STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF SOUTH JERSEY GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS	: : : : : :	**PETITION** **BPU DOCKET NO.**

CASE SUMMARY, PETITION, NOTICE AND EXHIBITS

Volume 3 of 3

Deborah M. Franco, Esq.
Director, Regulatory Affairs Counsel
SJI Utilities, Inc.
520 Green Lane
Union, New Jersey 07083

Kenneth T. Maloney, Esq.
Cullen and Dykman, LLP
1101 14th Street, N.W.
Suite 750
Washington, D.C. 20005

Attorney for Petitioner
South Jersey Gas Company

March 13, 2020

INSERT TAB:

A. FELSENTHAL

IN THE MATTER OF THE PETITION OF SOUTH JERSEY GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR20________

DIRECT TESTIMONY

OF

ALAN D. FELSENTHAL

PricewaterhouseCoopers LLP

On Behalf of
South Jersey Gas Company

Exhibit P-9

March 13, 2020

TABLE OF CONTENTS

Exhibit P-9

SOUTH JERSEY GAS COMPANY
DIRECT TESTIMONY OF
ALAN D. FELSENTHAL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, OCCUPATION AND EMPLOYER.

A. My name is Alan Felsenthal. My business address is One North Wacker Drive, Chicago, Illinois, 60606. I am a Managing Director at PricewaterhouseCoopers LLP ("PwC").

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?[1]

A. I am submitting this testimony on behalf of South Jersey Gas Company ("South Jersey Gas," "SJG," or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from the University of Illinois in 1971 and began my career at Arthur Andersen & Co ("Arthur Andersen"), where I was an auditor, and focused on audits of financial statements of regulated entities. In 2002, I joined PwC and became a Managing Director in their Power and Utilities Group and continued performing audits for regulated entities. I was hired by Huron Consulting Group ("Huron") in 2008 and returned to PwC in November of 2010. At both Arthur Andersen and PwC, I supervised audits of financial statements on which the

[1] This testimony was prepared in connection with the current South Jersey Gas Company rate case and for the use and benefit of South Jersey Gas. PwC disclaims any contractual or other responsibility to others based on their access to or use of this rebuttal testimony and the information contained herein.

firms issued audit opinions that were filed with the Securities and Exchange Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission ("FERC") and various state commissions. At Arthur Andersen, PwC and Huron, I consulted on a significant number of utility rate cases and helped develop testimony for myself and others on a variety of issues, including construction work in progress in rate base, projected test years, lead-lag studies, cost allocation, various accounting issues (*e.g.*, pension accounting, regulatory accounting, income tax accounting, cost of removal) and compliance with the income tax normalization requirements. I developed and presented utility accounting seminars focusing on the unique aspects of the regulatory process and the resulting accounting consequences of the application of Generally Accepted Accounting Principles ("GAAP"). I have also conducted these seminars in-house for the FERC, several state commissions and I have presented at various Edison Electric Institute and American Gas Association ratemaking and accounting seminars.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AT PWC.

A. I am currently a member of the firm's Complex Accounting and Regulatory Solutions ("CARS") practice. Throughout my career, my focus has been on the regulated industry sector, primarily electric, gas, telecommunications and water utilities. I have focused on utility accounting, income tax and regulatory issues, primarily as a result of auditing regulated enterprises. The unique accounting standards applicable to regulated entities embodied in Accounting Standards Codification ("ASC") 980, Regulated Operations (formerly, Statement of

Financial Accounting Standards ("SFAS") 71, FAS 90, FAS 92, FAS 101 and various Emerging Issues Task Force ("EITF") issues, all need to be understood so that auditors can determine whether a company's financial statements are fairly presented in accordance with GAAP. I have witnessed the issuance of these standards and have consulted with utilities as to how they should be applied. At both Arthur Andersen and PwC, I worked with the technical industry, accounting and auditing leadership to communicate and consult on utility accounting and audit matters. My curriculum vitae is attached as Schedule ADF-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("BOARD") OR ANY OTHER REGULATORY COMMISSION?

A. Yes. I have testified before the Board as well as the Arizona Corporation Commission, the Florida Public Service Commission, the Hawaii Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Maine Public Utilities Commission, the Public Utility Commission of Ohio, the Public Utility Commission of Texas, the Public Service Commission of Utah, the Washington Utilities and Transportation Commission and FERC. Schedule ADF-1 lists the various issues and testimony I have presented as well as the jurisdiction.

Q. HAVE YOU PROVIDED TRAINING ON THE APPLICATION OF GAAP TO REGULATED ENTERPRISES?

A. Yes. At Arthur Andersen, Huron and PwC, I developed and taught utility accounting seminars focusing on the unique aspects of the regulatory process and the resulting accounting consequences of the application of GAAP. I have presented seminars, as well as delivered training on an in-house basis. Seminar participants have included utility company and regulatory commission staff accountants, utility rate departments and internal auditors, tax accountants and others. I have also conducted these seminars for FERC and several state commissions, and I have presented at various Edison Electric Institute and American Gas Association ratemaking and accounting seminars. The income tax training programs I have presented include topics such as the normalization requirements for public utilities in the Internal Revenue Code ("IRC"), protected and unprotected deferred taxes and the mechanics and application of the Average Rate Assumption Method ("ARAM").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses certain income tax amounts included in the rate case filing of South Jersey Gas, specifically 1) the calculation of the Consolidated Tax Adjustment ("CTA"), which, in this filing, is zero; 2) the amount of excess accumulated deferred income taxes ("Excess ADIT") reversing in the test period as well as the balance of the net excess ADIT regulatory liability that reduces the Company's rate base.

Q. ARE YOU SPONSORING ANY SCHEDULES AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I am supporting the following schedules that were prepared by me or under my supervision or direction:

- Schedule ADF-1: Curriculum Vitae;
- Schedule ADF-2: Determination of CTA for the test period – Confidential;
- Schedule ADF-3: Calculation of excess ADIT test period reversal and the associated ADIT regulatory liability at end of test period; and
- Schedule ADF-4: Illustrative example of ARAM.

Q. WHERE DID YOU OBTAIN THE INFORMATION USED IN THE PREPARATION OF YOUR SCHEDULES ADF-2 AND ADF-3?

A. The primary sources of the data included in Schedules ADF-2 and ADF-3 were the Company's books and records. For determining the CTA, I used certain income tax return information of the Company, its affiliates and parent. For determining the excess ADIT Liability and excess ADIT Net Operating Loss ("NOL") Asset, I used information from the Company's Power Tax software application.

