be required to supply gas service until the Customer's installation has been approved by the authorities with jurisdiction. The Company also reserves the right to withhold its service, or to discontinue its service, whenever such installation or part thereof is deemed by the Company to be unsafe, inadequate, or unsuitable for receiving service, or interferes with or impairs the continuity or quality of service to the Customer or to others.

7.3 FINAL CONNECTION

In all cases, no final connection between the Company's equipment and the Customer's installation shall be made without final inspection from the Department of Community Affairs or its designee.

7.4 CHANGE IN CUSTOMER'S INSTALLATION

The Customer shall give immediate notice to the Company of any: 1) proposed additions in connected appliances or equipment, 2) change in demand or other conditions of use, or 3) change of purpose or location of the installation. Changes in service conditions shall not be made effective until the Customer notifies the Company and receives the Company's approval of same. Failure to give notice of additions or changes in load or location shall render Customer liable for any damages to the meters or other apparatus and equipment of the Company caused by the additional or changed installation.

7.5 COMPANY'S LIABILITY

The Company shall not be liable for any claim for damages resulting from the supply, use, care or handling of the gas or from the presence or operation of the Company’s structures, equipment, pipes, or devices, except for general or direct damages that follow from the Company's negligence, recklessness, or willful misconduct. The Company shall not be liable for special or consequential damages.

STANDARD TERMS AND CONDITIONS

7. CUSTOMER'S INSTALLATION (continued)

All Customer Equipment shall be suitable for the use of natural gas and shall be installed, inspected, repaired and maintained solely by the Customer and solely at the Customer's expense in a manner approved by the public authorities having jurisdiction over the same, and in good and safe condition in accordance with all applicable codes. The Customer shall be solely responsible for the selection of the Customer Equipment and the Company shall have no duty or responsibility for the design, selection, installation, operation or repair of said Equipment. The Customer shall be responsible for the design of the venting and piping associated with the Customer Equipment downstream of the Point of Delivery. The Company does not, by inspection, non-rejection or any other way, give any warranty, express or implied, as to the adequacy, safety or other characteristics of the Customer Equipment. The Company shall not be liable for damages to the Customer Equipment or for injuries sustained by the Customer or others, due to the condition or character of the Customer Equipment. The Company shall not be responsible for the use, care or handling of the gas delivered to the Customer after it passes beyond the point at which the Company's service facilities connect to the Customer Equipment.

The Company may, but need not, conduct a limited inspection of the appliances, venting system and leak integrity of the Customer's piping and venting downstream of the Point of Delivery as a courtesy to the Customer at the time of the initiation of service or thereafter at the request of the Customer. In no event, however, shall the Company have any duty to inspect Customer Equipment or be responsible for any failure of the Customer Equipment or any harm arising from the operation of the Customer Equipment, even if, the Company undertakes, as a courtesy to the Customer, to conduct a limited inspection at the time of initiation of service or otherwise. The Customer shall, at all times, be solely responsible for the inspection, integrity and safety of all Customer Equipment.

7.6 BACK PRESSURE AND SUCTION

When the nature of the Customer's gas equipment is such that it may cause back pressure or suction in the piping system, meters, or other associated equipment of the Company, suitable protective devices subject to approval by the Company, shall be furnished, installed, and maintained by the Customer.

When the Customer uses an alternate fuel that is gas, a three-way valve (a check valve is not permissible) is required to be installed at the Customer's expense subject to the Company's approval.

7.7 LEAKAGE

The Customer shall give notice immediately of any escape of gas on or about the premises to the Company.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING

8.1 EVIDENCE OF CONSUMPTION

The quantities of service delivered to the Customer as recorded by the Company's meter or meters, subject to any necessary adjustments for pressure and temperature in accordance with Section 3.1 of this Tariff, shall be final and conclusive except when the metering equipment fails to register or is determined to be in error.

8.2 MONTHLY METER READING

The Company shall read meters on a monthly schedule. Nothing in this section shall be deemed to limit the applicability of Section 8.3 below.

8.3 ESTIMATED USAGE

Where the Company is unable to read the meter, the Company may estimate the amount of gas supplied and submit an estimated bill. An adjustment of the Customer's estimated use to actual use will be made after an actual meter reading is obtained in accordance with N.J.A.C. 14:3-7.2(e), as may be amended or superseded.

8.4 ADJUSTMENT FOR INACCURATE METER RECORDING

When it is determined that the Company's meter is inaccurate or defective, the use of gas service shall be determined by a test of the meter, or by registration of the meter set in its place during the period next following, or after due consideration of previous or subsequent properly measured deliveries. Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2% due to progressive inaccuracy, an adjustment of charges may be made except for residential accounts, where no adjustment shall be made. An adjustment may be made on any account with a meter that is determined by a Company test of the meter to be defective or non-registering. A defective or non-registering meter is any meter not properly functioning due to a physical inability to meet original manufacturing standards. Any adjustment to the Customer's account resulting from the terms in this section will be billed or applied to the account in accordance with N.J.A.C. 14:3-4.6, as may be amended or superseded. If the adjustment results in a credit, such amount may be refunded upon request from the Customer. If the Customer does not request a refund, a bill credit will be applied to the Customer's account.

If a meter is found to be registering less than 100% of the service provided, the Company shall only adjust the charges retrospectively and/or require the Customer to repay the amount undercharged if: 1) the meter was tampered with; 2) the meter failed to register at all; or 3) the circumstances are such that the Customer should reasonably have known that the bill did not reflect the actual usage. In rebilling a Customer under this Section, the Company may perform a load analysis or degree day analysis.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING (continued)

8.5 THERM CONVERSION FACTOR

For billing purposes, the reading of the Customer's meter in cubic feet first will be converted to standard cubic feet, then converted to therms by multiplying the use in cubic feet by the weighted average of the BTU content of all gas purchased from all pipeline suppliers for the second preceding calendar month and divided by 100,000. Such calculation shall be to the closest 1/100 of a therm.

8.6 BILLING PERIOD

When the billing interval is substantially greater or less than one month, bills will be computed by prorating charges provided under the applicable Service Classification on the basis of the relationship between the time covered by the billing period and a full month.

8.7 EQUAL PAYMENT PLAN

The Company will provide to customers, on request, an equal payment plan in accordance with N.J.A.C. 14:3-7.5. Adjustments will be made annually if actual charges are more or less than the equal payment plan amounts billed. Further, there shall be at least one comparison of actual charges to the monthly equal payment plan amount, and if this comparison reveals an increase or decrease of 25 percent or more of the monthly equal payment plan amount, the monthly equal payment plan amount will be adjusted for the balance of the equal payment plan year.

8.8 PAYMENT OF BILLS

Bills normally will be rendered monthly and may be paid through the Company's authorized payment methods including, but not limited to, at any business office of the Company during its regular office hours, at any of its authorized payment locations during regular office hours of such agencies, on the Company's website at www.njng.com, authorized electronic payment remitters, auto-debit enrollment, by phone {1-800-221-0051}, or by mail.

8.9 PAYMENT OBLIGATION

Unless otherwise specified all bills are net and payable within at least twenty (20) days from the date the bill is sent. Failure to make payment may be deemed sufficient reason for the Company to consider the Customer's account delinquent. The Company may discontinue service for nonpayment of bills provided it gives the Customer at least ten days written notice of its intention to discontinue. The notice of discontinuance shall not be served until the expiration of the said 20 day period. However, in cases of fraud, illegal use, or when it is clearly indicated that the Customer is preparing to leave, immediate payment of account may be required.

The Company shall apply the regulations set forth in N.J.A.C. 14:3-3A.2, as may be amended or superseded, and shall discontinue service for nonpayment only if one or both of the following criteria are met: 1) the Customer's arrearage is more than $200.00; 2) the Customer's account is more than three months in arrears.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING (continued)

8.10 LATE PAYMENT CHARGE

A late payment charge at the rate of 1.5% per monthly billing period shall be applied to all non-residential customers. The charge will be applied to all amounts previously billed including late payment charges and accounts payable that are not paid at the time the next monthly bill is prepared and shall not be applied sooner than twenty-five (25) days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). Service to governmental entities will not be subject to a late payment charge. The amount of the late payment charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late charge rate. When payment is received by the Company from a Customer who has an unpaid balance which includes charges for late payment, the Customer's payment shall be applied first to such late payment charges and then to the remainder of the unpaid balance.

8.11 FINAL BILL

A Customer intending to discontinue service must give the Company reasonable notice thereof. Within forty-eight (48) hours of said notice, the Company shall discontinue service or obtain a meter reading for the purpose of calculating a final bill, unless a holiday or weekend intervenes. Where such notice is not received by the utility, the Customer shall be liable for service until the final reading of the meter is taken. Notice to discontinue service will not relieve a Customer from any minimum or guaranteed payment under any contract or Service Classification.

8.12 RETURNED PAYMENT FEE

The Company will charge $10.00 to process Customer payments that are uncollectible and returned by the Company's bank.

8.13 FIELD COLLECTION CHARGE

A charge of $15.00 may be made when the Company makes a collection visit to the Customer or premises.

STANDARD TERMS & CONDITIONS

9. DISCONTINUANCE OF SERVICE

9.1 COMPANY CAUSES

The Company shall, upon reasonable notice, when it reasonably can be given, have the right to suspend, curtail, or discontinue its service for any of the following reasons:

a. For the purpose of making repairs, changes, replacements, or improvements in any part of its system.

b. For compliance in good faith with any governmental order or directive, whether Federal, State, Municipal, or otherwise, even if such order or directive subsequently is held to be invalid.

c. In the event of an emergency threatening the integrity of its system if, in the Company's sole judgment, such action will prevent or lessen the emergency condition.

9.2 CUSTOMER ACTS OR OMISSIONS

The Company also shall have the right to suspend, curtail or discontinue its service for any of the following act(s) or omission(s) on the Customer's part:

a. Nonpayment of any bill due for service furnished at the present or any previous location, in accordance with N.J.A.C. 14:3-3A.2, as may be amended or superseded. However, nonpayment for business service shall not be a reason for discontinuance of residential service, except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8, as may be amended or superseded and service shall not be discontinued for nonpayment of appliance repair, installation charges, service contracts, and other services unrelated to gas service.

b. Tampering with any facility of the Company.

c. Fraudulent representation in relation to the use of gas service.

d. Customer moving from the premises unless that Customer requests that service be continued.

e. Delivering gas service to others without written approval of the Company except as permitted under Standard Terms and Conditions Sections 6.11 and 6.12 Sub-Metering and Check-Metering.

f. Failure to make or increase an advance payment or deposit when required by the Company.

g. Refusal to contract for service where a contract is required.

h. Connecting and operating equipment in such a manner as to produce disturbing effects on the service of the Company or other Customers.

STANDARD TERMS & CONDITIONS

9. DISCONTINUANCE OF SERVICE (continued)

i. Where the conditions of the Customer's installation presents a hazard to life or property.

j. Failure of the Customer to repair any faulty equipment or lines.

k. Failure to comply with any of these Standard Terms and Conditions or with any of the terms of the service classification or contract under which gas service is furnished.

l. Failure to provide reasonable access to the premises, and to the Company's meter and other service facilities on the premises, for the purposes of meter installation, reading, testing, inspection, maintenance, removal, or replacement of meters or other service facilities.

Reasonable access means that premises shall not become obstructed or hazardous, and that the Customer shall not construct, pave over, or otherwise obstruct the Company's service line or other facilities. In the event reasonable access, as described here, is not complied with, the Company may, upon reasonable notice, discontinue service and remove its equipment from the Customer's premises.

Any costs of protecting or relocating such service line or facilities shall be borne by the Customer.

m. In the event a writ of execution is issued against a Customer, or in case the premises to which service is supplied is levied upon, or in the case of assignment or act of bankruptcy on the part of the Customer.

n. Service to a residential customer shall only be discontinued between the hours of 8:00 a.m. and 4:00 p.m. Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Fridays, Saturdays, and Sundays or on the day before a holiday or on a holiday, absent such emergency.

9.3 CHARGES PAYABLE UPON TERMINATION

If gas service is terminated for any of the above reasons where the Customer is under written contract, the minimum charge for the unexpired portion of the term shall become due and payable immediately, provided, however, that if satisfactory arrangements are subsequently made by Customer for reconnection of the service, the immediate payment of the minimum charge for the unexpired portion of the contract term may be waived or modified as the circumstances indicate would be just and reasonable.

9.4 NON-WAIVER

Failure of the Company to exercise its rights to suspend, curtail or discontinue service, for any of the above reasons, shall not be deemed a waiver of the Company's rights.

STANDARD TERMS & CONDITIONS

9. DISCONTINUANCE OF SERVICE (continued)

9.5 RESTORATION OF SERVICE

The Company shall not reconnect service to the Customer's premises, where service has been discontinued by reason of any act or default of the Customer, until such time as the Customer has rectified the condition or conditions causing discontinuance of service. Service shall not be reconnected until the Customer has met all financial requirements including satisfactory payment arrangements called for under these Standard Terms and Conditions and the applicable Service Classification, or if the Board so directs when a complaint involving such a matter is pending before the Board in accordance with N.J.A.C. 14:3-3A.9, as may be amended or superseded.

The Company shall treat the restoration of service and the turn-on of new accounts on a first come, first serve basis during periods outside of the winter moratorium. The Company shall give priority to the restoration of service during the winter moratorium.

9.6 RECONNECTION CHARGE

The Customer shall pay a reconnection charge of $45.00 for the restoration of service when service has been suspended for any of the reasons cited in Section 9.2, with the exception of 9.2.d, of these Standard Terms and Conditions.

STANDARD TERMS & CONDITIONS

10. FOR CUSTOMERS PURCHASING GAS SUPPLY FROM A THIRD PARTY SUPPLIER

10.1 CONDITIONS PRECEDENT

The Customer shall designate a Third Party Supplier, formerly referred to as Marketer or Broker, who will act as the Customer's agent with the Company for purposes of receiving nominations, satisfying delivery obligations, daily and monthly balancing, selection of billing option and all related charges. The Third Party Supplier must be authorized by the Company and is subject to the service requirements of the Third Party Supplier Requirements ("TPS") Service Classification. The Customer is responsible for payment of any costs if additional facilities are necessary to provide service. The Company reserves the right to limit new customers served under this service, if it determines that service expansion is detrimental to existing firm customers.

10.2 RETURN TO FIRM SALES SERVICE

Customers shall be permitted to return to firm sales service in accordance with N.J.A.C. 14:4-2.6(f), as may be amended or suspended. Transport customers who terminate such service and who wish to return to firm sales service, will be viewed as new applicants for such firm sales service. Such service will be offered subject to the conditions contained in Section 3.4 of the Company's Standard Terms and Conditions in its Tariff.

10.3 WARRANTY

NJNG warrants that at the time of delivery to the Customer at the Delivery Point said gas quantities shall be free and clear of all liens, encumbrances and claims whatsoever which may result solely from NJNG's possession or transportation of gas hereunder and, further, that it will indemnify and hold the Customer harmless from all suits, actions, debts, accounts, damages, costs, losses, and expense arising from or out of adverse claims of any or all persons to said gas quantities, arising out of, relating to or resulting from such possession or transportation.

10.4 CONTRACT

Written application on Company's Standard Application Form may be required.

STANDARD TERMS & CONDITIONS

10. FOR CUSTOMERS PURCHASING GAS SUPPLY FROM A THIRD PARTY SUPPLIER (continued)

10.5 REGULATORY APPROVALS

The Customer is responsible for securing approvals from all regulatory bodies having jurisdiction and making any filings or reports, as required, pertaining to the acquisition of the gas and/or the transportation of the gas from the Customer's source to the Company's designated delivery meters.

The Company reserves the right, in its sole reasonable judgment, to deny service hereunder if it determines that the underlying contracts or transportation agreements do not comply with all applicable Federal or State laws, rules or regulations, including those of all appropriate regulatory agencies; or if it determines that the requested transportation service is not operationally feasible.

10.6 CHANGE OF THIRD PARTY SUPPLIER

Customers shall be permitted to switch suppliers in accordance with N.J.A.C. 14:4-2.6(f), as may be amended or superseded.

STANDARD TERMS & CONDITIONS

11. CONDITIONS UNDER WHICH RATE DISCOUNTS SHALL BE CONSIDERED

11.1 CUSTOMERS WITH ABILITY TO BYPASS

A Customer requesting a discount from NJNG's Tariff Rate for Gas Service due to the Customer's asserted ability to physically bypass the Company's distribution and/or transmission system facilities shall provide the following information to the Company:

a. A statement from the interstate natural gas pipeline that the proposed interconnection is operationally viable, that sufficient capacity is available and the pipeline would serve the party if requested;

b. Maps or flow diagrams for the bypass connection, which shall identify the route of the pipeline from the interconnection with the pipeline and the Customer's site, the size of the connecting pipeline from the interconnection with the pipeline and the Customer's site, the size of the connecting pipeline and any other appurtenant facilities required;

c. Engineering studies setting forth the estimated cost(s) to complete construction;

d. Status of all reliability and environmental permits required by State and Federal agencies; and

e. Other information that the Company deems appropriate in considering the Customer's request.

Each request will be evaluated on a case-by-case basis to determine whether a discount from NJNG's Tariff Rate for Gas Service would be just and reasonable. Any agreement between the Customer and the Company for a discount from NJNG's Tariff Rate for Gas Service is subject to Board approval.

11.2 CUSTOMERS WITH CIRCUMSTANCES OTHER THAN AN ASSERTED ABILITY TO PHYSICALLY BYPASS

A new Customer or existing Customer who requests a discount from NJNG's Tariff Rate for Gas Service due to circumstances other than the asserted ability to physically bypass the Company's distribution and/or transmission system facilities shall contact the Company in writing with its request. The new or existing Customer shall provide all of the information that the Company deems appropriate in considering the Customer's request. Each request will be evaluated on a case-by-case basis to determine whether a discount from NJNG's Tariff Rate for Gas Service would be just and reasonable. Any agreement between the Customer and the Company for a discount from NJNG's Tariff Rate for Gas Service is subject to Board approval.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet Nos. 36-50*

RESERVED FOR FUTURE USE

SERVICE CLASSIFICATION - RS

RESIDENTIAL SERVICE

AVAILABILITY

This service is available to any residential Customer in the territory served by the Company using gas for any domestic purpose. This rate is applicable to individually-metered apartments and to rooming and boarding houses where the number of rental bedrooms is not more than twice the number of bedrooms used by the Customer.

Gas delivered under this schedule may not be used for other than domestic purposes except when such use is incidental to domestic use.

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$15.00

Delivery Charge:

Residential Heating

Delivery Charge per therm	$1.2585

Residential Non-Heating

Delivery Charge per therm	$1.2052

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

SERVICE CLASSIFICATION - RS

RESIDENTIAL SERVICE (continued)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SPECIAL PROVISIONS

I. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Metering***

   An Automated Meter Reading (AMR) device will not be required for this service. However, the Company reserves the right to install an AMR device at its own expense. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

   When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

   Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

2. ***Additional Requirements***

   Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

CONTRACT

Written application on Company's Standard Application Form may be required.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions.

SERVICE CLASSIFICATION – DGR

DISTRIBUTED GENERATION SERVICE - RESIDENTIAL

AVAILABILITY

This service is available to any residential customer using distributed generation technologies including, but not limited to, microturbines and fuel cells to generate electricity for domestic purposes.

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$15.00

Delivery Charge:

November - April	$0.4212
May - October	$0.3679

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge. Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SERVICE CLASSIFICATION - DGR

DISTRIBUTED GENERATION SERVICE - RESIDENTIAL (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers Under This Service Classification*

1. ***Metering***

All service rendered hereunder shall be metered separately from any other gas service provided to Customer at the Customer's location.

An Automated Meter Reading (AMR) device with daily meter reads will not be required for this service. However, upon prior notice to the Customer, the Company reserves the right to install an AMR at its own expense. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Additional Requirements***

Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 55*

SERVICE CLASSIFICATION – GSS

GENERAL SERVICE - SMALL

AVAILABILITY

This service is available to any Customer in the entire territory served by the Company who uses less than 5,000 therms annually and uses gas for all purposes other than residential service and interruptible service. Where the Customer uses the Cooling, Air Conditioning and Pool Heating service ("CAC") under Special Provision I.2, the Company may, upon application by the Customer, meter the space heating and CAC use separately. Street Lighting Service also will be supplied under this schedule (Special Provision II.1).

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$57.50

Delivery Charge:

Delivery Charge per therm	$1.1391

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SERVICE CLASSIFICATION - GSS

GENERAL SERVICE - SMALL (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers Under This Service Classification*

1. ***Annual Review***
The Company shall review, at least once a year, each GSS Customer's annual usage based on the most recent twelve (12) months of billing information to determine if the General Service – Large ("GSL") Service Classification is applicable to the Customer. If the Customer's normalized annual usage is greater than or equal to 5,500 therms, the customer will be switched to GSL prospectively.

2. ***Air Conditioning and Pool Heating***
Upon separate application, GSS Customers who have installed and are using gas air conditioning and/or pool heating equipment will be billed on the above Monthly Rates and will be billed a credit of ($0.7404) per therm for all monthly consumption of gas for services rendered between May 1 and September 30 of each year. This credit is the difference between the delivery charge for service rendered between May 1 and September 30 of each year under this Special Provision of $0.3987 per therm, which includes $0.1463 per therm margin, all appropriate riders, taxes, assessments and surcharges, and the delivery charge for Service Classification GSS.

Commercial Air Conditioning and Pool Heating ("CAC") customers will be separately metered, except, at the Company's sole discretion, existing Customers may use the same meter for their cooling, air conditioning or pool heating load and their space heating load as long as there is minimal base load during the period air conditioning rates are in effect.

Where a CAC Customer uses gas under this service classification in a direct-fired chiller/heater and the heating load is metered through the same meter as the cooling, air conditioning or pool heating load, and further, where the gas used for heating is billed separately, the GSS Customer Charge shall be waived, provided the Customer pays the Customer Charge under its heating service in all twelve (12) months of the year.

3. ***Veterans' Organization Service***
Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

a. Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

SERVICE CLASSIFICATION - GSS

GENERAL SERVICE - SMALL (continued)

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

b. The Customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' Customer Charges and Delivery Charges under this Special Provision for all relevant periods. If the comparable Customer Charges and Delivery Charges under Service Classification Residential Service (RS) are lower than the charges under their current Service Classification, a credit in the amount of the difference will be applied to the Customer's next bill.

4. ***Metering***

An Automated Meter Reading (AMR) device will not be required for this service. However, the Company reserves the right to install an AMR device at its own expense. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

II. *Applicable to All Customers Purchasing Gas Supply Under Rider "A" BGSS*

1. ***Street Lighting Service***

Street Lighting Service is not subject to Rider "I" of this Tariff. The delivery charge per therm for Street Lighting Service is $1.5076 per therm.

III. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Additional Requirements***

Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE

AVAILABILITY

This service is available to any Customer in the entire territory served by the Company who uses greater than or equal to 5,000 therms annually and uses gas for all purposes other than residential service and interruptible service. Where the Customer uses the Cooling, Air Conditioning and Pool Heating service ("CAC") under Special Provision I.4, the Company may, upon application by the Customer, meter the space heating and CAC use separately.

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$142.50

Demand Charge:

Demand Charge per therm applied to HMAD	$4.50

Delivery Charge:

Delivery Charge per therm	$0.7364

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge and the Demand Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***Determination of Demand***

The highest monthly average daily usage (HMAD) that occurs in any billing period will be used to calculate the Demand Charge. The HMAD shall be determined based upon the Customer's highest normalized average daily usage for a month in the most recent twenty-four (24) month period. Estimated data may be used when actual data is not available. At least once a year, the Company shall review and modify, if necessary, each GSL customer's HMAD based upon the most recent twenty-four (24) months of billing information. Any modification will be on a prospective basis. The Company reserves the right to determine the HMAD for any Customer by actually metering daily usage.

2. ***Metering***

An Automated Meter Reading (AMR) device with daily meter reads will not be required for this service. However, the Company reserves the right to install an AMR if it believes such a device will provide a more accurate HMAD than the Determination of Demand set forth above. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

3. ***Annual Review***

The Company shall review, at least once a year, each GSL customer's annual usage based on the most recent twelve (12) months of billing information to determine if the General Service - Small ("GSS") Service Classification is applicable to the Customer. If the Customer's normalized annual usage is less than or equal to 4,500 therms, the Customer will be switched to GSS prospectively.

4. ***Air Conditioning and Pool Heating***

Upon separate application, GSL Customers who have installed and are using gas air conditioning and/or pool heating equipment will be billed on the above Monthly Rates and will be billed a credit of ($0.3377) per therm for all monthly consumption of gas for services rendered between May 1 and September 30 of each year. This credit is the difference between the delivery charge for service rendered between May 1 and September 30 of each year under this Special Provision of $0.3987 per therm which includes $0.1493 per therm margin, all appropriate riders, taxes, assessments and surcharges, and the delivery charge for Service Classification GSL.

Commercial Air Conditioning and Pool Heating ("CAC") Customers will be separately metered, except, at the Company's sole discretion, existing Customers may use the same meter for their cooling, air conditioning or pool heating load and their space heating load as long as there is minimal base load during the period air conditioning rates are in effect.

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE (continued)

Where a CAC Customer uses gas under this service classification in a direct-fired chiller/heater and the heating load is metered through the same meter as the cooling, air conditioning or pool heating load, and further, where the gas used for heating is billed separately, the GSL Customer Charge shall be waived, provided the Customer pays the Customer Charge under its heating service in all twelve (12) months of the year.

5. ***Veterans' Organization Service***
Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

a. Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company, who will determine eligibility. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

b. The Customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' Customer Charges, Demand Charges, and Delivery Charges under this Special Provision for all relevant periods. If the comparable Customer Charges and Delivery Charges under Service Classification Residential Service (RS) are lower than the charges under their current Service Classification, a credit in the amount of the difference will be applied to the Customer's next bill.

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence**.**

2. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - FT

FIRM TRANSPORTATION SERVICE

AVAILABILITY

This service is available to any customer who would otherwise qualify for service under Service Classifications GSS, GSL, IS, or NGV. The Company may require the Customer to provide to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution systems.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$475.00

Demand Charge:

Demand Charge per therm applied to MDQ	$3.75

Delivery Charge:

Delivery Charge per therm	$0.1891

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge and the Demand Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SERVICE CLASSIFICATION - FT

FIRM TRANSPORTATION SERVICE (continued)

SPECIAL PROVISIONS

1. ***Determination of Demand***

   The Maximum Daily Quantity (MDQ) will be initially set by determining the highest monthly average daily usage (HMAD) without normalization and multiplying that result by 1.30. The MDQ will be stated in therms.

   The Company shall deliver to the Customer the gas quantity provided by the Customer up to the MDQ level. Should the Customer's usage exceed the MDQ, the MDQ will be deemed to have changed. The MDQ for service and billing purposes will remain at the highest actual daily volume served. The Customer may request a decrease to its MDQ when the Customer has installed energy efficient equipment or significantly modified its operations resulting in decreased maximum daily usage. Any decrease in the MDQ will be granted in the Company's sole judgment on a prospective basis.

2. ***Automated Meter Reading Device***

   Metering shall include an automated meter reading device (AMR) with daily meter reads**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

   The Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over a twelve-month period with the prime interest rate used to calculate carrying costs.

3. ***Incremental Expenses***

   The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

4. ***Customer Responsibility***

   In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

SERVICE CLASSIFICATION - FT

FIRM TRANSPORTATION SERVICE (continued)

5. ***Inability to Secure Supply with a Third Party Supplier***

In the event that a new Customer cannot enroll with a Third Party Supplier prior to the commencement of service, or an existing Customer's Third Party Supplier ceases providing service to the Customer and the Customer is unable to secure supply from an alternate Third Party Supplier, Customers may elect to receive temporary supply service from the Company. The price for temporary service provided to the Customers shall be equal to the Monthly BGSS price in Rider "A".

If a Third Party Supplier has not submitted enrollment information for the Customer to the Company within thirty (30) days of a new Customer's commencement of service or an existing Customer's loss of its previous Third Party Supplier, the Customer will be switched to the appropriate sales service classification.

6. ***Additional Requirements***

Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - DGC

DISTRIBUTED GENERATION SERVICE - COMMERCIAL

AVAILABILITY

This service is available to any commercial customer using distributed generation technologies including, but not limited to, microturbines and fuel cells.

CONDITIONS PRECEDENT

If the Customer is served by a Third Party Supplier, the Third Party Supplier assumes the responsibility for all delivery requirements. The Company may require the Customer to provide, to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution systems. The Customer is responsible for payment of any costs if additional facilities, exclusive of metering facilities, are necessary to provide service. The Company reserves the right to limit new customers served under this service, if it determines that service expansion is detrimental to existing firm customers. The Customer must demonstrate that qualifying electric generation equipment has been installed at its location.

MONTHLY RATES

	DGC-Balancing	DGC-FT
Customer Charge:		
Customer Charge per meter per month	$142.50	$142.50
Demand Charge:		
Demand Charge per therm applied to PBQ	$3.25	$3.25
Delivery Charge per therm:		
November - April	$0.3314	$0.2043
May - October	$0.2988	$0.1717
BGSS Charge:		
BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff	N/A

The Delivery Charges for DGC-Balancing above include the Balancing Charge as reflected in Rider "A" of this Tariff for customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (3) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS. For DGC-FT customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (1) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS, the DGC-FT Delivery Charges above exclude the Balancing Charge reflected in Rider "A" of this Tariff.

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

SERVICE CLASSIFICATION - DGC

DISTRIBUTED GENERATION SERVICE - COMMERCIAL (continued)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the sum of the Customer Charge and the Demand Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***Determination of Demand***
The Peak Billing Quantity (PBQ) will be initially set based on the rated fuel requirements of the installed distributed generation equipment and the Customer's electric requirements. The Company shall deliver to the Customer the gas quantity provided by the Customer up to the PBQ level. Should the Customer's usage exceed the PBQ, the PBQ will be deemed to have changed. The PBQ for service and billing purposes will remain at the highest actual daily volume served.

2. ***Automated Meter Reading Device***
All service rendered hereunder shall be metered separately from any other gas service provided to the Customer at the Customer's location.

Metering shall include an automated meter reading device (AMR) with daily meter reads, which shall be furnished and installed by the Company. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

SERVICE CLASSIFICATION - DGC

DISTRIBUTED GENERATION SERVICE - COMMERCIAL (continued)

3. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

The Company's main and service extension policy set forth in Section 4 of the Standard Terms and Conditions shall apply to service rendered hereunder with the following exceptions: the Company will make gas main extensions and service line connections to serve individual firm DGC customers free of charge where the cost of such extension does not exceed three (3) times the estimated annual distribution revenue for equipment with an estimated life of less than 5 years; five (5) times the estimated annual distribution revenue for equipment with an estimated life between six (6) and ten (10) years; six (6) times the estimated annual distribution revenue for equipment with an estimated life between eleven (11) and sixteen (16) years. Equipment with an estimated life greater than sixteen (16) years will be subject to the ten (10) times policy set forth in Section 4 of the Standard Terms and Conditions.

Should the Customer take service under this classification for less than one (1) year, the Customer shall reimburse the Company for the cost of the extension.

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Customer Responsibility***
In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

2. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - ED

ECONOMIC DEVELOPMENT SERVICE

AVAILABILITY

Customers eligible to receive service under the following Service Classifications: General Service - Small ("GSS"), General Service - Large ("GSL"), or Firm Transportation Service ("FT").

CHARACTER OF SERVICE

Firm gas sales and transportation service.

CONDITIONS PRECEDENT

The Customer must meet the following conditions:

1. a. For new Customers, the building receiving service under this Tariff must be new or have been vacant for at least twelve months.

   b. Existing Customers must have been served for more than one year, and the space utilized for operations must have expanded by more than 5,000 square feet. Gas used in excess of the previous twelve months (base) usage will be subject to the Economic Development (ED) credit.

   c. An existing occupant (a) converts to natural gas and (b) expands space utilized for its operations by more than 5,000 square feet would be eligible for the credit. The Occupant must provide its energy usage for the previous twelve months (base) at the time of application for gas service. The Company will calculate the BTUs used by the Occupant in the base period and BTUs used in excess of the base period would be eligible for the ED credit.

2. The Customer must be adding at least two permanent full-time employees to a location in the Company's service territory. Relocation or consolidation of employees based at locations in the Company's service territory must net at least two new jobs in order to qualify for the ED credit. Employment growth will be confirmed by the Company and/or by affidavit from the Customer. The Company reserves the right, at its discretion, to periodically verify levels of employment. If after verification the required employment level has not been sustained, the Customer will no longer be eligible for the ED credit.

3. The Customer must apply for this service upon the initial application for gas service.

4. The Customer must execute a Service Agreement.

5. The building receiving service under this Tariff must be located within a community in our service territory with a ranking of 150 or less on the current Municipal Distress Index compiled by the New Jersey State Planning Commission.

SERVICE CLASSIFICATION - ED

ECONOMIC DEVELOPMENT SERVICE (continued)

MONTHLY RATES

The monthly rates shall be the same as the applicable service classification except that: 1) GSS Customers will be credited $0.1200 per therm for all eligible gas use, and 2) GSL and FT Customers' Demand charges will be reduced by fifty (50) percent. These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company.

MINIMUM MONTHLY CHARGE

The minimum monthly charge for GSS Customers shall be the Customer Charge. The minimum monthly charge for GSL and FT Customers shall be the Customer Charge and the Demand Charge.

SPECIAL PROVISIONS

1. ***Extension of Facilities***
   The Company will extend facilities per Sections 4, and 5 of the Standard Terms and Conditions of this Tariff utilizing the margins that result from the above Monthly Rates.

2. ***Tariff Availability***
   The Company reserves the right to offer this Tariff rate to customers located in areas of other communities, which demonstrate the characteristics warranting economic development to encourage such development and employment opportunities, if such offer meets public policy objectives of the state of New Jersey as administered by the State of New Jersey Department of Community Affairs or its successor.

SERVICE LIMITATIONS

This service is not available to federal, state, county or local governments or governmental entities.

CONTRACT

The maximum term of the service agreement shall be three years. A Customer's three year term of eligibility will commence no later than six months after the Service Agreement is executed.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - EGS

ELECTRIC GENERATION SERVICE

AVAILABILITY

This service is available to any existing or new customer who uses greater than or equal to 10,000 therms daily for the sole purpose of generating electricity. Year-Round firm service is available throughout the year. Off-Peak firm service is available beginning May 15 and ending September 15.

MONTHLY RATES

Customer Charge:

	Without SUT	With SUT
Customer Charge per month	$914.42	$975.00

Demand Charge Per therm Applied to MDQ:

	Without SUT	With SUT
Year-Round Firm Service Demand Charge per therm applied to MDQ	$1.8757	$2.00
Off -Peak Firm Service Demand Charge per therm applied to MDQ	$0.6253	$0.6667

Delivery Charge:

	Without SUT	With SUT
Delivery Charge per therm	$0.1168	$0.1244

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, applicable taxes, assessments or similar charges lawfully imposed by the Company. Natural gas used to generate electricity that is sold for resale by customers served under this Service Classification is exempt from Riders B, C, D, E, F and G and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge and the Demand Charge.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

SPECIAL PROVISIONS

1. ***Determination of Demand***
   The Maximum Daily Quantity (MDQ) will be: (1) initially determined by agreement between the Company and the Customer, (2) stated in therms, and (3) included in the Service Agreement.

2. ***Facilities***
   The Company shall install gas main extensions, service line connections, and facilities necessary to meet pressure and demand requirements at the Customer's location (collectively, the "Extension Cost") to serve the customer free of charge where the Extension Cost does not exceed ten (10) times the estimated annual distribution revenue. An applicant shall be required to provide a non-refundable contribution in aid of construction for the value of any Extension Cost that is greater than ten (10) times the annual distribution revenue. The Extension Cost for which the Company receives a contribution shall include the tax consequences incurred by the Company. The Company and applicant may agree upon a satisfactory revenue guarantee in lieu of a contribution.

   Where it is necessary to provide additional facilities to serve increased requirements of an existing Customer, the Company reserves the right to require the Customer to provide a non-refundable contribution in aid of construction in an amount equal to the cost of such additional facilities.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

3. ***Separately Metered***
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification.

4. ***Automated Meter Reading Device***
Metering shall include an automated meter reading device (AMR) with daily meter reads**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line or data plan, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

The customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over over a twelve-month period with the prime interest rate used to calculate carrying costs.

5. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

6. ***Nominations***
Customer's nominations for service under this Service Classification must be made on the Company's electronic bulletin board ("EBB") by the deadline specified on the Company's EBB on the day prior to gas flow for the next calendar day. Customer may request nomination changes after the deadline or during the intra-day through intra-day nominations no less frequently than is allowed under the then current North American Energy Standards Board ("NAESB") Nomination Standards. Customer shall have the right to request a new nomination, an Intra-day Nomination, for flow intra-day. The term "intra-day nomination" shall mean (i) a nomination received during a gas day for the same day of gas flow, and (ii) a nomination received after the Timely Nominations deadline for the following gas day. Customer shall notify the Company in writing of changes and the Company will enter and/or approve at the Company's sole discretion on the Company's EBB and the applicable interstate pipeline's EBB.

The Company reserves the right to reject nominations, in whole or in part, for deliveries in excess of Customer's estimated usage. This restriction will not apply to days with an Operational Flow Order ("OFO") in place and can be issued as a blanket for the entire system or for a single Third Party Supplier. The Company will provide written notice to a Third Party Supplier of the Company's rejection of the Third Party Supplier's deliveries prior to implementing the reductions on the affected pipeline.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

7. ***Balancing***

It is the intent that Customer's actual daily takes under this Service Classification match the Customer's daily nominations, and that Customer's actual daily deliveries match Customer's actual daily takes. The Customer shall be allowed a daily tolerance for the difference between their actual daily delivery and their actual daily take equal to the greater of 500 Dth or 2% of the Customer's daily takes. On any day that the Company has issued an OFO and/or the applicable interstate pipeline has issued an OFO, Action Alert, Force Majeure, or similar restriction, the tolerance for any negative imbalances (Customer used more than was delivered) is 0 (zero). On any day that the applicable interstate pipeline has issued an OFO limiting positive imbalances (Customer used less than was delivered), the tolerance for any positive imbalances is 0. A cash-out for any differences above the daily tolerance shall be charged or credited to the Customer each month.

If the imbalance is negative (Customer used more gas than was delivered), the Customer will purchase gas from the Company at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Highest price of daily ranges for delivery on the applicable pipeline at the zone of the Company's designated delivery meters, which are published in Platts Gas Daily in the table, "Daily Price Survey" ("Gas Daily High")
>5% - ≤ 10%	quantity >5% * Gas Daily High * 1.1 + level above
>10% - ≤ 15%	quantity >10% * Gas Daily High * 1.2 + levels above
>15% - ≤ 20%	quantity >15% * Gas Daily High * 1.3 + levels above
>20% - ≤ 25%	quantity >20% * Gas Daily High * 1.4 + levels above
>25%	quantity >25% * Gas Daily High * 1.5 + levels above

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

If the imbalance is positive (Customer delivered more gas than was used), the Company will purchase gas from the Customer at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Lowest price of daily ranges for delivery on the applicable pipeline at the zone of the Company's designated delivery meters, which are published in Platts Gas Daily in the table, "Daily Price Survey" ("Gas Daily Low")
>5% - ≤ 10%	quantity >5% * Gas Daily Low * .90 + level above
>10% - ≤ 15%	quantity >10% * Gas Daily Low * .80 + levels above
>15% - ≤ 20%	quantity >15% * Gas Daily Low * .70 + levels above
>20% - ≤ 25%	quantity >20% * Gas Daily Low * .60 + levels above
>25%	quantity >25% * Gas Daily Low * .50 + levels above

All revenues and purchases derived from imbalances will be credited to the BGSS.

8. ***Operational Flow Order ("OFO")***

The Company may issue an Operational Flow Order ("OFO") requiring delivery by the Customer of at least the volume of gas the Customer uses on the affected gas day ("OFO Required Volume").

A Customer who fails to deliver the OFO Required Volumes of gas may not be permitted to continue to operate on the system. In addition, the Customer will be billed at the applicable "Delivery Shortfall" charge in effect during the OFO period for the volume difference between the OFO required delivery and the actual delivered volume. There will be no penalties for delivering gas in excess of an OFO Required Volume.

9. ***Delivery Shortfall Charge***

In the event that the Customer fails to deliver the OFO Required Volume directed by the Company (a "Delivery Shortfall"), the Company shall bill the Customer and the Customer shall pay for the volume of the Delivery Shortfall at a rate equal to ten (10) times the highest price of daily ranges for delivery on the applicable pipeline in the zone of the Company's designated delivery meters, that are published in Platts Gas Daily on the table, "Daily Price Survey"; provided, however, the amount billed shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines that deliver gas to the Company. In the event of a Delivery Shortfall, the Company shall have the right to recover *pro rata* from all under-delivering Customers and Third Party Suppliers served under Service Classification TPS any penalties or other charges or damages assessed on the Company because of such under-deliveries for the days the Customers, Third Party Suppliers under-delivered.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

Notwithstanding the above, if contemporaneously with a Delivery Shortfall, the applicable pipeline has declared a force majeure on its system curtailing primary, in-path transportation in the zone of the Company's designated delivery meter, the Company may waive the above charges and may bill the Customer for the Company's Replacement Cost of Gas (defined below) provided that the under-delivering Customer is able to demonstrate to the Company's reasonable satisfaction that the applicable pipeline transportation contract on which the Customer had scheduled deliveries to the Company during the period in which the OFO was in effect entitled the Customer to firm transportation rights through the point at which the force majeure was declared and that the applicable pipeline curtailed Customer's deliveries *pro rata* with deliveries to other similarly situated delivery meters on the contract. The Customer must notify the Company in writing of the anticipated Delivery Shortfall before the nomination deadline for the next North American Energy Standards Board ("NAESB") nomination cycle. If there are no additional cycles, they must notify the Company in writing before the gas day ends. "Company's Replacement Cost of Gas" means the highest of (1) the Company's LNG inventory and gasification costs during the time period of the applicable pipeline force majeure event adjusted for all appropriate taxes, assessments and surcharges, (2) the prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the time period of the applicable pipeline force majeure event, or (3) the cost of gas purchased by the Company during the time period of the applicable pipeline force majeure event; plus any pipeline penalties or other charges or damages assessed on the Company.