Q. WHAT TEST PERIOD IS BEING USED IN SJG'S FILING IN THIS PROCEEDING?

A. The test year period for this proceeding is the twelve months beginning July 1, 2019 and ending June 30, 2020.

III. INCOME TAX ACCOUNTING AND RATEMAKING FUNDAMENTALS

Q. PLEASE DESCRIBE THE ACCOUNTING FOR INCOME TAXES UNDER GAAP?

A. Accounting for income taxes under GAAP is addressed in the accounting literature in section ASC 740 (formerly SFAS No. 109, Accounting for Income Taxes (SFAS 109)) of the accounting codification. There are several components to the calculation: currently payable income taxes; deferred income taxes; and investment tax credits. My testimony will only focus on the first two components as investment tax credits are not an issue in this proceeding. Also, my descriptions will focus on federal currently payable income taxes and federal deferred income taxes, although the same basic explanation would also be applicable for relevant state income taxing regimes.

Q. PLEASE DESCRIBE THE FIRST COMPONENT, CURRENTLY PAYABLE INCOME TAXES.

A. Currently payable income tax expense represents the estimated amount of current year income taxes payable to the U.S. Treasury based on current year taxable income, determined in accordance with the IRC. For purposes of preparing an income tax return each year, the IRC contains guidance for determining if and when an item is "taxable" or "deductible."

Q. ARE THE TAXABLE OR DEDUCTIBLE AMOUNTS UNDER THE IRC FOR DETERMINING IRC TAXABLE INCOME THE SAME AS THOSE USED IN DETERMINING REVENUE OR EXPENSE UNDER GAAP?

A. No, not always. The IRC rules for determining what is taxable or deductible may differ from what is reportable as "revenue," "income" or "expense" under GAAP. For instance, certain expenses recorded on the financial statements under GAAP in one year may be deductible on the tax return in a different accounting period. There are also instances where the amounts shown as deductions on the tax return in one year are not reflected on the financial statements until a later year. As a result, at the end of each reporting period, there will likely be accumulated differences on the book and income tax balance sheets of reported assets and liabilities resulting from different book treatment and tax return treatment of revenues, income and expenses. These differences are referred to as timing or temporary differences.

Q. CAN YOU FURTHER EXPLAIN WHAT IS MEANT BY A TIMING OR TEMPORARY DIFFERENCE AND PROVIDE AN EXAMPLE?

A. Yes. One common temporary difference relates to the concept of depreciation. For book purposes, when a company acquires a fixed asset, GAAP requires that the asset be depreciated over its estimated useful life in a systematic and rational manner. In so doing, the cost of the fixed asset is "allocated" to the periods in which the fixed asset is being used to provide service. Most utilities depreciate their fixed assets for book purposes using the straight-line depreciation method, wherein the same depreciation amount is recorded each year of a fixed asset's estimated useful life.

In contrast to the straight-line depreciation method used for determining depreciation expense under GAAP, an accelerated depreciation method is commonly used for income tax purposes. Under an accelerated depreciation approach, that same fixed asset may be depreciated on the income tax return using an accelerated method (more than a straight-line method) and/or different (generally shorter) estimated useful life. When the annual depreciation charge for book purposes is compared to the annual depreciation for income tax purposes, there will likely be differences. In the early years of an asset's life, tax depreciation using an accelerated method and/or shorter lives will be greater than book depreciation which is computed under a straight-line approach. In the later years, the reverse will be true because given the same capitalized asset cost, the cumulative tax and book depreciation amounts over the entire life of the asset must equal. The sum of the annual book-tax depreciation differences results in accumulated book-tax depreciation differences when comparing the net book value and net tax value of fixed assets.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE DEPRECIATION BOOK TAX DIFFERENCE ARISES AND REVERSES?

A. Yes. Assume a utility acquires property, plant and equipment for $10 million cash. The entry to record the asset is to debit property, plant and equipment and to credit cash. For book purposes, assume that asset has a useful life of ten years. For income tax purposes, assume that same asset qualifies as a five-year tax depreciation asset under the Modified Accelerated Cost Recovery System ("MACRS" – an allowable approach under the IRC). Under MACRS for a five-year asset, the asset is depreciated using double declining balance, switching to straight line at the tax midpoint of its life. Thus, the depreciation deduction is 20 percent the first year, 32 percent in year two, 19.2 percent in year three, 11.52 percent in years four and five and 5.76 percent in year six. The annual depreciation charges for book and tax would be as follows:

Year	Book Depreciation	Tax Depreciation	Difference	Cumulative Book-Tax Difference
1	1,000,000	2,000,000	1,000,000	1,000,000
2	1,000,000	3,200,000	2,200,000	3,200,000
3	1,000,000	1,920,000	920,000	4,120,000
4	1,000,000	1,152,000	152,000	4,272,000
5	1,000,000	1,152,000	152,000	4,424,000
6	1,000,000	576,000	(424,000)	4,000,000
7	1,000,000		(1,000,000)	3,000,000
8	1,000,000		(1,000,000)	2,000,000
9	1,000,000		(1,000,000)	1,000,000
10	1,000,000		(1,000,000)	0
Total	10,000,000	10,000,000	0	

At the end of year 1, the net book basis of property, plant and equipment for book purposes would be \$9 million (\$10 million gross plant, less \$1 million of accumulated book depreciation) while its tax basis would be \$8 million (\$10 million gross tax basis less \$2 million of accumulated tax depreciation). Each year's book depreciation expense would reduce the net book basis of property, plant and equipment and each year's tax depreciation would affect the tax basis of property, plant and equipment. The difference between the book basis and tax basis of property, plant and equipment represents a temporary difference under ASC 740.

However, because total depreciation expense/deductions are limited to the gross capitalized cost of the property, plant and equipment, accelerated income tax depreciation claimed in the early years (reducing income tax payments) will reverse in subsequent periods when book depreciation exceeds tax depreciation (increasing income tax payments) so that when the asset is retired, the depreciation temporary difference will have completely reversed.

Q. WHAT IS THE ACCOUNTING FOR TEMPORARY DIFFERENCES UNDER ASC 740?

A. Under GAAP, because the financial statements reflect accrual, not cash basis accounting, deferred income taxes are recorded on temporary differences. As a result, income tax expense under GAAP includes both a currently payable component (as previously described, based on the tax return) as well as a "deferred" income tax component (based on timing/temporary differences). Such deferred income taxes reflect the liability or asset for income taxes payable or receivable in the future stemming from transactions recorded in the financial statements currently. The balance sheet liability or asset for future taxes is ADIT. In other words, to the extent that accelerated tax depreciation is claimed on the income tax return in an amount that exceeds book depreciation reported on the financial statements (reducing the current year's taxable income and tax obligation), a liability for future taxes results. The future tax liability will be "paid" in later years when book depreciation exceeds income tax deductible tax depreciation.

Under ASC 740, a calculation of required ADIT is performed at the end of each annual reporting period. The required ADIT is measured by multiplying the temporary differences by the currently applicable income tax rates. The difference obtained by comparing the ADIT at the current balance sheet date to the ADIT at the previous balance sheet date results in "deferred income tax expense." For regulated entities, such as SJG, the process of recording deferred income taxes on temporary differences is referred to as "normalization," "deferred tax accounting," or "comprehensive interperiod income tax allocation."

Q. PLEASE EXPLAIN HOW CURRENT AND DEFERRED INCOME TAXES WOULD BE RECORDED ON THE FINANCIAL STATEMENTS FOR THE DEPRECIATION DIFFERENCE EXAMPLE YOU DISCUSSED PREVIOUSLY.

A. In year 1 of the example, the Company would record depreciation expense on the books in accordance with GAAP of $1 million. In that same year, they would reduce taxable income on the income tax return by tax depreciation of $2 million. Assuming a 21 percent income tax rate, by claiming a $2 million depreciation deduction, **current** taxes payable and **current** tax expense would be reduced by $420,000 (21 percent income tax rate times the $2 million tax depreciation deduction).

However, by claiming an additional $1 million of tax depreciation ($2 million tax depreciation compared to $1 million of book depreciation) the Company will also record a deferred income tax liability and deferred tax expense of $210,000 (21 percent income tax rate times book/tax difference of $1 million). The deferred tax will become payable when the book depreciation exceeds tax depreciation. In other words, by claiming accelerated depreciation (compared to straight line book depreciation) in years 1-5, the Company has incurred a deferred tax obligation that will become payable in years 6-10.

Thus, a timing or temporary difference that reduces current income tax expense and current taxes payable is offset by an equal increase in deferred tax expense and ADIT. When the timing or temporary difference reverses, current income tax expense and current taxes payable will increase and be offset by a decrease in deferred income tax expense and ADIT.

Q. HOW ARE DEFERRED INCOME TAXES TREATED IN THE RATEMAKING PROCESS?

A. In the ratemaking process, revenue requirements are unaffected by such timing or temporary differences (from the expense side) as the reduction (or increase) in current tax expense is offset by an equal and offsetting increase (or reduction) of deferred tax expense. In this manner, it should be noted that utility customers do not pay deferred income taxes (offsetting current and deferred expense amounts). Instead, the source of such deferred income taxes is the U.S. Treasury. As a result, ADIT balances are often characterized as an "interest free loan" from the U.S. Treasury. This was the objective Congress intended when it enacted accelerated depreciation in the IRC. Congress believed that allowing companies to increase their tax depreciation deductions (and thereby reduce current income tax payments), would lower the financing costs of their investment in capital assets and thus companies would be incented to make such expenditures.

Q. DOES THE IRC PROVIDE GUIDANCE ON HOW BOOK-TAX DIFFERENCES SHOULD BE TREATED IN THE UTILITY RATEMAKING PROCESS?

A. Yes. To ensure that regulated utilities enjoy the benefits intended by Congress, there are separate rules applicable to depreciation differences resulting from using tax methods and tax lives to determine deductible tax depreciation versus using book methods and lives to determine book depreciation on public utility property. These depreciation-related method and life timing/temporary differences are referred to as "protected differences" (protected by the IRC) in that the IRC governs how the associated deferred income taxes are to be treated in determining revenue requirements. The IRC requires that deferred income tax expense on such book-tax differences must be permitted as a recoverable expense in the ratemaking process with the related, remaining ADIT on such differences reducing rate base. Because the ADIT balance reduces rate base, the customer benefits from this procedure as the U.S. Treasury is providing funds that, in the absence of accelerated tax deductions and deferred tax accounting, would need to be obtained from other sources, such as debt and equity, which have a cost (interest or return).

To ensure compliance, if such normalization rules are not followed, the Company is prohibited from claiming accelerated depreciation for income tax purposes and, instead, can only use straight-line depreciation in determining the depreciation deduction for income tax purposes. In such a case, there is no depreciation book-tax difference and no interest-free loan. Being unable to claim accelerated depreciation is a significant penalty.

Q. YOU SAID THAT THE IRS NORMALIZATION RULES APPLY TO PROTECTED BOOK-TAX DIFFERENCES AND DEFINE PROTECTED BOOK-TAX DIFFERENCES AS PRIMARILY DUE TO DIFFERENCES BETWEEN THE BOOK AND TAX DEPRECIATION METHODS AND BETWEEN BOOK AND TAX LIVES USED IN THE CALCULATIONS. ARE THE REST OF A COMPANY'S BOOK-TAX TIMING/TEMPORARY DIFFERENCES CONSIDERED UNPROTECTED?

A. Basically, yes. The normalization rules apply to protected book-tax differences, which are primarily differences between book and tax depreciation caused by different depreciation methods (accelerated for tax, straight-line for books) and depreciation lives (different, generally shorter lives for tax purposes). There are several other book-tax differences that are also considered protected, such as the book-tax difference associated with contributions in aid of construction and the appropriate treatment of NOL Deferred Tax Assets. All other book-tax temporary/timing differences are considered unprotected and are not subject to the normalization requirements of the IRC. For example, rate case expense is deferred and amortized for book purposes, but a current income tax deduction is permitted for such expense in the year accrued.

Q. IS DEFERRED INCOME TAX ACCOUNTING APPROPRIATE FOR RATEMAKING PURPOSES?

A. Yes. Income tax expense in a given year is the result of that year's economic activity. In determining the revenue requirement, it is important for regulatory commissions to consider the recovery of all appropriate costs of providing service (return, operating expense, maintenance expense, depreciation expense, etc.) and, after such pre-tax amounts are determined, including the associated income tax effects of the permitted cost of service.

Q. FROM A RATEMAKING PERSPECTIVE, IS THERE A WAY TO COMPUTE OR CHECK THAT THE APPROPRIATE INCOME TAXES HAVE BEEN CONSIDERED IN DETERMINING THE REVENUE REQUIREMENT?

A. Yes. Federal income taxes requested by the Company and included in the revenue requirement determination should be based on pre-tax revenues, income and expenses included in the cost of service calculation. It is neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendition of utility service to customers.

Said another way, income taxes have no independent existence of their own. They are based on revenues, income and expenses. Once the Board decides on the appropriate revenues and expenses that are necessary for the provision of service, the related income taxes can be determined.

One way to check the ratemaking income tax calculation is to begin with after-tax equity return as a starting point. Under this method, equity return (rate base times the weighted cost of equity) , or total return less synchronized interest (rate base times the weighted cost of debt), is adjusted for items for which there is no tax deduction to offset amounts recovered through revenues – such as book amortization of flow-through differences (if any), permanent items, and the reversal of excess ADIT. The resulting “adjusted equity return” is then grossed-up to a revenue requirement level, multiplied by the statutory income tax rate and then adjusted for flow-through and permanent differences and the reversal of excess ADIT. This approach is used to determine Federal income tax expense in total, with no segregation between current and deferred Federal income taxes.