10. ***Customer Responsibility***

In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a *pro rata* share of any charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for balancing.

11. ***Third Party Supplier Requirements***

In the event the Customer designates a Third Party Supplier, service to the Third Party Supplier is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions, except as modified within this Service Classification.

PAYMENT

Unless otherwise specified, bills are due within ten days after the Company sends the bill and is subject to a late payment charge as set forth in Paragraph 8.9 of the Standard Terms and Conditions of this Tariff.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 75*

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

CONTRACT

A written service agreement on the Company's Standard Application Form shall be required for Electric Generation Customers. The service agreement will be in effect for a minimum term of 10 years and a maximum term of 20 years. The Tariff rates in effect at the beginning of a Customer's service agreement shall remain applicable to the Customer's service during the term of the agreement. If the agreement is renewed at the end of the term, the rates applicable to the Customer in the new service agreement shall be the rates effective at that time for this Service Classification.

CREDIT REQUIREMENTS

If the customer is not deemed creditworthy by the Company, a parental guaranty, letter of credit, cash deposit or other security acceptable to Company will be required. The amount will equal six (6) months of demand charges and three (3) months of delivery charges.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE

AVAILABILITY

This service is available to any residential or commercial customer for the purpose of fueling natural gas vehicles at Company owned and operated compressed natural gas ("CNG") re-fueling facilities ("Company facilities") and at separately metered Customer owned and operated CNG re-fueling facilities ("Customer owned facilities").

CONDITIONS PRECEDENT

The Customer must sign a service agreement which sets forth the vehicles to be served to be eligible for this service.

DEFINITION OF TERM USED HEREIN

"GGE" is the Gasoline Gallon Equivalent for converting a price per therm of natural gas to a price per gallon of gasoline. The GGE shall be determined in accordance with local standards.

CHARACTER OF SERVICE

Firm sales gas service where Customer who uses Company facilities purchases gas supply pursuant to the Company's Rider "A" for Basic Gas Supply Service ("BGSS"). Firm sales or transportation gas service where Customer who uses Customer owned facilities purchases gas supply pursuant to the Company's Rider "A" for BGSS or from a Third Party Supplier, respectively.

LICENSING, PERMITS AND LEGAL REQUIREMENTS

Customers installing CNG re-fueling facilities on their premises must meet all applicable licensing, permitting and other legal requirements associated with owning and operating CNG refueling facilities. The failure of the customer to comply with this provision may result in the Company suspending or terminating gas service to such facilities without further liability.

MONTHLY RATES

	Gas Available at Company Facilities	Customer Owned Facilities
Customer Charge:		
Residential Customer Charge per meter per month	N/A	$15.00
Commercial Customer Charge per meter per month	N/A	$142.50
Delivery Charge:		
Delivery Charge per therm	$0.5062 ($0.633 per GGE)	$0.5062 ($0.633 per GGE)

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

	Gas Available at Company Facilities	Customer Owned Facilities
Compression Charge:		
Compression Charge per therm	$0.4958 ($0.620 per GGE)	N/A

BGSS Charge:

Monthly BGSS Charge per therm for Sales Customers	See "Summary of Rate Components" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders with the exception of the State of New Jersey Motor Vehicle fuel tax and Federal excise tax. These rates are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See "Summary of Rate Components" at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SPECIAL PROVISIONS

I. Applicable to All Customers in this Service Classification

1. ***Taxes, Assessments and Surcharges***
   The Customer shall pay all riders, taxes, assessments and surcharges that are lawfully imposed upon the Company in providing service under this classification.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

II. *Applicable to All Customers Who Use Customer Owned Facilities*

1. ***Facilities***

The Company shall install gas main extensions and service line connections at the Customer's location (collectively, the "Extension Cost") to serve the customer free of charge where the Extension Cost does not exceed ten (10) times the estimated annual distribution revenue. An applicant shall be required to provide an Extension Cost Deposit for the value of any Extension Cost that is greater than ten (10) times the annual distribution revenue. The Extension Cost for which the Company receives a deposit shall include the tax consequences incurred by the Company.

The Extension Cost Deposit, as defined above, shall remain, without interest, in the possession of the Company, subject to an annual review of the Customer's actual annual distribution revenue for up to ten years from when the Customer began receiving service. Annually, if the Customer's actual annual distribution revenue for the prior year is greater than the estimated annual distribution revenue used to determine the Extension Cost or greater than any prior year's actual distribution revenue, the Company shall provide a refund in the amount of the remaining years of the ten (10) years times the difference between that year's actual distribution revenue and the greater of the estimated annual distribution revenue used to determine the Extension Cost Deposit and the highest prior year's actual distribution revenue. No further calculation shall be performed when accumulated refunds are equal to the Extension Cost Deposit and in no event shall refunds exceed the initial deposit.

All deposits not returned to the applicant within a period of ten (10) years after the Company first makes gas service available shall remain the property of the Company with no further obligation of refund. The Company and applicant may agree upon a satisfactory revenue guarantee in lieu of a deposit or contribution.

Where it is necessary to provide additional facilities to serve increased requirements of an existing Customer, the Company reserves the right to require the Customer to contribute or deposit an amount equal to the cost of such additional facilities. This amount shall be subject to refund as outlined earlier in this section except that refunds shall be a function of the incremental distribution revenue generated by the increased requirements over a predetermined base.

2. ***Separately Metered***

Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

3. ***Automated Meter Reading Device***
For Commercial customers, metering shall include an automated meter reading device (AMR)**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish an electrical supply and phone line or data plan, as needed, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

The Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over a twelve-month period with the prime interest rate used to calculate carrying costs. Payments made by the Customer shall not give the Customer ownership of the AMR equipment. The AMR equipment is and shall remain the sole property of the Company.

For Residential customers, an AMR device will not be required for this service. However, upon prior notice to the Customer, the Company reserves the right to install an AMR at its own expense. Should the Company decide to install the AMR, the Customer shall furnish an electrical supply and phone line or data plan, as needed, for the operation of the device, in an area acceptable to the Company. Should the Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

4. ***Maximum Quantities***
The maximum monthly and hourly quantities of gas to be delivered shall be specified in the service agreement and may be changed only with approval of the Company.

5. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, permitting, licensing, and legal expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence and may include these expenses as part of the Facilities cost referenced in Section I of this Service Classification.

6. ***Resale of Vehicle Fuel***
If the Customer provides natural gas for resale as a vehicle fuel, the Customer will be responsible for collecting and paying all applicable taxes on the gas compressed for resale and for the metering of such sale in accordance with all applicable standards and regulations.

III. Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier

1. ***Customer Responsibility***
The Company may require the Customer to provide, to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution system. In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

2. ***Additional Requirements***
   Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

PAYMENT

Unless otherwise specified, bills are due within 10 days after the Company sends the bill and subject to a late payment charge as set forth in Paragraph 8.9 of the Standard Terms and Conditions of this Tariff.

CONTRACT

A written service agreement shall be required for Natural Gas Vehicle Service Customers.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE

AVAILABILITY

This service is applicable to Commercial and Industrial Customers whose minimum connected load is not less than 150 therms per hour, provided that gas is used only at locations where the Company has 1) adequate distribution facilities and 2) an adequate supply of natural gas. Customers will be required to specify that they have alternate fuel facilities installed in operating condition with an adequate fuel supply, as discussed in Special Provision 1.

CHARACTER OF SERVICE

Interruptible gas sales and transportation service.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$725.00

Delivery Charge:

Customers with Alternate Fuel

Delivery Charge per therm	$0.1928

Customers without Alternate Fuel

Delivery Charge per therm	$0.5544

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge applicable shall be the Customer Charge. Where service is taken for less than one month, the minimum charge will be prorated.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***Alternate Fuel Certification***
If the Customer desires to be categorized as a customer with alternate fuel then, as of November 1st of each year, the Customer must certify in a signed affidavit that the installation being served is physically and legally capable of using the fuel oil and the specific sulfur content as indicated or that it may legally and physically use propane at the Customer's end-use facility. The alternate fuel certification and related details will be held confidential except as same information shall be utilized by the Company for preparation of periodic reports to the Board. It is the Customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times. Adequate supply requirements for customers using No. 2 fuel oil, No. 4 fuel oil, jet fuel or kerosene are seven (7) days of alternate fuel either on hand or, if a customer's on-site storage capacity is less than seven (7) days, then full storage capacity plus additional firm contractual supply arrangements to equal seven (7) days. No customer is required to build additional storage. All customers that use non-distillate fuels as an alternate supply, or will agree to suspend operations during an interruption, are exempt from the alternate fuel requirement, but must file a certification with the Company indicating the alternate fuel used or their intention to discontinue operations.

If the Customer does not file a certification with the Company, the Customer will be served and billed as an Interruptible Customer without Alternate Fuel.

2. ***Separately Metered***
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification.

3. ***Automated Meter Reading Device***
Metering shall include an automated meter reading device (AMR) with daily meter reads**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line or data plan for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

The Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over a twelve-month period with the prime interest rate used to calculate carrying costs.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE (continued)

4. ***Service Interruption***
The Customer agrees to discontinue the use of gas service at any time, and from time to time upon notice from the Company. The Company shall notify the Customer of the date and time of a service interruption by telephone and e-mail or fax. The Company's determination to discontinue service or to reinstate service following a discontinuance shall be conclusive.

5. ***Unauthorized Use***
In the event the Company notifies the Customer to discontinue the use of gas service at any time and the Customer fails to do so, the Company shall have the right to terminate service, to transfer the Customer to a firm service classification and/or to bill the Customer for usage occurring during the interruption period at the applicable "Unauthorized Use" charge in effect.

6. ***Incremental Gas Service***
During periods of gas service interruption, Customers in need of gas may request service under the Incremental Gas Service ("IGS") Classification.

II. *Applicable to All Customers Purchasing Gas Supply Under Rider "A" BGSS*

1. ***Maximum Quantities***
The maximum monthly and hourly quantities of gas to be delivered shall be specified in the service agreement and may be changed only with approval of the Company.

2. ***Service Nominations***
Upon request by the Company on any day, the Customer shall furnish an estimate of the amount of gas to be taken under this Service Classification during the next 24-hour period. The Customer must notify the Company in writing at least twenty-four (24) hours before it plans to discontinue the use of gas service.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE (continued)

3. ***BGSS***
   Customers will be supplied under the Monthly BGSS service which will be applied to all therms billed each month. See "Rate Summaries" for the current price.

III. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Return to Sales Classification***
   Upon a Customer's election to return to sales service under the IS Service Classification, it shall be required to provide the Company with no less than 30 days' notice of the Customer's intention to return to sales service under Service Classification IS. The Company may accept less than thirty (30) days' notice if gas is available to serve the Customer.

2. ***Incremental Expenses***
   The Customer will reimburse the Company for any out-of-pocket expenses (including, but not limited to legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

3. ***Service Charge Waiver***
   The Customer charge for IS sales service will be waived in months when a Customer uses IS transportation service to meet all its gas needs.

4. ***Customer Responsibility***
   In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Unauthorized Use or for Monthly Imbalances.

5. ***Additional Requirements***
   Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

CONTRACT

A written service agreement on the Company's Standard Application Form for a minimum one-year period may be required for IS Customers. Successive one-year terms will be in effect unless terminated by written notice at least two (2) months prior to the expiration of the service agreement. The Company reserves the right to require an updated written service agreement.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - IGS

INCREMENTAL GAS SERVICE

AVAILABILITY

This service is available when requested by a Customer, and when the Company has the capability to deliver incrementally purchased gas supplies. The service will be available for a limited term to Customers served under Service Classification IS.

CONDITIONS PRECEDENT

The Customer shall request IGS and provide the expected time period of service and the estimated volume of sales. If IGS is available, the Company will authorize service under IGS. The request and authorization may be made by telephone and agreed to in writing (fax, e-mail, etc. are acceptable).

CHARACTER OF SERVICE

Gas service will be provided only to the extent that gas supplies may be incrementally purchased and are offered for sale by the Company.

The Company reserves the right to curtail or interrupt this service immediately if, in the Company's sole discretion, continuance of this service would adversely affect service to other Customers.

OFFERING OF SERVICE

This service will be offered to customer classes as follows:

Non-Firm

December through March - rates must be at least the level of otherwise applicable tariff rates.
April through November - rates may be below otherwise applicable tariff rates.

When rates are offered below otherwise applicable tariff rates, this service is offered only for volumes of gas that are incremental and which would not be used except for the existence of this offer.

SERVICE CLASSIFICATION - IGS

INCREMENTAL GAS SERVICE (continued)

RATES

The rates for service will be set by the Company and will include a commodity charge equal to the highest of:

A. The "Company's Replacement Cost of Gas" (See Special Provision 5 of this Service Classification);
B. The Monthly BGSS price applicable to Service Classification IS;
C. The highest price of the daily ranges that are published in Platts Gas Daily on the table "Daily Price Survey" for delivery in Texas Eastern Zone M-3; or
D. The highest price of the daily ranges that are published in Platts Gas Daily on the table "Daily Price Survey" for delivery in Transco Zone 6 NNY North.

In addition, such rates shall include all applicable riders, taxes, assessments and surcharges that are lawfully imposed upon the Company in providing service under this classification. The Customer will continue to be charged the Customer Charge and Delivery Charge under Service Classification IS.

SPECIAL PROVISIONS

1. ***Service Interruption***
   The Customer agrees to discontinue the use of gas service at any time, and from time to time upon notice from the Company. The Company shall notify the Customer of the date and time of a service interruption by telephone and e-mail or fax. The Company's determination to discontinue service or to reinstate service following a discontinuance shall be conclusive.

2. ***Unauthorized Use***
   In the event the Company notifies the Customer to discontinue the use of gas service at any time and the Customer fails to do so, the Company shall have the right to terminate service and/or to bill the Customer for usage occurring after the expiration of the period of notice specified in the service agreement at the applicable "Unauthorized Use" charge in effect.

3. ***Service Nominations***
   Upon request by the Company on any day, the Customer shall furnish an estimate of the amount of gas to be taken under this Service Classification during the next 24-hour period. The Customer must notify the Company in writing at least 24 hours before it plans to discontinue the use of gas service.

4. ***Required Purchases***
   When the Customer requests IGS service and the Company commits to an incremental purchase of gas, the Customer will be required to pay for the contracted gas service whether or not the Customer uses the gas.

SERVICE CLASSIFICATION - IGS

INCREMENTAL GAS SERVICE (continued)

5. ***Company's Replacement Cost of Gas***

"Company's Replacement Cost of Gas" means the highest of:

A. Company's LNG inventory and gasification costs adjusted for all appropriate taxes, assessments and surcharges;,
B. The prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the period of IGS service; or
C. The cost of gas purchased by the Company.

The Company's Replacement Cost of Gas shall also include any pipeline penalties or other charges or damages assessed on the Company.

REPORTS

The Company will provide 48 hours' notice to the Board prior to any sales being made which would occur at rates that are less than the Customer's applicable Service Classification. The Company will submit a monthly report providing details of all IGS sales in any month sales are made.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIER REQUIREMENTS

AVAILABILITY

This service classification is for Third Party Suppliers (formerly referred to as Marketers or Brokers) who have been engaged by transportation customers using RS, GSS, GSL, FT, DGC, CNG, NGV or IS Services to be responsible for delivering natural gas to the Company's designated delivery meters on behalf of those Customers. All Third Party Suppliers who wish to act on behalf of Customers will be required to be authorized by the Company. Pursuant to this authorization, the Third Party Suppliers will be required to sign a service agreement and post a deposit or letter of credit in order to have the Company accept its natural gas at the designated delivery meters.

CONDITIONS PRECEDENT

The Third Party Supplier shall execute a service agreement with the Company.

The Third Party Supplier shall provide a written or electronic notification to the Company of the identity of Customer(s) on whose behalf they are acting.

The Third Party Supplier shall post an Initial Deposit, consisting of cash or letter of credit in the amount of $50,000 to serve RS customers and/or $25,000 to serve commercial customers including GSS, GSL, FT, DGC, CNG, NGV or IS customers. If the Third Party Supplier initially plans to serve only RS customers, the Initial Deposit shall be in the amount of $50,000 and if that Third Party Supplier later also serves commercial customers, an additional deposit of $25,000 shall be required for a total Initial Deposit of $75,000. If the Third Party Supplier initially plans to serve only commercial customers, the Initial Deposit shall be in the amount of $25,000 and if that Third Party Supplier later also serves RS customers, an additional deposit of $50,000 shall be required for a total Initial Deposit of $75,000. The total deposit provided by the Third Party Supplier shall be the greater of:

A. the Initial Deposit; or
B. an amount equal to the total of:
    i. at least three (3) times the estimated usage for one (1) day in January times the most current January's price for the higher of Texas Eastern Zone M-3 or Transco Zone 6 NNY North for any and all Customers on whose behalf the Third Party Supplier is acting;
    ii. for Customers using Billing Option 3, an additional amount equal to at least two (2) times the January delivery charges for each service classification for any and all Customers on whose behalf the Third Party Supplier is acting; and
    iii. the value of the Third Party Supplier's imbalance which is determined by multiplying the aggregate imbalance position for RS, GSS, GSL, DGC, and NGV residential customers on whose behalf the Third Party Supplier is acting by the midpoint price of daily ranges for the applicable delivery zone that are published in Platts Gas Daily on the table, "Daily Price Survey."

The deposit held from the Third Party Supplier will not bear interest. The Third Party Supplier shall agree the Company has the right to access and apply the cash deposit or letter of credit to any payment obligations which are deemed to be late or in arrears. In lieu of a cash deposit or letter of credit from a Third Party Supplier, the Company may, in its sole discretion, agree to accept a guaranty from such financially responsible parent or parent companies of the Third Party Supplier for the payment of any liabilities or obligations to be incurred by the Third Party Supplier. If any negative change in the financial condition of the guaranteeing party occurs, the Company reserves its right to request a deposit from the Third Party Supplier.

NEW JERSEY NATURAL GAS COMPANY

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SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

RATES

Basic Service	$65.00 per month	includes administration of nominations, balancing, inquiry, customer enrollment changes and security review

BILLING OPTIONS

Option 1 - Utility Consolidated Billing

The Third Party Supplier will provide the Company with the billing parameters for the "commodity charge" to be included in the calculation of each Customer's bill and the Company will send the total bill to each customer. The Company will purchase the receivable from the Third Party Supplier and be solely responsible for the processing of payments, collections and basic customer inquiries. Each Third Party Supplier operating under this option will be required to execute an agreement summarizing the terms and conditions of their services. This option includes electronic summaries for each cycle. The following charges are applicable to Billing Option 1:

Billing Option 1	$ 0.75	per bill

Option 2 – Dual Billing

The Company will provide a bill to the Customer for the transportation services provided on its distribution system. The Company will provide to the Third Party Supplier a summary of the usage and transportation charges for each customer during each billing period.

Option 3 - Third Party Supplier Consolidated Billing

The Third Party Supplier will send the total bill to each Customer and remit to the Company the transportation charges associated with the Customer. Third Party Supplier shall receive a total annual credit of $3.60 per customer for each FT, GSL, RS and GSS Customer billed according to this option. Such credit shall be applied monthly on a pro-rated basis.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

DELIVERIES TO COMPANY'S DESIGNATED DELIVERY METERS

1. ***FT, DGC-FT, CNG, NGV Commercial, and IS Service***

The Third Party Supplier agrees to deliver gas to the Company's designated delivery meters for each Customer on whose behalf it is operating. The Company may offer a Third Party Supplier the option to deliver a specified volume to the Company's designated delivery meter on the Transcontinental Gas Pipeline. If the Third Party Supplier accepts the offer but fails to deliver the specified volume to the designated delivery meter on the Transcontinental Gas Pipeline, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect for the volume not delivered.

The Third Party Supplier shall use its best efforts to achieve a balance between its deliveries (net of Special Provision 3, Fuel Use and Unaccounted for Gas) and its aggregate customer requirements on a daily basis. The Company reserves the right to require a Third Party Supplier to balance deliveries and takes of transported gas. If the Third Party Supplier has an accumulated imbalance between deliveries and takes of transported gas, the Company reserves the right to reject the Third Party Supplier's requested deliveries in whole or in part.

If at any time during the month, the aggregate Third Party Supplier's account is out of balance by more than 30%, the Third Party Supplier may be required, upon 2 business days' prior notice from the Company, to initiate corrective action to balance its account within the following 3-day period. Third Party Suppliers who fail to adhere to this requirement and have a positive cumulative imbalance (in aggregate the Third Party Supplier delivered more gas than was used in aggregate by its Customers), will have their subsequent nominations, on days with no Operational Flow Orders or IS Daily Balancing restrictions, rejected until they are returned to at or below a 10% imbalance. Third Party Suppliers who fail to adhere to this requirement and have a negative cumulative imbalance (in aggregate the Customers used more gas than was delivered in aggregate by the Third Party Supplier), will be charged at the "Delivery Shortfall" charge for the volume required to bring them to a 10% imbalance. Third Party Suppliers who fail to take corrective action to balance their account may not be permitted to continue to operate on the system.

The Company reserves the right to reject nominations, in whole or in part, for a Third Party Supplier's deliveries in excess of its estimated aggregate customer requirements, plus Special Provision 3, Fuel Use and Unaccounted for Gas. This restriction will not apply to days with an Operational Flow Order or IS Daily Balancing in place and can be issued as a blanket for the entire system or for a single Third Party Supplier. The Company will provide written notice to a Third Party Supplier of the Company's rejection of the Third Party Supplier's deliveries prior to implementing the reductions on the affected pipeline.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

2. ***IS Service***

The Company reserves the right to curtail IS Service at any time upon notice to the Customer(s) receiving the service. This requirement may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

In the event the Company notifies a Customer to discontinue the use of IS service at any time, and the Customer fails to do so, the Company shall have the right to terminate service, to transfer the Customer to a firm service classification and/or to bill the Customer for usage occurring during the curtailment period at the applicable "Unauthorized Use" charge in effect.

3. ***RS, GSS, GSL, DGC-Balancing, and NGV Residential Service***

The Third Party Supplier agrees to deliver to the Company's designated delivery meters a volume of gas for each day of the month equal to the average daily usage for that month for each Customer on whose behalf it is operating as specified by the Company ("Daily Delivery Volume"). The Company will provide the Third Party Supplier with the Daily Delivery Volume by month in advance during the year.

If the Third Party Supplier fails to deliver the Daily Delivery Volume, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect.

In the event that, at any time, the sum of a Third Party Supplier's cumulative imbalances, for non-Force Majeure reasons and for the time period which the Company has not yet received payment (including period since last bill), are under-deliveries that are at least three (3) times the Daily Delivery Volume, the Company will notify the Third Party Supplier. If such under-deliveries are at least five (5) times the Daily Delivery Volume, the Third Party Supplier will have four (4) business days to post and maintain for a one (1) year period a cash deposit or letter of credit in an amount equal to two (2) times that otherwise required pursuant to the Conditions Precedent of this Service Classification. At the conclusion of the one (1) year period, if the Third Party Supplier has had no additional occurrence of under-deliveries, the Third Party Supplier's credit requirement will be reduced to the amount required in the Conditions Precedent of this Service Classification. If the Third Party Supplier has had an additional under-delivery event during the one (1) year period, the Third Party Supplier will maintain the cash deposit or letter of credit in an amount equal to two (2) times that otherwise required pursuant to the Conditions Precedent of this Service Classification for an additional one (1) year period. The Company has the right to remove the Third Party Supplier from the New Jersey Natural Gas system for continued non-performance.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS

1. ***Monthly Imbalances***

   a. ***FT, DGC-FT, CNG, NGV Commercial and IS Transportation Services***

The Third Party Supplier shall use its best efforts to achieve a balance between its Customers' deliveries and requirements on a daily basis. Monthly imbalances in the volumes of gas delivered for the aggregate Customers' accounts (net of Special Provision 3, Fuel Use and Unaccounted for Gas) and the volumes of gas used in the aggregate by the Customers, will be cashed-out each month so that no imbalances will be carried into the next month. The cashout will be charged to the Third Party Supplier each month. The Company will use the average weekly spot index price for New York City citygate, as published by *Natural Gas Week's "Major Market Prices"*.

If the imbalance is negative (in aggregate the Customers used more gas than was delivered in aggregate by the Third Party Supplier), the Third Party Supplier will purchase gas from the Company at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Highest Weekly Index Price
>5% - ≤ 10%	quantity >5% * Highest Weekly * 1.1 + level above
>10% - ≤ 15%	quantity >10% * Highest Weekly * 1.2 + levels above
>15% - ≤ 20%	quantity >15% * Highest Weekly * 1.3 + levels above
>20% - ≤ 25%	quantity >20% * Highest Weekly * 1.4 + levels above
>25%	quantity >25% * Highest Weekly * 1.5 + levels above

If the imbalance is positive (in aggregate the Third Party Supplier delivered more gas than was used in aggregate by its Customers), the Company will purchase gas from the Third Party Supplier at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Lowest Weekly Index Price
>5% - ≤ 10%	quantity >5% * Lowest Weekly * .90 + level above
>10% - ≤ 15%	quantity >10% * Lowest Weekly * .80 + levels above
>15% - ≤ 20%	quantity >15% * Lowest Weekly * .70 + levels above
>20% - ≤ 25%	quantity >20% * Lowest Weekly * .60 + levels above
>25%	quantity >25% * Lowest Weekly * .50 + levels above

All revenues and purchases derived from imbalances will be credited to the BGSS.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

b. ***RS, GSS, GSL, DGC-Balancing , and NGV Residential Service***

For each Third Party Supplier, imbalances in the volumes of gas delivered for the Customer's account (net of Special Provision 3, Fuel Use and Unaccounted for Gas) and the volumes of gas used by the Customer, will be rolled over each month so that any imbalance will be carried into the next month. The Company will select the time period to net any imbalances with the monthly Daily Delivery Volume.

If the Third Party Supplier's account is out of balance by more than 30% of the total amount transported in the prior month, the Third Party Supplier may be required to modify its deliveries for the following month. In addition, the Company reserves the right to require additional volumes to be delivered for the following month for any volumes owed to the Company.

2. ***Daily Balancing***

a. ***FT and DGC-FT Services***

The Company may issue an Operational Flow Order (OFO) requiring delivery by the Third Party Supplier of at least the volume of gas the Customers, in aggregate, use on the affected gas day ("OFO Required Volume") plus Special Provision 3, Fuel Use and Unaccounted for Gas. An OFO may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

Third Party Suppliers who fail to deliver the OFO Required Volumes of gas may not be permitted to continue to operate on the system. In addition, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume.

There will be no daily or monthly penalties for delivering gas in excess of an OFO Required Volume. If the Third Party Supplier ends the month with a positive imbalance (in aggregate the Third Party Supplier delivered more gas than was used by its Customers), the portion of the imbalance related to overdeliveries on OFO days will be carried forward to the following month and be included in that month's cashout determination pursuant to Special Provision 1.a. of this Service Classification. If the Company issues additional OFOs in the month of the cashout determination, the Company, in its sole discretion, may waive the tiering of the cashout prices for positive imbalances greater than 5 percent initially incurred on OFO days.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

b. ***CNG and NGV Commercial Services***

The Company may issue an Operational Flow Order (OFO) requiring delivery by the Third Party Supplier of at least the volume of gas the Customers, in aggregate, use on the affected gas day ("OFO Required Volume") plus Special Provision 3, Fuel Use and Unaccounted for Gas. An OFO may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

Third Party Suppliers who fail to deliver the OFO Required Volumes of gas ("Delivery Shortfall") may not be permitted to continue to operate on the system. In addition, the Third Party Supplier will be billed at the highest of:

i. The "Company's Replacement Cost of Gas" (defined below);
ii. The highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey" in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume; or
iii. The highest price of daily ranges for delivery in Transco Zone 6 NNY North that are published in Platts Gas Daily on the table, "Daily Price Survey" in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume.

However, in a month that the Company does not allow Third Party Suppliers to deliver to the Company on the Transcontinental Gas Pipeline, the Company shall bill the Third Party Supplier at the higher of:

i. The "Company's Replacement Cost of Gas" (defined below); or
ii. The highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey" in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume.

There will be no daily or monthly penalties for delivering gas in excess of an OFO Required Volume. If the Third Party Supplier ends the month with a positive imbalance (in aggregate the Third Party Supplier delivered more gas than was used by its Customers), the portion of the imbalance related to overdeliveries on OFO days will be carried forward to the following month and be included in that month's cashout determination pursuant to Special Provision 1.a. of this Service Classification. If the Company issues additional OFOs in the month of the cashout determination, the Company, in its sole discretion, may waive the tiering of the cashout prices for positive imbalances greater than 5 percent initially incurred on OFO days.

"Company's Replacement Cost of Gas" means the highest of:

i. The Company's LNG inventory and gasification costs adjusted for all appropriate taxes, assessments and surcharges;
ii. The prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the OFO period; or
iii. The cost of gas purchased by the Company.

The Company's Replacement Cost of Gas shall also include any pipeline penalties or other charges or damages assessed on the Company.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

c. ***IS Services***

The Company may issue an IS Daily Balancing Restriction (IS-DB) requiring delivery by the Third Party Supplier of at least the volume of gas the Customers, in aggregate, use on the affected gas day ("IS Daily Balancing Volume") plus Special Provision 3, Fuel Use and Unaccounted for Gas. This requirement may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

Third Party Suppliers who fail to deliver the IS Daily Balancing Volumes of gas may not be permitted to continue to operate on the system. In addition, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect during the IS-DB period for the volume difference between the IS Daily Balancing Volume and the actual delivered volume.

There will be no daily or monthly penalties for delivering gas in excess of an IS Daily Balancing Volume. If the Third Party Supplier ends the month with a positive imbalance (in aggregate the Third Party Supplier delivered more gas than was used by its Customers), the portion of the imbalance related to overdeliveries on IS-DB days will be carried forward to the following month and be included in that month's cashout determination pursuant to Special Provision 1.a. of this Service Classification. If the Company issues additional IS-DB restrictions in the month of the cashout determination, the Company, in its sole discretion, may waive the tiering of the cashout prices for positive imbalances greater than 5 percent initially incurred on IS-DB restriction days.

3. ***Fuel Use and Unaccounted for Gas***

A 2% adjustment for fuel use and unaccounted for gas will be made to the quantity of gas received for the Customers' accounts. The quantity of gas ultimately delivered to the Customers shall be reduced by 2% from the level received by the Company for the Customers' account.

4. ***Taxes, Assessments And Surcharges***

The Third Party Supplier shall pay all taxes or surcharges that are lawfully imposed upon the Company in providing service under this service classification.

5. ***Incremental Expenses***

The Third Party Supplier shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence. Reimbursements for any costs associated with special non-recurring projects requested by a Third Party Supplier may be collected through this special provision. These special projects represent a level of service not anticipated in any of our administrative charges. The price for these projects shall be mutually agreed to prior to the initiation of any work related to the special project.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

6. ***Unauthorized Use Charge***

In the event the Company notifies a Customer to discontinue the use of transportation service at any time, and the Customer fails to do so ("Unauthorized Use"), the Company shall bill the Customer for usage occurring during the period of Unauthorized Use at a rate equal to the higher of:

i. Ten (10) times the highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey"; or

ii. Ten (10) times the highest price of the daily ranges for delivery in Transco Zone 6 NNY North that are published in Platts Gas Daily on the table, "Daily Price Survey".

The Company reserves the right to bill a rate equal to the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines that deliver gas to the Company. The Company shall also have the right to terminate the Customer's service.

Additionally, the Company has the right to recover proportionately from undelivered Customers any penalties or other charges or damages assessed on the Company as a result of any Unauthorized Use by the Customers.

7. ***Delivery Shortfall Charge***

In the event that the Third Party Supplier fails to deliver the Daily Delivery Volume, OFO Required Volume, or IS Daily Balancing Volume as directed by the Company (a "Delivery Shortfall"), the Company shall bill the Third Party Supplier for the volume of the Delivery Shortfall at a rate equal to the higher of:

i. Ten (10) times the highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey"; or

ii. Ten (10) times the highest price of daily ranges for delivery in Transco Zone 6 NNY North that are published in Platts Gas Daily on the table, "Daily Price Survey".

However, in a month that the Company does not allow Third Party Suppliers to deliver to the Company on the Transcontinental Gas Pipeline, the Company shall bill the Third Party Supplier for the volume of the Delivery Shortfall at a rate equal to ten (10) times the highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey."

If such Delivery Shortfall occurs when the Company has issued an OFO or required daily balancing, the Company reserves the right to bill a rate equal to the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines that deliver gas to the Company. Additionally, in the event of a Delivery Shortfall, the Company shall have the right to recover *pro rata* from all under-delivering Third Party Suppliers any penalties or other charges or damages assessed on the Company because of such under-deliveries for the days the Third Party Suppliers under-delivered.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

7. ***Delivery Shortfall Charge (continued)***

Notwithstanding the above, if contemporaneously with a Delivery Shortfall, an interstate pipeline that delivers to an NJNG delivery meter has declared a force majeure on its pipeline system curtailing primary, in-path transportation in the delivery meter's zone of delivery, the Company may waive the above charges and may bill the Third Party Supplier for the Company's Replacement Cost of Gas (defined below) provided that the under-delivering Third Party Supplier is able to demonstrate to the Company's reasonable satisfaction that the transportation contract on which the Third Party Supplier had scheduled deliveries to the Company's delivery meter during the period in which the OFO was in effect entitled the Third Party Supplier to firm transportation rights through the point at which the force majeure was declared and that the pipeline curtailed Third Party Supplier's deliveries pro rata with deliveries to other similarly situated delivery meters on the contract. The Third Party Supplier must notify the Company in writing of the anticipated Delivery Shortfall before the nomination deadline for the next North American Energy Standards Board ("NAESB") nomination cycle. If there are no additional cycles, they must notify the Company in writing before the gas day ends. "Company's Replacement Cost of Gas" means the highest of:

i. The Company's LNG inventory and gasification costs adjusted for all appropriate taxes, assessments and surcharges;
ii. The prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the time period of the force majeure; or
iii. The cost of gas purchased by the Company.

The Company's Replacement Cost of Gas shall also include any pipeline penalties or other charges or damages assessed on the Company.

8. ***Individual Customer Responsibility***

Customers taking service under Service Classifications RS, FT, GSL, GSS, DGC and IS may elect to designate one Third Party Supplier per account to have responsibility for nominations, daily balancing and/or monthly balancing on behalf of the Customer. The Company will provide both individual and summary bills to each such Third Party Supplier, with a summary of usage and associated charges provided for each Customer. If a Customer's designated Third Party Supplier should default on any obligation for payment under this Service Classification, the Customer will be responsible for its proportional share of charges, including payment for "Unauthorized Use", "Delivery Shortfall" or for monthly imbalances.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

9. ***Nominations***

By the deadline specified on the Company's electronic bulletin board (EBB), the Third Party Supplier shall enter nominations onto the Company's EBB on the day prior to gas flow for the next calendar day. The Third Party Supplier's nomination shall contain its Customers' transportation volumes and the contract number, along with the pipeline transporter. The Third Party Supplier may change any daily or monthly nominations in a timely manner on the Company's EBB by the time of the day prior to gas flow specified on the Company's EBB. The Third Party Supplier may request changes to nominations after the time specified on the Company's EBB in writing by e-mailing the Company, however any late changes are completely at the discretion of the Company. Any agreed to changes will have to be formally requested in writing.

The Company will not be required to accept any gas rendered by the pipeline transporter that: (a) does not conform to the Third Party Supplier's currently effective nominations or (b) is not delivered to a mutually agreeable delivery meter. The Company shall not be obligated to provide transportation service during an hourly, daily or monthly period in excess of the levels specified in the service agreement.

PAYMENT

Unless otherwise specified, bills are due within 10 days after the Company sends each Third Party Supplier's individual bill and is subject to a late payment charge as set forth in Paragraph 8.9 of the Standard Terms and Conditions of this Tariff. In preparing the bill, Company may net all amounts due and owing, and/or past due, such that the party owing the greater amount shall make a single payment of the net amount to the other party. The Company may elect to utilize the deposit to satisfy any payments deemed to be late and to notify the Third Party Supplier of the need to replenish the deposit. The Company may offset any payments deemed to be late against any amounts owed by the Company to the Third Party Supplier. Additionally, if a Third Party Supplier's account is in arrears, the Company reserves the right to cease new enrollments for the Third Party Supplier and has the right to remove the Third Party Supplier from the New Jersey Natural Gas system.

CONTRACT

The term of the initial Service Agreement will be for a minimum of one year. Thereafter, successive one-year terms will be in effect until terminated by written notice at least two (2) months prior to the expiration of the service agreement.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff, the applicable transportation Service Classification and the service agreement.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS

AVAILABILITY

This service is available to any customer who would otherwise qualify for service under Service Classifications RS, GSS, GSL, FT, IS, or NGV and who will utilize natural gas for the purpose of fueling natural gas vehicles at Company owned compressed natural gas re-fueling facilities operated by the Customer on its property ("Host Customer").

Availability of this Service Classification is subject to the terms and conditions approved in BPU Docket No. GR11060361. This Service Classification is closed.

CONDITIONS PRECEDENT

The Host Customer must sign an Agreement with the Company. The Host Customer must provide assurance that it will use initially at least twenty (20) percent of the re-fueling facility's capacity. The Host Customer must agree to provide the general public with reasonable access to a re-fueling facility for purposes of fueling the general public's natural gas vehicles.

DEFINITION OF TERM USED HEREIN

"GGE" is the Gasoline Gallon Equivalent for converting a price per therm of natural gas to a price per gallon of gasoline. The GGE shall be determined in accordance with local standards.

CHARACTER OF SERVICE

Firm gas service where Host Customer may purchase gas supply pursuant to the Company's Rider "A" for Basic Gas Supply Service ("BGSS"), from the Company through a contract, or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$142.50

Delivery Charge:

Delivery Charge per therm	$0.7862 ($0.983 per GGE)

BGSS Charge:

Monthly BGSS Charge per therm for Sales Customers without a gas supply contract	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***CNG Re-Fueling Facilities***

The Company shall install and own Compressed Natural Gas ("CNG") re-fueling facilities on the Host Customer's property. The Company shall maintain these facilities. The Host Customer is required to monitor and operate these facilities at its own expense. The Host Customer is also required to provide reasonable access to the re-fueling station to the general public and non-host customer fleets.

2. ***Automated Meter Reading Device***

Metering shall include an automated meter reading device (AMR), which shall be furnished and installed by the Company at the Host Customer's expense. The Host Customer shall furnish an electrical supply and phone line for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Host Customer's expense for such installation.

The Host Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over the life of the initial CNG agreement with the prime interest rate used to calculate carrying costs on the unpaid balance.

3. ***Incremental Expenses***

The Host Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

4. ***Taxes, Assessments and Surcharges***

The Customer shall pay all riders, taxes, assessments and surcharges that are lawfully imposed upon the Company in providing service under this classification.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS (continued)

5. ***Pricing to the General Public***

The Host Customer shall post the charge to the general public for its re-fueling volume at a price per GGE provided by the Company. Prior to the beginning of each month, the Company will notify the Host Customer of the price, the components of which are defined below:

a. Monthly BGSS Charge as set forth in Rider "A" converted to a price per GGE
b. CNG Delivery Charge as set forth in Service Classification CNG converted to a price per GGE
c. Applicable state and federal excise taxes
d. $0.20 per GGE for the Host Customer's expenses to operate the facilities.

The Host Customer shall display the price per GGE at the re-fueling station. The Company shall credit the Host Customer for the monthly volume sold to the general public at the price per GGE for the Host Customer's expenses to operate the facilities as defined in 5(d) above.

6. ***Pricing to Non-Host Company Fleets***

Other fleets re-fueling vehicles at the Company owned CNG re-fueling facilities operated by the Host Customer on its property may purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS"), from the Company through a contract, or from a Third Party Supplier pursuant to Section II herein. The Company shall charge other fleets for re-fueling volumes at a price per GGE, the components of which are defined below:

a. Monthly BGSS Charge as set forth in Rider "A" or a gas supply contract price or the price provided by a Third Party Supplier, converted to a price per GGE
b. CNG Delivery Charge as set forth in Service Classification CNG converted to a price per GGE
c. Applicable state and federal excise taxes
d. $0.20 per GGE for the Host Customer's expenses to operate the facilities.

The Company shall credit the Host Customer for the monthly volume sold to the other fleets at the price per GGE for the Host Customer's expenses to operate the facilities as defined in 6(d) above.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS (continued)

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Customer Responsibility***
The Company may require the Customer to provide, to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution system. In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

2. ***Billing***
Customers purchasing gas supply from a Third Party Supplier can only be billed through Billing Option 1 as defined in Service Classification-TPS.

3. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

CONTRACT

A written agreement shall be required for Compressed Natural Gas Host Customers and non-Host Customers Fleets.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions of this Tariff.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet Nos. 103-150*

RESERVED FOR FUTURE USE

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS

Applicable to the following service classifications:

RS	Residential Service		
DGR	Distributed Generation - Residential	ED	Economic Development
DGC	Distributed Generation - Commercial	NGV	Natural Gas Vehicles
GSS	General Service - Small	IS	Interruptible Service
GSL	General Service - Large	CNG	Compressed Natural Gas

I. Periodic Basic Gas Supply Service Charge

By June 1 of each year, the Company shall file with the Board, a request for an October 1 implementation of a Periodic Basic Gas Supply Service ("Periodic BGSS") Charge, which shall be applicable to customers on the RS, GSS, and DGR, service classifications listed above and to customers on the ED service classification listed above who are eligible to receive service under Service Classification GSS.

A. Determination of the Initial Periodic BGSS Factor for the BGSS Year

The Periodic BGSS Factor shall be derived in the following manner:

(1) An estimate shall be made of the total volume of prospective gas supplies from all sources, including pipeline natural gas and all substitute and supplement gas supplies, and of the estimated overall commodity cost of all such prospective supplies, including pipeline refunds and other credits, excluding Company labor costs, for the remainder of the BGSS year ending September 30. The estimated overall commodity costs of prospective supplies will be comprised of 1) the value of gas withdrawn from storage; 2) the value of volumes whose price was previously set by hedges or other financial instruments; 3) current flowing gas, which will be priced at the arithmetic average of (i) the NYMEX closing price for the last trading day prior to each respective month and (ii) the average of the estimated Inside FERC prices for the producing locations that relate to the Company's purchases; and 4) the variable cost of transportation and fuel.

(2) An estimate shall be made of the total volume of prospective firm sales of gas (in therms) for the BGSS year ending September 30.

RIDER "A"

BASIC GAS SUPPLY SERVICE – BGSS (continued)

(3) The cost of prospective gas supplies (per paragraph (1)) shall be adjusted upward or downward to the extent of the cumulative amount of any prior under-recovery or over-recovery of gas commodity costs to determine the total commodity gas costs to be recovered and then shall be divided by the estimated total volume of prospective firm sales (per paragraph (2)), to determine the per unit commodity cost recovery rate.

(4) An estimate shall be made of the fixed pipeline, fixed storage, and supplier demand costs for the BGSS year ending September 30. The estimated fixed demand shall be adjusted upward or downward to the extent of the cumulative amount of any prior under-recovery or over-recovery of fixed costs and then shall be divided by the estimated total volume of prospective firm sales (per paragraph (2)), to determine the per unit demand cost recovery rate.

(5) The adjusted commodity gas costs to be recovered, as determined per paragraph (3), shall then be added to the per unit demand cost recovery as determined per paragraph (4) and the result carried for four (4) decimal places.

B. Determination of Revised Periodic BGSS Factors

(1) Following Board approval of the initial Periodic BGSS Charge, the Company shall have the opportunity to implement increases to be effective December 1 and February 1 on a self-implementing basis subject to a maximum rate increase of up to 5% of the average residential customer total bill.

(2) The Company may implement, at its discretion, bill credits, refunds, or self-implementing rate reductions during the BGSS year ending September 30.

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS (continued)

II. Monthly Basic Gas Supply Service Charge

On the second day following the close of the trading of the NYMEX Henry Hub natural gas contracts for the prospective month, the Company shall submit to the Board, a Monthly Basic Gas Supply Service ("BGSS") Charge, which shall be applicable to customers in the GSL, DGC, NGV, CNG, and IS service classifications, and to customers in the ED service classification listed above who are eligible to receive service under Service Classification GSL.

A. Derivation of the Monthly BGSS Factor

The Monthly BGSS Factor shall be derived in the following manner:

(1) An estimate shall be made of the fixed pipeline, fixed storage, and supplier demand costs for the BGSS year ending September 30. An estimate shall be made of the total volume of prospective firm sales of gas (in therms) for the BGSS year ending September 30. The estimated fixed demand shall then be divided by the estimated total volume of prospective firm sales to determine the per unit demand cost recovery rate.

(2) The overall Monthly BGSS Charge will be established prior to the beginning of each month based on the sum of: 1) the arithmetic average of (i) the NYMEX closing price for the last trading day prior to each respective month and (ii) the average of the estimated Inside FERC prices for the producing locations that relate to the Company's purchases; 2) the variable cost of transportation and fuel; and 3) the per unit demand cost recovery rate as determined in accordance with paragraph (1). The Monthly BGSS Factor shall be adjusted for taxes, assessments or surcharges. The result shall be carried for four (4) decimal places.

(3) The Monthly Gas Cost Recovery Charge shall be added to all tariff rates then in effect, effective for service rendered commencing the first day of such month of such year, and continuing in effect until the effective date of the subsequent monthly or other filing of a revision of modification thereof.

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS (continued)

III. Tracking the Operation of the BGSS

The net amount of gas costs and recoveries, including pipeline refunds and other credits, if any, shall be maintained in a separate clearing account which will be reviewed as part of the annual filing.

Interest shall be computed monthly, at the overall annual rate of return as authorized by the Board of Public Utilities, on the average monthly balances of over or under-recovery of excess purchased gas costs and supplier refunds. In the event such interest computations result in a cumulative net interest credit at the end of the year, such credit shall be applied against the gas costs in calculating the Periodic BGSS factor for the following year.

In accordance with P.L., 1997 c. 162, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT"), and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS(continued)

PERIODIC BASIC GAS SUPPLY SERVICE (BGSS) CHARGE

SERVICE CLASSIFICATION	*APPLICATION*	*CHARGE*
RS and GSS sales customers, and ED sales customers eligible for service under Service Classification GSS	Included in the Basic Gas Supply Charge	$0.4290 per therm

BALANCING CHARGE

SERVICE CLASSIFICATION	*APPLICATION*	*CHARGE*
RS, GSS, GSL, DGR, DGC-Balancing, and ED customers eligible for service under Service Classifications GSS and GSL	Included in the Delivery Charge	$0.1271 per therm

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS(continued)

MONTHLY BASIC GAS SUPPLY SERVICE (BGSS) CHARGE

SERVICE CLASSIFICATION	*APPLICATION*
GSL, DGC-Balancing, and CNG sales customers, and ED sales customers eligible for service under Service Classification GSL	Included in the Basic Gas Supply Charge

Effective Date	Charge Per Therm for IS, CNG, NGV	Charge Per Therm for GSL, DGC-Balancing[1]
January 1, 2023	$0.7993	$0.6613
February 1, 2023	$0.6657	$0.5277
March 1, 2023	$0.6085	$0.4705
April 1, 2023	$0.5620	$0.4240
May 1, 2023	$0.5510	$0.4130
June 1, 2023	$0.5154	$0.3774
July 1, 2023	$0.5181	$0.3801
August 1, 2023	$0.5037	$0.3657
September 1, 2023	$0.4928	$0.3548
October 1, 2023	$0.5079	$0.3813
November 1, 2023	$0.5658	$0.4392
December 1, 2023	$0.5908	$0.4642
January 1, 2024	$0.5989	$0.4723

[1] For GSL and DGC customers, the BGSS charge per therm is reduced by the Balancing Charge which is included in the Delivery Charge.

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS(continued)

BGSS SAVINGS COMPONENT RELATED TO THE CONSERVATION INCENTIVE PROGRAM (CIP) IN RIDER "I"

SERVICE CLASSIFICATION	*APPLICATION*	*CREDIT*
RS, GSS, GSL, and ED sales customers	Embedded within the Periodic Basic Gas Supply Charge and the Monthly Basic Gas Supply Charge	($0.0270) per therm

TEMPORARY BGSS RATE CREDIT ADJUSTMENT

Applicable to RS and GSS sales customers and ED customers eligible for service under Service Classification GSS

EFFECTIVE DATES	*CREDIT PER THERM*
December 1, 2020 through January 31, 2021	($0.1220)
March 1, 2023 through March 31, 2023	($0.5054)

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 158*

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT)

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 159*

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT) (continued)

In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this Tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable under this Tariff shall be reduced by the provision for the SUT) included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey. [P.L. 1997, c.162]

2. Natural gas or utility service that is used to generate electricity that is sold for resale or to an end user other than the end user located on the property the cogeneration or self-generation unit that generated the electricity is located. [P.L. 2009, c. 240]

3. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997. [P.L. 1997, c.162]

4. Natural gas and utility service that is used for cogeneration facility that is constructed after January 1, 2010. Any cogeneration facility that was in operation prior to January 1, 2010 and was subject to New Jersey SUT for the purchase and use of natural gas and utility service for cogeneration purposes shall continue to be subject to, and responsible for payment of, such tax. [P.L. 2009, c. 240]

5. Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998. [P.L. 1997, c.162]

6. Agencies or instrumentalities of the federal government. [P.L. 1997, c.162]

7. International organizations of which the United States of America is a member. [P.L. 1997, c.162]

8. Cemetery companies, pursuant to N.J.S.A 8A:5-10. (must provide an Exempt Use Certificate (ST-4) to seller).

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 160*

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT) (continued)

9. Amtrak (National Railroad Passenger Corporation) and New Jersey Transit Rail Operations.

10. Limited Dividend Housing Corporations organized under N.J.S.A. 55:16-1 seq., for use at the qualified housing project. (must provide an Exempt Use Certificate (ST-4) to seller).

In addition, the Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c.374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. a qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

2. a group of two or more persons:

   a) each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.);

   b) that collectively employ at least 500 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;

   c) are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and

   d) collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone;

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT) (continued)

3. a business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (1), (2) or (3) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 162*

RIDER "C"

SOCIETAL BENEFITS CHARGE (SBC)

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Societal Benefits Charge ("SBC") and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The below rates shall be calculated in accordance with the provisions of the referenced Riders of this Tariff and are collected through the SBC on a per-therm basis within the Delivery Charge for all service classifications to which Rider "C" applies.

:

SBC Rate Component:			
Remediation Adjustment ("RA")		$0.0228	Rider D
New Jersey's Clean Energy Program		$0.0245	Rider E
Universal Service Fund ("USF"):			
Lifeline	$0.0062		
USF	$0.0115		
Total USF Billing Factor		$0.0177	Rider F
Total SBC		$0.0650	

Date of Issue:
Issued by: *Mark G. Kahrer, Senior Vice President*
Wall, NJ 07719

Effective for service rendered on and after March 1, 2024

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NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No.163*

RIDER "D"

REMEDIATION ADJUSTMENT (RA)

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Remediation Adjustment ("RA") and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The RA Factor will be determined as follows:

I. DEFINITION OF TERMS USED HEREIN

1. ***"Remediation Costs"*** are all investigation, testing, land acquisition if appropriate, remediation and/or litigation costs/expenses or other liabilities excluding personal injury claims and specifically relating to former gas manufacturing facility sites, disposal sites, or sites to which material may have migrated, as a result of the earlier operation or decommissioning of gas manufacturing facilities.

2. ***"Recovery Year"*** is each October 1 to September 30 year and is the time period over which the amortized expenses shall be received from Customers.

3. ***"Remediation Year"*** is each July 1 to June 30 year and is the time period over which the remediation costs are incurred.

RIDER "D"

REMEDIATION ADJUSTMENT (RA) (continued)

DEFINITIONS OF TERMS USED HEREIN (continued)

4. ***"Third Party Claims"*** are all claims by New Jersey Natural Gas Company against any entity including insurance companies, from which recoveries may be received and will be charged through the RA factor as follows:

   a) Fifty percent of the reasonable transaction costs and expenses in pursuing Third Party Claims shall be included as Remediation Costs and shall be recovered as part of the RA clause. The remaining 50% shall be deferred until such time as the specific claim is resolved.

   b) In the event that the Company is successful in obtaining a reimbursement from any Third Party, the Company shall be permitted to retain the deferred 50% as specified in 4a. The balance of the reimbursement, if any, shall be applied against the Remediation Costs in the year it is received and will be amortized over seven years.

5. ***Sale of Property*** shall be calculated by taking the proceeds of any sale of a former manufacturing gas plant site, less all reasonable expenses associated with selling the site, and subtracting the total costs that were incurred in cleaning up the site and amortized through rates. The proceeds associated with the total costs that were incurred in cleaning up the site will be included as a credit to the remediation costs incurred in the year of the sale. The remainder shall be equally shared between the Company and ratepayers.

RIDER "D"

REMEDIATION ADJUSTMENT (RA) (continued)

II. DETERMINATION OF THE REMEDIATION ADJUSTMENT

At the end of the remediation year, the Company shall file with the Board all bills and receipts relating to the amount of any remediation costs incurred in the preceding remediation year for which it seeks to begin recovery. In the same filing, the Company shall include similar material and information to support any expenses and/or recoveries resulting from Third Party claims. The Company shall also submit in its annual filing a projection of remediation costs for the following remediation year.

The RA factor shall be calculated by taking one seventh of the Actual Remediation Costs plus applicable Third Party Claims and Sale of Property allocations incurred each year, until fully amortized, plus the prior years' RA over or under-recovery plus appropriate carrying costs and dividing this amount by the Company's total volume of prospective sales for the upcoming recovery year. The result shall be carried for four (4) decimal places.

The RA will be calculated as the difference between revenues calculated by multiplying the RA factor times actual monthly firm sales and remediation costs allowable per the formula.

The total annual charge to the Company's ratepayers for remediation costs during any recovery year shall not exceed five (5%) percent of the Company's total revenues from gas sales during the preceding Remediation Year. If this limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular Recovery Year and the mechanism is not reopened at the request of any party, then the remediation costs in excess of the 5% shall be included in the subsequent year's collection. The Company shall calculate carrying costs on any under-or over-recovered RA cost balances, and the deferred tax benefit associated with those balances, using the same interest rate, which rate will be adjusted each August 31 based upon the seven-year constant maturity Treasury rate, shown in the Federal Reserve Statistical Release, plus 60 basis points. Interest applicable to the Company's unamortized RA balance shall be calculated and will accrue on a monthly basis and shall be rolled into the RA balance at the beginning of each recovery year.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 166*

RIDER "D"

REMEDIATION ADJUSTMENT (RA) (continued)

III. TRACKING THE OPERATION OF THE REMEDIATION ADJUSTMENT CLAUSE

The revenues billed, net of taxes and assessments through the application of the Remediation Adjustment factor shall be accumulated for each month and be applied against the total amortized Remediation Costs calculated for that year. Any over or under collection at the end of the Recovery Year will be included in the determination of the following year's RA factor.

In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT") and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

The RA factor shall be collected through the SBC on a per-therm basis within the Delivery Charge for all service classifications to which Rider "D" applies. The RA factor is set forth below:

$0.0228

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 167*

RIDER "E"

NEW JERSEY'S CLEAN ENERGY PROGRAM

AVAILABILITY

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with NJ's Clean Energy Program and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The Company shall file with the Board, an annual NJ's Clean Energy Program factor concurrent with the Company's SBC filing, which shall be derived in the following manner:

1. The Company's funding obligation based upon the most recently BPU approved NJ's Clean Energy Program, previously referred to as the Comprehensive Resource Analysis ("CRA") Plan.

2. The difference between the approved funding obligation for the preceding year and the actual recovery of the NJ's Clean Energy Program costs plus appropriate carrying costs.

3. An estimate shall be made of the total volume of prospective jurisdictional therm sales of gas for the applicable service classifications for the twelve (12) months of the recovery year.

RIDER "E"

NEW JERSEY'S CLEAN ENERGY PROGRAM (continued)

4. The total NJ's Clean Energy Program costs to be recovered, as determined per paragraphs (1), (2) and (3) shall then be divided by the total volume of prospective jurisdictional therm sales (per paragraph (3)), and the result carried to four (4) decimal places. Such result shall constitute the NJ's Clean Energy Program factor effective for service rendered commencing the effective date of approval, and continuing in effect until the effective date of any subsequent annual or other filing of a revision of modification thereof.

The net amount shall be maintained in a separate deferred account. In the event that the Company determines that an existing NJ's Clean Energy Program rate, if left unchanged, would result in a material over- or under-collection of amounts incurred or expected to be incurred during the current NJ's Clean Energy Program Recovery Year, the Company may file with the BPU for approval of an interim revision of the NJ's Clean Energy Program rate. Such interim revision shall be designed to minimize or eliminate the over- or under-collection expected to result absent such revision either over: (a) the remaining billing months of the current NJ's Clean Energy Program Recovery Year or (b) over such other time period as the BPU shall determine.

The Company shall calculate carrying costs on the average monthly balances of under-or over-recovery of deferred costs, and the deferred tax benefit associated with those balances, using the same interest rate, which will be adjusted each August 31 based upon the seven-year constant maturity Treasury rate, shown in the Federal Reserve Statistical Release, plus 60 basis points. Interest will accrue on a monthly basis and shall be rolled into the balance each October 1.

In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT") and when billed to customers exempt from this tax, as set forth in Rider SUT, shall be reduced by the amount of such tax included therein.

The NJ's Clean Energy Program factor shall be collected through the SBC on a per therm basis within the Delivery Charge for all service classifications to which this Rider "E" applies. The NJ's Clean Energy Program factor is as set forth below:

$0.0245

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 169*

RIDER "F"

UNIVERSAL SERVICE FUND – USF

AVAILABILITY

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Universal Service Fund ("USF") and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The USF is a fund established by the New Jersey Board Public Utilities ("NJBPU") to provide affordable access for electric and natural gas service to all residential customers in the State. The Electric Discount and Energy Competition Act mandated the establishment of the USF in New Jersey.

Revenues collected through this rider are used to fund the State's USF program for qualified low-income customers and the Lifeline Credit program, a special program for qualified low-income elderly and disable citizens. The USF is administered by the State of New Jersey Department of Community Affairs and the Lifeline Credit Program is administered by the State of New Jersey Department of Human Resources. The USF program Year is intended to run from October 1st to September 30th of each year.

NEW JERSEY NATURAL GAS COMPANY

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RIDER "F"

UNIVERSAL SERVICE FUND – USF (continued)

DETERMINATION OF THE USF

On an annual basis, the NJBPU shall consider the following: estimated USF benefits for upcoming USF program Year; Lifeline budget for upcoming USF program year; estimated administrative expenses; the projected current year under/over recovery position, and annual forecasted volumes in order to establish a USF rate for the upcoming USF program year. This state wide rate shall be adjusted for all applicable taxes and assessments and shall be provided to all utilities to be included in their annual SBC filings for notice and public hearing purposes.

The Company shall calculate carrying costs on any under-or over-recovered USF balances based upon the two-year constant maturity Treasury rate, as published in the Federal Reserve Statistical Release on the first day of each month, or the closest day thereafter on which rates are published, plus sixty (60) basis points; provided, however, that this interest rate does not exceed the overall rate of return as authorized by the Board. The interest rate shall be reset each month. The carrying cost calculation shall be based on the net of tax beginning and end average monthly balance. The carrying costs shall accrue on a monthly basis and shall be rolled into the USF balance at the end of each USF year.

The USF shall be collected on a per therm basis and shall remain in effect until changed by order of the NJBPU:

Lifeline	$0.0062
USF	$0.0115
USF Billing Factor	$0.0177

In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT"), and when billed to customer exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

RIDER "G"

ENERGY EFFICIENCY - EE

AVAILABILITY

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Energy Efficiency ("*EE")* Rider and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The EE rate is for recovering authorized expenditures related to the energy-efficiency programs as approved in BPU Docket Nos. GO10030225, GR11070425, GO12070640, GO14121412, and GO18030355, collectively referred to as "Energy Efficiency Programs Established 2010-2018", and GO20090622 ("Energy Efficiency Programs Established 2021-Present").

DETERMINATION OF THE EE

The Company shall file an annual request with the Board for implementation of an EE charge, which shall be applicable to customers on all service classifications to which Rider "G" applies. The EE recovery year is intended to run from October 1st to September 30th of each year.

RIDER "G"

ENERGY EFFICIENCY – EE (continued)

I. Determination of the Rate

The EE rate shall have two components, an Energy Efficiency Programs 2010-2018 rate and an Energy Efficiency Programs Established 2021-Present rate, which shall be derived in the following manner:

1. An estimate shall be made of the total annual cost related to the programs. This rider will include only expenses for energy-efficiency programs approved by the Board for Energy Efficiency Programs 2010-2018 and Energy Efficiency Programs Established 2021-Present unless modified further by Board Order.

2. An estimate shall be made of the total annual volume of prospective jurisdictional sales of gas (in therms) to NJNG's sales and transportation customers.

3. The prospective costs for Energy Efficiency Programs 2010-2018 and Energy Efficiency Programs Established 2021-Present (per paragraph (1)) shall separately be adjusted upward or downward to the extent of the amount of any prior under-recovery or over-recovery to determine the total costs to be recovered and then shall be divided by the estimated total volume of prospective sales (per paragraph (2)), to determine the per unit cost recovery rate. The result shall be carried for four (4) decimal places.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 173*

RIDER "G"

ENERGY EFFICIENCY – EE (continued)

II. Tracking the Operation of the EE

The Company shall calculate carrying costs on the average monthly balances of under-or over-recovery of deferred costs based upon the Company's monthly commercial paper rate. The carrying cost calculation shall be based on the net of tax beginning and end average monthly balance. The carrying costs shall accrue on a monthly basis and shall be rolled into the balance at the end of each EE recovery year.

In accordance with P.L., 1997 c. 162, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT"), and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

The EE rate shall be credited/collected on a per therm basis within the Delivery Charge for all service classifications to which Rider "G" applies. The EE rate is as set forth below:

Energy Efficiency Programs Established 2010-2018	$0.0247
Energy Efficiency Programs Established 2021-Present	$0.0247
EE	$0.0494

Date of Issue:
Issued by: *Mark G. Kahrer, Senior Vice President*
Wall, NJ 07719

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NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 174*

RIDER "H"

INFRASTRUCTURE INVESTMENT PROGRAM - IIP

Applicable to the following service classifications:

RS	Residential Service	DGC	Distributed Generation Commercial
DGR	Distributed Generation Residential	ED	Economic Development
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	CNG	Compressed Natural Gas
FT	Firm Transportation		

INCREMENTAL BASE RATE CHARGES

Service Classification		*Pre-Tax Rate*	*After-tax Rate*
RS	IIP Base Rate Charge per therm	$0.0090	$0.0096
DGR	IIP Base Rate Charge per therm	$0.0000	$0.0000
GSS	IIP Base Rate Charge per therm	$0.0115	$0.0123
GSS CAC	IIP Base Rate Charge per therm	$0.0015	$0.0016
GSL	IIP Base Rate Charge per therm	$0.0083	$0.0088
GSL CAC	IIP Base Rate Charge per therm	$0.0015	$0.0016
FT	IIP Base Rate Charge per therm	$0.0043	$0.0046
DGC	IIP Base Rate Charge per therm	$0.0025	$0.0027
NGV	IIP Base Rate Charge per therm	$0.0051	$0.0054
CNG	IIP Base Rate Charge per therm	$0.0051	$0.0054

The above IIP Base Rate Charges will be included in total Delivery Charges on customer bills.

RIDER "H"

INFRASTRUCTURE INVESTMENT PROGRAM - IIP (continued)

DETERMINATION OF THE IIP

The purpose of the Infrastructure Investment Program Rider is to set forth the base rate adjustments associated with the Company's approved Infrastructure Investment Program pursuant to N.J.A.C. 14:3-2A.1 et seq. The Company shall file periodic requests with the Board for implementation of IIP charges applicable to customers on service classifications to which Rider "H" applies. Filings will be made according to the Company's recovery periods approved in BPU Docket No. GR19020278.

Recovery under the IIP is contingent on an earnings test for the annual period. If the calculated return on equity ("ROE") in the applicable annual IIP filing exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the IIP shall not be allowed in the applicable annual IIP filing. Any disallowance resulting from the earnings test will not be charged to customers in a subsequent IIP filing period, but the Company may seek such recovery in a subsequent rate case. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's regulated jurisdictional net income for the annual period by the Company's average jurisdictional common equity balance for such annual period. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) other income, net of associated taxes, (2) margins retained from Off-System Sales and Capacity release, net of associated taxes, (3) margins retained from the Storage Incentive Program, net of associated taxes, and (4) margins retained from the energy efficiency programs of Rider "G", net of associated taxes. The Company's average jurisdictional common equity balance for any annual period shall be derived by multiplying the average of the Company's beginning and ending net rate base for the annual period by the equity ratio approved in the Company's most recent rate case.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP

Applicable to the following service classifications:

RS	Residential Service
GSS	General Service - Small
GSL	General Service - Large
ED	Economic Development

I. DEFINITION OF TERMS AS USED HEREIN

1. ***Actual Number of Customers*** – The Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") applies. The ANC shall equal the aggregate actual booked number of customers for the month as recorded on the Company's books, plus any Incremental Large Customer Count Adjustment.

2. ***Actual Usage per Customer*** – the Actual Usage per Customer ("AUC") shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month.

3. ***Adjustment Period*** - shall be the year beginning immediately following the conclusion of the Annual Period.

4. ***Annual Period*** – shall be the twelve consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

5. ***Baseline Usage per Customer*** – the Baseline Usage per Customer ("BUC") shall be stated in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

6. ***Customer Class Group*** – For purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

   Group I: RS (non-heating customers only)
   Group II: RS (heating customers only)
   Group III: GSS, ED using less than 5,000 therms annually
   Group IV: GSL, ED using 5,000 therms or greater annually

7. ***Forecast Annual Usage*** – the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

8. ***Incremental Large Customer Count Adjustment*** – the Company shall maintain a list of incremental commercial and industrial customers added to its system on or after July 1, 2024 whose connected load is greater than that typical for the Company's average commercial and industrial customer. For purposes of the CIP, large incremental customers shall be those customers whose connected load exceeds 5,700 cubic feet per hour ("CFH"). A new customer at an existing location previously connected to NJNG's facilities shall not be considered an incremental customer. The Actual Number of Customers for the Customer Class Group shall be adjusted to reflect the impact of all such incremental commercial or industrial customers. Specifically, the Incremental Large Customer Count Adjustment for the applicable month shall equal the aggregate connected load for all active customers that exceed the CFH threshold divided by 2,850 CFH less the number of active customers, rounded to the nearest whole number.

9. ***Margin Revenue Factor*** – the Margin Revenue Factor ("MRF") shall be the weighted-average margin rate as quoted in the individual service classes to which the CIP applies. The MRFs by Customer Class Group are as follows:

Group I (RS non-heating):	$0.8680
Group II (RS heating):	$0.8680
Group III (GSS, ED using less than 5,000 therms annually)	$0.7851
Group IV (GSL, ED using 5,000 therms or greater annually)	$0.4310

The MRF shall be reset each time new base rates are placed into effect.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

II. BASELINE USAGE PER CUSTOMER

The BUC for each Customer Class Group by month are as follows:

Month	Group I: RS Non-Heating	Group II: RS Heating	Group III: GSS, ED using less than 5,000 therms annually	Group IV: GSL, ED using 5,000 therms or greater annually
Oct.	15.5	46.5	51.1	993.5
Nov.	15.2	95.3	119.8	1,733.1
Dec.	20.6	154.8	210.4	2,636.2
Jan.	23.4	188.9	266.1	3,153.5
Feb.	20.8	163.0	225.5	2,734.3
Mar.	17.3	128.5	168.6	2,252.1
Apr.	11.5	69.0	79.5	1,326.2
May	10.4	36.3	36.2	759.8
Jun.	17.2	23.4	21.0	528.3
Jul.	17.8	24.6	26.5	581.8
Aug.	13.0	21.5	20.7	536.2
Sep.	15.8	21.8	21.9	537.6
Total Annual	198.5	973.6	1,247.3	17,772.6

The BUC shall be reset each time new base rates are placed into effect.

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM RATE

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the Actual Number of Customers and then multiplying the resulting therms by the Margin Revenue Factor.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

2. The normal degree days and degree day consumption factors per customer to be used for the calculation of the weather related change in customer usage, are set forth below:

		Consumption Factors per customer (therms per customer per degree day)		
Month	**Degree Days**	**Group II- Residential Heating**	**Group III- GSS**	**Group IV- GSL**
October	225	0.1657	0.1719	2.7305
November	516	0.1814	0.2171	2.7897
December	793	0.1932	0.2587	2.8903
January	954	0.1971	0.2670	2.9560
February	801	0.1971	0.2679	2.9257
March	658	0.1932	0.2537	2.9033
April	346	0.1894	0.2180	2.8689
May	122	0.1971	0.2070	2.8673

These consumption factors per customer shall be multiplied by the actual number of customers to determine the consumption factors. The weather related change in customer usage shall be calculated as the difference between actual degree days and the above normal degree days multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this Rider.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGSS savings test and a Margin Revenue recovery limitation ("recovery tests"). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGSS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGSS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this Rider I.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

4. In addition, cost recovery under the CIP is contingent on an earnings test for the Annual Period. If the calculated return on equity ("ROE") exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the CIP shall not be allowed. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's regulated jurisdictional net income for the Annual Period by the Company's average jurisdictional common equity balance for such Annual Period. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) the CIP booked margin revenue accruals, net of associated taxes, (2) other income, net of associated taxes, (3) margins retained from Off-System Sales and Capacity release, net of associated taxes, (4) margins retained from the Storage Incentive Program, net of associated taxes, and (5) margins retained from the energy efficiency programs of Rider "G", net of associated taxes. The Company's average jurisdictional common equity balance for any Annual Period shall be derived by multiplying the average of the Company's beginning and ending net rate base for the Annual Period by the equity ratio approved in the Company's most recent rate case.

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

In accordance with P.L. 1997, c. 192, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT") and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

The annual filing for the adjustment to the CIP rate shall be concurrent with the annual filing for BGSS. The CIP factor shall be credited/collected on a basis within the Delivery Charge for all service classifications stated above.

The currently effective CIP factor by Customer Class Group are as follows:

Group I (RS non-heating):	$0.0382
Group II (RS heating):	$0.0915
Group III (GSS, ED using less than 5,000 therms annually):	$0.0605
Group IV (GSL, ED using 5,000 therms or greater annually):	$0.0353

For the recovery of the October 2022 through September 2023 CIP margin deficiency, the recovery of the margin deficiency associated with non-weather related change in customer usage included in the above factors are offset by the BGSS savings component, as set forth in Rider A. The BGSS savings component is embedded within the Periodic BGSS Charge and the Monthly BGSS Charge.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 182-250*

RESERVED FOR FUTURE USE

Date of Issue:
Issued by: *Mark G. Kahrer, Senior Vice President*
Wall, NJ 07719

Effective for service rendered on and after March 1, 2024

Filed pursuant to Order of the Board of Public Utilities entered in Docket No.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 251*

SUMMARY OF RATE COMPONENTS

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 252*

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Residential Heating Customers

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		15.00	15.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.8590	0.8590	
Pre-tax IIP Base Rate		0.0090	0.0090	Rider H
Total Pre-tax Base Rate (Margin Revenue Factor)		0.8680	0.8680	
SUT		0.0575	0.0575	Rider B
After-tax Base Rate		0.9255	0.9255	
CIP		0.0915	0.0915	Rider I
EE		0.0494	0.0494	Rider G
Subtotal	a	*1.0664*	*1.0664*	
Balancing Charge	b	*0.1271*	*0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**1.2585**	**1.2585**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**x**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 253*

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Residential Non-Heating Customers

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		15.00	15.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.8590	0.8590	
Pre-tax IIP Base Rate		0.0090	0.0090	Rider H
Total Pre-tax Base Rate (Margin Revenue Factor)		0.8680	0.8680	
SUT		0.0575	0.0575	Rider B
After-tax Base Rate		0.9255	0.9255	
CIP		0.0382	0.0382	Rider I
EE		0.0494	0.0494	Rider G
Subtotal	a	*1.0131*	*1.0131*	
Balancing Charge	b	*0.1271*	*0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**1.2052**	**1.2052**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**x**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 254*

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Residential Distributed Generation Service

		Nov - Apr	May - Oct	Reference
Customer Charge				
Customer Charge per meter per month		15.00	15.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.1685	0.1185	
Pre-tax IIP Base Rate		0.0000	0.0000	Rider H
Total Pre-tax Base Rate		0.1685	0.1185	
SUT		0.0112	0.0079	Rider B
After-tax Base Rate		0.1797	0.1264	
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.2291*	*0.1758*	
Balancing Charge	b	*0.1271*	*0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0262	0.0262	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	c	0.0650	0.0650	Rider C
Delivery Charge (DEL)	a+b+c=d	**0.4212**	**0.3679**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**0.4290**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

General Service - Small (GSS)

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		57.50	57.50	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.7736	0.7736	
Pre-tax IIP Base Rate		0.0115	0.0115	Rider H
Total Pre-tax Base Rate (Margin Revenue Factor)		0.7851	0.7851	
SUT		0.0520	0.0520	Rider B
After-tax Base Rate		0.8371	0.8371	
CIP		0.0605	0.0605	Rider I
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.9470*	*0.9470*	
Balancing Charge	b	*0.1271*	*0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**1.1391**	**1.1391**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**x**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 256*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

General Service - Large (GSL)

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		142.50	142.50	
Demand Charge				
Demand Charge per month applied to HMAD		4.50	4.50	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.4227	0.4227	
Pre-tax IIP Base Rate		0.0083	0.0083	Rider H
Total Pre-tax Base Rate (Margin Revenue Factor)		0.4310	0.4310	
SUT		0.0286	0.0286	Rider B
After-tax Base Rate		0.4596	0.4596	
CIP		0.0353	0.0353	Rider I
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.5443*	*0.5443*	
Balancing Charge	b	*0.1271*	*0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**0.7364**	**0.7364**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**$0.4723**	**X**	Rider A

With the exception of the Customer Charge and Demand charges, these rates are on a per-therm basis.

Total Customer, Total Demand, DEL, and BGS charges are presented on customer bills.

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

FIRM TRANSPORTATION (FT)

		Transport	Reference
Customer Charge			
Customer Charge per meter per month		475.00	
Demand Charge			
Demand Charge per therm per month applied to MDQ		3.75	
Delivery Charge ("DEL") per therm			
Pre-tax Base Rate		0.0658	
Pre-tax IIP Base Rate		0.0043	Rider H
Total Pre-tax Base Rate		0.0701	
SUT		0.0046	Rider B
After-tax Base Rate		0.0747	
EE		0.0494	Rider G
Subtotal	a	*0.1241*	
Societal Benefits Charge ("SBC"):			
NJ's Clean Energy		0.0245	Rider E
RA		0.0228	Rider D
USF		0.0177	Rider F
Total SBC	b	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**0.1891**	

With the exception of the Customer Charge and Demand charges, these rates are on a per-therm basis.

Total Customer, Total Demand, and DEL, charges are presented on customer bills.

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Commercial Distributed Generation Service – DGC-Balancing

		Nov - Apr	May - Oct	Reference
Customer Charge				
Customer Charge per meter per month		142.50	142.50	
Demand Charge				
Demand Charge per therm per month applied to PBQ		3.25	3.25	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.0818	0.0512	
Pre-tax IIP Base Rate		0.0025	0.0025	Rider H
Total Pre-tax Base Rate		0.0843	0.0537	
SUT		0.0056	0.0036	Rider B
After-tax Base Rate		0.0899	0.0573	
EE		0.0494	0.0494	Rider G
Subtotal	a	0.1393	0.1067	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	b	*0.0650*	*0.0650*	Rider C
Balancing Charge	c	*0.1271*	*0.1271*	
DGC-Balancing Delivery Charge (DEL)	a+b+c=d	**0.3314**	**0.2988**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**$0.4723**	**$0.4723**	Rider A

The Delivery Charges for DGC-Balancing above include the Balancing Charge as reflected in Rider "A" of this Tariff for customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (3) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS.

With the exception of the Customer Charge and Demand Charge, these rates are on a per-therm basis.

Total Customer Charge, Total Demand Charge, DEL, and BGS charges are presented on customer bills.

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Commercial Distributed Generation Service – DGC-FT

		Nov - Apr	May - Oct	Reference
Customer Charge				
Customer Charge per meter per month		142.50	142.50	
Demand Charge				
Demand Charge per therm per month applied to PBQ		3.25	3.25	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.0818	0.0512	
IIP Pre-tax Base Rate		0.0025	0.0025	Rider H
Total Pre-tax Base Rate		0.0843	0.0537	
SUT		0.0056	0.0036	Rider B
After-tax Base Rate		0.0899	0.0573	
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.1393*	*0.1067*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	b	*0.0650*	*0.0650*	Rider C
DGC-FT Delivery Charge (DEL)	a+b=c	**0.2043**	**0.1717**	

For DGC-FT customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (1) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS, the DGC-FT Delivery Charges above exclude the Balancing Charge reflected in Rider "A" of this Tariff.

With the exception of the Customer Charge and Demand Charge, these rates are on a per-therm basis.

Total Customer Charge, Total Demand Charge, and DEL rate are presented on customer bills

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Electric Generation Service (EGS)

		Without SUT	With SUT	Reference
Customer Charge				
Customer Charge per meter per month		914.42	975.00	
Demand Charge				
Year-Round Firm Service Demand Charge per therm per month applied to MDQ		1.8757	2.00	
Off-Peak Firm Service Demand Charge per therm per month applied to MDQ		0.6253	0.6667	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.0094	0.0094	
SUT		0.0000	0.0006	Rider B
Delivery Charge excluding Riders C, D, E, F and G	a	0.0094	0.0100	
EE	b	0.0464	0.0494	Rider G
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0230	0.0245	Rider E
RA		0.0214	0.0228	Rider D
USF		0.0166	0.0177	Rider F
Total SBC	c	*0.0610*	*0.0650*	Rider C
Delivery Charge (DEL) including Riders C, D, E, F and G	a+b+c=d	**0.1168**	**0.1244**	

With the exception of the Customer Charge and Demand charges, these rates are on a per-therm basis.

Customer, Demand, and DEL charges are presented on customer bills.

Natural gas used to generate electricity that is sold for resale by customers served under this Service Classification is exempt from Riders B, C, D, E, F, and G and shall not be billed for such charges subject to the Customer's submission of an Annual Certification form.

SUMMARY OF INTERRUPTIBLE RATE COMPONENTS

INTERRUPTIBLE SALES AND TRANSPORTATION

With Alternate Fuel

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		725.00	725.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.0735	0.0735	
SUT		0.0049	0.0049	Rider B
After-tax Base Rate		0.0784	0.0784	
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.1278*	*0.1278*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	b	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**0.1928**	**0.1928**	
Basic Gas Supply Charge ("BGS")				
BGS	d	**$0.5989**	**X**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Customer Charge, DEL rate and BGS rate are presented on customer bills.

SUMMARY OF INTERRUPTIBLE RATE COMPONENTS

INTERRUPTIBLE SALES AND TRANSPORTATION

Without Alternate Fuel

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		725.00	725.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.4127	0.4127	
SUT		0.0273	0.0273	Rider B
After-tax Base Rate		0.4400	0.4400	
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.4894*	*0.4894*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	b	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**0.5544**	**0.5544**	
Basic Gas Supply Charge ("BGS")				
BGS	d	**$0.5989**	**X**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Customer Charge, DEL rate and BGS rate are presented on customer bills.

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Compressed Natural Gas (CNG)

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		142.50	142.50	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.3624	0.3624	
IIP Pre-tax Base Rate		0.0051	0.0051	Rider H
CNG Charge		0.2626	0.2626	
Total Pre-tax Base Rate		0.6301	0.6301	
SUT		0.0417	0.0417	Rider B
After-tax Base Rate		0.6718	0.6718	
EE		0.0494	0.0494	Rider G
Subtotal	a	*0.7212*	*0.7212*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D
USF		0.0177	0.0177	Rider F
Total SBC	b	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**0.7862**	**0.7862**	
Basic Gas Supply Charge ("BGS")				
BGS	d	**$0.5989**	**X**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer, DEL, and BGSS charges are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 264*

SUMMARY OF RESIDENTIAL AND FIRM COMMERCIAL RATE COMPONENTS

Natural Gas Vehicles (NGV)

Gas Available at Company Facilities

				Reference
Delivery Charge ("DEL")		$ per therm	$ per GGE	
Pre-tax Base Rate		0.3624		
IIP Pre-tax Base Rate		0.0051		Rider H
Total Pre-tax Base Rate		0.3675		
SUT		0.0243		Rider B
After-tax Base Rate		0.3918		
EE		0.0494		Rider G
Subtotal	a	*0.4412*		
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245		Rider E
RA		0.0228		Rider D
USF		0.0177		Rider F
Total SBC	b	*0.0650*		Rider C
Delivery Charge (DEL)	a+b=c	**0.5062**	**0.633**	
Compression Charge	d	**0.4958**	**0.620**	
Basic Gas Supply Charge ("BGS")	e	**0.5989**	**0.749**	Rider A
Total Variable Charge	c+d+e=f	**1.6009**	**2.002**	
New Jersey Motor Vehicle Fuel Tax	g		**0.000**	
Federal Excise Fuel Tax *	h		**0.185**	
Federal Excise Fuel Tax Credit *	i		**(0.517)**	
Total Price	f+g+h+i =j		**1.670**	

*Adjusted to reflect Internal Revenue Service GGE Conversion.