IV. CONSOLIDATED TAX ADJUSTMENT

Q. PLEASE EXPLAIN THE CONCEPT OF A CTA.

A. A CTA is calculated as the "benefit realized" attributable to an affiliated group's filing of a consolidated income tax return and results when the consolidated tax liability for the group is less than what the liability would have been had each member of the group calculated income taxes on a stand-alone basis. For example, consider a simple example of a consolidated group with two members, A and B, both newly formed corporations owned by a Parent entity with no taxable income of its own. If A has net taxable income of $1,000 for the tax year but B generates a net operating loss of $1,000 for such year, the consolidated group of A, B and the Parent would have no tax liability even though, on a stand-alone basis and assuming a 21 percent income tax rate, A would have had a tax liability of $210 (21 percent of $1,000) and B would have had no liability. The consolidated tax savings realized by the consolidated group is $210. However, it is clear that the $210 consolidated tax savings relates entirely to the net operating loss of Member B. In this example, Member A would record a current income tax expense of $210 and remit that amount to the Parent entity as that is the amount that relates to its taxable income. Depending on the tax sharing agreement, the Parent may either reimburse Member

B $210 for its taxable loss or retain such amount and distribute to Member B when it is able to utilize such benefit on a stand-alone basis.

Q. DOES THE BOARD HAVE RULES FOR CTAS?

A. Yes. The Board has issued rules that require that, for determining revenue requirements, CTAs are to be calculated and applied. The Board's methodology for the CTA calculation has fluctuated over the years. However, recently, the Board has adopted regulations that clarified the CTA methodology for rate case filings. The Board's regulations state that a CTA calculation shall be included in a regulatory filing if the company filing the rate case is a member of a group that files a consolidated tax return. Under the recently enacted rule, the CTA is to be calculated using each affiliate's taxable income/loss for five consecutive years (including the complete tax year within the utility's test year) using statutory income tax rates or the alternative minimum tax, whichever is applicable. The CTA calculation sums each affiliate's taxable income/taxable loss for the five- year period and separates the result into "taxable loss" and "taxable income" companies. The calculated total of taxable losses is then apportioned to the taxable income companies in proportion to each affiliate's share of the total taxable income. To the extent that a regulated affiliate has cumulative taxable income in this five-year period, the amount of taxable losses allocated to this regulated affiliate becomes the CTA. Under the recently enacted Board CTA rules, the rate base may be reduced by up to 25 percent of the full CTA.

Q. HAS SOUTH JERSEY GAS COMPUTED A CTA IN THE MANNER REQUIRED BY THE BOARD'S REGULATIONS?

A. Yes. Schedule ADF-2 (Confidential) is the CTA calculation for South Jersey Gas.

Q. PLEASE DESCRIBE THE CTA CALCULATION ON SCHEDULE ADF-2.

A. For each of the five years 2015-2019, the entities included in SJI's consolidated tax return were identified, along with their taxable income or losses each year. The cumulative taxable income or loss for each entity over this period was identified. Those entities with taxable losses were summed and then allocated to the entities with cumulative taxable income over this same period in proportion to each taxable entity's share of the cumulative taxable income. In this manner, the amount of the loss companies that is theoretically monetized (through taxable income of the income entities) is determined. Because South Jersey Gas has a cumulative taxable loss during this period, there is no CTA and no CTA adjustment to rate base.

Q. IS THE CONCEPT OF A CTA COMMON ACROSS REGULATORY JURISDICTIONS INCLUDING THE FERC?

A. No. Almost all regulatory jurisdictions, including FERC, have rejected the concept of the CTA. Almost all regulatory jurisdictions use a "stand-alone" approach for determining regulated income tax expense. Under a stand-alone methodology, federal income taxes are computed based on revenues and expenses of the Company included in the utility's revenue requirement as if the Company were a stand-alone taxpayer. This approach appropriately allocates federal income taxes among members of the consolidated group using the benefits/burdens criteria outlined by FERC in Opinion 173.[2] Under this method, federal income taxes calculated for the Company relate to and result from the revenue, income and expenses associated with providing utility service to customers. The benefits and burdens criterion refer to computing the tax consequences of transactions based on the revenue and expense transactions themselves.

With that said, in this proceeding the Company applied the CTA methodology required under the Board's regulations and determined that no CTA exists and therefore there should be no CTA reflected as a reduction to rate base.

V. <u>EXCESS ADIT AND THE TAX CUTS AND JOBS ACT OF 2017 ("TCJA")</u>

Q. PLEASE GENERALLY DESCRIBE THE TCJA.

A. The TCJA was enacted by the United States Congress on December 20, 2017 and was signed into law by the President on December 22, 2017. *See Tax Cuts and Jobs Act of 2017*, Pub. Law 115-97, 131 Stat. 2054 (2017). The TCJA amends the IRC and contains the most significant set of changes to the federal income tax laws since the Tax Reform Act of 1986. The TCJA makes major changes in many areas of our nation's tax laws, some of which directly affect regulated utilities like South Jersey Gas.

---

[2] *Columbia Gulf Transmission Co. et al.*, 23 FERC ¶ 61,396 (1983).

Q. PLEASE DESCRIBE THE PROVISIONS OF THE TCJA THAT HAVE THE GREATEST IMPACT ON REGULATED UTILITIES LIKE SJG AND THEIR CUSTOMERS.

A. The TCJA has significant, though varying, impacts on most utilities in terms of reported tax expenses charged against the company's operations, cash flows and the calculation of revenue requirements and cost of service.

The most significant provision of the TCJA for regulated utilities, including SJG, is the reduction of the Federal Income Tax Rate from 35 percent to 21 percent, which will reduce current income tax expense and originating deferred tax expense. At the previous 35 percent federal income tax rate, revenue of $1.5385 was required to provide $1.00 of after-tax income. A corporate tax rate of 21 percent requires $1.2685 of revenue to generate $1.00 of after-tax income. A separate New Jersey state income tax rate of 9 percent exists. The New Jersey state income tax rate is deductible for federal income tax purposes so the "combined federal and state income tax rate" has gone from 40.85 percent to 28.11 percent. The combined income tax gross-up factor before and after the TCJA has been reduced from 1.6906 to 1.3910, respectively.

Further, as a result of the lower 21 percent income tax rate becoming effective under the TCJA, all companies, including utilities, were required under ASC 740 to "remeasure," as of December 31, 2017, the amounts of ADIT in their financial statements. Regulated utilities reclassified the reduction in ADIT to a regulatory liability representing the excess ADIT that will be used to reduce future revenue requirements.

Q. WHAT IS "EXCESS" ADIT AND HOW IS IT CALCULATED?

A. Excess ADIT is the portion of the ADIT balance existing immediately prior to the reduction in the corporate tax rate (the ADIT balance at December 31, 2017) less the amount that would have been in the ADIT balance had that balance been determined using the revised lower corporate income tax rate.

Q. CAN YOU EXPLAIN HOW THE REDUCTION IN THE FEDERAL CORPORATE INCOME TAX RATE AFFECTED SJG'S ADIT, INCLUDING EXCESS ADIT?

A. Yes. The Company calculated the excess ADIT amounts at December 31, 2017 by comparing the ADIT existing at that date to the ADIT that would have been recorded had the lower 21 percent income tax rate always been in effect. The difference is the excess ADIT. The excess ADIT were then separated into three "buckets": Excess ADIT relating to protected book-tax differences; excess ADIT relating to the NOL; and excess ADIT relating to unprotected book-tax differences. The reason for separating the excess ADIT in this manner is because of different ratemaking treatment, in some cases required, for the reversal.

Q. DID THE TCJA DISCUSS HOW REGULATED PUBLIC UTILITIES WERE TO PASS BACK <u>PROTECTED</u> EXCESS ADIT?

A. Yes. The TCJA addressed how ADIT on protected book-tax differences (primarily depreciation-related method and life differences) are to be treated in the ratemaking process. The TCJA requires that excess ADIT on such protected book-tax differences reduce customer rates over the book lives of the related property no more rapidly than under the Average Rate Assumption Method ("ARAM"), which

I will describe subsequently. If the necessary books and records are not available to compute the reversal under ARAM, an alternative approach, referred to as the Reverse South Georgia Method ("RSGM"), can be used. The RSGM is straightforward: Determine the excess ADIT and spread the amount over the estimated remaining useful lives of the assets giving rise to the excess ADIT. The choice of ARAM vs. RSGM is not optional, ARAM must be used unless the records needed to compute ARAM are not available.

Q. HOW IS THE ARAM COMPUTED?

A. The ARAM requires the development of an average rate which is determined by dividing the aggregate normalized protected timing/temporary differences into the ADIT that have been provided on such timing/temporary differences. The average rate so calculated is applied to reversing timing differences to derive the deferred taxes that are credited to income tax expense. Under this approach, protected ADIT are reduced over the remaining lives of the property which gave rise to the ADIT as the timing/temporary differences reverse. Public utilities must take care to properly apply the ARAM to protected ADIT because a normalization violation could occur if the amount of protected excess ADIT is reduced more rapidly or to a greater extent than under the ARAM. If the normalization rules were so violated, two negative results would occur: 1) current income taxes would become payable for the more rapid reduction plus, more importantly, 2) accelerated depreciation methods would not be permitted for income tax purposes going forward. Rather, book depreciation would have to be used for income tax purposes.

Q. HAVE YOU PREPARED A SCHEDULE THAT DEMONSTRATES HOW THE ARAM IS TO BE CALCULATED?

A. Yes, Schedule ADF-4 provides an example describing the originating and reversing book-tax differences and the required ADIT each year when there is a change (in this case, a reduction) in the federal income tax rate. This example is based on the assumptions used in my previous example describing depreciation book-tax differences and how such differences originate and reverse. I begin with an income tax rate of 35 percent in the early years that is reduced to 21 percent before the asset is fully depreciated. The example again assumes a $1 million asset placed in service in 2016 with a 10-year book life and a five-year MACRS life, with no bonus tax depreciation. The MACRS rate is shown in Column B and each year's tax depreciation is shown in Column C. Book depreciation is $100,000 each year and Column E contains the difference between tax and book depreciation each year. Column F contains the cumulative difference between book and tax at the end of each year. Column G contains the income tax rates, beginning with 35 percent in 2016 and 2017, reducing that rate to 21 percent at the beginning of 2018. Columns H and I show each year's deferred tax expense, with Column H showing the deferred tax expense on originating book-tax differences and Column I showing the deferred tax expense on reversing book-tax differences. Column J shows the ADIT balance, increasing and decreasing the previous year's balance by the deferred tax expense. Column M shows the excess ADIT balance, decreasing as it reverses according to the ARAM methodology.

Q. CAN YOU EXPLAIN THE DETERMINATION OF EXCESS ADIT AND HOW THE ARAM IS USED TO REVERSE THE ADIT FOR THE TAX RATE CHANGE?

A. Yes. When the tax rate changed at the end of 2017, the balance of ADIT was $112,000 (Column J). This balance was derived by applying the 35 percent tax rate to the cumulative book-tax differences at that time in Column F ($320,000). The remeasurement necessitated by the change in tax rates is shown on Line 2a where the ADIT balance at December 31, 2017 is allocated into two components: The "normal" ADIT amount and the excess ADIT amount. The normal ADIT balance is calculated by applying the new 21 percent tax rate to those cumulative book-tax differences at the time of the rate change ($320,000 x 21 percent = $67,200) and comparing that amount to the then existing ADIT balance with the difference representing the excess ADIT ($112,000-$67,200 = $44,800).

Under the ARAM, this excess ADIT balance does not begin reversing until 2021 when the book-tax difference begins to reverse. In 2018 through 2020, book-tax differences continue to originate, now at the lower 21 percent income tax rate with no reversal permitted for excess ADIT.

At the end of 2020 the combined ADIT and excess ADIT balance is $137,704 (Column H: $35,000+$77,000+$19,320+$3,192+$3,192) and the cumulative book-tax difference is $442,400 (the 2016 through 2020 differences in Column F). The average rate at which the $137,704 combined ADIT and excess ADIT balance was accumulated is thus 31.1266 percent ($137,704 / $442,400). This is the average rate that must be applied to the book-tax differences reversing in each year beginning in 2021 (Column E) broken into two components: 1) the statutory rate (21 percent) applied to the reversing book-tax differences beginning in 2021 to reduce the normal ADIT balance (Column I), and 2) the excess ADIT rate (31.1266 percent minus 21 percent = 10.1266 percent, shown in Column K) also applied to the reversing book-tax differences beginning in 2021.

At the end of its useful life, the originating and reversing deferred tax expense (consisting of both the normal ADIT reversal plus the excess ADIT reversal) equal one another, and the ADIT balance is $0.

Q. HOW IS THIS TYPICALLY REFLECTED IN A RATE CASE?

A. Reversal of ADIT is included in the normal calculation of income tax expense (i.e. the statutory rate multiplied by pre-tax net income). No special calculation is required for this component of total tax expense. Once the normal calculation of income tax expense is determined, the reversal of the <u>excess</u> ADIT must be added/subtracted to obtain the amount that is included in the calculation of revenue requirement.

Q. IN THAT EXAMPLE, IF A RATE HIGHER THAN THE COMBINED AVERAGE RATE OF 31.1266 PERCENT WERE USED TO REDUCE THE REVERSING ADIT OR IF ANY OF THE EXCESS ADIT WERE REVERSED PRIOR TO 2020 WHAT WOULD HAPPEN?

A. Flowing back protected ADIT more rapidly than permitted under the ARAM will result in a violation of the normalization rules. I have already discussed the two-fold penalty for violating the normalization rules for excess ADIT: (1) currently payable income tax is increased by the amount by which the utility reduced its excess tax reserve more rapidly than permitted under the ARAM or the RSGM, and (2) the utility will be unable to claim accelerated depreciation for income tax purposes.

Q. DOES THE TCJA PRESCRIBE A METHOD FOR REVERSING EXCESS ADIT ON "UNPROTECTED" EXCESS ADIT?

A. No. Prior to the TCJA, the ADIT provided on all book-tax differences typically reversed at the tax rate used to record the deferred tax expense when the book-tax difference originated; however, the TCJA does not contain such a requirement on the excess ADIT on unprotected book-tax differences. Reversal of the balance of unprotected ADIT is thus up to a decision by the utility and its regulator.