NEW JERSEY NATURAL GAS COMPANY

SUMMARY OF RESIDENTIAL AND FIRM COMMERCIAL RATE COMPONENTS

Natural Gas Vehicles (NGV)

Customer Owned Facilities

				Reference
Customer Charge				
Residential Customer Charge per month		15.00		
Commercial Customer Charge per meter per month		142.50		
Delivery Charge ("DEL")		$ per therm	$ per GGE	
Pre-tax Base Rate		0.3624		
IIP Pre-tax Base Rate		0.0051		Rider H
Total Pre-tax Base Rate		0.3675		
SUT		0.0243		Rider B
After-tax Base Rate		0.3918		
EE		0.0494		Rider G
Subtotal	a	0.4412		
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245		Rider E
RA		0.0228		Rider D
USF		0.0177		Rider F
Total SBC	b	*0.0650*		Rider C
Delivery Charge (DEL)	a+b=c	**0.5062**	**0.633**	
Basic Gas Supply Charge ("BGS")	d	**0.5989**	**0.749**	Rider A
Total Variable Charge	c+d=e	**1.1051**	**1.382**	

Customer, DEL, and BGS charges are presented on customer bills for Firm Sales Gas Service.
Customer and DEL charges are presented on customer bills for Firm Transport Gas Service

NJNG TARIFF - BPU NO. ~~11~~12 - GAS

NEW JERSEY NATURAL GAS COMPANY

TARIFF

FOR GAS SERVICE

BPU No. ~~11~~12 - Gas

APPLICABLE IN

All service areas of the Company
located in parts of
Middlesex, Monmouth, Ocean, Morris, Sussex and Burlington Counties

ISSUED BY: Mark G. Kahrer
Senior Vice President
Wall, New Jersey

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No. 4*

LIST OF COMMUNITIES SERVED

BURLINGTON COUNTY

Bass River Township
Washington Township

MIDDLESEX COUNTY

Old Bridge Township (*)
Sayreville (*)

MONMOUTH COUNTY

Aberdeen Township
Allenhurst Borough
Asbury Park, City of
Atlantic Highlands Borough
Avon-By-The-Sea Borough
Belmar Borough
Bradley Beach Borough
Brielle Borough
Colts Neck Township
Deal Borough
Eatontown Borough
Englishtown Borough
Fair Haven Borough
Farmingdale Borough
Freehold Borough
Freehold Township
Hazlet Township
Highlands Borough
Holmdel Township
Howell Township
Interlaken Borough
Keansburg Borough
Keyport Borough
Lake Como Borough
Little Silver Borough
Loch Arbour Village
Long Branch, City of
Manalapan Township
Manasquan Borough
Marlboro Township
Matawan Borough
Middletown Township
Monmouth Beach Borough
Neptune City Borough
Neptune Township
Oceanport Borough
Ocean Township
Red Bank Borough
Rumson Borough
Sea Bright Borough
Sea Girt Borough
Shrewsbury Borough
Shrewsbury Township
Spring Lake Borough
Spring Lake Heights Borough
Tinton Falls Borough
Union Beach Borough
Wall Township
West Long Branch Borough

MORRIS COUNTY

Boonton, Town of
Boonton Township
Denville Township
Dover, Town of
Jefferson Township
Kinnelon Borough
Lincoln Park Borough
Mine Hill Township
Montville Township
Mountain Lakes Borough
Mount Arlington Borough
Mount Olive Township (*)
Netcong Borough
Parsippany-Troy Hills Township (*)
Randolph Township
Rockaway Borough
Rockaway Township
Roxbury Township
Washington Township (*)
Wharton Borough
Victory Gardens Borough

OCEAN COUNTY

Barnegat Light Borough
Barnegat Township
Bay Head Borough
Beach Haven Borough
Beachwood Borough
Berkeley Township
Brick Township
Dover Township
Eagleswood Township
Harvey Cedars Borough
Island Heights Borough
Jackson Township
Lacey Township
Lakehurst Borough
Lakewood Township
Lavallette Borough
Little Egg Harbor Township
Long Beach Township
Manchester Township
Mantoloking Borough
Ocean Gate Borough
Ocean Township
Pine Beach Borough
Point Pleasant Borough
Point Pleasant Beach Borough
Seaside Heights Borough
Seaside Park Borough
Ship Bottom Borough
South Toms River Borough
Stafford Township
Surf City Borough
Toms River Township
Tuckerton Borough

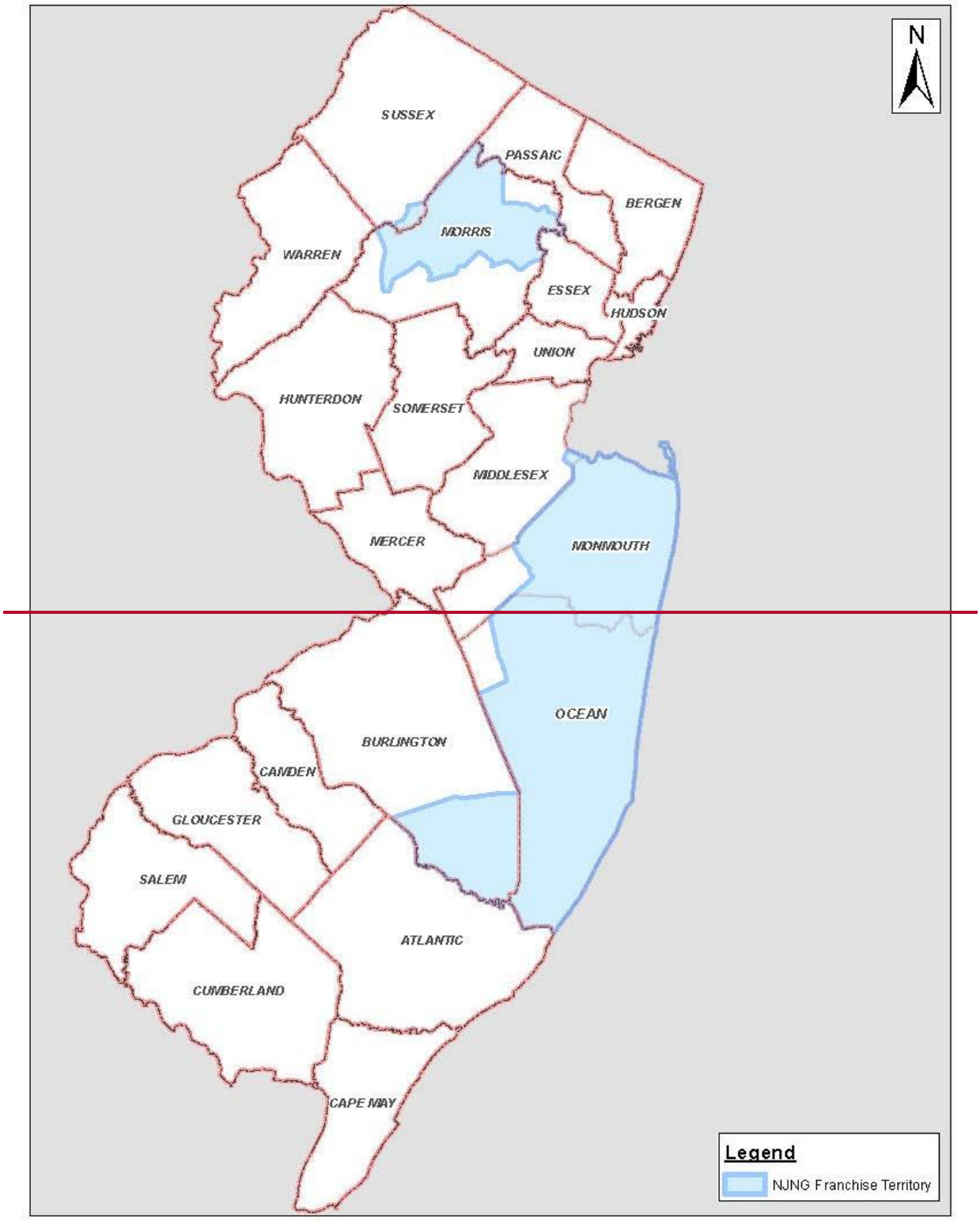
SUSSEX COUNTY

Byram Township (*)
Hopatcong Borough
Stanhope Borough

(*) Partial Franchise

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas ***Original Sheet No. 5***



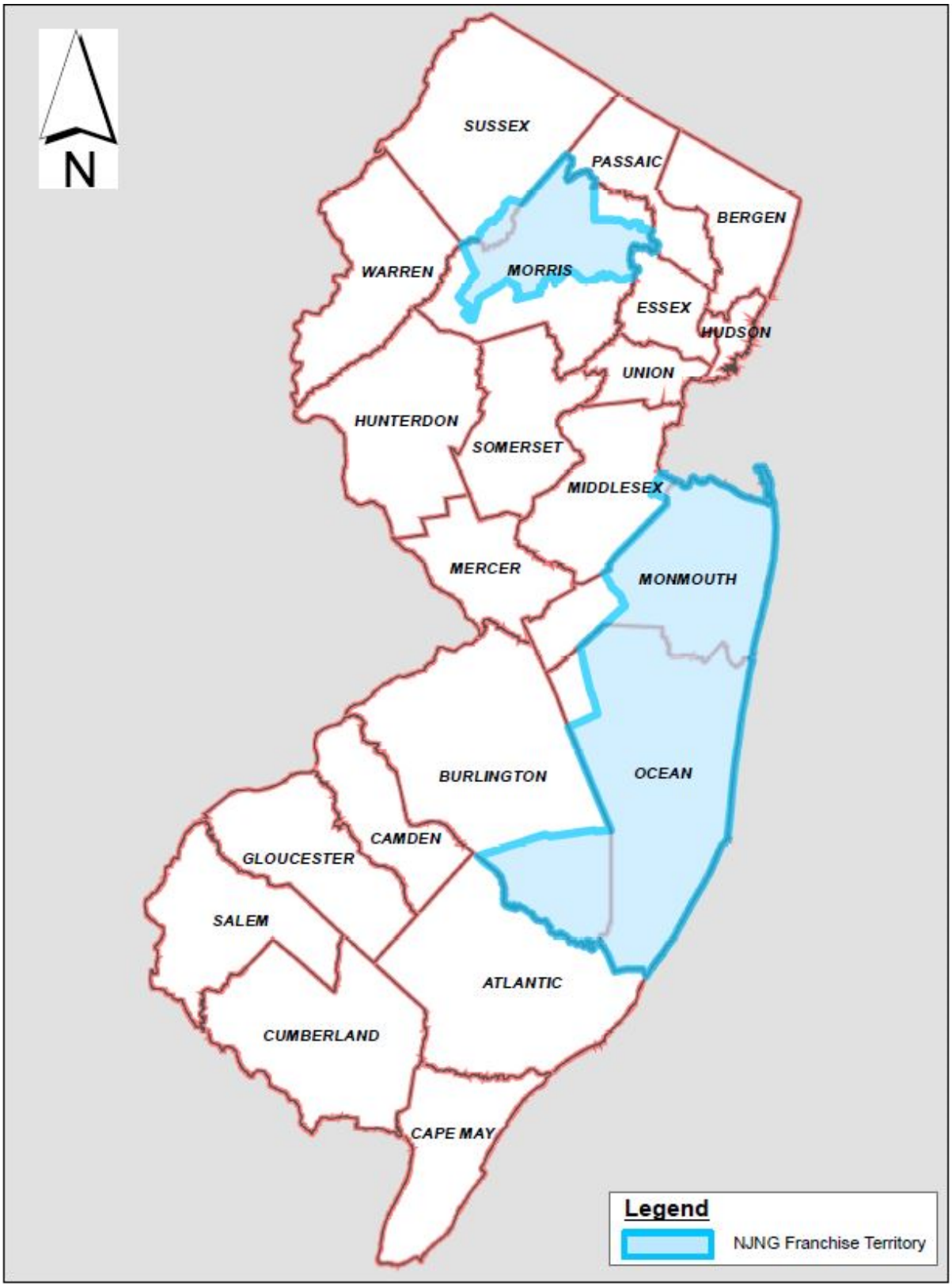
Date of Issue: ***~~November 18, 2021~~***
Issued by: ***Mark G. Kahrer, Senior Vice President***
~~2021~~March 1, 2024
Wall, NJ 07719

Effective for service rendered on and after ~~December 1,~~

Filed pursuant to Order of the Board of Public Utilities entered in Docket No. ~~GR21030679~~

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No. 5*



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NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No. 6*

STANDARD TERMS AND CONDITIONS - INDEX

STANDARD TERMS AND CONDITIONS – INDEX (continued)

STANDARD TERMS AND CONDITIONS

DEFINITIONS

A. "*Board*" means the Board of Public Utilities of the state of New Jersey. Customers can contact the Board Division of Customer Assistance by calling 1-609-341-9188 or 1-800-624-0241 and at their website~~Web site~~, www.nj.gov/bpu/.

B. "*Company*" means New Jersey Natural Gas Company, or any legal successor.

C. "*Customer*" means a person that is an end user, a customer of record, or both, as these terms are defined in this section.

D. *"Customer of record"* means the person that applies for utility service and is identified in the account records of a public utility as the person responsible for payment of the public utility bill. A customer may or may not be an end user, as defined herein.

E. *"End user"* means a person who receives, uses, or consumes gas service. An end user may or may not be a customer of record, as defined in this section.

F. "*Month*" is used for billing purposes to designate a period of 26 to 34 days.

G. "*Year*" is used to designate a period of twelve consecutive "months".

H. "*MCF*" is used to designate one thousand (1,000) cubic feet of gas.

I. "*BTU*" (British Thermal Unit) is used to designate the amount of heat required to raise the temperature of one (1) pound of water @ 60°Fahrenheit, 1° Fahrenheit.

J. "*Therm*" is used to designate a unit of heating value equivalent to 100,000 BTUs.

K. "*FERC*" means the Federal Energy Regulatory Commission.

L. "*Tampering*" means the unauthorized connecting, disconnecting, or causing to be connected or disconnected, or in any other manner interfering with the operation of the Company's meters, pipes, conduits, other equipment or attachments, or as otherwise provided by this Tariff (see Sections 6.6, 6.13, and 6.15).

M. *"Point of Delivery"* shall be that point where the Company delivers metered gas (outlet of Company gas meter) to the Customer's installation unless otherwise specified in the service agreement. The gas supplied by Company becomes the property of the Customer at the Point of Delivery.

STANDARD TERMS AND CONDITIONS

DEFINITIONS (continued)

N. *"Customer Equipment"* shall mean all appliances, piping, vents, connectors, valves, fittings or any other gas utilization or distribution equipment at or on the Customer's side of the Point of Delivery with the exception of Company owned facilities, e.g., Compressed Natural Gas ("CNG") re-fueling facilities. Customer Equipment also includes equipment leased by the Customer from third parties.

O. *"Gas Service"* shall mean the provision of gas service to customers. The gas provided shall be a service and shall not constitute goods for any purpose.

Main and Service Extension Related Terms

P. **"***Extension***"** means the construction or installation of plant and/or facilities by the Company to convey service from existing or new plant and/or facilities to one or more new customers, and also means the plant and/or facilities themselves. This term includes all plant and/or facilities for transmission and/or distribution, whether located overhead or underground, on a public street or right of way, or on a private property or private right of way, including the pipe, conduit or other means of conveying service from existing plant and/or facilities to each unit or structure to be served. An extension begins at the existing infrastructure and ends at the meter, inclusive of the meter;

Q. **"***Distribution Revenue***"** means total annual revenue, inclusive of related Sales and Use Tax collected from a Customer, less the Basic Gas Supply Service and Balancing charges, inclusive of related Sales and Use Tax, assessed in accordance with the Tariff.

R. **"***Applicant***"** means a person that has applied to the appropriate regulated entity, as defined at N.J.A.C. 14:3-1 for construction of an extension, as defined at N.J.A.C. 14:3-8.2 and above.

S. **"***Cost***"** means, with respect to the cost of construction of an extension, actual and/or site-specific unitized expenses incurred for materials and labor (including both internal and external labor) employed in the actual design, construction, and/or installation of the extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for mapping and design. This term does not include expenses for clerical, dispatching, supervision, or general office functions. Costs shall be determined by the Company and shall include all costs inclusive of upgrades to existing infrastructure.

STANDARD TERMS & CONDITIONS

1. GENERAL

1.1 INTRODUCTION

These Standard Terms and Conditions, filed as part of the Tariff of New Jersey Natural Gas Company (referred to as "the Company" or "Company"), set forth the terms and conditions under which service is rendered and will be supplied. They govern all classes of service, to the extent applicable, and are made a part of all agreements for the supply of gas service, unless specifically modified by the terms of a particular service classification, or by special terms written in and made a part of a contract for service.

Failure by the Company to enforce any provisions, terms or conditions set forth in this Tariff shall not be deemed a waiver of such provisions, terms or conditions.

1.2 APPLICATION OF TARIFF

This Tariff applies to all persons, partnerships, corporations or others herein designated as Customers who are lawfully receiving gas service from the Company, under the prescribed service classification whether service is based upon contract, agreement, or accepted signed application. If any terms and conditions contained in this Tariff are in conflict with the New Jersey Administrative Code, the New Jersey Administrative Code shall prevail. The Tariff will not be construed to be in conflict with the New Jersey Administrative Code if the Tariff provides for a more liberal treatment of Customers than that provided for in the New Jersey Administrative Code.

1.3 FILING AND POSTING OF TARIFF

A copy of this Tariff is filed with the Board of Public Utilities (referred to as "the Board" or "Board"), of the state of New Jersey. Copies are posted and open for inspection at the offices of the Company and on the Company's website~~Web site~~ at https://www.njng.com/regulatory/tariff.aspx.~~www.njng.com/regulatory/tariff.asp.~~

1.4 REVISION OF TARIFF

This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the rules of procedure determined by the Board.

1.5 STATEMENTS BY AGENTS

No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto, and the Company shall not be bound thereby.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE

2.1 APPLICATION FOR SERVICE

Application for gas service may be made in person at any customer service office of the Company, by mail, by telephone, by the Company's website at https://www.njng.com/, ~~by facsimile transmission~~ or by electronic mail, where available. The applicant shall state, at the time of making application for service, the conditions under which service will be required, and may be required to sign an agreement covering special circumstances for the supply of gas service. The applicant also may be required to supply proof of identification, in accordance with N.J.A.C. 14:3-3.2(e) and (h), as may be amended or superseded.

2.2 ACCOUNT OPENING CHARGE

The applicant shall be required to pay a $15.00 account opening charge each time service is turned on at a new or existing location. However, the Company may waive the account opening fee if a field visit is not required to establish service.

2.3 SERVICE INFORMATION FROM COMPANY

Upon receipt of application from the prospective Customer, the Company will advise the Customer of the type and character of gas service which will be furnished, the point at which service will be delivered and the location to be provided for the Company's metering and regulating equipment.

All customers shall be given a copy of the "Customer Bill of Rights" approved by the Board, effective at the time of service initiation. The copy shall be presented no later than at the time of the issuance of the customer's first bill or 30 days after the initiation of service, whichever is later.

2.4 FORM OF APPLICATION

Standard applications or agreements to supply gas service shall be in accordance with the particular service classification. The Company, in its sole discretion, reserves the right to require contributions toward the investment required for such service and to establish such minimum charges and facilities charges as may be appropriate.

Additionally, the Company may require a special service agreement and/or charge when: 1) large or special investment is necessary to supply service, 2) special facilities are required to serve a Customer, or 3) the hourly capacity of the Company's facilities, necessary to serve the Customer's demand, may be out of proportion with the monthly or annual use of gas service for occasional, intermittent, or low load factor purposes.

When a Customer signs a main and/or service extension agreement, and subsequently does not install any or all of the indicated equipment within a reasonable time, not to exceed six (6) months, or does not purchase the volumes of gas included in the service agreement, the Company reserves the right to charge the Customer for the full cost of providing the main and/or service.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE (continued)

2.5 SELECTION OF SERVICE CLASSIFICATION

Upon the request of a Customer, the Company will assist in the selection of the available rate most desirable to the Customer. Any advice given by the Company will be based on the Customer's oral or written statements as to the class of service desired and the manner in which it is intended to be used. However, by giving such advice, the Company assumes no responsibility related to the customer selection for class of service.

2.6 CHANGE OF SERVICE CLASSIFICATION

Within three months after service has begun, a Customer may request in writing to change the service classification or provision within a service classification under which they are billed. Subsequent to initial selection of a service classification, a Customer may request in writing a change to the service classification or provision within a service classification under which they are billed if their character or use of gas service has changed. Any change in schedule, if permitted, will be applicable to the next regular billing subsequent to such notification by the Customer.

2.7 DEPOSIT AND GUARANTEE

Before the Company renders service, a deposit or other guarantee satisfactory to the Company may be required as security for the payment of future and final bills from any new or existing Customer who has not established credit with the Company. A deposit also may be required from a Customer whose credit has become impaired. A new Customer, who provides the Company with a letter of reference from another utility or source acceptable to the Company, may have the deposit waived. The deposit shall be in accordance with the provisions set forth in N.J.A.C. 14:3-3.4, as may be amended or superseded.

If a Customer's service has been terminated for non-payment of bills, the Company may not condition restoration of service on payment of the deposit, unless the deposit has been included on prior bills, or notice has been provided to the Customer.

2.8 AMOUNT OF GUARANTEE DEPOSIT

The Company may require a deposit to guarantee payments of bills equivalent to the estimated gross bill for natural gas service for any single billing period plus an additional billing period.

2.9 INTEREST ON GUARANTEE DEPOSIT

The Company will credit simple interest at the applicable interest rate established annually by the Board on customer deposits provided such amount remains on deposit for not less than three (3) consecutive months.

Interest shall be payable annually and/or when the deposit is refunded or applied in accordance with N.J.A.C. 14:3-3.5, as may be amended or superseded.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE (continued)

2.10 RETURN OF GUARANTEE DEPOSIT

The Company shall review residential Customer accounts at least once every year and non-residential Customer accounts at least once every two years. If the review indicates that a Customer has established good credit, the Company will apply the deposit, plus any interest, to the outstanding balance on the Customer's account and will send a refund check to the Customer for any amount over and above the outstanding balance. Upon termination of service, the Customer will receive the balance of the deposit, plus interest, less any unpaid charges in accordance with N.J.A.C. 14:3-3.5, as may be amended or superseded.

2.11 PERMITS

The Customer shall obtain or cause to be obtained all legally-required permits and/or certificates necessary to give the Company or its representatives access to the Customer's equipment and to enable its mains to be connected with the Customer's equipment. If the Company makes application for any permits and/or certificates, the Customer will be required to pay the application fee/charge, if any. The Company shall not be obliged to furnish service unless and until such permits and/or certificates have been delivered to the Company.

When the Customer is not the owner of the premises or the owner of the property lying between the premises and the Company's mains, the Customer may be required to obtain from the proper owner(s) the necessary consent to install and maintain all necessary equipment to supply gas at the Customer's premises.

2.12 TEMPORARY SERVICE

Temporary service is available, for a limited period, to any Customer who can be served from the Company's existing lines or facilities, when and where the Company is permitted to provide such service. The Customer shall pay the total cost of connecting and disconnecting the gas service, including any piping, metering equipment, or other facilities that may be necessary. The Company may require an advance payment covering the estimated cost of construction or gas supplied, or both.

STANDARD TERMS & CONDITIONS

2. OBTAINING SERVICE (continued)

2.13 SERVICE TO FORMER CUSTOMERS

Service will not be supplied by the Company to former Customers until such time as any and all amounts or outstanding balances owed to the Company for previous service have been paid or otherwise discharged in accordance with N.J.A.C. 14:3-3A.9, as may be amended or superseded. Customers qualifying for Winter Termination Protection who have a prior outstanding balance due from their existing service location may have service restored upon the establishment of satisfactory payment arrangements. The Company may refuse to initiate service, or may discontinue service after proper notice and in accordance with N.J.A.C. 14:3-3A.2, as may be amended or superseded, to a residential applicant, or a member of the household then indebted to the Company for services provided by the Company at any location, if the Company reasonably determines that substantially the same household occupies the premises to be or being served. The Company may refuse to initiate service or may discontinue service after proper notice and in accordance with N.J.A.C. 14:3-3A.2, as may be amended or superseded, to a commercial applicant, or an officer, director, general or limited partner, business associate, or other agent, of an entity then indebted to the Company for services provided by the Company at any location, if the Company has reason to believe that substantially the same entity occupies the premises to be or being served.

STANDARD TERMS & CONDITIONS

3. CHARACTERISTICS OF SERVICE

3.1 GENERAL

Gas service supplied by the Company in the entire territory served shall be straight natural gas, or any mixture of straight natural gas and substitute gas. The volume of gas to be delivered shall be measured in accordance with the published recommendation of the American Gas Association, as amended or superseded from time to time.

The basic unit of volume or one standard cubic foot shall be one cubic foot of gas at a temperature of 60° Fahrenheit (F) and an absolute pressure of 14.73 pounds per square inch. The average atmospheric pressure shall be assumed to be 14.73 pounds per square inch irrespective of variations in atmospheric pressure from time to time. The volume of gas measured, other than at the standard temperature and/or pressure shall be adjusted in accordance with Boyle's Law for measuring gas at varying pressures and the Charles Law for measuring gas at varying temperatures.

3.2 SINGLE POINT OF DELIVERY

The Company will furnish, install and maintain a single meter for each service classification under which a Customer receives service unless, in the sole and final judgment of the Company, the volume of the Customer's requirements, economic considerations, conditions on its distribution system, or other reasons make it desirable to install additional meters.

3.3 CONTINUITY OF SERVICE

The Company will use reasonable diligence to provide a regular and uninterrupted supply of service, but should the supply be suspended, curtailed or discontinued by the Company for any of the reasons set forth in Section 9 of these Standard Terms and Conditions, or should the supply of service be interrupted, curtailed, deficient, defective or fail by reason of any Act of God, accident, strike, legal process, governmental interference, or other cause whatsoever beyond its control, the Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, defect, interruption, curtailment, deficiency or failure.

3.4 UNUSUAL CONDITIONS

The Company reserves the right to place limitations on the amount and character of gas service it will supply; to refuse service to new Customers or existing Customers for additional load if unable to obtain sufficient supply for such service; to reject applications for service or additional service where such service is not available, or where such service might affect the supply of gas to other Customers; or for other good and sufficient reasons subject to the orders or rules of the Board.

STANDARD TERMS & CONDITIONS

4. GAS DISTRIBUTION MAIN AND SERVICE EXTENSIONS

4.1 GENERAL PROVISIONS

The Company will construct, own, and maintain gas mains located on streets and highways and on rights-of-way acquired by the Company. The formulae for the extension of utility service set forth below shall not serve to prevent the parties hereto from exercising their rights under the N.J.S.A. 48:2-27 and the applicable New Jersey Administrative Code provisions.

Where it is necessary to provide additional facilities to serve the requirements of either existing customers or new applicants, the Company may require a deposit or a contribution in aid of construction according to the conditions specified below. The Company, in its sole discretion, will determine the appropriate amount of such deposit or contribution in aid of construction. The Extension cost for which the Company receives a deposit or a non-refundable contribution shall include the tax consequences incurred by the Company.

4.2 RESIDENTIAL AND FIRM COMMERCIAL CUSTOMER - MAIN EXTENSION AND SERVICE LINE CONNECTION

The Company will install facilities and make gas main extensions and service line connections to serve individual permanent residential customers and firm commercial customers without alternate fuel capacity and taking service under service classifications included in Rider "I" Conservation Incentive Program (CIP) free of charge where the Extension Cost does not exceed ten (10) times the annual distribution revenue at the baseline usage per customer volume for the Customer's respective CIP group and subject to the terms described in Paragraph 5.2. For residential customers, the Extension Cost shall not include the cost of the meter.

An applicant shall be required to provide an Extension Cost Deposit or a non-refundable contribution in aid of construction for the value of any Extension Cost that is greater than ten (10) times the annual distribution revenue at the baseline usage per customer volume for the Customer's respective CIP group. If the Company accepts an application for an extension of a residential customer, the Company may furnish and place, at no cost to the Customer, up to 200 feet of normal residential facilities. The Company shall waive a required deposit of $3,000 or less.

For customers taking service under firm service classifications not included in Rider "I" CIP, the Company will install facilities and make gas main extensions and service line connections to serve individual customers without alternate fuel capacity free of charge where the Extension Cost does not exceed ten (10) times the estimated annual distribution revenue, unless otherwise specified in the service classification. An applicant shall be required to provide an Extension Cost Deposit or a non-refundable contribution in aid of construction for the value of any Extension Cost that is greater than ten (10) times the estimated annual distribution revenue and subject to the terms described in Paragraph 5.2; however, the Company shall waive a required deposit of $3,000 or less.

STANDARD TERMS & CONDITIONS

4. GAS DISTRIBUTION MAIN AND SERVICE EXTENSIONS (continued)

The Extension Cost Deposit, as defined above, shall remain, without interest, in the possession of the Company unless additional customers connect to the particular extension. At such time there will be refunded to the depositor, the annual baseline distribution revenue value for the additional connecting Customer based upon the ratio in effect when the deposit was made. Once a portion of the deposit has been refunded to the applicant, the calculation shall only be reviewed for subsequent additional customers connecting to the particular extension. No further calculation shall be performed when accumulated refunds are equal to the sum deposited and in no event shall refunds exceed the initial deposit.

All deposits not returned to the applicant within a period of ten (10) years after the Company first makes gas service available shall remain the property of the Company with no further obligation of refund. The Company and applicant may agree upon a satisfactory revenue guarantee in lieu of a deposit or contribution.

Where it is necessary to provide additional facilities to serve increased requirements of an existing Customer, the Company reserves the right to require the Customer to provide a non-refundable contribution in aid of construction or a deposit in an amount equal to the cost of such additional facilities. The deposit amount may be subject to refund as outlined earlier in this section except that refunds shall be a function of the incremental distribution revenue generated by the increased requirements over a predetermined base.

STANDARD TERMS & CONDITIONS

4. GAS DISTRIBUTION MAIN AND SERVICE EXTENSIONS (continued)

4.3 LAND DEVELOPMENT - MAIN EXTENSION AND SERVICE LINE CONNECTIONS

Where applications for extensions into newly developed tracts of land are made by individuals, partnerships, or corporations interested in the development and sale of land but not as ultimate residents, the Company shall require a deposit from the applicant covering the entire cost of installing the necessary mains, services and common distribution facilities to serve the tracts. However, if an individual, partnership, or corporation has contracted sales to ultimate residents, the Company may waive a required deposit for the value of any Extension Cost that is less than or equal to ten (10) times the annual distribution revenue at the baseline usage per customer volume for the ultimate residents' respective CIP group.

Such deposits are to be returned to the depositor, without interest, if during a ten-year period from the date of the original deposit, when and as new services abutting on such mains are completed, the prospective Customer's gas equipment is installed, and the dwellings are occupied by bona-fide owners or responsible tenants who have entered into an agreement for use of gas service. Upon such completion and occupation, there shall be returned to the depositor an amount equal to the product of residential customer ratio in effect in Paragraph 4.2 when the deposit was made and the annual baseline distribution revenue for each of the dwellings as described above but not in excess of the amount deposited. In no event shall more than the original deposit be returned to the depositor. All deposits not returned to the applicant within a period of ten (10) years after the Company first made gas service available to the tract of land shall remain the property of the Company with no further obligation of refund. The Company may agree upon a satisfactory revenue guarantee in lieu of a deposit or contribution.

4.4 ALTERNATE FUEL CUSTOMER - MAIN EXTENSION

The Company reserves the right to require any alternate fuel customer to make a non-refundable contribution in aid of construction of an amount equal to the entire cost of the new facilities required to provide service. Where it is necessary to provide additional facilities to serve the increased requirements of any existing Customer, the Company reserves the right to require the Customer to provide a non-refundable contribution in aid of construction in an amount equal to the cost of such additional facilities and shall include the tax consequences incurred by the Company.

The Company is under no obligation to refund any of the contribution but the Company reserves the right in its sole judgment to do so where economics and revenue conditions warrant said action. In lieu of a contribution, the Company may agree upon a satisfactory revenue guarantee.

STANDARD TERMS & CONDITIONS

5. SERVICE LINE CONNECTIONS

5.1 GENERAL PROVISIONS

Gas service will normally be supplied to each premise through a single service line, except where, in the judgment of the Company, it is deemed desirable to install more than one service line. The Company may also choose to install multiple meters on one service line providing service to several premises. If more than one service line is installed for the convenience of the Customer, each location will be considered as a separate Customer.

5.2 FIRM CUSTOMERS

The Company shall furnish and place, a service line in accordance with the terms described in Paragraph 4.2 above, measured at right angles from the nearest curb line to Customer's building, at the point of service entrance designated by the Company. Should the Customer request a service entrance at a location other than that designated by the Company, the Customer shall pay any additional cost associated with said change in point of service entrance and shall include the tax consequences incurred by the Company.

5.3 ALTERNATE FUEL CUSTOMERS

The Company shall provide a service line connection at the Customer's expense.

5.4 CHANGE IN EXISTING INSTALLATIONS

Any change in the existing service line, which may include installation of an Excess Flow Valve, and/or metering facilities requested by the Customer and approved by the Company shall be made at the Customer's expense and shall include the tax consequences incurred by the Company. If the change in the service line or metering facilities is to serve increased usage requirements, deposits or contributions in aid of construction shall be administered in accordance with Section 4 of these Standard Terms and Conditions.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT

6.1 GENERAL

A suitable meter or meters will be installed, owned and maintained by the Company for the purpose of measuring the quantity of gas service delivered to the Customer. The type and make of metering equipment will be in accordance with the Company's specification which, from time to time, may be changed or altered. It is the sole obligation of the Company to furnish meters that provide adequate and accurate records for billing purposes in accordance with N.J.A.C. 14:3-4.1, as may be amended or superseded.
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6.2 METER LOCATION

The Customer shall provide on the premises, at a location satisfactory to the Company, proper space for metering and associated equipment. The meter location shall be kept free and clear of obstructions so that properly authorized representatives of the Company may gain easy access to the meter location for the purpose of operating valves, reading meters, or emergencies in accordance with N.J.A.C. 14:3-4.2, as may be amended or superseded.
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6.3 CHANGE OF METER LOCATION

Any change requested by the Customer in the point of location of the meter or service facilities, if approved by the Company, shall be made at the expense of the Customer and shall include the tax consequences incurred by the Company.

6.4 CUSTOMER'S RESPONSIBILITY

The Customer shall be responsible for the protection and safekeeping of the equipment and facilities of the Company while it is on the Customer's premises. The Customer shall permit access to the Company's equipment to duly authorized representatives of the Company or duly authorized governmental officials.

6.5 ACCESS TO CUSTOMER'S PREMISES

Properly identified and authorized representatives of the Company shall have free access to the Customer's premises at all reasonable times for the purpose of reading meters, for inspection and repairs, for investigation of emergencies or hazardous conditions, for removal of the Company's property or for any other purposes incident to the supply of gas service, in accordance with N.J.A.C. 14:3-3.6, as may be amended or superseded. The Customer is requested to contact the Company immediately if a question arises regarding the authority or credentials of any person claiming to represent the Company.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.6 AUTHORIZATION TO TURN ON GAS

No person other than a duly authorized employee or representative of the Company shall turn gas service on or into any new system of piping or into any old system of piping from which the use of gas has been discontinued. Disconnections, reconnections, or meter removals performed by persons other than authorized Company personnel are prohibited and shall constitute Tampering.

6.7 UNAUTHORIZED USE

The use of service in excess of 30 days without the Company's express authorization may be terminated by the Company without notice. The use of natural gas service, without notice to the Company, shall render the user liable for any amount reasonably determined by the Company to be due for gas service supplied to the premises since the last meter reading recorded and billed by the Company.

6.8 OWNERSHIP AND REMOVAL

All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove its equipment from the premises of the Customer at any time after termination of service.

6.9 PAYMENT FOR REPAIRS OR LOSS

The Customer shall pay the Company for any necessary repairs for damage to or any loss of the Company's property located on the Customer's premises, and for the reconnection of service interrupted by such damage or loss, when the damage or loss is caused by negligence or willful misconduct on the part of Customer, or the Customer's family members, employees or agents, or by the failure of the Customer or foregoing persons to comply with the Standard Terms and Conditions and applicable service classifications under which service is furnished. The reconnection charge shall be $45.00 per Customer interruption. This charge will be waived when the appropriate Company personnel are on site at the time of the repair and able to reconnect the Customer safely.

6.10 REMOTE METER READING EQUIPMENT

The Company, in its sole discretion and as a condition of service, may install at the Company's expense a remote meter reading device, e.g., an Automated Meter Reading (AMR) device, to monitor a Customer's gas consumption. When such device requires attachment to services including, but not limited to, telephone utilities, electric utilities, or a data plan, the Customer shall provide suitable connections.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company. The Customer may reimburse the Company for the remote meter reading device expense, either in a lump sum payment or over a twelve-month period with the prime interest rate used to calculate carrying costs. All equipment remains the sole property of the Company.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.11 SUB-METERING

Sub-metering, the practice in which the customer of record buys gas from the company and resells it through some metering device to tenants at a profit, is not permitted in any form. Gas service supplied by the Company shall not be resold by the Customer to others except where the Customer is another publicly regulated gas utility company, or where the natural gas is used for conversion to compressed natural gas, or when check-metering as defined below is being used by the Customer.

6.12 CHECK-METERING

Check-metering is defined as the practice in which a Customer, through the use of a gas check meter, monitors or evaluates his own consumption or the consumption of a tenant for accountability or conservation purposes.

Gas check meters are devices that measure the volume of gas being delivered to particular locations in a system after measurement by a utility-owned meter. Gas check meters provide the Customer the means to apportion among the end users the cost of gas service being supplied through the Company meter.

Check-metering is permitted in new or existing buildings or premises where the basic characteristic of service is industrial or commercial. Check-metering is not permitted in new or existing buildings or premises where the basic characteristic of service is residential, except for condominiums or cooperative housing, or where such buildings or premises are publicly financed or government owned or are charitable in nature, or where the gas use is restricted to cooking gas. Check-metering is not permitted for space heating in residential premises subject to the exceptions set forth above.

If the Customer charges the tenant for usage incurred by the tenant, reasonable administrative expenses may be included, but such charges shall not exceed the amount the Company would charge if the tenant was served and billed directly by the Company.

Prior to the installation of any gas check metering devices, the Customer is required to contact the Company in order to ascertain whether the affected premises are located within a utilization pressure area of the Company's distribution system and whether or not the installation of a check metering device will cause any significant pressure drop within the affected premises.

All gas-consuming devices in any tenant unit must be metered through a single gas check-meter.

The ownership of all check-metering devices is that of the Customer, along with all incidents in connection with said ownership, including accuracy of the meter reading and billing, liability arising from the presence of the equipment and the maintenance and repair of the equipment. Any additional costs which may result from and are attributable to the installation of check-metering devices shall be borne by the Customer.

STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.13 TAMPERING & OTHER DECEPTIVE PRACTICES

When it is established that Tampering has occurred and the Customer has caused or knowingly benefited from such Tampering, the Customer shall be required to bear all of the costs incurred by the Company including, but not limited to, the following: (a) investigations, (b) inspections, (c) costs related to administrative, civil or criminal proceedings, (d) attorneys' fees, (e) installation of any protective equipment deemed necessary by the Company, and (f) actual costs of damage to equipment.

Furthermore, when Tampering with Company facilities results in incorrect measurement, correctly measured service used without Company authorization or the omission of measurement of the service supplied, and the Customer has benefited from such Tampering, the Customer shall pay for such service as the Company may estimate from available information, to have been used on the premises.

If persons other than the Customer are identified as beneficiaries of service obtained at the Customer's premises by Tampering, or have created or contributed to the Tampering, the Company shall elect to hold such persons liable for all of the aforesaid costs incurred and the value of service (metered or unmetered) received. A "beneficiary" is any person who benefits from such Tampering.

The foregoing remedies against the Customer and other beneficiaries arising from Tampering shall also apply to gas service obtained by fraudulent means, imposture, theft of identity, impersonation, theft of service, theft by deception or other unlawful methods.

6.14 DIVERSION OF SERVICE

Diversion is an unauthorized connection to pipes by which the gas service registers on the Customer's meter, even if such service is being used by other than the Customer of record without his or her knowledge or cooperation. When a Customer alleges, or it is established, that service has been diverted outside of the Customer's premises, the Customer shall not be required to pay for such service without his or her consent. The definitions, procedures, investigations and determination of N.J.A.C. 14:3-7.8, as may be amended or superseded, shall apply.

6.15 SEALING OF METERS AND LOCKING DEVICES

For safety purposes, it is the practice of the Company to seal meters and regulators, and to install locking devices when needed. Removal of seals or locking devices by persons other than authorized Company personnel is prohibited and shall constitute Tampering.

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STANDARD TERMS AND CONDITIONS

6. METERING AND MEASURING EQUIPMENT (continued)

6.16 INABILITY TO ACCESS CUSTOMER LOCATION

If a Customer has requested that the Company perform work related to the installation of a meter set on Customer property and the Company is unable to complete that work due to the Customer not being available at the scheduled time or the required work not being completed by the Customer and/or contractor, the Customer shall be charged $45.00.

STANDARD TERMS AND CONDITIONS

7. CUSTOMER'S INSTALLATION

7.1 INSTALLATION RULES

Customer's appliances, piping, and installation shall be made and maintained in accordance with the standards of the Fuel Gas Subcode of the Uniform Construction Code set forth in N.J.A.C. 5:23-3.22 as may be amended or superseded and such other regulations as may be determined from time to time by any governmental agency having jurisdiction over the Customer's installations.

7.2 ADEQUACY AND SAFETY OF INSTALLATION

The Company shall not be required to supply gas service until the Customer's installation has been approved by the authorities with jurisdiction. The Company also reserves the right to withhold its service, or to discontinue its service, whenever such installation or part thereof is deemed by the Company to be unsafe, inadequate, or unsuitable for receiving service, or interferes with or impairs the continuity or quality of service to the Customer or to others.