Q. IS UNPROTECTED EXCESS ADIT ADDRESSED IN THIS RATE FILING?

A. No. The unprotected excess ADIT is subject to a separate rider, Rider H, which was proposed to the Board and approved in 2018 under Docket Nos. AX18010001 and GR18030230 ("2018 Rider H Filing"). Under Rider H, the unprotected excess ADIT balances are being reversed through rates (tariffs) using a five-year, straight-line amortization period, beginning with the fiscal period beginning October 1, 2018. Rider H tracks the actual amount being credited to customers and contains a true-up mechanism. Continuing Rider H for this credit will ensure that the unprotected excess ADIT will be fully returned to customers. Amounts over/under credited in one period (due to changes in volumes) will be trued-up, with interest, in a subsequent period.

Q. DID THE 2018 RIDER H FILING ADDRESS PROTECTED EXCESS ADIT, INCLUDING THE PROTECTED EXCESS RELATING TO THE NOL DEFERRED TAX ASSET?

A. No. The 2018 Rider H Filing only covered the unprotected excess ADIT. In a subsequent proceeding involving the Company's 2019 Rider H Filing, Docket Nos. AX18010001 and GR18030230 and GR19060701, the parties entered into a Stipulation ("2019 Rider H Stipulation") and agreed to address the protected excess ADIT Liability and the protected excess ADIT NOL Asset as follows:

- The protected excess ADIT Liability amounts will reverse using ARAM.
- The protected excess ADIT NOL Asset will reverse using the RSGM as the necessary vintage year detail was unavailable to allocate the excess ADIT NOL Asset using ARAM. Instead, the average remaining life of the ADIT contributing to the NOL and excess ADIT NOL Asset was determined and used for the reversal.

The 2019 Rider H Stipulation is pending consideration by the Board.

Q. IS THE REVERSAL OF EITHER THE PROTECTED EXCESS ADIT LIABILITY OR PROTECTED EXCESS ADIT NOL ASSET INCLUDED IN RIDER H?

A. No. In accordance with the 2019 Rider H Stipulation, Rider H includes only the unprotected excess ADIT; the return of the protected excess ADIT (the net of the excess ADIT Liability and the excess ADIT NOL Asset) is being effectuated in this base rate filing. Thus, Rider H only covers the benefit to customers of reversing excess ADIT on unprotected excess ADIT and this rate case filing excludes such amounts.

Q. HOW ARE THE PROTECTED EXCESS ADIT BEING TREATED IN THIS FILING?

A. The Company is treating the protected excess ADIT in accordance with the provisions of the 2019 Rider H Stipulation. Prior to this filing, there has been no reversal in SJG's books and records of the TCJA protected excess ADIT Liability using ARAM nor any reversal of the excess ADIT Asset related to the Company's NOL. Instead, in this filing, the Company is calculating the reversal of protected excess ADIT Liability using ARAM and the excess ADIT NOL Asset using RSGM and proposing a *pro forma* adjustment to reflect the test year excess ADIT amortization as well as the remaining excess ADIT balances that will reduce end of period rate base.

Schedule ADF-3 shows the initial calculation of protected excess ADIT Liability and the calculated reversal under ARAM, beginning January 1, 2018. The protected plant-related excess ADIT Liability as of December 31, 2017 was originally calculated as $198,471,424. A portion of this calculated protected amount, $19,898,890, was subsequently reclassified as "unprotected," increasing the amount to be credited to customers under Rider H. In addition, a return to accrual adjustment of $2,468,313 was recorded, producing an adjusted protected plant-related excess ADIT Liability of $181,040,847 as of December 31, 2017.

Applying the ARAM methodology to this balance results in annual and monthly ARAM reversals as follows:

2018--$2,177,376 ($181,448 per month)

2019--$2,359,511 ($196,626 per month)

2020--$3,083,553 ($256,963 per month)

As the test year in this rate case is July 1, 2019 to June 30, 2020, the amount of protected excess ADIT reversing under ARAM in this period is $2,721,532 calculated as follows:

6 months (July-December 2019 @ $196,626/month) =$1,179,756

6 months (January-June 2020 @ $256,963/month) = $1,541,776

Q. HOW HAS SOUTH JERSEY GAS TREATED THE "DELAYED" PROTECTED EXCESS ADIT LIABILITY REVERSAL USING ARAM FROM JANUARY 1, 2018 TO THE BEGINNING OF THE TEST PERIOD?

A. As I stated, none of the calculated ARAM reversal of the protected excess ADIT Liability has been credited to customers prior to this rate case. However, the amount of the protected excess ADIT Liability that would have reversed under ARAM from January 1, 2018 through June 30, 2019 that has not yet been credited to customers is $3,357,132 calculated as follows:

2018 reversal = $2,177,376

2019 reversal (6 months at $196,626/month) = $1,179,756

In addition to crediting customers for the ARAM reversal occurring in the July 1, 2019 to June 30, 2020 test period, the Company is proposing to credit this "delayed" amount to customers over five-years on a straight-line basis, or $671,426 per year ($3,357,132/5=$671,426). In this manner, customers will be made whole for the delayed implementation of ARAM within a reasonable, relatively short, period.

Thus, the total reversal of protected excess ADIT Liability reflected in this rate case is $3,392,958 ($2,721,532+671,426=$3,392,958). As none of this reversal has been reflected on the Company's books, a *pro forma* adjustment is included for the test year amortization.

Q. HOW IS THE PROTECTED EXCESS ADIT NOL ASSET TREATED IN THIS FILING?

A. The Company is treating the protected excess ADIT NOL in accordance with the provisions of the 2019 Rider H Stipulation. The adjusted protected excess ADIT Asset relating to the Company's NOL is $31,570,143. The Company is proposing to amortize this amount using a RSGM approach. The blended estimated average remaining life of the book-tax method and life depreciation differences giving rise to the excess ADIT NOL Asset is 40.8 years. Applying the average remaining life to the excess ADIT NOL Asset, results in the reversal of $955,720 ($79,643 per month) in the July 1, 2019 to June 30, 2020 test period.

Q. CAN YOU EXPLAIN HOW YOU DETERMINED THE BLENDED ESTIMATED AVERAGE REMAINING BOOK LIVES USED TO CALCULATE THE RSGM?

A. Yes. The NOL carryforward giving rise to the excess ADIT NOL Asset was allocated to the tax classes of the underlying assets. Each tax class was mapped to a book asset class (FERC Functional Account) based on data within the PowerTax deferred tax grid and PowerTax Tax-Book Translation table. For tax classes that were assigned to multiple book asset classes, a weighted average allocation was developed. The remaining average useful life of the assets within each class was then obtained. For each of the asset classes, the applicable remaining book life was applied creating a schedule of reversals over the estimated remaining book lives of the various asset classes giving rise to the NOL. In this manner, as the assets in the different asset classes become fully depreciated, the reversal of the associated excess ADIT NOL Asset will have fully reversed. While some asset classes have longer book lives and others have relatively shorter book lives, the blended average remaining book lives of such various asset classes as of December 31, 2017 (the date that the excess ADIT NOL Asset was measured) is 40.8 years.

Q. HOW HAS SOUTH JERSEY GAS TREATED THE DELAYED REVERSAL OF THE PROTECTED EXCESS ADIT NOL ASSET THAT WOULD HAVE REVERSED (CHARGED/COLLECTED FROM CUSTOMERS) FROM JANUARY 1, 2018 TO THE BEGINNING OF THE TEST PERIOD?

A. For the period January 1, 2018 through June 30, 2019, none of the excess ADIT NOL Asset has been recovered from customers. Had reversal of the excess ADIT NOL Asset using RSGM started on January 1, 2018, approximately $1,433,580 would have previously been charged to customers ($79,643 per month times 18 months). Consistent with the approach for delayed ARAM amounts, the Company is proposing a five-year recovery of the NOL excess ADIT not yet recovered. Thus, an additional $286,716 ($1,433,580 divided by five years) is being added to the test year NOL excess ADIT reversing in the test period, producing a total test year reversal (*pro forma* adjustment) of $1,242,436 ($955,720 + $286,716=$1,242,436).

Q. PLEASE SUMMARIZE HOW COST OF SERVICE INCOME TAX EXPENSE HAS BEEN ADJUSTED FOR THE REVERSAL OF THE PROTECTED EXCESS ADIT, BOTH THE EXCESS ADIT LIABILITY AND THE EXCESS ADIT NOL ASSET.

A. The adjusted excess ADIT amortization for the test year is a decrease to income tax expense of $2,150,522 (a customer benefit), consisting of a credit of $3,392,958 related to the reversal of property-related excess ADIT Liability subject to ARAM (and amortization of the delayed ARAM credit over five years) offset by an increase of $1,242,436 to recover the excess ADIT NOL Asset using RSGM (and recovery of the delayed excess ADIT NOL Asset over five years). Because neither amount has been recorded on SJG's books prior to this rate case, such amortization is included as a *pro forma* adjustment.

Q. HAS THE IRS ADDRESSED THE AMORTIZATION PERIOD FOR AN EXCESS ADIT NOL ASSET OR PROVIDED GUIDANCE ON HOW A DELAYED ARAM IMPLEMENTATION OF THE EXCESS ADIT LIABILITY IS TO BE TREATED?

A. No. However, the IRS has issued a notice (2019-33) indicating they plan to issue guidance on certain ratemaking issues that have arisen or are anticipated to arise due to the corporate income tax rate reduction. The IRS asked for comments on various ratemaking issues with comments due in July 2019. As a result of this notice, the IRS is not responding to ruling requests awaiting resulting guidance.

It is important that when such guidance is formalized, that public utilities read the IRS response and, if necessary, adjust the ratemaking positions to comply.

Said another way, to the extent that the IRS guidance is contrary to excess ADIT positions taken prior to such guidance, utilities and regulators, including South Jersey Gas and the Board, should be allowed to implement any required adjustments to comply with such requirements.

Q. ARE THERE OTHER ISSUES BEING ADDRESSED BY THE IRS IN NOTICE 2019-33 THAT MAY AFFECT SOUTH JERSEY GAS?

A. One other issue that could have an impact is whether the book-tax difference due to different book versus tax treatment of cost of removal is protected or unprotected. For book purposes cost of removal is accrued over the book life of the related property, plant and equipment as a component of book depreciation. The composite book depreciation rate includes an estimate for the eventual cost to remove or be received as salvage. For income tax purposes, cost of removal or salvage is recognized in the period the removal cost is paid or when salvage amounts are received. There is diversity in practice as to whether the ADIT (and excess ADIT) related to cost of removal is a protected book-tax difference subject to ARAM or whether it is unprotected. In this filing, the Company has treated the excess ADIT on cost of removal as a protected book-tax difference. As I stated, guidance on this issue should be forthcoming when the IRS addresses the matters contained in the notice.

Q. PLEASE SUMMARIZE HOW THE EXCESS ADIT ARE BEING TREATED IN THIS FILING.

A. The Company is treating excess ADIT in accordance with the terms of the 2019 Rider H Stipulation as follows:

Unprotected excess ADIT: Not reflected in this filing. Rider H exists to credit customers with the full amount of unprotected excess ADIT.

Protected excess ADIT Liability subject to ARAM: The amortization of the protected excess ADIT Liability is calculated using ARAM reversals during the July 1, 2019 through June 30, 2020 test period. I identified the annual excess ADIT Liability reversals under ARAM for 2019 and 2020 and converted the annual amounts to monthly amounts. I then used the last six months of 2019 reversals and the first six months of 2020 reversals to compute the test year reversals included as a *pro forma* adjustment in the rate case filing. The test year reversals were then applied to the previously determined excess ADIT Liability balance to obtain the *pro forma* excess ADIT Liability balance at the end of the test year, June 30, 2020.

Protected excess ADIT NOL Asset: The *pro forma* adjustment for the reversal of the protected excess ADIT NOL Asset is calculated using RSGM, including the amount reversing in the July 1, 2019 to June 30, 2020 test period.

Additional amount due to delayed implementation of ARAM from the beginning of the reversal period (January 1, 2018 through the beginning of the test period): Because of the delayed implementation of crediting/charging customers for ARAM and NOL amounts, I calculated the ARAM and excess NOL amounts that would have reversed beginning January 2018 through June 2019, and added the amortization of these delayed reversals (using a five-year amortization period) to the pro forma amortization adjustment.

Q. WHAT IS THE RATE BASE IMPACT OF THE PROTECTED EXCESS ADIT BALANCES?

A. The balance of the net protected excess ADIT at June 30, 2020, the end of the test period, including *pro forma* adjustments is projected to be $147,320,182. This balance consists of $177,647,889 for the property-related excess ADIT Liability (using ARAM) offset by the excess ADIT NOL Asset of $ 30,327,707 (reversing using RSGM).

The normalization rules require consistency between rate base components (Property, Plant and Equipment, Accumulated Depreciation, ADIT, including excess ADIT). Because South Jersey Gas determines these other components using an end of period rate base, the rate base reduction for excess ADIT at the end of the test period was used.