7.3 FINAL CONNECTION

In all cases, no final connection between the Company's equipment and the Customer's installation shall be made without final inspection from the Department of Community Affairs or its designee.

7.4 CHANGE IN CUSTOMER'S INSTALLATION

The Customer shall give immediate notice to the Company of any: 1) proposed additions in connected appliances or equipment, 2) change in demand or other conditions of use, or 3) change of purpose or location of the installation. Changes in service conditions shall not be made effective until the Customer notifies the Company and receives the Company's approval of same. Failure to give notice of additions or changes in load or location shall render Customer liable for any damages to the meters or other apparatus and equipment of the Company caused by the additional or changed installation.

7.5 COMPANY'S LIABILITY

The Company shall not be liable for any claim for damages resulting from the supply, use, care or handling of the gas or from the presence or operation of the Company's structures, equipment, pipes, or devices, except for general or direct damages that follow from the Company's negligence, recklessness, or willful misconduct. The Company shall not be liable for special or consequential damages.

STANDARD TERMS AND CONDITIONS

7. CUSTOMER'S INSTALLATION (continued)

All Customer Equipment shall be suitable for the use of natural gas and shall be installed, inspected, repaired and maintained solely by the Customer and solely at the Customer's expense in a manner approved by the public authorities having jurisdiction over the same, and in good and safe condition in accordance with all applicable codes. The Customer shall be solely responsible for the selection of the Customer Equipment and the Company shall have no duty or responsibility for the design, selection, installation, operation or repair of said Equipment. The Customer shall be responsible for the design of the venting and piping associated with the Customer Equipment downstream of the Point of Delivery. The Company does not, by inspection, non-rejection or any other way, give any warranty, express or implied, as to the adequacy, safety or other characteristics of the Customer Equipment. The Company shall not be liable for damages to the Customer Equipment or for injuries sustained by the Customer or others, due to the condition or character of the Customer Equipment. The Company shall not be responsible for the use, care or handling of the gas delivered to the Customer after it passes beyond the point at which the Company's service facilities connect to the Customer Equipment.

The Company may, but need not, conduct a limited inspection of the appliances, venting system and leak integrity of the Customer's piping and venting downstream of the Point of Delivery as a courtesy to the Customer at the time of the initiation of service or thereafter at the request of the Customer. In no event, however, shall the Company have any duty to inspect Customer Equipment or be responsible for any failure of the Customer Equipment or any harm arising from the operation of the Customer Equipment, even if, the Company undertakes, as a courtesy to the Customer, to conduct a limited inspection at the time of initiation of service or otherwise. The Customer shall, at all times, be solely responsible for the inspection, integrity and safety of all Customer Equipment.

7.6 BACK PRESSURE AND SUCTION

When the nature of the Customer's gas equipment is such that it may cause back pressure or suction in the piping system, meters, or other associated equipment of the Company, suitable protective devices subject to approval by the Company, shall be furnished, installed, and maintained by the Customer.

When the Customer uses an alternate fuel that is gas, a three-way valve (a check valve is not permissible) is required to be installed at the Customer's expense subject to the Company's approval.

7.7 LEAKAGE

The Customer shall give notice immediately of any escape of gas on or about the premises to the Company.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING

8.1 EVIDENCE OF CONSUMPTION

The quantities of service delivered to the Customer as recorded by the Company's meter or meters, subject to any necessary adjustments for pressure and temperature in accordance with Section 3.1 of this Tariff, shall be final and conclusive except when the metering equipment fails to register or is determined to be in error.

8.2 MONTHLY METER READING

The Company shall read meters on a monthly schedule. Nothing in this section shall be deemed to limit the applicability of Section 8.3 below.

8.3 ESTIMATED USAGE

Where the Company is unable to read the meter, the Company may estimate the amount of gas supplied and submit an estimated bill. An adjustment of the Customer's estimated use to actual use will be made after an actual meter reading is obtained in accordance with N.J.A.C. 14:3-7.2(e), as may be amended or superseded.

8.4 ADJUSTMENT FOR INACCURATE METER RECORDING

When it is determined that the Company's meter is inaccurate or defective, the use of gas service shall be determined by a test of the meter, or by registration of the meter set in its place during the period next following, or after due consideration of previous or subsequent properly measured deliveries. Whenever a meter is found to be registering fast by 2% or more, an adjustment of charges shall be made. When a meter is found to be registering slow by more than 2% due to progressive inaccuracy, an adjustment of charges may be made except for residential accounts, where no adjustment shall be made. An adjustment may be made on any account with a meter that is determined by a Company test of the meter to be defective or non-registering. A defective or non-registering meter is any meter not properly functioning due to a physical inability to meet original manufacturing standards. Any adjustment to the Customer's account resulting from the terms in this section will be billed or applied to the account in accordance with N.J.A.C. 14:3-4.6, as may be amended or superseded. If the adjustment results in a credit, such amount may be refunded upon request from the Customer. If the Customer does not request a refund, a bill credit will be applied to the Customer's account.

If a meter is found to be registering less than 100% of the service provided, the Company shall only adjust the charges retrospectively and/or require the Customer to repay the amount undercharged if: 1) the meter was tampered with; 2) the meter failed to register at all; or 3) the circumstances are such that the Customer should reasonably have known that the bill did not reflect the actual usage. In rebilling a Customer under this Section, the Company may perform a load analysis or degree day analysis.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING (continued)

8.5 THERM CONVERSION FACTOR

For billing purposes, the reading of the Customer's meter in cubic feet first will be converted to standard cubic feet, then converted to therms by multiplying the use in cubic feet by the weighted average of the BTU content of all gas purchased from all pipeline suppliers for the second preceding calendar month and divided by 100,000. Such calculation shall be to the closest 1/100 of a therm.

8.6 BILLING PERIOD

When the billing interval is substantially greater or less than one month, bills will be computed by prorating charges provided under the applicable Service Classification on the basis of the relationship between the time covered by the billing period and a full month.

8.7 EQUAL PAYMENT PLAN

The Company will provide to customers, on request, an equal payment plan in accordance with N.J.A.C. 14:3-7.5. Adjustments will be made annually if actual charges are more or less than the equal payment plan amounts billed. Further, there shall be at least one comparison of actual charges to the monthly equal payment plan amount, and if this comparison reveals an increase or decrease of 25 percent or more of the monthly equal payment plan amount, the monthly equal payment plan amount will be adjusted for the balance of the equal payment plan year.

8.~~8~~7 PAYMENT OF BILLS

Bills normally will be rendered monthly and may be paid through the Company's authorized payment methods including, but not limited to, at any business office of the Company during its regular office hours, at any of its authorized payment locations during regular office hours of such agencies, on the Company's website~~Web site~~ at www.njng.com, authorized electronic payment remitters, auto-debit enrollment, by phone {1-800-221-0051}, or by mail.

8.~~9~~8 PAYMENT OBLIGATION

Unless otherwise specified all bills are net and payable within at least twenty~~fifteen~~ (20~~15~~) days from the date the bill is sent. Failure to make payment may be deemed sufficient reason for the Company to consider the Customer's account delinquent. The Company may discontinue service for nonpayment of bills provided it gives the Customer at least ten days written notice of its intention to discontinue. The notice of discontinuance shall not be served until the expiration of the said 20~~15~~ day period. However, in cases of fraud, illegal use, or when it is clearly indicated that the Customer is preparing to leave, immediate payment of account may be required.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING (continued)

The Company shall apply the regulations set forth in N.J.A.C. 14:3-3A.2, as may be amended or superseded, and shall discontinue service for nonpayment only if one or both of the following criteria are met: 1) the Customer's arrearage is more than $200.00~~100.00~~; 2) the Customer's account is more than three months in arrears.

STANDARD TERMS & CONDITIONS

8. METER READING AND BILLING (continued)

8.~~10~~9 LATE PAYMENT CHARGE

A late payment charge at the rate of 1.5% per monthly billing period shall be applied to all non-residential customers. The charge will be applied to all amounts previously billed including late payment charges and accounts payable that are not paid at the time the next monthly bill is prepared and shall not be applied sooner than twenty-five (25) days after a bill is rendered, in accordance with N.J.A.C. 14:3-7.1(e). Service to governmental entities will not be subject to a late payment charge. The amount of the late payment charge to be added to the unpaid balance shall be calculated by multiplying the unpaid balance by the late charge rate. When payment is received by the Company from a Customer who has an unpaid balance which includes charges for late payment, the Customer's payment shall be applied first to such late payment charges and then to the remainder of the unpaid balance.

8.1~~0~~0 FINAL BILL

A Customer intending to discontinue service must give the Company reasonable notice thereof. Within forty-eight (48) hours of said notice, the Company shall discontinue service or obtain a meter reading for the purpose of calculating a final bill, unless a holiday or weekend intervenes. Where such notice is not received by the utility, the Customer shall be liable for service until the final reading of the meter is taken. Notice to discontinue service will not relieve a Customer from any minimum or guaranteed payment under any contract or Service Classification.

8.1~~1~~2 RETURNED PAYMENT FEE

The Company will charge $10.00 to process Customer payments that are uncollectible and returned by the Company's bank.

8.1~~2~~3 FIELD COLLECTION CHARGE

A charge of $15.00 may be made when the Company makes a collection visit to the Customer or premises.

STANDARD TERMS & CONDITIONS

9. DISCONTINUANCE OF SERVICE

9.1 COMPANY CAUSES

The Company shall, upon reasonable notice, when it reasonably can be given, have the right to suspend, curtail, or discontinue its service for any of the following reasons:

a. For the purpose of making repairs, changes, replacements, or improvements in any part of its system.

b. For compliance in good faith with any governmental order or directive, whether Federal, State, Municipal, or otherwise, even if such order or directive subsequently is held to be invalid.

c. In the event of an emergency threatening the integrity of its system if, in the Company's sole judgment, such action will prevent or lessen the emergency condition.

9.2 CUSTOMER ACTS OR OMISSIONS

The Company also shall have the right to suspend, curtail or discontinue its service for any of the following act(s) or omission(s) on the Customer's part:

a. Nonpayment of any bill due for service furnished at the present or any previous location, in accordance with N.J.A.C. 14:3-3A.2~~1~~, as may be amended or superseded. However, nonpayment for business service shall not be a reason for discontinuance of residential service, except in cases of diversion of service pursuant to N.J.A.C. 14:3-7.8, as may be amended or superseded and service shall not be discontinued for nonpayment of appliance repair, installation charges, service contracts, and other services unrelated to gas service.

b. Tampering with any facility of the Company.

c. Fraudulent representation in relation to the use of gas service.

d. Customer moving from the premises unless that Customer requests that service be continued.

e. Delivering gas service to others without written approval of the Company except as permitted under Standard Terms and Conditions Sections 6.11 and 6.12 Sub-Metering and Check-Metering.

f. Failure to make or increase an advance payment or deposit when required by the Company.

g. Refusal to contract for service where a contract is required.

h. Connecting and operating equipment in such a manner as to produce disturbing effects on the service of the Company or other Customers.

STANDARD TERMS & CONDITIONS

9. DISCONTINUANCE OF SERVICE (continued)

i. Where the conditions of the Customer's installation presents a hazard to life or property.

j. Failure of the Customer to repair any faulty equipment or lines.

k. Failure to comply with any of these Standard Terms and Conditions or with any of the terms of the service classification or contract under which gas service is furnished.

l. Failure to provide reasonable access to the premises, and to the Company's meter and other service facilities on the premises, for the purposes of meter installation, reading, testing, inspection, maintenance, removal, or replacement of meters or other service facilities.

Reasonable access means that premises shall not become obstructed or hazardous, and that the Customer shall not construct, pave over, or otherwise obstruct the Company's service line or other facilities. In the event reasonable access, as described here, is not complied with, the Company may, upon reasonable notice, discontinue service and remove its equipment from the Customer's premises.

Any costs of protecting or relocating such service line or facilities shall be borne by the Customer.

m. In the event a writ of execution is issued against a Customer, or in case the premises to which service is supplied is levied upon, or in the case of assignment or act of bankruptcy on the part of the Customer.

n. Service to a residential customer shall only be discontinued between the hours of 8:00 a.m. and 4:00 p.m. Monday through Thursday, unless there is a safety related emergency. There shall be no involuntary termination of service on Fridays, Saturdays, and Sundays or on the day before a holiday or on a holiday, absent such emergency.

9.3 CHARGES PAYABLE UPON TERMINATION

If gas service is terminated for any of the above reasons where the Customer is under written contract, the minimum charge for the unexpired portion of the term shall become due and payable immediately, provided, however, that if satisfactory arrangements are subsequently made by Customer for reconnection of the service, the immediate payment of the minimum charge for the unexpired portion of the contract term may be waived or modified as the circumstances indicate would be just and reasonable.

9.4 NON-WAIVER

Failure of the Company to exercise its rights to suspend, curtail or discontinue service, for any of the above reasons, shall not be deemed a waiver of the Company's rights.

STANDARD TERMS & CONDITIONS

9. DISCONTINUANCE OF SERVICE (continued)

9.5 RESTORATION OF SERVICE

The Company shall not reconnect service to the Customer's premises, where service has been discontinued by reason of any act or default of the Customer, until such time as the Customer has rectified the condition or conditions causing discontinuance of service. Service shall not be reconnected until the Customer has met all financial requirements including satisfactory payment arrangements called for under these Standard Terms and Conditions and the applicable Service Classification, or if the Board so directs when a complaint involving such a matter is pending before the Board in accordance with N.J.A.C. 14:3-3A.9, as may be amended or superseded.

The Company shall treat the restoration of service and the turn-on of new accounts on a first come, first serve basis during periods outside of the winter moratorium. The Company shall give priority to the restoration of service during the winter moratorium.

9.6 RECONNECTION CHARGE

The Customer shall pay a reconnection charge of $45.00 for the restoration of service when service has been suspended for any of the reasons cited in Section 9.2, with the exception of 9.2.d, of these Standard Terms and Conditions.

STANDARD TERMS & CONDITIONS

10. FOR CUSTOMERS PURCHASING GAS SUPPLY FROM A THIRD PARTY SUPPLIER

10.1 CONDITIONS PRECEDENT

The Customer shall designate a Third Party Supplier, formerly referred to as Marketer or Broker, who will act as the Customer's agent with the Company for purposes of receiving nominations, satisfying delivery obligations, daily and monthly balancing, selection of billing option and all related charges. The Third Party Supplier must be authorized by the Company and is subject to the service requirements of the Third Party Supplier Requirements ("TPS") Service Classification. The Customer is responsible for payment of any costs if additional facilities are necessary to provide service. The Company reserves the right to limit new customers served under this service, if it determines that service expansion is detrimental to existing firm customers.

10.2 RETURN TO FIRM SALES SERVICE

Customers shall be permitted to return to firm sales service in accordance with N.J.A.C. 14:4-2.6(f), as may be amended or suspended. Transport customers who terminate such service and who wish to return to firm sales service, will be viewed as new applicants for such firm sales service. Such service will be offered subject to the conditions contained in Section 3.4 of the Company's Standard Terms and Conditions in its Tariff.

10.3 WARRANTY

NJNG warrants that at the time of delivery to the Customer at the Delivery Point said gas quantities shall be free and clear of all liens, encumbrances and claims whatsoever which may result solely from NJNG's possession or transportation of gas hereunder and, further, that it will indemnify and hold the Customer harmless from all suits, actions, debts, accounts, damages, costs, losses, and expense arising from or out of adverse claims of any or all persons to said gas quantities, arising out of, relating to or resulting from such possession or transportation.

10.4 CONTRACT

Written application on Company's Standard Application Form may be required.

STANDARD TERMS & CONDITIONS

10. FOR CUSTOMERS PURCHASING GAS SUPPLY FROM A THIRD PARTY SUPPLIER (continued)

10.5 REGULATORY APPROVALS

The Customer is responsible for securing approvals from all regulatory bodies having jurisdiction and making any filings or reports, as required, pertaining to the acquisition of the gas and/or the transportation of the gas from the Customer's source to the Company's designated delivery meters.

The Company reserves the right, in its sole reasonable judgment, to deny service hereunder if it determines that the underlying contracts or transportation agreements do not comply with all applicable Federal or State laws, rules or regulations, including those of all appropriate regulatory agencies; or if it determines that the requested transportation service is not operationally feasible.

10.6 CHANGE OF THIRD PARTY SUPPLIER

Customers shall be permitted to switch suppliers in accordance with N.J.A.C. 14:4-2.6(f), as may be amended or superseded.

STANDARD TERMS & CONDITIONS

11. CONDITIONS UNDER WHICH RATE DISCOUNTS SHALL BE CONSIDERED

11.1 CUSTOMERS WITH ABILITY TO BYPASS

A Customer requesting a discount from NJNG's Tariff Rate for Gas Service due to the Customer's asserted ability to physically bypass the Company's distribution and/or transmission system facilities shall provide the following information to the Company:

a. A statement from the interstate natural gas pipeline that the proposed interconnection is operationally viable, that sufficient capacity is available and the pipeline would serve the party if requested;

b. Maps or flow diagrams for the bypass connection, which shall identify the route of the pipeline from the interconnection with the pipeline and the Customer's site, the size of the connecting pipeline from the interconnection with the pipeline and the Customer's site, the size of the connecting pipeline and any other appurtenant facilities required;

c. Engineering studies setting forth the estimated cost(s) to complete construction;

d. Status of all reliability and environmental permits required by State and Federal agencies; and

e. Other information that the Company deems appropriate in considering the Customer's request.

Each request will be evaluated on a case-by-case basis to determine whether a discount from NJNG's Tariff Rate for Gas Service would be just and reasonable. Any agreement between the Customer and the Company for a discount from NJNG's Tariff Rate for Gas Service is subject to Board approval.

11.2 CUSTOMERS WITH CIRCUMSTANCES OTHER THAN AN ASSERTED ABILITY TO PHYSICALLY BYPASS

A new Customer or existing Customer who requests a discount from NJNG's Tariff Rate for Gas Service due to circumstances other than the asserted ability to physically bypass the Company's distribution and/or transmission system facilities shall contact the Company in writing with its request. The new or existing Customer shall provide all of the information that the Company deems appropriate in considering the Customer's request. Each request will be evaluated on a case-by-case basis to determine whether a discount from NJNG's Tariff Rate for Gas Service would be just and reasonable. Any agreement between the Customer and the Company for a discount from NJNG's Tariff Rate for Gas Service is subject to Board approval.

RESERVED FOR FUTURE USE

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas ~~Fifth Revised Sheet No. 51~~ ~~Superseding Fourth Revised~~Original Sheet No. 51

SERVICE CLASSIFICATION - RS

RESIDENTIAL SERVICE

AVAILABILITY

This service is available to any residential Customer in the territory served by the Company using gas for any domestic purpose. This rate is applicable to individually-metered apartments and to rooming and boarding houses where the number of rental bedrooms is not more than twice the number of bedrooms used by the Customer.

Gas delivered under this schedule may not be used for other than domestic purposes except when such use is incidental to domestic use.

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~11.00~~15.00

Delivery Charge:

Residential Heating

Delivery Charge per therm	$~~0.9500~~1.2585

Residential Non-Heating

Delivery Charge per therm	$~~0.8967~~1.2052

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

SERVICE CLASSIFICATION - RS

RESIDENTIAL SERVICE (continued)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SPECIAL PROVISIONS

I. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Metering***

   An Automated Meter Reading (AMR) device will not be required for this service. However, the Company reserves the right to install an AMR device at its own expense. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

   When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

   Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

2. ***Additional Requirements***

   Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

CONTRACT

Written application on Company's Standard Application Form may be required.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions.

NEW JERSEY NATURAL GAS COMPANY

~~Fifth~~ ~~Revised Sheet No. 53~~

BPU No. ~~11~~12 - Gas ~~Superseding Fourth Revised~~ Original Sheet No. 53

SERVICE CLASSIFICATION – DGR

DISTRIBUTED GENERATION SERVICE - RESIDENTIAL

AVAILABILITY

This service is available to any residential customer using distributed generation technologies including, but not limited to, microturbines and fuel cells to generate electricity for domestic purposes.

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~11.00~~15.00

Delivery Charge:

November - April	$~~0.4207~~0.4212
May - October	$~~0.3674~~0.3679

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge. Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SERVICE CLASSIFICATION - DGR

DISTRIBUTED GENERATION SERVICE - RESIDENTIAL (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers Under This Service Classification*

1. ***Metering***

All service rendered hereunder shall be metered separately from any other gas service provided to Customer at the Customer's location.

An Automated Meter Reading (AMR) device with daily meter reads will not be required for this service. However, upon prior notice to the Customer, the Company reserves the right to install an AMR at its own expense. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Additional Requirements***

Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas ~~Fifth Revised Sheet No. 55~~ ~~Superseding Fourth Revised~~ Original Sheet No. 55

SERVICE CLASSIFICATION – GSS

GENERAL SERVICE - SMALL

AVAILABILITY

This service is available to any Customer in the entire territory served by the Company who uses less than 5,000 therms annually and uses gas for all purposes other than residential service and interruptible service. Where the Customer uses the Cooling, Air Conditioning and Pool Heating service ("CAC") under Special Provision I.2, the Company may, upon application by the Customer, meter the space heating and CAC use separately. Street Lighting Service also will be supplied under this schedule (Special Provision II.1).

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~42.00~~57.50

Delivery Charge:

Delivery Charge per therm	$~~0.8409~~1.1391

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SERVICE CLASSIFICATION - GSS

GENERAL SERVICE - SMALL (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers Under This Service Classification*

1. ***Annual Review***
The Company shall review, at least once a year, each GSS Customer's annual usage based on the most recent twelve (12) months of billing information to determine if the General Service – Large ("GSL") Service Classification is applicable to the Customer. If the Customer's normalized annual usage is greater than or equal to 5,500 therms, the customer will be switched to GSL prospectively.

2. ***Air Conditioning and Pool Heating***
Upon separate application, GSS Customers who have installed and are using gas air conditioning and/or pool heating equipment will be billed on the above Monthly Rates and will be billed a credit of ($~~0.4820~~0.7404) per therm for all monthly consumption of gas for services rendered between May 1 and September 30 of each year. This credit is the difference between the delivery charge for service rendered between May 1 and September 30 of each year under this Special Provision of $~~0.3589~~0.3987 per therm, which includes $0.1463~~0.1096~~ per therm margin, all appropriate riders, taxes, assessments and surcharges, and the delivery charge for Service Classification GSS.

Commercial Air Conditioning and Pool Heating ("CAC") customers will be separately metered, except, at the Company's sole discretion, existing Customers may use the same meter for their cooling, air conditioning or pool heating load and their space heating load as long as there is minimal base load during the period air conditioning rates are in effect.

Where a CAC Customer uses gas under this service classification in a direct-fired chiller/heater and the heating load is metered through the same meter as the cooling, air conditioning or pool heating load, and further, where the gas used for heating is billed separately, the GSS Customer Charge shall be waived, provided the Customer pays the Customer Charge under its heating service in all twelve (12) months of the year.

3. ***Veterans' Organization Service***
Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

a. Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service

SERVICE CLASSIFICATION - GSS

GENERAL SERVICE - SMALL (continued)

delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

SERVICE CLASSIFICATION - GSS

GENERAL SERVICE - SMALL (continued)

The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

b. The Customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' Customer Charges and Delivery Charges under this Special Provision for all relevant periods. If the comparable Customer Charges and Delivery Charges under Service Classification Residential Service (RS) are lower than the charges under their current Service Classification, a credit in the amount of the difference will be applied to the Customer's next bill.

4. **Metering**

An Automated Meter Reading (AMR) device will not be required for this service. However, the Company reserves the right to install an AMR device at its own expense. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

II. *Applicable to All Customers Purchasing Gas Supply Under Rider "A" BGSS*

1. **Street Lighting Service**

Street Lighting Service is not subject to Rider "I" of this Tariff. The delivery charge per therm for Street Lighting Service is $~~0.7804~~1.5076 per therm.

III. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. **Additional Requirements**

Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions of this Tariff.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas ~~Fifth Revised Sheet No. 58~~ ~~Superseding Fourth Revised Original~~ Sheet No. 58

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE

AVAILABILITY

This service is available to any Customer in the entire territory served by the Company who uses greater than or equal to 5,000 therms annually and uses gas for all purposes other than residential service and interruptible service. Where the Customer uses the Cooling, Air Conditioning and Pool Heating service ("CAC") under Special Provision I.4, the Company may, upon application by the Customer, meter the space heating and CAC use separately.

CHARACTER OF SERVICE

Firm gas service where Customer may either purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS") or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~104.00~~142.50

Demand Charge:

Demand Charge per therm applied to HMAD	$~~3.41~~4.50

Delivery Charge:

Delivery Charge per therm	$~~0.6192~~0.7364

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge and the Demand Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

BALANCING CHARGE ADJUSTMENTS

The Balancing Charge is included in the Delivery Charge and is subject to adjustment in the Company's annual BGSS proceeding. All revenues derived from this Charge will be credited to the BGSS. See Rider "A" for the current Balancing Charge.

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***Determination of Demand***

The highest monthly average daily usage (HMAD) that occurs in any billing period will be used to calculate the Demand Charge. The HMAD shall be determined based upon the Customer's highest normalized average daily usage for a month in the most recent twenty-four (24) month period. Estimated data may be used when actual data is not available. At least once a year, the Company shall review and modify, if necessary, each GSL customer's HMAD based upon the most recent twenty-four (24) months of billing information. Any modification will be on a prospective basis. The Company reserves the right to determine the HMAD for any Customer by actually metering daily usage.

2. ***Metering***

An Automated Meter Reading (AMR) device with daily meter reads will not be required for this service. However, the Company reserves the right to install an AMR if it believes such a device will provide a more accurate HMAD than the Determination of Demand set forth above. Should the Company decide to install an AMR, the Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company.

When a remote meter reading device is requested by the Customer, it shall be installed at the Customer's expense if the installation is deemed feasible by the Company.

Should the Company decide to install an AMR or a Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

3. ***Annual Review***

The Company shall review, at least once a year, each GSL customer's annual usage based on the most recent twelve (12) months of billing information to determine if the General Service - Small ("GSS") Service Classification is applicable to the Customer. If the Customer's normalized annual usage is less than or equal to 4,500 therms, the Customer will be switched to GSS prospectively.

4. ***Air Conditioning and Pool Heating***

Upon separate application, GSL Customers who have installed and are using gas air conditioning and/or pool heating equipment will be billed on the above Monthly Rates and will be billed a credit of ($~~0.2603~~0.3377) per therm for all monthly consumption of gas for services rendered between May 1 and September 30 of each year. This credit is the difference between the delivery charge for service rendered between May 1 and September 30 of each year under this Special Provision of $~~0.3589~~0.3987 per therm which includes $0.1493~~0.1096~~ per therm margin, all appropriate riders, taxes, assessments and surcharges, and the delivery charge for Service Classification GSL.

Commercial Air Conditioning and Pool Heating ("CAC") Customers will be separately metered, except, at the Company's sole discretion, existing Customers may use the same meter for their cooling, air conditioning or pool heating load and their space heating load as long as there is minimal base load during the period air conditioning rates are in effect.

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE (continued)

Where a CAC Customer uses gas under this service classification in a direct-fired chiller/heater and the heating load is metered through the same meter as the cooling, air conditioning or pool heating load, and further, where the gas used for heating is billed separately, the GSL Customer Charge shall be waived, provided the Customer pays the Customer Charge under its heating service in all twelve (12) months of the year.

5. ***Veterans' Organization Service***
Pursuant to N.J.S.A 48:2-21.41, when natural gas service is delivered to a customer that is a Veterans' Organization serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

   a. Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

   The Customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company, who will determine eligibility. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

   b. The Customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' Customer Charges, Demand Charges, and Delivery Charges under this Special Provision for all relevant periods. If the comparable Customer Charges and Delivery Charges under Service Classification Residential Service (RS) are lower than the charges under their current Service Classification, a credit in the amount of the difference will be applied to the Customer's next bill.

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

2. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No. 60*

SERVICE CLASSIFICATION - GSL

GENERAL SERVICE - LARGE (continued)

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - FT

FIRM TRANSPORTATION SERVICE

AVAILABILITY

This service is available to any customer who would otherwise qualify for service under Service Classifications GSS, GSL, IS, or NGV. The Company may require the Customer to provide to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution systems.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~350.00~~475.00

Demand Charge:

Demand Charge per therm applied to MDQ	$~~2.50~~3.75

Delivery Charge:

Delivery Charge per therm	$~~0.2016~~0.1891

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge and the Demand Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SERVICE CLASSIFICATION - FT

FIRM TRANSPORTATION SERVICE (continued)

SPECIAL PROVISIONS

1. ***Determination of Demand***
   The Maximum Daily Quantity (MDQ) will be initially set by determining the highest monthly average daily usage (HMAD) without normalization and multiplying that result by 1.30. The MDQ will be stated in therms.

   The Company shall deliver to the Customer the gas quantity provided by the Customer up to the MDQ level. Should the Customer's usage exceed the MDQ, the MDQ will be deemed to have changed. The MDQ for service and billing purposes will remain at the highest actual daily volume served. The Customer may request a decrease to its MDQ when the Customer has installed energy efficient equipment or significantly modified its operations resulting in decreased maximum daily usage. Any decrease in the MDQ will be granted in the Company's sole judgment on a prospective basis.

2. ***Automated Meter Reading Device***
   Metering shall include an automated meter reading device (AMR) with daily meter reads**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

   The Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over a twelve-month period with the prime interest rate used to calculate carrying costs.

3. ***Incremental Expenses***
   The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

4. ***Customer Responsibility***
   In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

SERVICE CLASSIFICATION - FT

FIRM TRANSPORTATION SERVICE (continued)

5. ***Inability to Secure Supply with a Third Party Supplier***
In the event that a new Customer cannot enroll with a Third Party Supplier prior to the commencement of service, or an existing Customer's Third Party Supplier ceases providing service to the Customer and the Customer is unable to secure supply from an alternate Third Party Supplier, Customers may elect to receive temporary supply service from the Company. The price for temporary service provided to the Customers shall be equal to the Monthly BGSS price in Rider "A".

If a Third Party Supplier has not submitted enrollment information for the Customer to the Company within thirty (30) days of a new Customer's commencement of service or an existing Customer's loss of its previous Third Party Supplier, the Customer will be switched to the appropriate sales service classification.

6. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Superseding Fourth Revised~~Original Sheet No. 64* *~~Fifth Revised Sheet No. 64~~*

SERVICE CLASSIFICATION - DGC

DISTRIBUTED GENERATION SERVICE - COMMERCIAL

AVAILABILITY

This service is available to any commercial customer using distributed generation technologies including, but not limited to, microturbines and fuel cells.

CONDITIONS PRECEDENT

If the Customer is served by a Third Party Supplier, the Third Party Supplier assumes the responsibility for all delivery requirements. The Company may require the Customer to provide, to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution systems. The Customer is responsible for payment of any costs if additional facilities, exclusive of metering facilities, are necessary to provide service. The Company reserves the right to limit new customers served under this service, if it determines that service expansion is detrimental to existing firm customers. The Customer must demonstrate that qualifying electric generation equipment has been installed at its location.

MONTHLY RATES

	DGC-Balancing	DGC-FT
Customer Charge:		
Customer Charge per meter per month	$~~104.00~~142.50	$~~104.00~~142.50
Demand Charge:		
Demand Charge per therm applied to PBQ	$~~2.35~~3.25	$~~2.35~~3.25
Delivery Charge per therm:		
November - April	$~~0.3184~~0.3314	$~~0.1918~~0.2043
May - October	$~~0.2858~~0.2988	$~~0.1592~~0.1717
BGSS Charge:		
BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff	N/A

The Delivery Charges for DGC-Balancing above include the Balancing Charge as reflected in Rider "A" of this Tariff for customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (3) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS. For DGC-FT customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (1) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS, the DGC-FT Delivery Charges above exclude the Balancing Charge reflected in Rider "A" of this Tariff.

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

SERVICE CLASSIFICATION - DGC

DISTRIBUTED GENERATION SERVICE - COMMERCIAL (continued)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the sum of the Customer Charge and the Demand Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***Determination of Demand***
The Peak Billing Quantity (PBQ) will be initially set based on the rated fuel requirements of the installed distributed generation equipment and the Customer's electric requirements. The Company shall deliver to the Customer the gas quantity provided by the Customer up to the PBQ level. Should the Customer's usage exceed the PBQ, the PBQ will be deemed to have changed. The PBQ for service and billing purposes will remain at the highest actual daily volume served.

2. ***Automated Meter Reading Device***
All service rendered hereunder shall be metered separately from any other gas service provided to the Customer at the Customer's location.

Metering shall include an automated meter reading device (AMR) with daily meter reads, which shall be furnished and installed by the Company. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line, or data plan, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

SERVICE CLASSIFICATION - DGC

DISTRIBUTED GENERATION SERVICE - COMMERCIAL (continued)

3. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

The Company's main and service extension policy set forth in Section 4 of the Standard Terms and Conditions shall apply to service rendered hereunder with the following exceptions: the Company will make gas main extensions and service line connections to serve individual firm DGC customers free of charge where the cost of such extension does not exceed three (3) times the estimated annual distribution revenue for equipment with an estimated life of less than 5 years; five (5) times the estimated annual distribution revenue for equipment with an estimated life between six (6) and ten (10) years; six (6) times the estimated annual distribution revenue for equipment with an estimated life between eleven (11) and sixteen (16) years. Equipment with an estimated life greater than sixteen (16) years will be subject to the ten (10) times policy set forth in Section 4 of the Standard Terms and Conditions.

Should the Customer take service under this classification for less than one (1) year, the Customer shall reimburse the Company for the cost of the extension.

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Customer Responsibility***
In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

2. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATION - ED

ECONOMIC DEVELOPMENT SERVICE

AVAILABILITY

Customers eligible to receive service under the following Service Classifications: General Service - Small ("GSS"), General Service - Large ("GSL"), or Firm Transportation Service ("FT").

CHARACTER OF SERVICE

Firm gas sales and transportation service.

CONDITIONS PRECEDENT

The Customer must meet the following conditions:

1. a. For new Customers, the building receiving service under this Tariff must be new or have been vacant for at least twelve months.

   b. Existing Customers must have been served for more than one year, and the space utilized for operations must have expanded by more than 5,000 square feet. Gas used in excess of the previous twelve months (base) usage will be subject to the Economic Development (ED) credit.

   c. An existing occupant (a) converts to natural gas and (b) expands space utilized for its operations by more than 5,000 square feet would be eligible for the credit. The Occupant must provide its energy usage for the previous twelve months (base) at the time of application for gas service. The Company will calculate the BTUs used by the Occupant in the base period and BTUs used in excess of the base period would be eligible for the ED credit.

2. The Customer must be adding at least two permanent full-time employees to a location in the Company's service territory. Relocation or consolidation of employees based at locations in the Company's service territory must net at least two new jobs in order to qualify for the ED credit. Employment growth will be confirmed by the Company and/or by affidavit from the Customer. The Company reserves the right, at its discretion, to periodically verify levels of employment. If after verification the required employment level has not been sustained, the Customer will no longer be eligible for the ED credit.

3. The Customer must apply for this service upon the initial application for gas service.

4. The Customer must execute a Service Agreement.

5. The building receiving service under this Tariff must be located within a community in our service territory with a ranking of 150 or less on the current Municipal Distress Index compiled by the New Jersey State Planning Commission.

SERVICE CLASSIFICATION - ED

ECONOMIC DEVELOPMENT SERVICE (continued)

MONTHLY RATES

The monthly rates shall be the same as the applicable service classification except that: 1) GSS Customers will be credited $0.1200 per therm for all eligible gas use, and 2) GSL and FT Customers' Demand charges will be reduced by fifty (50) percent. These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company.

MINIMUM MONTHLY CHARGE

The minimum monthly charge for GSS Customers shall be the Customer Charge. The minimum monthly charge for GSL and FT Customers shall be the Customer Charge and the Demand Charge.

SPECIAL PROVISIONS

1. ***Extension of Facilities***
   The Company will extend facilities per Sections 4, and 5 of the Standard Terms and Conditions of this Tariff utilizing the margins that result from the above Monthly Rates.

2. ***Tariff Availability***
   The Company reserves the right to offer this Tariff rate to customers located in areas of other communities, which demonstrate the characteristics warranting economic development to encourage such development and employment opportunities, if such offer meets public policy objectives of the state of New Jersey as administered by the State of New Jersey Department of Community Affairs or its successor.

SERVICE LIMITATIONS

This service is not available to federal, state, county or local governments or governmental entities.

CONTRACT

The maximum term of the service agreement shall be three years. A Customer's three year term of eligibility will commence no later than six months after the Service Agreement is executed.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Superseding Fourth Revised~~Original Sheet No. 69* *~~Fifth Revised Sheet No. 69~~*

SERVICE CLASSIFICATION - EGS

ELECTRIC GENERATION SERVICE

AVAILABILITY

This service is available to any existing or new customer who uses greater than or equal to 10,000 therms daily for the sole purpose of generating electricity. Year-Round firm service is available throughout the year. Off-Peak firm service is available beginning May 15 and ending September 15.

MONTHLY RATES

Customer Charge:

	Without SUT	With SUT
Customer Charge per month	$~~877.26~~914.42	$~~935.38~~975.00

Demand Charge Per therm Applied to MDQ:

	Without SUT	With SUT
Year-Round Firm Service Demand Charge per therm applied to MDQ	$~~1.5132~~1.8757	$~~1.6134~~2.00
Off -Peak Firm Service Demand Charge per therm applied to MDQ	$0.6253	$0.6667

Delivery Charge:

	Without SUT	With SUT
Delivery Charge per therm	$~~0.1121~~0.1168	$~~0.1194~~0.1244

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, applicable taxes, assessments or similar charges lawfully imposed by the Company. Natural gas used to generate electricity that is sold for resale by customers served under this Service Classification is exempt from Riders B, C, D, E, F and G~~H~~ and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge and the Demand Charge.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

SPECIAL PROVISIONS

1. ***Determination of Demand***
   The Maximum Daily Quantity (MDQ) will be: (1) initially determined by agreement between the Company and the Customer, (2) stated in therms, and (3) included in the Service Agreement.

2. ***Facilities***
   The Company shall install gas main extensions, service line connections, and facilities necessary to meet pressure and demand requirements at the Customer's location (collectively, the "Extension Cost") to serve the customer free of charge where the Extension Cost does not exceed ten (10) times the estimated annual distribution revenue. An applicant shall be required to provide a non-refundable contribution in aid of construction for the value of any Extension Cost that is greater than ten (10) times the annual distribution revenue. The Extension Cost for which the Company receives a contribution shall include the tax consequences incurred by the Company. The Company and applicant may agree upon a satisfactory revenue guarantee in lieu of a contribution.

   Where it is necessary to provide additional facilities to serve increased requirements of an existing Customer, the Company reserves the right to require the Customer to provide a non-refundable contribution in aid of construction in an amount equal to the cost of such additional facilities.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

3. ***Separately Metered***
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification.

4. ***Automated Meter Reading Device***
Metering shall include an automated meter reading device (AMR) with daily meter reads**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line or data plan, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

The customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over over a twelve-month period with the prime interest rate used to calculate carrying costs.

5. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

6. ***Nominations***
Customer's nominations for service under this Service Classification must be made on the Company's electronic bulletin board ("EBB") by the deadline specified on the Company's EBB on the day prior to gas flow for the next calendar day. Customer may request nomination changes after the deadline or during the intra-day through intra-day nominations no less frequently than is allowed under the then current North American Energy Standards Board ("NAESB") Nomination Standards. Customer shall have the right to request a new nomination, an Intra-day Nomination, for flow intra-day. The term "intra-day nomination" shall mean (i) a nomination received during a gas day for the same day of gas flow, and (ii) a nomination received after the Timely Nominations deadline for the following gas day. Customer shall notify the Company in writing of changes and the Company will enter and/or approve at the Company's sole discretion on the Company's EBB and the applicable interstate pipeline's EBB.

The Company reserves the right to reject nominations, in whole or in part, for deliveries in excess of Customer's estimated usage. This restriction will not apply to days with an Operational Flow Order ("OFO") in place and can be issued as a blanket for the entire system or for a single Third Party Supplier. The Company will provide written notice to a Third Party Supplier of the Company's rejection of the Third Party Supplier's deliveries prior to implementing the reductions on the affected pipeline.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

7. ***Balancing***

It is the intent that Customer's actual daily takes under this Service Classification match the Customer's daily nominations, and that Customer's actual daily deliveries match Customer's actual daily takes. The Customer shall be allowed a daily tolerance for the difference between their actual daily delivery and their actual daily take equal to the greater of 500 Dth or 2% of the Customer's daily takes. On any day that the Company has issued an OFO and/or the applicable interstate pipeline has issued an OFO, Action Alert, Force Majeure, or similar restriction, the tolerance for any negative imbalances (Customer used more than was delivered) is 0 (zero). On any day that the applicable interstate pipeline has issued an OFO limiting positive imbalances (Customer used less than was delivered), the tolerance for any positive imbalances is 0. A cash-out for any differences above the daily tolerance shall be charged or credited to the Customer each month.

If the imbalance is negative (Customer used more gas than was delivered), the Customer will purchase gas from the Company at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Highest price of daily ranges for delivery on the applicable pipeline at the zone of the Company's designated delivery meters, which are published in Platts Gas Daily in the table, "Daily Price Survey" ("Gas Daily High")
>5% - ≤ 10%	quantity >5% * Gas Daily High * 1.1 + level above
>10% - ≤ 15%	quantity >10% * Gas Daily High * 1.2 + levels above
>15% - ≤ 20%	quantity >15% * Gas Daily High * 1.3 + levels above
>20% - ≤ 25%	quantity >20% * Gas Daily High * 1.4 + levels above
>25%	quantity >25% * Gas Daily High * 1.5 + levels above

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

If the imbalance is positive (Customer delivered more gas than was used), the Company will purchase gas from the Customer at the rates below:

Imbalance Level	*Calculation*
0% - ≤ 5%	quantity * Lowest price of daily ranges for delivery on the applicable pipeline at the zone of the Company's designated delivery meters, which are published in Platts Gas Daily in the table, "Daily Price Survey" ("Gas Daily Low")
>5% - ≤ 10%	quantity >5% * Gas Daily Low * .90 + level above
>10% - ≤ 15%	quantity >10% * Gas Daily Low * .80 + levels above
>15% - ≤ 20%	quantity >15% * Gas Daily Low * .70 + levels above
>20% - ≤ 25%	quantity >20% * Gas Daily Low * .60 + levels above
>25%	quantity >25% * Gas Daily Low * .50 + levels above

All revenues and purchases derived from imbalances will be credited to the BGSS.

8. ***Operational Flow Order ("OFO")***

The Company may issue an Operational Flow Order ("OFO") requiring delivery by the Customer of at least the volume of gas the Customer uses on the affected gas day ("OFO Required Volume").

A Customer who fails to deliver the OFO Required Volumes of gas may not be permitted to continue to operate on the system. In addition, the Customer will be billed at the applicable "Delivery Shortfall" charge in effect during the OFO period for the volume difference between the OFO required delivery and the actual delivered volume. There will be no penalties for delivering gas in excess of an OFO Required Volume.

9. ***Delivery Shortfall Charge***

In the event that the Customer fails to deliver the OFO Required Volume directed by the Company (a "Delivery Shortfall"), the Company shall bill the Customer and the Customer shall pay for the volume of the Delivery Shortfall at a rate equal to ten (10) times the highest price of daily ranges for delivery on the applicable pipeline in the zone of the Company's designated delivery meters, that are published in Platts Gas Daily on the table, "Daily Price Survey"; provided, however, the amount billed shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines that deliver gas to the Company. In the event of a Delivery Shortfall, the Company shall have the right to recover *pro rata* from all under-delivering Customers and Third Party Suppliers served under Service Classification TPS any penalties or other charges or damages assessed on the Company because of such under-deliveries for the days the Customers, Third Party Suppliers under-delivered.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

Notwithstanding the above, if contemporaneously with a Delivery Shortfall, the applicable pipeline has declared a force majeure on its system curtailing primary, in-path transportation in the zone of the Company's designated delivery meter, the Company may waive the above charges and may bill the Customer for the Company's Replacement Cost of Gas (defined below) provided that the under-delivering Customer is able to demonstrate to the Company's reasonable satisfaction that the applicable pipeline transportation contract on which the Customer had scheduled deliveries to the Company during the period in which the OFO was in effect entitled the Customer to firm transportation rights through the point at which the force majeure was declared and that the applicable pipeline curtailed Customer's deliveries *pro rata* with deliveries to other similarly situated delivery meters on the contract. The Customer must notify the Company in writing of the anticipated Delivery Shortfall before the nomination deadline for the next North American Energy Standards Board ("NAESB") nomination cycle. If there are no additional cycles, they must notify the Company in writing before the gas day ends. "Company's Replacement Cost of Gas" means the highest of (1) the Company's LNG inventory and gasification costs during the time period of the applicable pipeline force majeure event adjusted for all appropriate taxes, assessments and surcharges, (2) the prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the time period of the applicable pipeline force majeure event, or (3) the cost of gas purchased by the Company during the time period of the applicable pipeline force majeure event; plus any pipeline penalties or other charges or damages assessed on the Company.

10. ***Customer Responsibility***
In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a *pro rata* share of any charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for balancing.

11. ***Third Party Supplier Requirements***
In the event the Customer designates a Third Party Supplier, service to the Third Party Supplier is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions, except as modified within this Service Classification.

PAYMENT

Unless otherwise specified, bills are due within ten days after the Company sends the bill and is subject to a late payment charge as set forth in Paragraph 8.9 of the Standard Terms and Conditions of this Tariff.

SERVICE CLASSIFICATIONS - EGS

ELECTRIC GENERATION SERVICE (continued)

CONTRACT

A written service agreement on the Company's Standard Application Form shall be required for Electric Generation Customers. The service agreement will be in effect for a minimum term of 10 years and a maximum term of 20 years. The Tariff rates in effect at the beginning of a Customer's service agreement shall remain applicable to the Customer's service during the term of the agreement. If the agreement is renewed at the end of the term, the rates applicable to the Customer in the new service agreement shall be the rates effective at that time for this Service Classification.

CREDIT REQUIREMENTS

If the customer is not deemed creditworthy by the Company, a parental guaranty, letter of credit, cash deposit or other security acceptable to Company will be required. The amount will equal six (6) months of demand charges and three (3) months of delivery charges.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE

AVAILABILITY

This service is available to any residential or commercial customer for the purpose of fueling natural gas vehicles at Company owned and operated compressed natural gas ("CNG") re-fueling facilities ("Company facilities") and at separately metered Customer owned and operated CNG re-fueling facilities ("Customer owned facilities").

CONDITIONS PRECEDENT

The Customer must sign a service agreement which sets forth the vehicles to be served to be eligible for this service.

DEFINITION OF TERM USED HEREIN

"GGE" is the Gasoline Gallon Equivalent for converting a price per therm of natural gas to a price per gallon of gasoline. The GGE shall be determined in accordance with local standards.

CHARACTER OF SERVICE

Firm sales gas service where Customer who uses Company facilities purchases gas supply pursuant to the Company's Rider "A" for Basic Gas Supply Service ("BGSS"). Firm sales or transportation gas service where Customer who uses Customer owned facilities purchases gas supply pursuant to the Company's Rider "A" for BGSS or from a Third Party Supplier, respectively.

LICENSING, PERMITS AND LEGAL REQUIREMENTS

Customers installing CNG re-fueling facilities on their premises must meet all applicable licensing, permitting and other legal requirements associated with owning and operating CNG refueling facilities. The failure of the customer to comply with this provision may result in the Company suspending or terminating gas service to such facilities without further liability.

MONTHLY RATES

	Gas Available at Company Facilities	Customer Owned Facilities
Customer Charge:		
Residential Customer Charge per meter per month	N/A	$~~11.00~~15.00
Commercial Customer Charge per meter per month	N/A	$~~104.00~~142.50
Delivery Charge:		
Delivery Charge per therm	$~~0.4059~~0.5062 ($~~0.507~~0.633 per GGE)	$~~0.4059~~0.5062 ($~~0.507~~0.633 per GGE)

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

	Gas Available at Company Facilities	Customer Owned Facilities
Compression Charge:		
Compression Charge per therm	$0.4958 ($0.620 per GGE)	N/A

BGSS Charge:

Monthly BGSS Charge per therm for Sales Customers — See "Summary of Rate Components" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders with the exception of the State of New Jersey Motor Vehicle fuel tax and Federal excise tax. These rates are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See "Summary of Rate Components" at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

Where service is taken for less than one month, the minimum charge will be prorated.

SPECIAL PROVISIONS

I. Applicable to All Customers in this Service Classification

1. ***Taxes, Assessments and Surcharges***
   The Customer shall pay all riders, taxes, assessments and surcharges that are lawfully imposed upon the Company in providing service under this classification.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

II. *Applicable to All Customers Who Use Customer Owned Facilities*

1. ***Facilities***

The Company shall install gas main extensions and service line connections at the Customer's location (collectively, the "Extension Cost") to serve the customer free of charge where the Extension Cost does not exceed ten (10) times the estimated annual distribution revenue. An applicant shall be required to provide an Extension Cost Deposit for the value of any Extension Cost that is greater than ten (10) times the annual distribution revenue. The Extension Cost for which the Company receives a deposit shall include the tax consequences incurred by the Company.

The Extension Cost Deposit, as defined above, shall remain, without interest, in the possession of the Company, subject to an annual review of the Customer's actual annual distribution revenue for up to ten years from when the Customer began receiving service. Annually, if the Customer's actual annual distribution revenue for the prior year is greater than the estimated annual distribution revenue used to determine the Extension Cost or greater than any prior year's actual distribution revenue, the Company shall provide a refund in the amount of the remaining years of the ten (10) years times the difference between that year's actual distribution revenue and the greater of the estimated annual distribution revenue used to determine the Extension Cost Deposit and the highest prior year's actual distribution revenue. No further calculation shall be performed when accumulated refunds are equal to the Extension Cost Deposit and in no event shall refunds exceed the initial deposit.

All deposits not returned to the applicant within a period of ten (10) years after the Company first makes gas service available shall remain the property of the Company with no further obligation of refund. The Company and applicant may agree upon a satisfactory revenue guarantee in lieu of a deposit or contribution.

Where it is necessary to provide additional facilities to serve increased requirements of an existing Customer, the Company reserves the right to require the Customer to contribute or deposit an amount equal to the cost of such additional facilities. This amount shall be subject to refund as outlined earlier in this section except that refunds shall be a function of the incremental distribution revenue generated by the increased requirements over a predetermined base.

2. ***Separately Metered***

Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

3. ***Automated Meter Reading Device***
For Commercial customers, metering shall include an automated meter reading device (AMR)**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish an electrical supply and phone line or data plan, as needed, for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

The Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over a twelve-month period with the prime interest rate used to calculate carrying costs. Payments made by the Customer shall not give the Customer ownership of the AMR equipment. The AMR equipment is and shall remain the sole property of the Company.

For Residential customers, an AMR device will not be required for this service. However, upon prior notice to the Customer, the Company reserves the right to install an AMR at its own expense. Should the Company decide to install the AMR, the Customer shall furnish an electrical supply and phone line or data plan, as needed, for the operation of the device, in an area acceptable to the Company. Should the Customer request an AMR, the installation shall be in accordance with Paragraph 6.10 of the Standard Terms and Conditions.

4. ***Maximum Quantities***
The maximum monthly and hourly quantities of gas to be delivered shall be specified in the service agreement and may be changed only with approval of the Company.

5. ***Incremental Expenses***
The Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, permitting, licensing, and legal expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence and may include these expenses as part of the Facilities cost referenced in Section I of this Service Classification.

6. ***Resale of Vehicle Fuel***
If the Customer provides natural gas for resale as a vehicle fuel, the Customer will be responsible for collecting and paying all applicable taxes on the gas compressed for resale and for the metering of such sale in accordance with all applicable standards and regulations.

III. Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier

1. ***Customer Responsibility***
The Company may require the Customer to provide, to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution system. In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

SERVICE CLASSIFICATION - NGV

NATURAL GAS VEHICLE SERVICE (continued)

2. ***Additional Requirements***
   Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

PAYMENT

Unless otherwise specified, bills are due within 10 days after the Company sends the bill and subject to a late payment charge as set forth in Paragraph 8.9 of the Standard Terms and Conditions of this Tariff.

CONTRACT

A written service agreement shall be required for Natural Gas Vehicle Service Customers.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE

AVAILABILITY

This service is applicable to Commercial and Industrial Customers whose minimum connected load is not less than 150 therms per hour, provided that gas is used only at locations where the Company has 1) adequate distribution facilities and 2) an adequate supply of natural gas. Customers will be required to specify that they have alternate fuel facilities installed in operating condition with an adequate fuel supply, as discussed in Special Provision 1.

CHARACTER OF SERVICE

Interruptible gas sales and transportation service.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~572.98~~725.00

Delivery Charge:

Customers with Alternate Fuel

Delivery Charge per therm	$~~0.1671~~0.1928

Customers without Alternate Fuel

Delivery Charge per therm	$~~0.4079~~0.5544

BGSS Charge:

BGSS Charge per therm for Sales Customers	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge applicable shall be the Customer Charge. Where service is taken for less than one month, the minimum charge will be prorated.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***Alternate Fuel Certification***
If the Customer desires to be categorized as a customer with alternate fuel then, as of November 1st of each year, the Customer must certify in a signed affidavit that the installation being served is physically and legally capable of using the fuel oil and the specific sulfur content as indicated or that it may legally and physically use propane at the Customer's end-use facility. The alternate fuel certification and related details will be held confidential except as same information shall be utilized by the Company for preparation of periodic reports to the Board. It is the Customer's full responsibility to have standby equipment installed and maintained in operating condition and a fuel supply adequate for its operation at all times. Adequate supply requirements for customers using No. 2 fuel oil, No. 4 fuel oil, jet fuel or kerosene are seven (7) days of alternate fuel either on hand or, if a customer's on-site storage capacity is less than seven (7) days, then full storage capacity plus additional firm contractual supply arrangements to equal seven (7) days. No customer is required to build additional storage. All customers that use non-distillate fuels as an alternate supply, or will agree to suspend operations during an interruption, are exempt from the alternate fuel requirement, but must file a certification with the Company indicating the alternate fuel used or their intention to discontinue operations.

If the Customer does not file a certification with the Company, the Customer will be served and billed as an Interruptible Customer without Alternate Fuel.

2. ***Separately Metered***
Gas delivered hereunder will be separately metered and shall not be used interchangeably with gas supplied under any other service classification.

3. ***Automated Meter Reading Device***
Metering shall include an automated meter reading device (AMR) with daily meter reads**,** which shall be furnished and installed by the Company at the Customer's expense. The Customer shall furnish the necessary infrastructure to support the AMR, including, but not limited to, an electrical supply and phone line or data plan for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Customer's expense for such installation.

The Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over a twelve-month period with the prime interest rate used to calculate carrying costs.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE (continued)

4. ***Service Interruption***
The Customer agrees to discontinue the use of gas service at any time, and from time to time upon notice from the Company. The Company shall notify the Customer of the date and time of a service interruption by telephone and e-mail or fax. The Company's determination to discontinue service or to reinstate service following a discontinuance shall be conclusive.

5. ***Unauthorized Use***
In the event the Company notifies the Customer to discontinue the use of gas service at any time and the Customer fails to do so, the Company shall have the right to terminate service, to transfer the Customer to a firm service classification and/or to bill the Customer for usage occurring during the interruption period at the applicable "Unauthorized Use" charge in effect.

6. ***Incremental Gas Service***
During periods of gas service interruption, Customers in need of gas may request service under the Incremental Gas Service ("IGS") Classification.

II. *Applicable to All Customers Purchasing Gas Supply Under Rider "A" BGSS*

1. ***Maximum Quantities***
The maximum monthly and hourly quantities of gas to be delivered shall be specified in the service agreement and may be changed only with approval of the Company.

2. ***Service Nominations***
Upon request by the Company on any day, the Customer shall furnish an estimate of the amount of gas to be taken under this Service Classification during the next 24-hour period. The Customer must notify the Company in writing at least twenty-four (24) hours before it plans to discontinue the use of gas service.

SERVICE CLASSIFICATION - IS

INTERRUPTIBLE SERVICE (continued)

3. ***BGSS***
   Customers will be supplied under the Monthly BGSS service which will be applied to all therms billed each month. See "Rate Summaries" for the current price.

III. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Return to Sales Classification***
   Upon a Customer's election to return to sales service under the IS Service Classification, it shall be required to provide the Company with no less than 30 days' notice of the Customer's intention to return to sales service under Service Classification IS. The Company may accept less than thirty (30) days' notice if gas is available to serve the Customer.

2. ***Incremental Expenses***
   The Customer will reimburse the Company for any out-of-pocket expenses (including, but not limited to legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

3. ***Service Charge Waiver***
   The Customer charge for IS sales service will be waived in months when a Customer uses IS transportation service to meet all its gas needs.

4. ***Customer Responsibility***
   In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Unauthorized Use or for Monthly Imbalances.

5. ***Additional Requirements***
   Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

CONTRACT

A written service agreement on the Company's Standard Application Form for a minimum one-year period may be required for IS Customers. Successive one-year terms will be in effect unless terminated by written notice at least two (2) months prior to the expiration of the service agreement. The Company reserves the right to require an updated written service agreement.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff and the service agreement.

SERVICE CLASSIFICATION - IGS

INCREMENTAL GAS SERVICE

AVAILABILITY

This service is available when requested by a Customer, and when the Company has the capability to deliver incrementally purchased gas supplies. The service will be available for a limited term to Customers served under Service Classification IS.

CONDITIONS PRECEDENT

The Customer shall request IGS and provide the expected time period of service and the estimated volume of sales. If IGS is available, the Company will authorize service under IGS. The request and authorization may be made by telephone and agreed to in writing (fax, e-mail, etc. are acceptable).

CHARACTER OF SERVICE

Gas service will be provided only to the extent that gas supplies may be incrementally purchased and are offered for sale by the Company.

The Company reserves the right to curtail or interrupt this service immediately if, in the Company's sole discretion, continuance of this service would adversely affect service to other Customers.

OFFERING OF SERVICE

This service will be offered to customer classes as follows:

Non-Firm

December through March - rates must be at least the level of otherwise applicable tariff rates.
April through November - rates may be below otherwise applicable tariff rates.

When rates are offered below otherwise applicable tariff rates, this service is offered only for volumes of gas that are incremental and which would not be used except for the existence of this offer.

SERVICE CLASSIFICATION - IGS

INCREMENTAL GAS SERVICE (continued)

RATES

The rates for service will be set by the Company and will include a commodity charge equal to the highest of:

A. The "Company's Replacement Cost of Gas" (See Special Provision 5 of this Service Classification);
B. The Monthly BGSS price applicable to Service Classification IS;
C. The highest price of the daily ranges that are published in Platts Gas Daily on the table "Daily Price Survey" for delivery in Texas Eastern Zone M-3; or
D. The highest price of the daily ranges that are published in Platts Gas Daily on the table "Daily Price Survey" for delivery in Transco Zone 6 NNY North.

In addition, such rates shall include all applicable riders, taxes, assessments and surcharges that are lawfully imposed upon the Company in providing service under this classification. The Customer will continue to be charged the Customer Charge and Delivery Charge under Service Classification IS.

SPECIAL PROVISIONS

1. ***Service Interruption***
   The Customer agrees to discontinue the use of gas service at any time, and from time to time upon notice from the Company. The Company shall notify the Customer of the date and time of a service interruption by telephone and e-mail or fax. The Company's determination to discontinue service or to reinstate service following a discontinuance shall be conclusive.

2. ***Unauthorized Use***
   In the event the Company notifies the Customer to discontinue the use of gas service at any time and the Customer fails to do so, the Company shall have the right to terminate service and/or to bill the Customer for usage occurring after the expiration of the period of notice specified in the service agreement at the applicable "Unauthorized Use" charge in effect.

3. ***Service Nominations***
   Upon request by the Company on any day, the Customer shall furnish an estimate of the amount of gas to be taken under this Service Classification during the next 24-hour period. The Customer must notify the Company in writing at least 24 hours before it plans to discontinue the use of gas service.

4. ***Required Purchases***
   When the Customer requests IGS service and the Company commits to an incremental purchase of gas, the Customer will be required to pay for the contracted gas service whether or not the Customer uses the gas.

SERVICE CLASSIFICATION - IGS

INCREMENTAL GAS SERVICE (continued)

5. ***Company's Replacement Cost of Gas***

"Company's Replacement Cost of Gas" means the highest of:

A. Company's LNG inventory and gasification costs adjusted for all appropriate taxes, assessments and surcharges;,

B. The prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the period of IGS service; or

C. The cost of gas purchased by the Company.

The Company's Replacement Cost of Gas shall also include any pipeline penalties or other charges or damages assessed on the Company.

REPORTS

The Company will provide 48 hours' notice to the Board prior to any sales being made which would occur at rates that are less than the Customer's applicable Service Classification. The Company will submit a monthly report providing details of all IGS sales in any month sales are made.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIER REQUIREMENTS

AVAILABILITY

This service classification is for Third Party Suppliers (formerly referred to as Marketers or Brokers) who have been engaged by transportation customers using RS, GSS, GSL, FT, DGC, CNG, NGV or IS Services to be responsible for delivering natural gas to the Company's designated delivery meters on behalf of those Customers. All Third Party Suppliers who wish to act on behalf of Customers will be required to be authorized by the Company. Pursuant to this authorization, the Third Party Suppliers will be required to sign a service agreement and post a deposit or letter of credit in order to have the Company accept its natural gas at the designated delivery meters.

CONDITIONS PRECEDENT

The Third Party Supplier shall execute a service agreement with the Company.

The Third Party Supplier shall provide a written or electronic notification to the Company of the identity of Customer(s) on whose behalf they are acting.

The Third Party Supplier shall post an Initial Deposit, consisting of cash or letter of credit in the amount of $50,000 to serve RS customers and/or $25,000 to serve commercial customers including GSS, GSL, FT, DGC, CNG, NGV or IS customers. If the Third Party Supplier initially plans to serve only RS customers, the Initial Deposit shall be in the amount of $50,000 and if that Third Party Supplier later also serves commercial customers, an additional deposit of $25,000 shall be required for a total Initial Deposit of $75,000. If the Third Party Supplier initially plans to serve only commercial customers, the Initial Deposit shall be in the amount of $25,000 and if that Third Party Supplier later also serves RS customers, an additional deposit of $50,000 shall be required for a total Initial Deposit of $75,000. The total deposit provided by the Third Party Supplier shall be the greater of:

A. the Initial Deposit; or
B. an amount equal to the total of:
   i. at least three (3) times the estimated usage for one (1) day in January times the most current January's price for the higher of Texas Eastern Zone M-3 or Transco Zone 6 NNY North for any and all Customers on whose behalf the Third Party Supplier is acting;
   ii. for Customers using Billing Option 3, an additional amount equal to at least two (2) times the January delivery charges for each service classification for any and all Customers on whose behalf the Third Party Supplier is acting; and
   iii. the value of the Third Party Supplier's imbalance which is determined by multiplying the aggregate imbalance position for RS, GSS, GSL, DGC, and NGV residential customers on whose behalf the Third Party Supplier is acting by the midpoint price of daily ranges for the applicable delivery zone that are published in Platts Gas Daily on the table, "Daily Price Survey."

The deposit held from the Third Party Supplier will not bear interest. The Third Party Supplier shall agree the Company has the right to access and apply the cash deposit or letter of credit to any payment obligations which are deemed to be late or in arrears. In lieu of a cash deposit or letter of credit from a Third Party Supplier, the Company may, in its sole discretion, agree to accept a guaranty from such financially responsible parent or parent companies of the Third Party Supplier for the payment of any liabilities or obligations to be incurred by the Third Party Supplier. If any negative change in the financial condition of the guaranteeing party occurs, the Company reserves its right to request a deposit from the Third Party Supplier.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

RATES

Basic Service	$65.00 per month	includes administration of nominations, balancing, inquiry, customer enrollment changes and security review

BILLING OPTIONS

Option 1 - Utility Consolidated Billing

The Third Party Supplier will provide the Company with the billing parameters for the "commodity charge" to be included in the calculation of each Customer's bill and the Company will send the total bill to each customer. The Company will purchase the receivable from the Third Party Supplier and be solely responsible for the processing of payments, collections and basic customer inquiries. Each Third Party Supplier operating under this option will be required to execute an agreement summarizing the terms and conditions of their services. This option includes electronic summaries for each cycle. The following charges are applicable to Billing Option 1:

Billing Option 1	$ 0.75	per bill

Option 2 – Dual Billing

The Company will provide a bill to the Customer for the transportation services provided on its distribution system. The Company will provide to the Third Party Supplier a summary of the usage and transportation charges for each customer during each billing period.

Option 3 - Third Party Supplier Consolidated Billing

The Third Party Supplier will send the total bill to each Customer and remit to the Company the transportation charges associated with the Customer. Third Party Supplier shall receive a total annual credit of $3.60 per customer for each FT, GSL, RS and GSS Customer billed according to this option. Such credit shall be applied monthly on a pro-rated basis.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

DELIVERIES TO COMPANY'S DESIGNATED DELIVERY METERS

1. ***FT, DGC-FT, CNG, NGV Commercial, and IS Service***

The Third Party Supplier agrees to deliver gas to the Company's designated delivery meters for each Customer on whose behalf it is operating. The Company may offer a Third Party Supplier the option to deliver a specified volume to the Company's designated delivery meter on the Transcontinental Gas Pipeline. If the Third Party Supplier accepts the offer but fails to deliver the specified volume to the designated delivery meter on the Transcontinental Gas Pipeline, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect for the volume not delivered.

The Third Party Supplier shall use its best efforts to achieve a balance between its deliveries (net of Special Provision 3, Fuel Use and Unaccounted for Gas) and its aggregate customer requirements on a daily basis. The Company reserves the right to require a Third Party Supplier to balance deliveries and takes of transported gas. If the Third Party Supplier has an accumulated imbalance between deliveries and takes of transported gas, the Company reserves the right to reject the Third Party Supplier's requested deliveries in whole or in part.

If at any time during the month, the aggregate Third Party Supplier's account is out of balance by more than 30%, the Third Party Supplier may be required, upon 2 business days' prior notice from the Company, to initiate corrective action to balance its account within the following 3~~5~~-day period. Third Party Suppliers who fail to adhere to this requirement and have a positive cumulative imbalance (in aggregate the Third Party Supplier delivered more gas than was used in aggregate by its Customers), will have their subsequent nominations, on days with no Operational Flow Orders or IS Daily Balancing restrictions, rejected until they are returned to at or below a 10% imbalance. Third Party Suppliers who fail to adhere to this requirement and have a negative cumulative imbalance (in aggregate the Customers used more gas than was delivered in aggregate by the Third Party Supplier), will be charged at the "Delivery Shortfall" charge for the volume required to bring them to a 10% imbalance. Third Party Suppliers who fail to take corrective action to balance their account may not be permitted to continue to operate on the system.

The Company reserves the right to reject nominations, in whole or in part, for a Third Party Supplier's deliveries in excess of its estimated aggregate customer requirements, plus Special Provision 3, Fuel Use and Unaccounted for Gas. This restriction will not apply to days with an Operational Flow Order or IS Daily Balancing in place and can be issued as a blanket for the entire system or for a single Third Party Supplier. The Company will provide written notice to a Third Party Supplier of the Company's rejection of the Third Party Supplier's deliveries prior to implementing the reductions on the affected pipeline.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

2. ***IS Service***

The Company reserves the right to curtail IS Service at any time upon notice to the Customer(s) receiving the service. This requirement may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

In the event the Company notifies a Customer to discontinue the use of IS service at any time, and the Customer fails to do so, the Company shall have the right to terminate service, to transfer the Customer to a firm service classification and/or to bill the Customer for usage occurring during the curtailment period at the applicable "Unauthorized Use" charge in effect.

3. ***RS, GSS, GSL, DGC-Balancing, and NGV Residential Service***

The Third Party Supplier agrees to deliver to the Company's designated delivery meters a volume of gas for each day of the month equal to the average daily usage for that month for each Customer on whose behalf it is operating as specified by the Company ("Daily Delivery Volume"). The Company will provide the Third Party Supplier with the Daily Delivery Volume by month in advance during the year.

If the Third Party Supplier fails to deliver the Daily Delivery Volume, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect.

In the event that, at any time, the sum of a Third Party Supplier's cumulative imbalances, for non-Force Majeure reasons and for the time period which the Company has not yet received payment (including period since last bill), are under-deliveries that are at least~~exceed~~ three (3) times the Daily Delivery Volume, the Company will notify the Third Party Supplier. If such under-deliveries are at least~~exceed~~ five (5) times the Daily Delivery Volume, the Third Party Supplier will have four (4) business days to post and maintain for a one (1) year period a cash deposit or letter of credit in an amount equal to two (2) times that otherwise required pursuant to the Conditions Precedent of this Service Classification. At the conclusion of the one (1) year period, if the Third Party Supplier has had no additional occurrence of under-deliveries, the Third Party Supplier's credit requirement will be reduced to the amount required in the Conditions Precedent of this Service Classification. If the Third Party Supplier has had an additional under-delivery event during the one (1) year period, the Third Party Supplier will maintain the cash deposit or letter of credit in an amount equal to two (2) times that otherwise required pursuant to the Conditions Precedent of this Service Classification for an additional one (1) year period. The Company has the right to remove the Third Party Supplier from the New Jersey Natural Gas system for continued non-performance.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS

1. ***Monthly Imbalances***

   a. ***FT, DGC-FT, CNG, NGV Commercial and IS Transportation Services***

The Third Party Supplier shall use its best efforts to achieve a balance between its Customers' deliveries and requirements on a daily basis. Monthly imbalances in the volumes of gas delivered for the aggregate Customers' accounts (net of Special Provision 3, Fuel Use and Unaccounted for Gas) and the volumes of gas used in the aggregate by the Customers, will be cashed-out each month so that no imbalances will be carried into the next month. The cashout will be charged to the Third Party Supplier each month. The Company will use the average weekly spot index price for New York City citygate, as published by *Natural Gas Week's "Major Market Prices"*.

If the imbalance is negative (in aggregate the Customers used more gas than was delivered in aggregate by the Third Party Supplier), the Third Party Supplier will purchase gas from the Company at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Highest Weekly Index Price
>5% - ≤ 10%	quantity >5% * Highest Weekly * 1.1 + level above
>10% - ≤ 15%	quantity >10% * Highest Weekly * 1.2 + levels above
>15% - ≤ 20%	quantity >15% * Highest Weekly * 1.3 + levels above
>20% - ≤ 25%	quantity >20% * Highest Weekly * 1.4 + levels above
>25%	quantity >25% * Highest Weekly * 1.5 + levels above

If the imbalance is positive (in aggregate the Third Party Supplier delivered more gas than was used in aggregate by its Customers), the Company will purchase gas from the Third Party Supplier at the rates below:

Imbalance Level	***Calculation***
0% - ≤ 5%	quantity * Lowest Weekly Index Price
>5% - ≤ 10%	quantity >5% * Lowest Weekly * .90 + level above
>10% - ≤ 15%	quantity >10% * Lowest Weekly * .80 + levels above
>15% - ≤ 20%	quantity >15% * Lowest Weekly * .70 + levels above
>20% - ≤ 25%	quantity >20% * Lowest Weekly * .60 + levels above
>25%	quantity >25% * Lowest Weekly * .50 + levels above

All revenues and purchases derived from imbalances will be credited to the BGSS.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

b. ***RS, GSS, GSL, DGC-Balancing , and NGV Residential Service***

For each Third Party Supplier, imbalances in the volumes of gas delivered for the Customer's account (net of Special Provision 3, Fuel Use and Unaccounted for Gas) and the volumes of gas used by the Customer, will be rolled over each month so that any imbalance will be carried into the next month. The Company will select the time period to net any imbalances with the monthly Daily Delivery Volume.

If the Third Party Supplier's account is out of balance by more than 30% of the total amount transported in the prior month, the Third Party Supplier may be required to modify its deliveries for the following month. In addition, the Company reserves the right to require additional volumes to be delivered for the following month for any volumes owed to the Company.

2. ***Daily Balancing***

a. ***FT and DGC-FT Services***

The Company may issue an Operational Flow Order (OFO) requiring delivery by the Third Party Supplier of at least the volume of gas the Customers, in aggregate, use on the affected gas day ("OFO Required Volume") plus Special Provision 3, Fuel Use and Unaccounted for Gas. An OFO may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

Third Party Suppliers who fail to deliver the OFO Required Volumes of gas may not be permitted to continue to operate on the system. In addition, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume.

There will be no daily or monthly penalties for delivering gas in excess of an OFO Required Volume. If the Third Party Supplier ends the month with a positive imbalance (in aggregate the Third Party Supplier delivered more gas than was used by its Customers), the portion of the imbalance related to overdeliveries on OFO days will be carried forward to the following month and be included in that month's cashout determination pursuant to Special Provision 1.a. of this Service Classification. If the Company issues additional OFOs in the month of the cashout determination, the Company, in its sole discretion, may waive the tiering of the cashout prices for positive imbalances greater than 5 percent initially incurred on OFO days.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

b. ***CNG and NGV Commercial Services***

The Company may issue an Operational Flow Order (OFO) requiring delivery by the Third Party Supplier of at least the volume of gas the Customers, in aggregate, use on the affected gas day ("OFO Required Volume") plus Special Provision 3, Fuel Use and Unaccounted for Gas. An OFO may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

Third Party Suppliers who fail to deliver the OFO Required Volumes of gas ("Delivery Shortfall") may not be permitted to continue to operate on the system. In addition, the Third Party Supplier will be billed at the highest of:

i. The "Company's Replacement Cost of Gas" (defined below);
ii. The highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey" in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume; or
iii. The highest price of daily ranges for delivery in Transco Zone 6 NNY North that are published in Platts Gas Daily on the table, "Daily Price Survey" in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume.

However, in a month that the Company does not allow Third Party Suppliers to deliver to the Company on the Transcontinental Gas Pipeline, the Company shall bill the Third Party Supplier at the higher of:

i. The "Company's Replacement Cost of Gas" (defined below); or
ii. The highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey" in effect during the OFO period for the volume difference between the OFO Required Volume and the actual delivered volume.

There will be no daily or monthly penalties for delivering gas in excess of an OFO Required Volume. If the Third Party Supplier ends the month with a positive imbalance (in aggregate the Third Party Supplier delivered more gas than was used by its Customers), the portion of the imbalance related to overdeliveries on OFO days will be carried forward to the following month and be included in that month's cashout determination pursuant to Special Provision 1.a. of this Service Classification. If the Company issues additional OFOs in the month of the cashout determination, the Company, in its sole discretion, may waive the tiering of the cashout prices for positive imbalances greater than 5 percent initially incurred on OFO days.

"Company's Replacement Cost of Gas" means the highest of:

i. The Company's LNG inventory and gasification costs adjusted for all appropriate taxes, assessments and surcharges;
ii. The prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the OFO period; or
iii. The cost of gas purchased by the Company.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

The Company's Replacement Cost of Gas shall also include any pipeline penalties or other charges or damages assessed on the Company.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

c. ***IS Services***

The Company may issue an IS Daily Balancing Restriction (IS-DB) requiring delivery by the Third Party Supplier of at least the volume of gas the Customers, in aggregate, use on the affected gas day ("IS Daily Balancing Volume") plus Special Provision 3, Fuel Use and Unaccounted for Gas. This requirement may be issued as a blanket for the entire system or for a single Third Party Supplier or Customer.

Third Party Suppliers who fail to deliver the IS Daily Balancing Volumes of gas may not be permitted to continue to operate on the system. In addition, the Third Party Supplier will be billed at the applicable "Delivery Shortfall" charge in effect during the IS-DB period for the volume difference between the IS Daily Balancing Volume and the actual delivered volume.

There will be no daily or monthly penalties for delivering gas in excess of an IS Daily Balancing Volume. If the Third Party Supplier ends the month with a positive imbalance (in aggregate the Third Party Supplier delivered more gas than was used by its Customers), the portion of the imbalance related to overdeliveries on IS-DB days will be carried forward to the following month and be included in that month's cashout determination pursuant to Special Provision 1.a. of this Service Classification. If the Company issues additional IS-DB restrictions in the month of the cashout determination, the Company, in its sole discretion, may waive the tiering of the cashout prices for positive imbalances greater than 5 percent initially incurred on IS-DB restriction days.

3. ***Fuel Use and Unaccounted for Gas***

A 2% adjustment for fuel use and unaccounted for gas will be made to the quantity of gas received for the Customers' accounts. The quantity of gas ultimately delivered to the Customers shall be reduced by 2% from the level received by the Company for the Customers' account.

4. ***Taxes, Assessments And Surcharges***

The Third Party Supplier shall pay all taxes or surcharges that are lawfully imposed upon the Company in providing service under this service classification.

5. ***Incremental Expenses***

The Third Party Supplier shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence. Reimbursements for any costs associated with special non-recurring projects requested by a Third Party Supplier may be collected through this special provision. These special projects represent a level of service not anticipated in any of our administrative charges. The price for these projects shall be mutually agreed to prior to the initiation of any work related to the special project.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

6. ***Unauthorized Use Charge***

In the event the Company notifies a Customer to discontinue the use of transportation service at any time, and the Customer fails to do so ("Unauthorized Use"), the Company shall bill the Customer for usage occurring during the period of Unauthorized Use at a~~the~~ rate equal to the higher of:

i. ~~of t~~Ten (10) times the highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey"; or

ii. Ten (10) times the highest price of the daily ranges for delivery in Transco Zone 6 NNY North that~~which~~ are published in Platts Gas Daily on the table, "Daily Price Survey".

The Company reserves the right to bill a rate equal to the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines that deliver gas to the Company. The Company shall also have the right to terminate the Customer's service.

Additionally, ~~T~~the Company has the right to recover proportionately from undelivered Customers any penalties or other charges or damages assessed on the Company as a result of any Unauthorized Use by the Customers.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

7. ***Delivery Shortfall Charge***

In the event that the Third Party Supplier fails to deliver the Daily Delivery Volume, OFO Required Volume, or IS Daily Balancing Volume as directed by the Company (a "Delivery Shortfall"), the Company shall bill the Third Party Supplier for the volume of the Delivery Shortfall at a rate equal to the higher of:

i. Ten (10) times the highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey"; or

ii. Ten (10) times the highest price of daily ranges for delivery in Transco Zone 6 NNY North that are published in Platts Gas Daily on the table, "Daily Price Survey".

However, in a month that the Company does not allow Third Party Suppliers to deliver to the Company on the Transcontinental Gas Pipeline, the Company shall bill the Third Party Supplier for the volume of the Delivery Shortfall at a rate equal to ten (10) times the highest price of daily ranges for delivery in Texas Eastern Zone M-3 that are published in Platts Gas Daily on the table, "Daily Price Survey."

If such Delivery Shortfall occurs when the Company has issued an OFO or required daily balancing, the Company reserves the right to bill a rate equal to the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines that deliver gas to the Company. Additionally, ~~I~~in the event of a Delivery Shortfall, the Company shall have the right to recover *pro rata* from all under-delivering Third Party Suppliers any penalties or other charges or damages assessed on the Company because of such under-deliveries for the days the Third Party Suppliers under-delivered.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

7. Delivery Shortfall Charge (continued)

Notwithstanding the above, if contemporaneously with a Delivery Shortfall, an interstate pipeline that delivers to an NJNG delivery meter has declared a force majeure on its pipeline system curtailing primary, in-path transportation in the delivery meter's zone of delivery, the Company may waive the above charges and may bill the Third Party Supplier for the Company's Replacement Cost of Gas (defined below) provided that the under-delivering Third Party Supplier is able to demonstrate to the Company's reasonable satisfaction that the transportation contract on which the Third Party Supplier had scheduled deliveries to the Company's delivery meter during the period in which the OFO was in effect entitled the Third Party Supplier to firm transportation rights through the point at which the force majeure was declared and that the pipeline curtailed Third Party Supplier's deliveries pro rata with deliveries to other similarly situated delivery meters on the contract. The Third Party Supplier must notify the Company in writing of the anticipated Delivery Shortfall before the nomination deadline for the next North American Energy Standards Board ("NAESB") nomination cycle. If there are no additional cycles, they must notify the Company in writing before the gas day ends. "Company's Replacement Cost of Gas" means the highest of:

i. The Company's LNG inventory and gasification costs adjusted for all appropriate taxes, assessments and surcharges;
ii. The prevailing market price, as determined by the Company based on a published index or independent trading platform, for delivered gas to any NJNG citygate during the time period of the force majeure; or
iii. The cost of gas purchased by the Company.

The Company's Replacement Cost of Gas shall also include any pipeline penalties or other charges or damages assessed on the Company.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

8. ***Individual Customer Responsibility***
Customers taking service under Service Classifications RS, FT, GSL, GSS, DGC and IS may elect to designate one Third Party Supplier per account to have responsibility for nominations, daily balancing and/or monthly balancing on behalf of the Customer. The Company will provide both individual and summary bills to each such Third Party Supplier, with a summary of usage and associated charges provided for each Customer. If a Customer's designated Third Party Supplier should default on any obligation for payment under this Service Classification, the Customer will be responsible for its proportional share of charges, including payment for "Unauthorized Use", "Delivery Shortfall" or for monthly imbalances.

SERVICE CLASSIFICATION - TPS

THIRD PARTY SUPPLIERS REQUIREMENTS (continued)

SPECIAL PROVISIONS (continued)

9. ***Nominations***

By the deadline specified on the Company's electronic bulletin board (EBB), the Third Party Supplier shall enter nominations onto the Company's EBB on the day prior to gas flow for the next calendar day. The Third Party Supplier's nomination shall contain its Customers' transportation volumes~~, the name of the supplier~~ and the contract number, along with the pipeline transporter. The Third Party Supplier may change any daily or monthly nominations in a timely manner on the Company's EBB by the time of the day prior to gas flow specified on the Company's EBB. The Third Party Supplier may request changes to nominations after the time specified on the Company's EBB in writing by e-mailing the Company, however any late changes are completely at the discretion of the Company. Any agreed to changes will have to be formally requested in writing.

The Company will not be required to accept any gas rendered by the pipeline transporter that: (a) does not conform to the Third Party Supplier's currently effective nominations or (b) is not delivered to a mutually agreeable delivery meter. The Company shall not be obligated to provide transportation service during an hourly, daily or monthly period in excess of the levels specified in the service agreement.

PAYMENT

Unless otherwise specified, bills are due within 10 days after the Company sends each Third Party Supplier's individual bill and is subject to a late payment charge as set forth in Paragraph 8.9 of the Standard Terms and Conditions of this Tariff. In preparing the bill, Company may net all amounts due and owing, and/or past due, such that the party owing the greater amount shall make a single payment of the net amount to the other party. The Company may elect to utilize the deposit to satisfy any payments deemed to be late and to notify the Third Party Supplier of the need to replenish the deposit. The Company may offset any payments deemed to be late against any amounts owed by the Company to the Third Party Supplier. Additionally, if a Third Party Supplier's account is in arrears, the Company reserves the right to cease new enrollments for the Third Party Supplier and has the right to remove the Third Party Supplier from the New Jersey Natural Gas system.

CONTRACT

The term of the initial Service Agreement will be for a minimum of one year. Thereafter, successive one-year terms will be in effect until terminated by written notice at least two (2) months prior to the expiration of the service agreement.

TERMS AND CONDITIONS

Service is subject to the Standard Terms and Conditions of this Tariff, the applicable transportation Service Classification and the service agreement.

NEW JERSEY NATURAL GAS COMPANY

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS

AVAILABILITY

This service is available to any customer who would otherwise qualify for service under Service Classifications RS, GSS, GSL, FT, IS, or NGV and who will utilize natural gas for the purpose of fueling natural gas vehicles at Company owned compressed natural gas re-fueling facilities operated by the Customer on its property ("Host Customer").

Availability of this Service Classification is subject to the terms and conditions approved in BPU Docket No. GR11060361. This Service Classification is closed.

CONDITIONS PRECEDENT

The Host Customer must sign an Agreement with the Company. The Host Customer must provide assurance that it will use initially at least twenty (20) percent of the re-fueling facility's capacity. The Host Customer must agree to provide the general public with reasonable access to a re-fueling facility for purposes of fueling the general public's natural gas vehicles.

DEFINITION OF TERM USED HEREIN

"GGE" is the Gasoline Gallon Equivalent for converting a price per therm of natural gas to a price per gallon of gasoline. The GGE shall be determined in accordance with local standards.

CHARACTER OF SERVICE

Firm gas service where Host Customer may purchase gas supply pursuant to the Company's Rider "A" for Basic Gas Supply Service ("BGSS"), from the Company through a contract, or from a Third Party Supplier.

MONTHLY RATES

Customer Charge:

Customer Charge per meter per month	$~~104.00~~142.50

Delivery Charge:

Delivery Charge per therm	$~~0.6192~~0.7862 ($~~0.774~~0.983 per GGE)

BGSS Charge:

Monthly BGSS Charge per therm for Sales Customers without a gas supply contract	See "Rate Summaries" at the end of this Tariff

These rates are inclusive of all applicable taxes and riders and are subject to adjustment for all other applicable riders, taxes, assessments or similar charges lawfully imposed by the Company. See Rate Summaries at the end of this Tariff for a summary of components incorporated in these rates.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the Customer Charge.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Superseding Fourth Revised Original~~ Sheet No. 99* *~~Fifth Revised Sheet No. 99~~*

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS

Where service is taken for less than one month, the minimum charge will be prorated.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS (continued)

SPECIAL PROVISIONS

I. *Applicable to All Customers in this Service Classification*

1. ***CNG Re-Fueling Facilities***
The Company shall install and own Compressed Natural Gas ("CNG") re-fueling facilities on the Host Customer's property. The Company shall maintain these facilities. The Host Customer is required to monitor and operate these facilities at its own expense. The Host Customer is also required to provide reasonable access to the re-fueling station to the general public and non-host customer fleets.

2. ***Automated Meter Reading Device***
Metering shall include an automated meter reading device (AMR), which shall be furnished and installed by the Company at the Host Customer's expense. The Host Customer shall furnish an electrical supply and phone line for the operation of the device, in an area acceptable to the Company. The Company shall provide technical assistance in order to minimize the Host Customer's expense for such installation.

The Host Customer may reimburse the Company for the AMR expense, either in a lump sum payment when service is initiated or over the life of the initial CNG agreement with the prime interest rate used to calculate carrying costs on the unpaid balance.

3. ***Incremental Expenses***
The Host Customer shall reimburse the Company for any out-of-pocket expenses (including, but not limited to, legal and travel expenses) incurred in connection with the initiation and rendering of service under this service classification. The Company shall provide an estimate of such expenses prior to their incurrence.

4. ***Taxes, Assessments and Surcharges***
The Customer shall pay all riders, taxes, assessments and surcharges that are lawfully imposed upon the Company in providing service under this classification.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS (continued)

5. ***Pricing to the General Public***

The Host Customer shall post the charge to the general public for its re-fueling volume at a price per GGE provided by the Company. Prior to the beginning of each month, the Company will notify the Host Customer of the price, the components of which are defined below:

a. Monthly BGSS Charge as set forth in Rider "A" converted to a price per GGE
b. CNG Delivery Charge as set forth in Service Classification CNG converted to a price per GGE
c. Applicable state and federal excise taxes
d. $0.20 per GGE for the Host Customer's expenses to operate the facilities.

The Host Customer shall display the price per GGE at the re-fueling station. The Company shall credit the Host Customer for the monthly volume sold to the general public at the price per GGE for the Host Customer's expenses to operate the facilities as defined in 5(d) above.

6. ***Pricing to Non-Host Company Fleets***

Other fleets re-fueling vehicles at the Company owned CNG re-fueling facilities operated by the Host Customer on its property may purchase gas supply from the Company's Rider "A" for Basic Gas Supply Service ("BGSS"), from the Company through a contract, or from a Third Party Supplier pursuant to Section II herein. The Company shall charge other fleets for re-fueling volumes at a price per GGE, the components of which are defined below:

a. Monthly BGSS Charge as set forth in Rider "A" or a gas supply contract price or the price provided by a Third Party Supplier, converted to a price per GGE
b. CNG Delivery Charge as set forth in Service Classification CNG converted to a price per GGE
c. Applicable state and federal excise taxes
d. $0.20 per GGE for the Host Customer's expenses to operate the facilities.

The Company shall credit the Host Customer for the monthly volume sold to the other fleets at the price per GGE for the Host Customer's expenses to operate the facilities as defined in 6(d) above.

SERVICE CLASSIFICATION - CNG

COMPRESSED NATURAL GAS (continued)

II. *Applicable to All Customers Purchasing Gas Supply from a Third Party Supplier*

1. ***Customer Responsibility***
The Company may require the Customer to provide, to the Company's satisfaction, proof of a firm gas supply having marketable title of gas with firm transportation capacity to the Company's distribution system. In the event the Customer designates a Third Party Supplier in accordance with Service Classification TPS, the Customer will remain responsible for a pro rata share of any Charges which such Third Party Supplier fails to pay to the Company including payments for Delivery Shortfall or for Monthly Imbalance.

2. ***Billing***
Customers purchasing gas supply from a Third Party Supplier can only be billed through Billing Option 1 as defined in Service Classification-TPS.

3. ***Additional Requirements***
Service is subject to the terms and conditions of the Third Party Supplier Requirements section of this Tariff (Service Classification – TPS) and Section 10 of the Company's Standard Terms and Conditions.

CONTRACT

A written agreement shall be required for Compressed Natural Gas Host Customers and non-Host Customers Fleets.

TERMS AND CONDITIONS

Service is subject to the Company's Standard Terms and Conditions of this Tariff.

RESERVED FOR FUTURE USE

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS

Applicable to the following service classifications:

RS	Residential Service		
DGR	Distributed Generation - Residential	ED	Economic Development
DGC	Distributed Generation - Commercial	NGV	Natural Gas Vehicles
GSS	General Service - Small	IS	Interruptible Service
GSL	General Service - Large	CNG	Compressed Natural Gas

I. Periodic Basic Gas Supply Service Charge

By June 1 of each year, the Company shall file with the Board, a request for an October 1 implementation of a Periodic Basic Gas Supply Service ("Periodic BGSS") Charge, which shall be applicable to customers on the RS, GSS, and DGR, service classifications listed above and to customers on the ED service classification listed above who are eligible to receive service under Service Classification GSS.

A. Determination of the Initial Periodic BGSS Factor for the BGSS Year

The Periodic BGSS Factor shall be derived in the following manner:

(1) An estimate shall be made of the total volume of prospective gas supplies from all sources, including pipeline natural gas and all substitute and supplement gas supplies, and of the estimated overall commodity cost of all such prospective supplies, including pipeline refunds and other credits, excluding Company labor costs, for the remainder of the BGSS year ending September 30. The estimated overall commodity costs of prospective supplies will be comprised of 1) the value of gas withdrawn from storage; 2) the value of volumes whose price was previously set by hedges or other financial instruments; 3) current flowing gas, which will be priced at the arithmetic average of (i) the NYMEX closing price for the last trading day prior to each respective month and (ii) the average of the estimated Inside FERC prices for the producing locations that relate to the Company's purchases; and 4) the variable cost of transportation and fuel.

(2) An estimate shall be made of the total volume of prospective firm sales of gas (in therms) for the BGSS year ending September 30.

RIDER "A"

BASIC GAS SUPPLY SERVICE – BGSS (continued)

(3) The cost of prospective gas supplies (per paragraph (1)) shall be adjusted upward or downward to the extent of the cumulative amount of any prior under-recovery or over-recovery of gas commodity costs to determine the total commodity gas costs to be recovered and then shall be divided by the estimated total volume of prospective firm sales (per paragraph (2)), to determine the per unit commodity cost recovery rate.

(4) An estimate shall be made of the fixed pipeline, fixed storage, and supplier demand costs for the BGSS year ending September 30. The estimated fixed demand shall be adjusted upward or downward to the extent of the cumulative amount of any prior under-recovery or over-recovery of fixed costs and then shall be divided by the estimated total volume of prospective firm sales (per paragraph (2)), to determine the per unit demand cost recovery rate.

(5) The adjusted commodity gas costs to be recovered, as determined per paragraph (3), shall then be added to the per unit demand cost recovery as determined per paragraph (4) and the result carried for four (4) decimal places.

B. Determination of Revised Periodic BGSS Factors

(1) Following Board approval of the initial Periodic BGSS Charge, the Company shall have the opportunity to implement increases to be effective December 1 and February 1 on a self-implementing basis subject to a maximum rate increase of up to 5% of the average residential customer total bill.

(2) The Company may implement, at its discretion, bill credits, refunds, or self-implementing rate reductions during the BGSS year ending September 30.

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS (continued)

II. Monthly Basic Gas Supply Service Charge

On the second day following the close of the trading of the NYMEX Henry Hub natural gas contracts for the prospective month, the Company shall submit to the Board, a Monthly Basic Gas Supply Service ("BGSS") Charge, which shall be applicable to customers in the GSL, DGC, NGV, CNG, and IS service classifications, and to customers in the ED service classification listed above who are eligible to receive service under Service Classification GSL.

A. Derivation of the Monthly BGSS Factor

The Monthly BGSS Factor shall be derived in the following manner:

(1) An estimate shall be made of the fixed pipeline, fixed storage, and supplier demand costs for the BGSS year ending September 30. An estimate shall be made of the total volume of prospective firm sales of gas (in therms) for the BGSS year ending September 30. The estimated fixed demand shall then be divided by the estimated total volume of prospective firm sales to determine the per unit demand cost recovery rate.

(2) The overall Monthly BGSS Charge will be established prior to the beginning of each month based on the sum of: 1) the arithmetic average of (i) the NYMEX closing price for the last trading day prior to each respective month and (ii) the average of the estimated Inside FERC prices for the producing locations that relate to the Company's purchases; 2) the variable cost of transportation and fuel; and 3) the per unit demand cost recovery rate as determined in accordance with paragraph (1). The Monthly BGSS Factor shall be adjusted for taxes, assessments or surcharges. The result shall be carried for four (4) decimal places.

(3) The Monthly Gas Cost Recovery Charge shall be added to all tariff rates then in effect, effective for service rendered commencing the first day of such month of such year, and continuing in effect until the effective date of the subsequent monthly or other filing of a revision of modification thereof.

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS (continued)

III. Tracking the Operation of the BGSS

The net amount of gas costs and recoveries, including pipeline refunds and other credits, if any, shall be maintained in a separate clearing account which will be reviewed as part of the annual filing.

Interest shall be computed monthly, at the overall annual rate of return as authorized by the Board of Public Utilities, on the average monthly balances of over or under-recovery of excess purchased gas costs and supplier refunds. In the event such interest computations result in a cumulative net interest credit at the end of the year, such credit shall be applied against the gas costs in calculating the Periodic BGSS factor for the following year.

In accordance with P.L., 1997 c. 162, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT"), and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~1~~12 - Gas

~~Fourth Revised Sheet No. 155~~
~~Superseding Third Revised~~Original Sheet No. 155

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS(continued)

PERIODIC BASIC GAS SUPPLY SERVICE (BGSS) CHARGE

SERVICE CLASSIFICATION	APPLICATION	CHARGE
RS and GSS sales customers, and ED sales customers eligible for service under Service Classification GSS	Included in the Basic Gas Supply Charge	$0.4290 per therm

BALANCING CHARGE

SERVICE CLASSIFICATION	APPLICATION	CHARGE
RS, GSS, GSL, DGR, DGC-Balancing, and ED customers eligible for service under Service Classifications GSS and GSL	Included in the Delivery Charge	$~~0.1266~~0.1271 per therm

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS(continued)

MONTHLY BASIC GAS SUPPLY SERVICE (BGSS) CHARGE

SERVICE CLASSIFICATION	APPLICATION
GSL, DGC-Balancing, and CNG sales customers, and ED sales customers eligible for service under Service Classification GSL	Included in the Basic Gas Supply Charge

Effective Date	Charge Per Therm for IS, CNG, NGV	Charge Per Therm for GSL, DGC-Balancing[1]
January 1, 2023	$0.7993	$0.6613
February 1, 2023	$0.6657	$0.5277
March 1, 2023	$0.6085	$0.4705
April 1, 2023	$0.5620	$0.4240
May 1, 2023	$0.5510	$0.4130
June 1, 2023	$0.5154	$0.3774
July 1, 2023	$0.5181	$0.3801
August 1, 2023	$0.5037	$0.3657
September 1, 2023	$0.4928	$0.3548
October 1, 2023	$0.5079	$0.3813
November 1, 2023	$0.5658	$0.4392
December 1, 2023	$0.5908	$0.4642
January 1, 2024	$0.5989	$0.4723

[1] For GSL and DGC customers, the BGSS charge per therm is reduced by the Balancing Charge which is included in the Delivery Charge.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~1~~12 - Gas *~~Third Revised Sheet No. 157~~ ~~Superseding Second Revised~~ Original Sheet No. 157*

RIDER "A"

BASIC GAS SUPPLY SERVICE - BGSS(continued)

BGSS SAVINGS COMPONENT RELATED TO THE CONSERVATION INCENTIVE PROGRAM (CIP) IN RIDER "I"

SERVICE CLASSIFICATION	*APPLICATION*	*CREDIT*
RS, GSS, GSL, and ED sales customers	Embedded within the Periodic Basic Gas Supply Charge and the Monthly Basic Gas Supply Charge	($0.0270) per therm

TEMPORARY BGSS RATE CREDIT ADJUSTMENT

Applicable to RS and GSS sales customers and ED customers eligible for service under Service Classification GSS

EFFECTIVE DATES	*CREDIT PER THERM*
~~November 1, 2015 through February 29, 2016~~	~~($0.2640)~~
~~November 1, 2016 through December 31, 2016~~	~~($0.1666)~~
~~January 1, 2017 through February 28, 2017~~	~~($0.1664)~~
December 1, 2020 through January 31, 2021	($0.1220)
March 1, 2023 through March 31, 2023	($0.5054)

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT)

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT) (continued)

In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this Tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable under this Tariff shall be reduced by the provision for the SUT) included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey. [P.L. 1997, c.162]

2. Natural gas or utility service that is used to generate electricity that is sold for resale or to an end user other than the end user located on the property the cogeneration or self-generation unit that generated the electricity is located. [P.L. 2009, c. 240]

3. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L. 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997. [P.L. 1997, c.162]

4. Natural gas and utility service that is used for cogeneration facility that is constructed after January 1, 2010. Any cogeneration facility that was in operation prior to January 1, 2010 and was subject to New Jersey SUT for the purchase and use of natural gas and utility service for cogeneration purposes shall continue to be subject to, and responsible for payment of, such tax. [P.L. 2009, c. 240]

5. Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998. [P.L. 1997, c.162]

6. Agencies or instrumentalities of the federal government. [P.L. 1997, c.162]

7. International organizations of which the United States of America is a member. [P.L. 1997, c.162]

8. Cemetery companies, pursuant to N.J.S.A 8A:5-10. (must provide an Exempt Use Certificate (ST-4) to seller).

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT) (continued)

9. Amtrak (National Railroad Passenger Corporation) and New Jersey Transit Rail Operations.

10. Limited Dividend Housing Corporations organized under N.J.S.A. 55:16-1 seq., for use at the qualified housing project. (must provide an Exempt Use Certificate (ST-4) to seller).

In addition, the Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c.374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. a qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and

2. a group of two or more persons:

   a) each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.);

   b) that collectively employ at least 500 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process;

   c) are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and

   d) collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone;

RIDER "B"

NEW JERSEY SALES AND USE TAX (SUT) (continued)

3. a business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c.373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in (1), (2) or (3) above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

RIDER "C"

SOCIETAL BENEFITS CHARGE (SBC)

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Societal Benefits Charge ("SBC") and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The below rates shall be calculated in accordance with the provisions of the referenced Riders of this Tariff and are collected through the SBC on a per-therm basis within the Delivery Charge for all service classifications to which Rider "C" applies.

:

SBC Rate Component:			
Remediation Adjustment ("RA")		$0.0228	Rider D
New Jersey's Clean Energy Program		$0.0245	Rider E
Universal Service Fund ("USF"):			
Lifeline	$0.0062		
USF	$0.0115		
Total USF Billing Factor		$0.0177	Rider F
Total SBC		$0.0650	

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No.16~~32~~*

RIDER "D~~C~~"

REMEDIATION ADJUSTMENT (RA)

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Remediation Adjustment ("RA") and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The RA Factor will be determined as follows:

I. DEFINITION OF TERMS USED HEREIN

1. ***"Remediation Costs"*** are all investigation, testing, land acquisition if appropriate, remediation and/or litigation costs/expenses or other liabilities excluding personal injury claims and specifically relating to former gas manufacturing facility sites, disposal sites, or sites to which material may have migrated, as a result of the earlier operation or decommissioning of gas manufacturing facilities.

2. ***"Recovery Year"*** is each October 1 to September 30 year and is the time period over which the amortized expenses shall be received from Customers.

3. ***"Remediation Year"*** is each July 1 to June 30 year and is the time period over which the remediation costs are incurred.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No. 16~~43~~*

RIDER "D~~C~~"

REMEDIATION ADJUSTMENT (RA) (continued)

DEFINITIONS OF TERMS USED HEREIN (continued)

4. ***"Third Party Claims"*** are all claims by New Jersey Natural Gas Company against any entity including insurance companies, from which recoveries may be received and will be charged through the RA factor as follows:

   a) Fifty percent of the reasonable transaction costs and expenses in pursuing Third Party Claims shall be included as Remediation Costs and shall be recovered as part of the RA clause. The remaining 50% shall be deferred until such time as the specific claim is resolved.

   b) In the event that the Company is successful in obtaining a reimbursement from any Third Party, the Company shall be permitted to retain the deferred 50% as specified in 4a. The balance of the reimbursement, if any, shall be applied against the Remediation Costs in the year it is received and will be amortized over seven years.

5. ***Sale of Property*** shall be calculated by taking the proceeds of any sale of a former manufacturing gas plant site, less all reasonable expenses associated with selling the site, and subtracting the total costs that were incurred in cleaning up the site and amortized through rates. The proceeds associated with the total costs that were incurred in cleaning up the site will be included as a credit to the remediation costs incurred in the year of the sale. The remainder shall be equally shared between the Company and ratepayers.

RIDER "D~~C~~"

REMEDIATION ADJUSTMENT (RA) (continued)

II. DETERMINATION OF THE REMEDIATION ADJUSTMENT

At the end of the remediation year, the Company shall file with the Board all bills and receipts relating to the amount of any remediation costs incurred in the preceding remediation year for which it seeks to begin recovery. In the same filing, the Company shall include similar material and information to support any expenses and/or recoveries resulting from Third Party claims. The Company shall also submit in its annual filing a projection of remediation costs for the following remediation year.

The RA factor shall be calculated by taking one seventh of the Actual Remediation Costs plus applicable Third Party Claims and Sale of Property allocations incurred each year, until fully amortized, plus the prior years' RA over or under-recovery plus appropriate carrying costs and dividing this amount by the Company's total volume of prospective sales for the upcoming recovery year. The result shall be carried for four (4) decimal places.

The RA will be calculated as the difference between revenues calculated by multiplying the RA factor times actual monthly firm sales and remediation costs allowable per the formula.

The total annual charge to the Company's ratepayers for remediation costs during any recovery year shall not exceed five (5%) percent of the Company's total revenues from gas sales during the preceding Remediation Year. If this limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular Recovery Year and the mechanism is not reopened at the request of any party, then the remediation costs in excess of the 5% shall be included in the subsequent year's collection. The Company shall calculate carrying costs on any under-or over-recovered RA cost balances, and the deferred tax benefit associated with those balances, using the same interest rate, which rate will be adjusted each August 31 based upon the seven-year constant maturity Treasury rate, shown in the Federal Reserve Statistical Release, plus 60 basis points. Interest applicable to the Company's unamortized RA balance shall be calculated and will accrue on a monthly basis and shall be rolled into the RA balance at the beginning of each recovery year.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Second Revised Sheet No. 165~~ ~~Superseding First Revised Original~~ Sheet No. 16~~65~~*

RIDER "D~~C~~"

REMEDIATION ADJUSTMENT (RA) (continued)

III. TRACKING THE OPERATION OF THE REMEDIATION ADJUSTMENT CLAUSE

The revenues billed, net of taxes and assessments through the application of the Remediation Adjustment factor shall be accumulated for each month and be applied against the total amortized Remediation Costs calculated for that year. Any over or under collection at the end of the Recovery Year will be included in the determination of the following year's RA factor.

In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT") and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

The RA factor shall be collected through the SBC on a per-therm basis within the Delivery Charge for all service classifications to which Rider "D~~A~~" applies. The RA factor is set forth below:

$0.0228

RIDER "E"

NEW JERSEY'S CLEAN ENERGY PROGRAM

AVAILABILITY

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with NJ's Clean Energy Program and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The Company shall file with the Board, an annual NJ's Clean Energy Program factor concurrent with the Company's SBC filing, which shall be derived in the following manner:

1. The Company's funding obligation based upon the most recently BPU approved NJ's Clean Energy Program, previously referred to as the Comprehensive Resource Analysis ("CRA") Plan.

2. The difference between the approved funding obligation for the preceding year and the actual recovery of the NJ's Clean Energy Program costs plus appropriate carrying costs.

3. An estimate shall be made of the total volume of prospective jurisdictional therm sales of gas for the applicable service classifications for the twelve (12) months of the recovery year.

NEW JERSEY NATURAL GAS COMPANY

RIDER "E"

NEW JERSEY'S CLEAN ENERGY PROGRAM (continued)

4. The total NJ's Clean Energy Program costs to be recovered, as determined per paragraphs (1), (2) and (3) shall then be divided by the total volume of prospective jurisdictional therm sales (per paragraph (3)), and the result carried to four (4) decimal places. Such result shall constitute the NJ's Clean Energy Program factor effective for service rendered commencing the effective date of approval, and continuing in effect until the effective date of any subsequent annual or other filing of a revision of modification thereof.

The net amount shall be maintained in a separate deferred account. In the event that the Company determines that an existing NJ's Clean Energy Program rate, if left unchanged, would result in a material over- or under-collection of amounts incurred or expected to be incurred during the current NJ's Clean Energy Program Recovery Year, the Company may file with the BPU for approval of an interim revision of the NJ's Clean Energy Program rate. Such interim revision shall be designed to minimize or eliminate the over- or under-collection expected to result absent such revision either over: (a) the remaining billing months of the current NJ's Clean Energy Program Recovery Year or (b) over such other time period as the BPU shall determine.

The Company shall calculate carrying costs on the average monthly balances of under-or over-recovery of deferred costs, and the deferred tax benefit associated with those balances, using the same interest rate, which will be adjusted each August 31 based upon the seven-year constant maturity Treasury rate, shown in the Federal Reserve Statistical Release, plus 60 basis points. Interest will accrue on a monthly basis and shall be rolled into the balance each October 1.

In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT") and when billed to customers exempt from this tax, as set forth in Rider SUT, shall be reduced by the amount of such tax included therein.

The NJ's Clean Energy Program factor shall be collected through the SBC on a per therm basis within the Delivery Charge for all service classifications to which this Rider "E" applies. The NJ's Clean Energy Program factor is as set forth below:

$0.0245

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *Original Sheet No. 16~~976~~*

RIDER "F~~H~~"

UNIVERSAL SERVICE FUND – USF

AVAILABILITY

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Universal Service Fund ("USF") and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The USF is a fund established by the New Jersey Board Public Utilities ("NJBPU") to provide affordable access for electric and natural gas service to all residential customers in the State. The Electric Discount and Energy Competition Act mandated the establishment of the USF in New Jersey.

Revenues collected through this rider are used to fund the State's USF program for qualified low-income customers and the Lifeline Credit program, a special program for qualified low-income elderly and disable citizens. The USF is administered by the State of New Jersey Department of Community Affairs and the Lifeline Credit Program is administered by the State of New Jersey Department of Human Resources. The USF program Year is intended to run from October 1st to September 30th of each year.

RIDER "~~F~~H"

UNIVERSAL SERVICE FUND – USF (continued)

DETERMINATION OF THE USF

On an annual basis, the NJBPU shall consider the following: estimated USF benefits for upcoming USF program Year; Lifeline budget for upcoming USF program year; estimated administrative expenses; the projected current year under/over recovery position, and annual forecasted volumes in order to establish a USF rate for the upcoming USF program year. This state wide rate shall be adjusted for all applicable taxes and assessments and shall be provided to all utilities to be included in their annual SBC filings for notice and public hearing purposes.

The Company shall calculate carrying costs on any under-or over-recovered USF balances based upon the two-year constant maturity Treasury rate, as published in the Federal Reserve Statistical Release on the first day of each month, or the closest day thereafter on which rates are published, plus sixty (60) basis points; provided, however, that this interest rate does not exceed the overall rate of return as authorized by the Board. The interest rate shall be reset each month. The carrying cost calculation shall be based on the net of tax beginning and end average monthly balance. The carrying costs shall accrue on a monthly basis and shall be rolled into the USF balance at the end of each USF year.

The USF shall be collected on a per therm basis and shall remain in effect until changed by order of the NJBPU:

Lifeline	$0.0062
USF	$0.0115
USF Billing Factor	$0.0177

In accordance with P.L. 1997, c. 162, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT"), and when billed to customer exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

RIDER "G~~F~~"

ENERGY EFFICIENCY - EE

AVAILABILITY

Applicable to the following service classifications:

RS	Residential Service	ED	Economic Development
DGR	Distributed Generation Residential	EGS	Electric Generation Service
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	IS	Interruptible Service
FT	Firm Transportation	IGS	Incremental Gas Service
DGC	Distributed Generation Commercial	CNG	Compressed Natural Gas

In accordance with P.L. 2011, c. 9, societal benefits charges pursuant to section 12 of P.L. 1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for societal, energy efficiency, conservation, environmental or renewable energy programs, are not applicable to natural gas delivery service or commodity that is used to generate electricity that is sold for resale. Natural gas used to generate electricity that is sold for resale by customers served under the above Service Classifications is exempt from costs associated with the Energy Efficiency ("*EE")* Rider and shall not be billed for such charges. In order to qualify for this exemption, a customer who uses natural gas to generate electricity for resale must complete an Annual Certification form, provided by the Company, to certify the percentage of natural gas used at the customer's New Jersey generation facilities during the previous calendar year to generate electricity that was sold for resale. For a new customer or a customer with less than twelve months of usage history, estimates supported by engineering and operational plans may be used to determine the percentage of natural gas used to generate electricity sold for resale.

The EE rate is for recovering authorized expenditures related to the energy-efficiency programs as approved in BPU Docket Nos. GO10030225, GR11070425, GO12070640, GO14121412, and GO18030355, collectively referred to as "Energy Efficiency Programs Established 2010-2018", and GO20090622 ("Energy Efficiency Programs Established 2021-Present").

DETERMINATION OF THE EE

The Company shall file an annual request with the Board for implementation of an EE charge, which shall be applicable to customers on all service classifications to which Rider "G~~F~~" applies. The EE recovery year is intended to run from October 1st to September 30th of each year.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~1~~12 - Gas *~~Third Revised Sheet No. 173 Superseding Second Revised~~ Original Sheet No. 17~~23~~*

RIDER "G~~F~~"

ENERGY EFFICIENCY – EE (continued)

I. Determination of the Rate

The EE rate shall have two components, an Energy Efficiency Programs 2010-2018 rate and an Energy Efficiency Programs Established 2021-Present rate, which shall be derived in the following manner:

1. An estimate shall be made of the total annual cost related to the programs. This rider will include only expenses for energy-efficiency programs approved by the Board for Energy Efficiency Programs 2010-2018 and Energy Efficiency Programs Established 2021-Present unless modified further by Board Order.

2. An estimate shall be made of the total annual volume of prospective jurisdictional sales of gas (in therms) to NJNG's sales and transportation customers.

3. The prospective costs for Energy Efficiency Programs 2010-2018 and Energy Efficiency Programs Established 2021-Present (per paragraph (1)) shall separately be adjusted upward or downward to the extent of the amount of any prior under-recovery or over-recovery to determine the total costs to be recovered and then shall be divided by the estimated total volume of prospective sales (per paragraph (2)), to determine the per unit cost recovery rate. The result shall be carried for four (4) decimal places.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Third Revised Sheet No. 173~~ ~~Superseding Second Revised~~ Original Sheet No. 173*

RIDER "G~~F~~"

ENERGY EFFICIENCY – EE (continued)

II. Tracking the Operation of the EE

The Company shall calculate carrying costs on the average monthly balances of under-or over-recovery of deferred costs based upon the Company's monthly commercial paper rate. The carrying cost calculation shall be based on the net of tax beginning and end average monthly balance. The carrying costs shall accrue on a monthly basis and shall be rolled into the balance at the end of each EE recovery year.

In accordance with P.L., 1997 c. 162, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT"), and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

The EE rate shall be credited/collected on a per therm basis within the Delivery Charge for all service classifications to which Rider "G~~F~~" applies. The EE rate is as set forth below:

Energy Efficiency Programs Established 2010-2018	$0.0247
Energy Efficiency Programs Established 2021-Present	$0.0247
EE	$0.0494

NEW JERSEY NATURAL GAS COMPANY

BPU No. 12 - Gas *Original Sheet No. 1~~74~~66*

RIDER "~~H~~HD"

INFRASTRUCTURE INVESTMENT PROGRAM - IIP

Applicable to the following service classifications:

RS	Residential Service	DGC	Distributed Generation Commercial
DGR	Distributed Generation Residential	ED	Economic Development
GSS	General Service - Small	NGV	Natural Gas Vehicle
GSL	General Service - Large	CNG	Compressed Natural Gas
FT	Firm Transportation		

INCREMENTAL BASE RATE CHARGES

Service Classification		*Pre-Tax Rate*	*After-tax Rate*
RS	IIP Base Rate Charge per therm	$0.0090	$0.0096
DGR	IIP Base Rate Charge per therm	$0.0000	$0.0000
GSS	IIP Base Rate Charge per therm	$0.0115	$0.0123
GSS CAC	IIP Base Rate Charge per therm	$0.0015	$0.0016
GSL	IIP Base Rate Charge per therm	$0.0083	$0.0088
GSL CAC	IIP Base Rate Charge per therm	$0.0015	$0.0016
FT	IIP Base Rate Charge per therm	$0.0043	$0.0046
DGC	IIP Base Rate Charge per therm	$0.0025	$0.0027
NGV	IIP Base Rate Charge per therm	$0.0051	$0.0054
CNG	IIP Base Rate Charge per therm	$0.0051	$0.0054

The above IIP Base Rate Charges will be included in total Delivery Charges on customer bills.

RIDER "~~H~~HD"

INFRASTRUCTURE INVESTMENT PROGRAM - IIP (continued)

DETERMINATION OF THE IIP

The purpose of the Infrastructure Investment Program Rider is to set forth the base rate adjustments associated with the Company's approved Infrastructure Investment Program pursuant to N.J.A.C. 14:3-2A.1 et seq. The Company shall file periodic requests with the Board for implementation of IIP charges applicable to customers on service classifications to which Rider "H~~D~~" applies. Filings will be made according to the Company's recovery periods approved in BPU Docket No. GR19020278.

Recovery under the IIP is contingent on an earnings test for the annual period. If the calculated return on equity ("ROE") in the applicable annual IIP filing exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the IIP shall not be allowed in the applicable annual IIP filing. Any disallowance resulting from the earnings test will not be charged to customers in a subsequent IIP filing period, but the Company may seek such recovery in a subsequent rate case. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's regulated jurisdictional net income for the annual period by the Company's average jurisdictional common equity balance for such annual period. The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) other income, net of associated taxes, (2) margins retained from Off-System Sales and Capacity release, net of associated taxes, (3) margins retained from the Storage Incentive Program, net of associated taxes, and (4) margins retained from the energy efficiency programs of Rider "G", net of associated taxes. The Company's average jurisdictional common equity balance for any annual period shall be derived by multiplying the average of the Company's beginning and ending net rate base for the annual period by the equity ratio approved in the Company's most recent rate case.

~~RIDER "G"~~

~~RESERVED FOR FUTURE USE~~

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP

Applicable to the following service classifications:

RS	Residential Service
GSS	General Service - Small
GSL	General Service - Large
ED	Economic Development

I. DEFINITION OF TERMS AS USED HEREIN

1. ***Actual Number of Customers*** – The Actual Number of Customers ("ANC") shall be determined on a monthly basis for each of the Customer Class Groups to which the Conservation Incentive Program ("CIP") applies. The ANC shall equal the aggregate actual booked number of customers for the month as recorded on the Company's books, plus any Incremental Large Customer Count Adjustment.

2. ***Actual Usage per Customer*** – the Actual Usage per Customer ("AUC") shall be determined in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The AUC shall equal the aggregate actual booked sales for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month.

3. ***Adjustment Period*** - shall be the year beginning immediately following the conclusion of the Annual Period.

4. ***Annual Period*** – shall be the twelve consecutive months from October 1 of one calendar year through September 30 of the following calendar year.

~~5. *Average 13 Month Common Equity Balance* - shall be the common equity balance at the beginning of the Annual Period (i.e., October 1) and the month ending balances for each of the twelve months in the Annual Period divided by thirteen (13).~~

~~6.~~5. ***Baseline Usage per Customer*** – the Baseline Usage per Customer ("BUC") shall be stated in therms on a monthly basis for each of the Customer Class Groups to which the CIP applies. The BUC shall be rounded to the nearest one tenth of one therm.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas ~~Second Revised Sheet No. 179 Superseding First Revised Original~~ Sheet No. 17~~9~~

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

6~~7~~. **Customer Class Group** – For purposes of determining and applying the CIP, customers shall be aggregated into four separate recovery class groups. The Customer Class Groups shall be as follows:

Group I: RS (non-heating customers only)
Group II: RS (heating customers only)
Group III: GSS, ED using less than 5,000 therms annually
Group IV: GSL, ED using 5,000 therms or greater annually

7~~8~~. **Forecast Annual Usage** – the Forecast Annual Usage ("FAU") shall be the projected total annual throughput for all customers within the applicable Customer Class Group. The FAU shall be estimated based on normal weather.

8~~9~~. **Incremental Large Customer Count Adjustment** – the Company shall maintain a list of incremental commercial and industrial customers added to its system on or after July 1, 2024~~September 1, 2021~~ whose connected load is greater than that typical for the Company's average commercial and industrial customer. For purposes of the CIP, large incremental customers shall be those customers whose connected load exceeds 5,700~~5,600~~ cubic feet per hour ("CFH"). A new customer at an existing location previously connected to NJNG's facilities shall not be considered an incremental customer. The Actual Number of Customers for the Customer Class Group shall be adjusted to reflect the impact of all such incremental commercial or industrial customers. Specifically, the Incremental Large Customer Count Adjustment for the applicable month shall equal the aggregate connected load for all active customers that exceed the ~~5,600~~ CFH threshold divided by 2,850~~2,800~~ CFH less the number of active customers, rounded to the nearest whole number.

9~~10~~. **Margin Revenue Factor** – the Margin Revenue Factor ("MRF") shall be the weighted-average margin rate as quoted in the individual service classes to which the CIP applies. The MRFs by Customer Class Group are as follows:

Group I (RS non-heating):	$~~0.5791~~0.8680
Group II (RS heating):	$~~0.5791~~0.8680
Group III (GSS, ED using less than 5,000 therms annually)	$~~0.5059~~0.7851
Group IV (GSL, ED using 5,000 therms or greater annually)	$~~0.3216~~0.4310

The MRF shall be reset each time new base rates are placed into effect.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

II. BASELINE USAGE PER CUSTOMER

The BUC for each Customer Class Group by month are as follows:

Month	Group I: RS Non-Heating	Group II: RS Heating	Group III: GSS, ED using less than 5,000 therms annually	Group IV: GSL, ED using 5,000 therms or greater annually
Oct.	15.5~~17.5~~	46.5~~43.4~~	51.1~~44.8~~	993.5~~883.1~~
Nov.	15.2~~13.9~~	95.3~~100.4~~	119.8~~119.2~~	1,733.1~~1,743.4~~
Dec.	20.6~~17.4~~	154.8~~160.8~~	210.4~~201.9~~	2,636.2~~2,598.8~~
Jan.	23.4~~20.4~~	188.9~~191.2~~	266.1~~264.1~~	3,153.5~~3,041.8~~
Feb.	20.8~~18.7~~	163.0~~163.3~~	225.5~~227.8~~	2,734.3~~2,534.1~~
Mar.	17.3~~19.8~~	128.5~~133.7~~	168.6~~180.9~~	2,252.1~~2,113.0~~
Apr.	~~–~~11.5~~10.9~~	69.0~~70.6~~	79.5~~82.3~~	1,326.2~~1,311.5~~
May	~~–~~10.4~~11.0~~	36.3~~37.0~~	36.2~~33.1~~	759.8~~836.9~~
Jun.	17.2~~18.0~~	23.4~~27.2~~	21.0~~19.4~~	528.3~~576.8~~
Jul.	17.8~~17.4~~	24.6~~23.8~~	26.5~~24.4~~	581.8~~556.1~~
Aug.	13.0~~16.3~~	21.5~~21.3~~	20.7~~20.6~~	536.2~~536.9~~
Sep.	15.8~~17.9~~	21.8~~23.0~~	21.9~~19.1~~	537.6~~490.3~~
Total Annual	198.5~~199.2~~	973.6~~995.7~~	1,247.3~~1,237.6~~	17,772.6~~17,222.7~~

The BUC shall be reset each time new base rates are placed into effect.

III. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM RATE

1. At the end of the Annual Period, a calculation shall be made that determines for each Customer Class Group the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Usage per Customer from the Actual Usage per Customer by the Actual Number of Customers and then multiplying the resulting therms by the Margin Revenue Factor.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

2. The normal degree days and degree day consumption factors per customer to be used for the calculation of the weather related change in customer usage, are set forth below:

		Consumption Factors per customer (therms per customer per degree day)		
Month	**Degree Days**	**Group II- Residential Heating**	**Group III- GSS**	**Group IV- GSL**
October	225~~238~~	0.1657~~0.1260~~	0.1719~~0.1771~~	2.7305~~1.7974~~
November	516~~524~~	0.1814~~0.1677~~	0.2171~~0.2195~~	2.7897~~2.3319~~
December	793~~813~~	0.1932~~0.1919~~	0.2587~~0.2603~~	2.8903~~2.6794~~
January	954~~968~~	0.1971~~0.2020~~	0.2670~~0.2744~~	2.9560~~2.8174~~
February	801~~814~~	0.1971~~0.1998~~	0.2679~~0.2684~~	2.9257~~2.7416~~
March	658~~674~~	0.1932~~0.1934~~	0.2537~~0.2513~~	2.9033~~2.4923~~
April	346~~346~~	0.1894~~0.1776~~	0.2180~~0.1841~~	2.8689~~1.9127~~
May	122	0.1971~~0.1458~~	0.2070~~0.1643~~	2.8673~~1.6686~~

These consumption factors per customer shall be multiplied by the actual number of customers to determine the consumption factors. The weather related change in customer usage shall be calculated as the difference between actual degree days and the above normal degree days multiplied by the consumption factors, and multiplying the result by the margin revenue factors as defined in Section I.10. of this Rider.

3. Recovery of margin deficiency associated with non-weather related changes in customer usage will be subject to a BGSS savings test and a Margin Revenue recovery limitation ("recovery tests"). Recovery of non-weather related margin deficiency will be limited to the smaller of (1) the level of BGSS savings achieved when such savings are less than 75 percent of the non-weather related margin deficiency, i.e. BGSS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both of the recovery tests in a future year consistent with the amount by which either or both of the non-weather related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather related portion shall be calculated as set forth in Section III.2. of this Rider I.

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

4. In addition, cost recovery under the CIP is contingent on an earnings test for the Annual Period. If the calculated return on equity ("ROE") exceeds the Company's most recently approved ROE by fifty (50) basis points or more, cost recovery under the CIP shall not be allowed. ~~the CIP shall not operate to permit the Company to recover any portion of a deficiency that will cause the Company to earn in excess of a 9.60% return on common equity for the Annual Period; any portion which is not recovered shall not be deferred.~~ For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's regulated jurisdictional net income for the Annual Period by the Company's average ~~13-month~~ jurisdictional common equity balance for such Annual Period~~, all as reflected in the Company's monthly reports to the Board of Public Utilities.~~ The Company's regulated jurisdictional net income shall be calculated by subtracting from total net income (1) the CIP booked margin revenue accruals, net of associated taxes, (2) other income, net of associated taxes, (3~~2~~) margins retained from Off-System Sales and Capacity release, net of associated taxes, (4~~3~~) margins retained from the Storage Incentive Program, net of associated taxes, and (5~~4~~) margins retained from the energy efficiency programs of Rider "G~~F~~", net of associated taxes. The Company's average ~~thirteen-month~~ jurisdictional common equity balance for any Annual Period shall be derived by multiplying the average of the Company's beginning and ending net rate base for the Annual Period by the equity ratio approved in the Company's most recent rate case. ~~the Company's average total common equity less the Company's average common equity investment in unregulated subsidiaries.~~

~~4.~~

5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Customer Class Group.

IV. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balances remaining from prior periods.

In accordance with P.L. 1997, c. 192, as amended by P.L. 2006, c. 44, P.L. 2009, c. 240, and P.L. 2016, c. 57, the charges applicable under this Rider include provision for the New Jersey Sales and Use Tax ("SUT") and when billed to customers exempt from this tax, as set forth in Rider "B", shall be reduced by the amount of such tax included therein.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Second Revised Sheet No. 183~~*
~~Superseding First Revised~~Original Sheet No. 18~~13~~

RIDER "I"

CONSERVATION INCENTIVE PROGRAM – CIP (continued)

The annual filing for the adjustment to the CIP rate shall be concurrent with the annual filing for BGSS. The CIP factor shall be credited/collected on a basis within the Delivery Charge for all service classifications stated above.

The currently effective CIP factor by Customer Class Group are as follows:

Group I (RS non-heating):	$0.0382
Group II (RS heating):	$0.0915
Group III (GSS, ED using less than 5,000 therms annually):	$0.0605
Group IV (GSL, ED using 5,000 therms or greater annually):	$0.0353

For the recovery of the October 2022 through September 2023 CIP margin deficiency, the recovery of the margin deficiency associated with non-weather related change in customer usage included in the above factors are offset by the BGSS savings component, as set forth in Rider A. The BGSS savings component is embedded within the Periodic BGSS Charge and the Monthly BGSS Charge.

RESERVED FOR FUTURE USE

SUMMARY OF RATE COMPONENTS

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Residential Heating Customers

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~11.00~~15.00	~~11.00~~15.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.5701~~0.8590	~~0.5701~~0.8590	
Pre-tax IIP Base Rate		0.0090	0.0090	Rider H~~D~~
Total Pre-tax Base Rate (Margin Revenue Factor)		~~0.5791~~0.8680	~~0.5791~~0.8680	
SUT		~~0.0384~~0.0575	~~0.0384~~0.0575	Rider B
After-tax Base Rate		~~0.6175~~0.9255	~~0.6175~~0.9255	
CIP		~~–~~0.0915	0.0915	Rider I
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.7584~~1.0664*	*~~0.7584~~1.0664*	
Balancing Charge	b	*~~0.1266~~0.1271*	*~~0.1266~~0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**~~0.9500~~1.2585**	**~~0.9500~~1.2585**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**x**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

NEW JERSEY NATURAL GAS COMPANY

~~Seventh Revised Sheet No. 252~~

BPU No. ~~11~~12 - Gas *~~Superseding Sixth Revised~~Original Sheet No. 252*

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

~~*Seventh Revised Sheet No. 253*~~

BPU No. ~~11~~12 - Gas ~~*Superseding Sixth Revised*~~*Original Sheet No. 253*

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Residential Non-Heating Customers

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~11.00~~15.00	~~11.00~~15.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.5701~~0.8590	~~0.5701~~0.8590	
Pre-tax IIP Base Rate		0.0090	0.0090	Rider H~~D~~
Total Pre-tax Base Rate (Margin Revenue Factor)		~~0.5791~~0.8680	~~0.5791~~0.8680	
SUT		~~0.0384~~0.0575	~~0.0384~~0.0575	Rider B
After-tax Base Rate		~~0.6175~~0.9255	~~0.6175~~0.9255	
CIP		0.0382	0.0382	Rider I
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.7051~~1.0131*	*~~0.7051~~1.0131*	
Balancing Charge	b	*~~0.1266~~0.1271*	*~~0.1266~~0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**~~0.8967~~1.2052**	**~~0.8967~~1.2052**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**x**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

NEW JERSEY NATURAL GAS COMPANY

~~*Seventh Revised Sheet No. 253*~~

BPU No. ~~11~~12 - Gas ~~*Superseding Sixth Revised*~~*Original Sheet No. 253*

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

~~Seventh Revised Sheet No. 254~~

BPU No. ~~11~~12 - Gas ~~Superseding Sixth Revised~~Original Sheet No. 254

SUMMARY OF RESIDENTIAL RATE COMPONENTS

Residential Distributed Generation Service

		Nov - Apr	May - Oct	Reference
Customer Charge				
Customer Charge per meter per month		~~11.00~~15.00	~~11.00~~15.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		0.1685	0.1185	
Pre-tax IIP Base Rate		0.0000	0.0000	Rider H~~D~~
Total Pre-tax Base Rate		0.1685	0.1185	
SUT		0.0112	0.0079	Rider B
After-tax Base Rate		0.1797	0.1264	
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*0.2291*	*0.1758*	
Balancing Charge	b	*~~0.1266~~0.1271*	*~~0.1266~~0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0262	0.0262	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	c	0.0650	0.0650	Rider C
Delivery Charge (DEL)	a+b+c=d	**~~0.4207~~0.4212**	**~~0.3674~~0.3679**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**0.4290**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

General Service - Small (GSS)

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~42.00~~57.50	~~42.00~~57.50	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.4944~~0.7736	~~0.4944~~0.7736	
Pre-tax IIP Base Rate		0.0115	0.0115	Rider H~~D~~
Total Pre-tax Base Rate (Margin Revenue Factor)		~~0.5059~~0.7851	~~0.5059~~0.7851	
SUT		~~0.0335~~0.0520	~~0.0335~~0.0520	Rider B
After-tax Base Rate		~~0.5394~~0.8371	~~0.5394~~0.8371	
CIP		0.0605	0.0605	Rider I
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.6493~~0.9470*	*~~0.6493~~0.9470*	
Balancing Charge	b	*~~0.1266~~0.1271*	*~~0.1266~~0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**~~0.8409~~1.1391**	**~~0.8409~~1.1391**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**0.4290**	**x**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

NEW JERSEY NATURAL GAS COMPANY

~~Seventh Revised Sheet No. 255~~

BPU No. ~~11~~12 - Gas *~~Superseding Sixth Revised~~Original Sheet No. 255*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Total Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

~~Thirty-First~~Revised ~~Sheet No. 256~~

BPU No. ~~11~~12 - Gas ~~Superseding Thirtieth~~Revised~~Original~~ Sheet No. 256

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

General Service - Large (GSL)

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~104.00~~142.50	~~104.00~~142.50	
Demand Charge				
Demand Charge per month applied to HMAD		~~3.41~~4.50	~~3.41~~4.50	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.3133~~0.4227	~~0.3133~~0.4227	
Pre-tax IIP Base Rate		0.0083	0.0083	Rider H~~D~~
Total Pre-tax Base Rate (Margin Revenue Factor)		~~0.3216~~0.4310	~~0.3216~~0.4310	
SUT		~~0.0213~~0.0286	~~0.0213~~0.0286	Rider B
After-tax Base Rate		~~0.3429~~0.4596	~~0.3429~~0.4596	
CIP		0.0353	0.0353	Rider I
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.4276~~0.5443*	*~~0.4276~~0.5443*	
Balancing Charge	b	*~~0.1266~~0.1271*	*~~0.1266~~0.1271*	Rider A
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	c	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b+c=d	**~~0.6192~~0.7364**	**~~0.6192~~0.7364**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**$0.4723**	**X**	Rider A

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NEW JERSEY NATURAL GAS COMPANY

~~Thirty-First~~Revised ~~Sheet No. 256~~

BPU No. ~~11~~12 - Gas *~~Superseding Thirtieth~~Revised~~Original~~ Sheet No. 256*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

With the exception of the Customer Charge and Demand charges, these rates are on a per-therm basis.

Total Customer, Total Demand, DEL, and BGS charges are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Superseding Fourth Revised~~ Original Sheet No. 257* *~~Fifth Revised Sheet No. 257~~*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

FIRM TRANSPORTATION (FT)

		Transport	Reference
Customer Charge			
Customer Charge per meter per month		~~350.00~~475.00	
Demand Charge			
Demand Charge per therm per month applied to MDQ		~~2.50~~3.75	
Delivery Charge ("DEL") per therm			
Pre-tax Base Rate		~~0.0775~~0.0658	
Pre-tax IIP Base Rate		0.0043	Rider H~~D~~
Total Pre-tax Base Rate		~~0.0818~~0.0701	
SUT		~~0.0054~~0.0046	Rider B
After-tax Base Rate		~~0.0872~~0.0747	
EE		0.0494	Rider G~~F~~
Subtotal	a	*~~0.1366~~0.1241*	
Societal Benefits Charge ("SBC"):			
NJ's Clean Energy		0.0245	Rider E
RA		0.0228	Rider D~~C~~
USF		0.0177	Rider F~~H~~
Total SBC	b	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**~~0.2016~~0.1891**	

With the exception of the Customer Charge and Demand charges, these rates are on a per-therm basis.

Total Customer, Total Demand, and DEL, charges are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Superseding Twenty-Ninth Revised~~ Original Sheet No. 258* *~~Thirtieth Revised Sheet No. 258~~*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Commercial Distributed Generation Service – DGC-Balancing

		Nov - Apr	May - Oct	Reference
Customer Charge				
Customer Charge per meter per month		~~104.00~~142.50	~~104.00~~142.50	
Demand Charge				
Demand Charge per therm per month applied to PBQ		~~2.35~~3.25	~~2.35~~3.25	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.0701~~0.0818	~~0.0395~~0.0512	
Pre-tax IIP Base Rate		0.0025	0.0025	Rider H~~D~~
Total Pre-tax Base Rate		~~0.0726~~0.0843	~~0.0420~~0.0537	
SUT		~~0.0048~~0.0056	~~0.0028~~0.0036	Rider B
After-tax Base Rate		~~0.0774~~0.0899	~~0.0448~~0.0573	
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	~~0.1268~~0.1393	~~0.0942~~0.1067	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	b	*0.0650*	*0.0650*	Rider C
Balancing Charge	c	*~~0.1266~~0.1271*	*~~0.1266~~0.1271*	
DGC-Balancing Delivery Charge (DEL)	a+b+c=d	**~~0.3184~~0.3314**	**~~0.2858~~0.2988**	
Basic Gas Supply Charge ("BGS")				
BGS	e	**$0.4723**	**$0.4723**	Rider A

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NEW JERSEY NATURAL GAS COMPANY

~~Thirtieth Revised Sheet No. 258~~

BPU No. ~~11~~12 - Gas *~~Superseding Twenty-Ninth Revised~~ Original Sheet No. 258*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

The Delivery Charges for DGC-Balancing above include the Balancing Charge as reflected in Rider "A" of this Tariff for customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (3) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS.

With the exception of the Customer Charge and Demand Charge, these rates are on a per-therm basis.

Total Customer Charge, Total Demand Charge, DEL, and BGS charges are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Fifth Revised Sheet No. 259~~*
~~Superseding Fourth Revised~~Original Sheet No. 259

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Commercial Distributed Generation Service – DGC-FT

		Nov - Apr	May - Oct	Reference
Customer Charge				
Customer Charge per meter per month		~~104.00~~142.50	~~104.00~~142.50	
Demand Charge				
Demand Charge per therm per month applied to PBQ		~~2.35~~3.25	~~2.35~~3.25	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.0701~~0.0818	~~0.0395~~0.0512	
IIP Pre-tax Base Rate		0.0025	0.0025	Rider H~~D~~
Total Pre-tax Base Rate		~~0.0726~~0.0843	~~0.0420~~0.0537	
SUT		~~0.0048~~0.0056	~~0.0028~~0.0036	Rider B
After-tax Base Rate		~~0.0774~~0.0899	~~0.0448~~0.0573	
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.1268~~0.1393*	*~~0.0942~~0.1067*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	b	*0.0650*	*0.0650*	Rider C
DGC-FT Delivery Charge (DEL)	a+b=c	**~~0.1918~~0.2043**	**~~0.1592~~0.1717**	

For DGC-FT customers whose Third Party Supplier delivers gas on their behalf pursuant to paragraph (1) under Deliveries to Company's Designated Delivery Meters section of Service Classification TPS, the DGC-FT Delivery Charges above exclude the Balancing Charge reflected in Rider "A" of this Tariff.

With the exception of the Customer Charge and Demand Charge, these rates are on a per-therm basis.

NEW JERSEY NATURAL GAS COMPANY

~~Fifth Revised Sheet No. 259~~

BPU No. ~~11~~12 - Gas *~~Superseding Fourth Revised~~Original Sheet No. 259*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Total Customer Charge, Total Demand Charge, and DEL rate are presented on customer bills

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Electric Generation Service (EGS)

		Without SUT	With SUT	Reference
Customer Charge				
Customer Charge per meter per month		~~877.26~~914.42	~~935.38~~975.00	
Demand Charge				
Year-Round Firm Service Demand Charge per therm per month applied to MDQ		~~1.5132~~1.8757	~~1.6134~~2.00	
Off-Peak Firm Service Demand Charge per therm per month applied to MDQ		0.6253	0.6667	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.0047~~0.0094	~~0.0047~~0.0094	
SUT		0.0000	~~0.0003~~0.0006	Rider B
Delivery Charge excluding Riders C, D, E, F and G~~H~~	a	~~0.0047~~0.0094	~~0.0050~~0.0100	
EE	b	0.0464	0.0494	Rider G~~F~~
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0230	0.0245	Rider E
RA		0.0214	0.0228	Rider D~~C~~
USF		0.0166	0.0177	Rider F~~H~~
Total SBC	c	*0.0610*	*0.0650*	Rider C
Delivery Charge (DEL) including Riders C, D, E, F and G~~H~~	a+b+c=d	**~~0.1121~~0.1168**	**~~0.1194~~0.1244**	

With the exception of the Customer Charge and Demand charges, these rates are on a per-therm basis.

NEW JERSEY NATURAL GAS COMPANY

~~Fifth Revised Sheet No. 260~~

BPU No. ~~11~~12 - Gas *~~Superseding Fourth Revised~~Original Sheet No. 260*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Customer, Demand, and DEL charges are presented on customer bills.

Natural gas used to generate electricity that is sold for resale by customers served under this Service Classification is exempt from Riders B, C, D, E, F, and G~~H~~ and shall not be billed for such charges subject to the Customer's submission of an Annual Certification form.

SUMMARY OF INTERRUPTIBLE RATE COMPONENTS

INTERRUPTIBLE SALES AND TRANSPORTATION

With Alternate Fuel

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~572.98~~725.00	~~572.98~~725.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.0494~~0.0735	~~0.0494~~0.0735	
SUT		~~0.0033~~0.0049	~~0.0033~~0.0049	Rider B
After-tax Base Rate		~~0.0527~~0.0784	~~0.0527~~0.0784	
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.1021~~0.1278*	*~~0.1021~~0.1278*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	b	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**~~0.1671~~0.1928**	**~~0.1671~~0.1928**	
Basic Gas Supply Charge ("BGS")				
~~Monthly BGSS~~	~~d~~	~~$0.5989~~	~~X~~	~~Rider A~~
BGS	d	**$0.5989**	**X**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

SUMMARY OF INTERRUPTIBLE RATE COMPONENTS

Customer Charge, DEL rate and BGS rate are presented on customer bills.

~~Thirty-First~~Revised Sheet No. 262

BPU No. ~~11~~12 - Gas *~~Superseding Twenty-Ninth Revised~~Original Sheet No. 262*

SUMMARY OF INTERRUPTIBLE RATE COMPONENTS

INTERRUPTIBLE SALES AND TRANSPORTATION

Without Alternate Fuel

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~572.98~~725.00	~~572.98~~725.00	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.2753~~0.4127	~~0.2753~~0.4127	
SUT		~~0.0182~~0.0273	~~0.0182~~0.0273	Rider B
After-tax Base Rate		~~0.2935~~0.4400	~~0.2935~~0.4400	
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.3429~~0.4894*	*~~0.3429~~0.4894*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	b	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**~~0.4079~~0.5544**	**~~0.4079~~0.5544**	
Basic Gas Supply Charge ("BGS")				
~~Monthly BGSS~~	~~d~~	~~$0.5989~~	~~X~~	~~Rider A~~
BGS	d	**$0.5989**	**X**	Rider A

With the exception of the Customer Charge, these rates are on a per-therm basis.

~~Thirty-First~~Revised Sheet No. 262
BPU No. ~~11~~12 - Gas *~~Superseding Twenty-Ninth Revised~~Original Sheet No. 262*

SUMMARY OF INTERRUPTIBLE RATE COMPONENTS

Customer Charge, DEL rate and BGS rate are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

~~Thirty-First~~Revised ~~Sheet No. 263~~

BPU No. ~~11~~12 - Gas *~~Superseding Thirtieth~~Original Revised Sheet No. 263*

SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Compressed Natural Gas (CNG)

		Bundled Sales	Transport	Reference
Customer Charge				
Customer Charge per meter per month		~~104.00~~142.50	~~104.00~~142.50	
Delivery Charge ("DEL") per therm				
Pre-tax Base Rate		~~0.2683~~0.3624	~~0.2683~~0.3624	
IIP Pre-tax Base Rate		0.0051	0.0051	Rider H~~D~~
CNG Charge		~~0.20000~~0.2626	~~0.20000~~0.2626	
Total Pre-tax Base Rate		~~0.4734~~0.6301	~~0.4734~~0.6301	~~Rider D~~
SUT		~~0.0314~~0.0417	~~0.0314~~0.0417	Rider B
After-tax Base Rate		~~0.5048~~0.6718	~~0.5048~~0.6718	
EE		0.0494	0.0494	Rider G~~F~~
Subtotal	a	*~~0.5542~~0.7212*	*~~0.5542~~0.7212*	
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245	0.0245	Rider E
RA		0.0228	0.0228	Rider D~~C~~
USF		0.0177	0.0177	Rider F~~H~~
Total SBC	b	*0.0650*	*0.0650*	Rider C
Delivery Charge (DEL)	a+b=c	**~~0.6192~~0.7862**	**~~0.6192~~0.7862**	
Basic Gas Supply Charge ("BGS")				
~~Monthly BGSS~~	~~d~~	~~$0.5989~~	~~X~~	~~Rider A~~
BGS	d	**$0.5989**	**X**	Rider A

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SUMMARY OF FIRM COMMERCIAL RATE COMPONENTS

Compressed Natural Gas (CNG)

With the exception of the Customer Charge, these rates are on a per-therm basis.

Total Customer, DEL, and BGSS charges are presented on customer bills.

NEW JERSEY NATURAL GAS COMPANY

BPU No. ~~11~~12 - Gas *~~Superseding Thirtieth Revised~~Original Sheet No. 264*

~~Thirty-First Revised Sheet No. 264~~

SUMMARY OF RESIDENTIAL AND FIRM COMMERCIAL RATE COMPONENTS

Natural Gas Vehicles (NGV)

Gas Available at Company Facilities

				Reference
Delivery Charge ("DEL")		$ per therm	$ per GGE	
Pre-tax Base Rate		~~0.2683~~0.3624		
IIP Pre-tax Base Rate		0.0051		Rider H~~D~~
Total Pre-tax Base Rate		~~0.2734~~0.3675		
SUT		~~0.0181~~0.0243		Rider B
After-tax Base Rate		~~0.2915~~0.3918		
EE		0.0494		Rider G~~F~~
Subtotal	a	*~~0.3409~~0.4412*		
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245		Rider E
RA		0.0228		Rider D~~C~~
USF		0.0177		Rider F~~H~~
Total SBC	b	*0.0650*		Rider C
Delivery Charge (DEL)	a+b=c	**~~0.4059~~0.5062**	**~~0.507~~0.633**	
Compression Charge	d	**0.4958**	**0.620**	
~~Monthly~~ Basic Gas Supply Charge ("BGS")	e	**0.5989**	**0.749**	Rider A
Total Variable Charge	c+d+e=f	**~~1.5006~~1.6009**	**~~1.876~~2.002**	
New Jersey Motor Vehicle Fuel Tax	g		**0.000**	
Federal Excise Fuel Tax *	h		**0.185**	

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NEW JERSEY NATURAL GAS COMPANY

~~Thirty-First Revised Sheet No. 264~~

BPU No. ~~11~~12 - Gas *~~Superseding Thirtieth Revised~~Original Sheet No. 264*

SUMMARY OF RESIDENTIAL AND FIRM COMMERCIAL RATE COMPONENTS

Natural Gas Vehicles (NGV)

Federal Excise Fuel Tax Credit *	i	**(0.517)**
Total Price	f+g+h+i =j	~~1.544~~1.670

*Adjusted to reflect Internal Revenue Service GGE Conversion.

SUMMARY OF RESIDENTIAL AND FIRM COMMERCIAL RATE COMPONENTS

Natural Gas Vehicles (NGV)

Customer Owned Facilities

				Reference
Customer Charge				
Residential Customer Charge per month		~~11.00~~15.00		
Commercial Customer Charge per meter per month		~~104.00~~142.50		
Delivery Charge ("DEL")		$ per therm	$ per GGE	
Pre-tax Base Rate		~~0.2683~~0.3624		
IIP Pre-tax Base Rate		0.0051		Rider H~~D~~
Total Pre-tax Base Rate		~~0.2734~~0.3675		
SUT		~~0.0181~~0.0243		Rider B
After-tax Base Rate		~~0.2915~~0.3918		
EE		0.0494		Rider G~~F~~
Subtotal	a	~~0.3409~~0.4412		
Societal Benefits Charge ("SBC"):				
NJ's Clean Energy		0.0245		Rider E
RA		0.0228		Rider D~~C~~
USF		0.0177		Rider F~~H~~
Total SBC	b	*0.0650*		Rider C
Delivery Charge (DEL)	a+b=c	**~~0.4059~~0.5062**	**~~0.507~~0.633**	
~~Monthly~~ Basic Gas Supply Charge ("BGS")	d	**0.5989**	**0.749**	Rider A
Total Variable Charge	c+d=e	**~~1.0048~~1.1051**	**~~1.256~~1.382**	

Customer, DEL, and BGS charges are presented on customer bills for Firm Sales Gas Service.

NEW JERSEY NATURAL GAS COMPANY

~~Thirty-First Revised Sheet No. 265~~

BPU No. ~~11~~12 - Gas *~~Superseding Thirtieth Revised~~Original Sheet No. 265*

SUMMARY OF RESIDENTIAL AND FIRM COMMERCIAL RATE COMPONENTS

Natural Gas Vehicles (NGV)

Customer and DEL charges are presented on customer bills for Firm Transport Gas Service

NEW JERSEY NATURAL GAS COMPANY

Summary of Proposed Tariff Changes

New Jersey Natural Gas Company Tariff – BPU No. 11 Gas is being replaced by New Jersey Natural Gas Company Tariff – BPU No. 12 Gas which includes modifications to various Tariff sheets. Many of these changes represent minor changes in language to provide clarifications and necessary updates. Descriptions of the significant changes to the Tariff are presented in the following sections:

I. List of Communities Served
II. Standard Terms and Conditions
III. Service Classification Electric Generation Service ("EGS")
IV. Service Classification Third Party Supplier Requirements ("TPS")
V. Riders

I. List of Communities Served

- Adding Byram Township to reflect its partial franchise.

II. Standard Terms and Conditions

- *Paragraph 8.7 Equal Payment Plan (Sheet No. 28)*
    - Addition of language to describe the Equal Payment Plan available to customers.
- *Paragraph 8.9 Payment Obligation (Sheet No. 28)*
    - Changing bills to be payable within fifteen (15) days to twenty (20) days in accordance with N.J.A.C. 14:3-3A.3.
    - Changing the notice of discontinuance issuance after the expiration of the 15 day period to 20 day period in accordance with N.J.A.C. 14:3-3A.3.
    - Changing the minimum arrearage for discontinuance of service for nonpayment from $100.00 to $200.00 in accordance with N.J.A.C. 14:3-3A.2.
- *Paragraph 9.2 Customer Acts or Omissions (Sheet No. 30)*
    - Changing the N.J.A.C. reference for nonpayment of any bill to N.J.A.C. 14:3-3A.2 to match the reference included in N.J.A.C. 14:3-3A.1(a)3.

III. Service Classification Electric Generation Service ("EGS")

- Adding language for the addition of Off-Peak firm service available May 15 through September 15 and an associated demand charge (Sheet No. 69).

IV. Service Classification Third Party Supplier ("TPS")

The Company is proposing the following changes to Service Classification TPS.

- *FT, DGC-FT, CNG, NGV Commercial, and IS Service (Sheet No. 90)*
    - Changing the number of days for a TPS whose account is out of balance by more than 30 percent to initiate corrective action from 5 days to 3 days to require the TPS to address the issue in a timelier manner.

- *RS, GSS, GSL, DGC-Balancing, and NGV Residential (Sheet No. 91)*
    - Changing the amount of a TPS' cumulative under-delivery imbalance during a period of non-payment that warrants the Company to notify the TPS from exceed three (3) times the Daily Delivery Volume to be at least three (3) times the Daily Delivery Volume to address the TPS' under-delivery issue in a timelier manner.
    - Changing the amount of a TPS' cumulative under-delivery imbalance during a period of non-payment that requires the TPS to post and maintain a deposit or letter of credit from exceed five (5) times the Daily Delivery Volume to be at least 5 times the Daily Delivery Volume to address the TPS' under-delivery issue in a timelier manner.

- *Unauthorized Use Charge (Sheet No. 96)*
    - Modifying the Unauthorized Use Charge description to clarify the determination of the charge and be consistent with the language for Delivery Shortfall Charge on Sheet No. 96.

- *Nominations (Sheet No. 98)*
    - Deleting the name of the supplier as required information for nominations as it is not a required field in NJNG's Electronic Bulletin Board (EBB).

- *Payment (Sheet No. 98)*
    - Additional language to clarify that the Company may net all amounts due or owed by the TPS and the Company in the TPS bills .

V. Riders

- *Rider "C" Societal Benefits Charge – SBC*
    - Addition of the SBC as a rider to define its components.
- *Riders "D" through "H"*
    - Riders "D" through "H" have been reordered so that the SBC related riders follow the new Rider "C". Only page number changes and language changes are shown in redline.
- *Rider "H" (current Rider "D") Infrastructure Investment Program – IIP*
    - Additional language to include a description of the IIP Earnings Test (Sheet No. 175).
- *Rider "I" Conservation Incentive Program - CIP*
    - Revisions to the baseline use per customer for each class based on test year billing determinants, the margin factors based on the base rates, the large customer adjustment based on the GSL baseline use per customer, and weather consumption factors based on test year billing determinants (Sheet Nos. 177-179).
    - Modifying the CIP Earnings Test calculation description to be similar to the IIP Earnings Test (Sheet Nos. 176, 180).

New Jersey Natural Gas Company
Calculation of Balancing Charge

	$000
Balancing Charge related to Inventory[1]	
12 month Average inventory balance (TETCO and Steckman Ridge storages and LNG)	$18,530
Rate of Return	9.83%
Storage Carrying Costs	$1,822
% of Peak Related to Balancing	54.3%
Balancing	$990
Annual Firm Therms (excluding FT) (000)	693,173
Pre-tax Balancing Charge	$0.0014
Balancing Charge related to Demand Charges[2]	
Pipeline Demand Charges	202,905
Adjustments (BGSS Incentive Credits)	($52,617)
Total	$150,288
% of Peak Related to Balancing	54.3%
Balancing	$81,668
Annual Firm Therms (000)	693,173
Pre-tax Balancing Charge	$0.1178
Total Balancing Charge	
Pre-tax Balancing Charge related to Inventory	$0.0014
Pre-tax Balancing Charge related to Demand Charges	$0.1178
Total Pre-tax Balancing Charge	$0.1192
Total After-tax Balancing Charge	**$0.1271**
Current After-tax Balancing Charge	$0.1266
Increase/(Decrease) to After-tax Balancing Charge	$0.0005
Calculation of % of Peak Related to Balancing	
	000 therms
Peak Day Therms	9,650
Average Therms on a January Day	4,406
Balancing Therms	5,244
% of Peak	54.3%

[1] In accordance with the Board's November 17, 2021 Order in BPU Docket No. GR21030679 ("Rate Case Order"), the Balancing Charge related to Inventory is updated in a base rate case. The % of Peak Related to Balancing and the Total Firm Therms reflects the amounts included in the Company's 2024 BGSS filing approved by in the Board's September 18, 2023 Order in BPU Docket No. GR23060348. The % of Peak Related to Balancing and the Total Firm Therms will be updated in the 12+0 to reflect the amounts included in the Company's 2025 BGSS filing to be submitted by June 1, 2024.The inventory balance will also be updated in the Company's 12+0 filing.

[2] The Balancing Charge related to Demand Charges is updated in the Company's annual BGSS filing and the above component was approved in the Board's September 18, 2023 Order in BPU Docket No. GR23060348. The Balancing Charge related to Demand Charges will be updated in the 12+0 to reflect the amounts included in the Company's 2025 BGSS filing to be submitted by June 1, 2024.

Storage and LNG balances

		TETCO SS		
		Storage Dth	Storage $	Storage $/Dth
Jul-23	a	966,103	3,167,410	3.279
Aug-23	a	889,107	2,917,192	3.281
Sep-23	a	1,445,437	4,596,626	3.180
Oct-23	a	2,085,915	6,377,052	3.057
Nov-23	a	1,854,967	5,676,630	3.060
Dec-23	e	1,787,146	5,469,083	3.060
Jan-24	e	1,231,347	3,768,209	3.060
Feb-24	e	711,406	2,177,068	3.060
Mar-24	e	175,109	535,873	3.060
Apr-24	e	466,330	1,147,107	2.460
May-24	e	757,552	1,782,999	2.354
Jun-24	e	1,048,774	2,434,698	2.321

		TETCO SS-1		
		Storage Dth	Storage $	Storage $/Dth
Jul-23	a	2,567,561	7,424,902	2.892
Aug-23	a	2,881,313	8,728,612	3.029
Sep-23	a	3,460,264	10,476,877	3.028
Oct-23	a	3,841,564	11,541,216	3.004
Nov-23	a	3,795,464	11,411,394	3.007
Dec-23	e	3,324,103	9,994,207	3.007
Jan-24	e	2,303,402	6,925,381	3.007
Feb-24	e	1,318,984	3,965,639	3.007
Mar-24	e	332,365	999,284	3.007
Apr-24	e	879,749	2,148,168	2.442
May-24	e	1,427,133	3,343,398	2.343
Jun-24	e	1,974,517	4,568,338	2.314

		Steckman Ridge		
		Storage Dth	Storage $	Storage $/Dth
Jul-23	a	1,657,587	5,162,499	3.114
Aug-23	a	2,051,767	6,806,641	3.317
Sep-23	a	2,583,267	8,418,418	3.259
Oct-23	a	2,896,267	9,296,288	3.210
Nov-23	a	2,582,767	8,295,049	3.212
Dec-23	e	1,862,667	5,982,310	3.212
Jan-24	e	925,967	2,973,920	3.212
Feb-24	e	370,407	1,189,633	3.212
Mar-24	e	141,457	454,316	3.212
Apr-24	e	549,820	1,311,414	2.385
May-24	e	958,184	2,203,088	2.299
Jun-24	e	1,366,547	3,116,927	2.281

		LNG Dth	LNG $	LNG $/Dth
Jul-23	a	886,442	4,842,444	5.463
Aug-23	a	866,265	4,845,503	5.594
Sep-23	a	851,329	4,818,678	5.660
Oct-23	a	983,683	5,230,158	5.317
Nov-23	a	963,115	5,193,641	5.393
Dec-23	e	885,115	4,773,022	5.393
Jan-24	e	635,115	3,424,886	5.393
Feb-24	e	495,915	2,674,244	5.393
Mar-24	e	478,915	2,582,571	5.393
Apr-24	e	461,915	2,490,897	5.393
May-24	e	444,915	2,399,224	5.393
Jun-24	e	426,915	2,302,158	5.393

		Total Dth	Total $	Total $/Dth
Jul-23	a	6,077,693	20,597,255	3.389
Aug-23	a	6,688,452	23,297,947	3.483
Sep-23	a	8,340,297	28,310,599	3.394
Oct-23	a	9,807,429	32,444,714	3.308
Nov-23	a	9,196,313	30,576,713	3.325
Dec-23	e	7,859,032	26,218,623	3.336
Jan-24	e	5,095,832	17,092,395	3.354
Feb-24	e	2,896,712	10,006,583	3.454
Mar-24	e	1,127,845	4,572,044	4.054
Apr-24	e	2,357,815	7,097,586	3.010
May-24	e	3,587,784	9,728,709	2.712
Jun-24	e	4,816,753	12,422,121	2.579
12 month average		5,654,330	18,530,441	3.277

New Jersey Natural Gas Company
Net impact of Proposed Rate Changes

Impact on Residential Non-Heating Customers

			25 therm bill
1/1/24 Rates			
Customer Charge	$11.00		$11.00
Delivery	$0.8967		$22.42
BGSS	$0.4290		$10.73
Total	$1.3257		$44.15
Proposed Rates			
Customer Charge	$15.00		$15.00
Delivery	$1.2052		$30.13
BGSS	$0.4290		$10.73
Total	$1.6342		$55.86
Increase			$11.71
Increase as a percent			26.5%

Impact on Residential Heating Customers

		100 therm bill	1000 therm annual bill
1/1/24 Rates			
Customer Charge	$11.00	$11.00	$132.00
Delivery	$0.9500	$95.00	$950.00
BGSS	$0.4290	$42.90	$429.00
Total	$1.3790	$148.90	$1,511.00
Proposed Rates			
Customer Charge	$15.00	$15.00	$180.00
Delivery	$1.2585	$125.85	$1,258.50
BGSS	$0.4290	$42.90	$429.00
Total	$1.6875	$183.75	$1,867.50
Increase		$34.85	$356.50
Increase as a percent		23.4%	23.6%

Impact on Commercial GSS Customers

		100 therm bill
1/1/24 Rates		
Customer Charge	$42.00	$42.00
Delivery	$0.8409	$84.09
BGSS	$0.4290	$42.90
Total	$1.2699	$168.99
Proposed Rates		
Customer Charge	$57.50	$57.50
Delivery	$1.1391	$113.91
BGSS	$0.4290	$42.90
Total	$1.5681	$214.31
Increase		$45.32
Increase as a percent		26.8%

Impact on Commercial GSL Customers

		1200 therm bill
1/1/24 Rates		
Customer Charge	$104.00	$104.00
Demand Charge	$3.41	$327.36
Delivery	$0.6192	$743.04
BGSS (January 2024)	$0.4723	$566.76
Total	$1.0915	$1,741.16
Proposed Rates		
Customer Charge	$142.50	$142.50
Demand Charge	$4.50	$432.00
Delivery	$0.7364	$883.68
BGSS (January 2024)	$0.4718	$566.16
Total	$1.2082	$2,024.34
Increase		$283.18
Increase as a percent		16.3%

Exhibit P-10

NEW JERSEY NATURAL GAS COMPANY

DIRECT TESTIMONY
OF
MARISSA TRAVALINE
VICE PRESIDENT, CUSTOMER SERVICE, MARKETING & ENERGY EFFICIENCY

I. INTRODUCTION AND BACKGROUND

Q. Please state your name, affiliation and business address.

A. My name is Marissa Travaline and I am the Vice President, Customer Service, Marketing & Energy Efficiency for New Jersey Natural Gas Company ("NJNG" or the "Company"). My business address is 1415 Wyckoff Road, Wall, New Jersey 07719.

Q. Please describe your education and experience.

A. I received a Bachelor of Arts degree in Political Science from The College of New Jersey in 2001, followed by a Master of Arts in Communications, with a focus on Public Relations, from Rowan University. In January 2005, I joined South Jersey Industries ("SJI") as a Legislative Policy Analyst. My role developed over the next seven (7) years to include responsibility for federal and local government affairs, corporate social investment, stakeholder relations, and corporate communications. In 2012, I was promoted to Director, Investor Relations and served for five (5) years as SJI's primary institutional investor contact, with responsibility for all investor communications, including SEC-required regulatory communications and filings, as well as for the shareholder services organization. In 2018, I was promoted to Vice President, Corporate Communications and added strategic and operational leadership of utility customer service in 2019. At the time I exited SJI in 2023, I was responsible for operations in support of approximately 715,000

customers and nearly 200 employees.

I joined NJNG in October 2023 as Vice President, Customer Service, Marketing & Energy Efficiency. In this role, I provide strategic leadership and operational oversight of the Company's customer service operations and initiatives, including the sales and marketing organizations, and its energy efficiency and decarbonization efforts via the SAVEGREEN initiative.

Q. Please summarize the purpose of your Direct Testimony.

A. In this rate case, I am serving as the Company's witness regarding customer service operations. My Direct Testimony addresses multiple areas of service and outreach to NJNG's customers.

II. CUSTOMER SERVICE METRICS AND REPORTING

Q. Does the Company track data regarding the performance of its customer service operations?

A. Yes. The Company tracks a number of metrics to assess the efficiency, prudency, and success of its customer service operations. Those metrics are evaluated cross the following key areas: 1) Call Center; 2) Meter Reading and Billing Integrity; 3) Safety and Reliability; and 4) Overall Customer Service and Satisfaction. Using multiple measures that span each of these areas provides a more comprehensive view of our customers' experiences and preferences so that we can work to best tailor our operations to customer needs and expectations.

Q. Does the Company provide this data to the New Jersey Board of Public Utilities ("BPU" or "Board") and the Division of Rate Counsel ("Rate Counsel")?

A. Yes. The Company submits the following metrics to the Staff of the BPU ("Staff") and

Rate Counsel on a quarterly or annual basis pursuant to the stipulation of settlement in its prior base rate case in BPU Docket Nos. GR21030679, GR21030680 and OAL Docket Nos. PUC 04111-21 and PUC 04113-21:

1. Call Center

A) Percentage of calls answered within 30 seconds

- Measure: Service Level
- Benchmark: 82% of calls answered within 30 seconds
- Definition: The percentage of customer contacts by phone requiring 30 seconds or less to be addressed from the time they enter the queue, whether through the Interactive Voice Response ("IVR") automated system or by a representative.
- Measured weekly, reported quarterly.

B) Abandoned Call Percentage ("ACP")

- Measure: ACP
- Benchmark: 5% or fewer calls abandoned
- Definition: The number of calls that reach the IVR system but are terminated by the caller before reaching a selected destination.
- Measured weekly, reported quarterly.

C) Average Speed of Answer ("ASA")

- Measure: ASA
- Benchmark: 30 seconds or less
- Definition: The number of seconds elapsed from the time a customer indicates the desire to speak to a representative to when the representative answers the call.
- Measured weekly, reported quarterly.

2. Meter Reading and Billing Integrity

A) Meter Reading

- Measure: Percentage of meters read
- Benchmark: 95% of meters read each month and year-to-date
- Definition: The percentage of all meters read prior to billing within the territory.

B) Meters Read by Town

- Measure: Percentage of meters read listed by town within the territory
- Benchmark: Track and monitor data point only
- Definition: The percentage of all meters read prior to billing, listed by town, within the territory.
- Measured and reported annually.

C) Billing Accuracy

- Measure: Number of rebills
- Benchmark: 20 or fewer bills per 1,000 customers
- Definition: The number of accounts requiring revised, cancelled or adjusted bills, per 1,000 customers, after bill is mailed.
- Measured monthly, reported quarterly.

3. Safety and Reliability

A) Safety

- Measure: Leak response Time
- Benchmark: 95% of leak calls responded to within 60 minutes
- Definition: Leak, odor and emergency call response measured from the initial customer call to the time qualified personnel arrive at the location to either assess or implement a "make safe" condition.
- Regular reporting measured weekly, reported quarterly. Exception Reporting measured upon occurrence, reported for all leak, odor and

emergency calls not responded to within 60 minutes, stating the reason(s) for the delay.

B) Reliability

- Measure: Percentage of service appointments met
- Benchmark: 99.9% of service appointments met
- Definition: The percentage of appointments completed on the day scheduled. Includes appointments for meter installations, disconnects and reconnects, billing investigations, initial and final meter reads. Excludes regularly scheduled meter reads, gas leaks/emergencies/outages and appointments missed by the customer.
- Measured weekly, reported quarterly

4. Overall Customer Satisfaction

A) BPU Complaints

- Measure: Customer complaints/contacts to the BPU
- Benchmark: Less than 1 complaint/contact per 1,000 customers annually
- Definition: The number of verbal or written complaints/contacts made to the BPU, not including complaints to the Company, which are measured as an annual average number of complaints per 1000 customers. The Company also shall report BPU complaints by root cause category, such as billing, collection, etc.
- Measured monthly, reported quarterly

B) Customer Satisfaction

- Measure: Customer satisfaction based on post-transaction surveys
- Benchmark: 89%
- Definition: The weighted percentage of responses on an 11-point scale indicating positive rating of "overall satisfaction with NJNG" around their transaction.
- Measured weekly, reported quarterly

III. CONCLUSION

Q. Does this conclude your Direct Testimony at this time?

A. Yes. However, I reserve the right to supplement this Direct Testimony as needed during this proceeding.