Q. WERE THERE ANY OTHER EXCESS ADIT TO CONSIDER?

A. Yes. While the focus of my testimony has been the TCJA impacts of the significant protected excess ADIT balances (excess ADIT Liability subject to ARAM and the excess NOL ADIT Asset subject to five-year amortization), the Company has a small amount of excess ADIT remaining related to the previous changes in income tax rates associated with the 1986 and 1993 tax reform initiatives. The excess ADIT related to prior tax reform was adjusted downwards to $729,595 as a result of 35 percent to 21 percent tax rate reduction under TCJA. Because the remaining excess ADIT balance for these prior amounts has been reduced to reflect the lower income tax rate, the annual reversal of this remaining balance has also been reduced (from $121,764 annually to $73,058 annually). The monthly reversal has been reduced from $10,147 to $6,088, beginning July 1, 2019 (the start of the test year). These amounts have been included in the Company's filing in addition to the TCJA excess ADIT effects discussed herein. There is no delayed impact for this pre-TCJA excess ADIT as SJG's current tariff includes a credit to customers for this item.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CURRICULUM VITAE

ALAN D. FELSENTHAL

EDUCATIONAL BACKGROUND

June, 1971	B.S. in Accounting University of Illinois Champaign, Illinois
May, 1972	Certified Public Accountant

EMPLOYMENT

2010-	Managing Director, Power and Utilities PricewaterhouseCoopers LLP
2008-2010	Managing Director-Utilities Industry Huron Consulting Group
2002-2007	Managing Director—Utilities Industry PricewaterhouseCoopers LLP
1985-2002	Principal in Utilities and Telecommunications Practice, Arthur Andersen LLP, Chicago
1976-1985	Manager in Utilities and Telecommunications Practice, Arthur Andersen LLP, Chicago
1971-1976	Staff and Senior Accountant, Arthur Andersen LLP, Utilities and Telecommunications Division, Chicago

TESTIMONY EXPERIENCE

Testified before the Illinois Commerce Commission on behalf of Town Gas Company of Illinois, 1985. Accounting witness covering cost of service issues.

Testified before the Illinois Commerce Commission on behalf of Town Gas Company of Illinois, 1986. Generic hearing regarding high gas costs.

Testified before the Florida Public Service Commission on behalf of Central Telephone Company of Florida (1991). Testimony addressed projected test year, a computer model we developed to simplify forecast procedures and propriety of including pension asset in rate base.

Submitted an expert report and testified in an appeal by Yellow Cab Company versus the City of Chicago, (2000). Topic dealt with the adequacy of taxicab lease rates. Yellow Cab was appealing the lease rates they were permitted to charge lessees. The model developed by the City of Chicago to set lease rates was based on traditional utility ratemaking principles. Was hired by the City of Chicago to review Yellow Cab's appeal compared to traditional ratemaking principles and submit a report. Yellow Cab appealed the decision and a hearing before a judge resulted.

Testified before the Arizona Corporation Commission on behalf of Tucson Electric Power Company, 2008. Rebuttal testimony addressed application of FAS 71 when a portion of the business was opened to competition and appropriate treatment of the FAS 143 cost of removal regulatory liability.

Testified before the Florida Public Service Commission on behalf of Tampa Electric Company and Peoples Gas, (2008). Direct testimony on income taxes, including the appropriate accumulated deferred income tax calculation when a projected test period is used.

Testified before the Washington Utilities and Transportation Commission on behalf of Avista Corporation, (2008).

Testified before the Illinois Commerce Commission on behalf of The Peoples Gas, Light and Coke Company/North Shore Gas Company (2009). Rebuttal and Surrebuttal testimony on the appropriate treatment of prepaid pension asset in rate base.

Testified before the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company (2009). Rebuttal testimony on the appropriate treatment of cost of removal vis a vis FAS 143.

Submitted an expert report and a reply expert report to a Seattle-based arbitration panel in a dispute involving Grays Harbor Energy LLC vs. Energy Northwest, 2009. Subject involved the appropriate determination of fixed costs and cost of capital pursuant to a purchase and sale agreement.

Testified before the Public Utility Commission of Texas on behalf of Centerpoint Energy (2010). Direct and Rebuttal testimony on a number of income tax issues including consolidated income tax adjustments and FIN 48.

Testified before the Indiana Utility Regulatory Commission on behalf of Indianapolis Power & Light Company (2015). Rebuttal testimony on including prepaid pension asset in rate base.

Testified before the Public Utility Commission of Ohio on behalf of Dayton Power & Light Company (2015). Direct testimony on the results of a lead-lag study.

Submitted rebuttal testimony to the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company (2016) on the appropriateness of including the prepaid pension asset in rate base.

Submitted an expert report to the Virginia State Corporation Commission regarding the allocation of Dominion Resources Inc. shared service costs to Virginia Electric Power Company (2016).

Submitted an expert report to the Oregon Public Service Commission regarding the capitalization of administrative and general overhead costs. (2017).

Testified before the Florida Public Service Commission on behalf of Tampa Electric Company and Peoples Gas on the subject of the appropriate treatment of excess Accumulated Deferred Income Taxes resulting from the Tax Cuts and Jobs Act (2018).

Testified before the Indiana Utility Regulatory Commission on behalf of Indianapolis Power & Light Company (2018). Rebuttal testimony on including a return on the Company's prepaid pension asset.

Testified before the FERC on behalf of GridLiance West (2018). Direct testimony supporting the derivation and reasonableness of the Company's Start-Up Regulatory Asset.

Submitted rebuttal testimony to the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company (2019) on reasons why including a return on the Company's prepaid pension asset is appropriate.

Submitted direct testimony to the New Jersey Board of Public Utilities on behalf of Elizabethtown Gas Company (2019) discussing consolidated income tax adjustments and Excess Accumulated Deferred Income Taxes being passed on to customers after the acquisition of the Company from Southern Company by South Jersey Industries.

Submitted direct testimony to the Hawaii Public Utilities Commission on behalf of Young Brothers (2019) on a number of income tax topics (Excess Accumulated Deferred Income Taxes, including the NOL Deferred Tax Asset in Rate Base, treatment of the Hawaii Capital Goods Excise Tax Credit) and including the prepaid pension asset in rate base.

Participated on accounting panels before the Maine Public Utilities Commission supporting 1) a market study of Central Maine Power Company's shared service costs and 2) the treatment of Excess Accumulated Deferred Income Taxes(2019).

Submitted rebuttal testimony before the Utah Public Service Commission on pension accounting symmetry in connection with the rate case of Dominion Energy Utah (2019).

REGULATORY CONSULTING EXPERIENCE

Synopsis—Throughout the late 1970's, the 1980's, 1990's, 2000's and 2010's assisted Andersen and PwC partners in the preparation of regulatory testimony covering a variety of accounting issues. Much of this testimony involved income tax accounting issues related to flow-through versus normalization or investment tax credit and the appropriate accounting and ratemaking treatment of excess accumulated deferred income taxes when statutory tax rates change. Also developed testimony on CWIP in rate base and working capital (lead-lag technique), appropriateness of allocation of service company costs to regulated entities, recovery of pre-operating cost regulatory assets and capital structure issues.

In 2015, assisted with the preparation of an Expert Report for EverSource Energy subsidiary Connecticut Light & Power which was submitted to the Connecticut regulator. The issue concerned reopening a rate order to address the treatment of accumulated deferred income taxes which was incorrectly decided in the rate order.

In 2018, assisted with the preparation of a private letter ruling by American Transmission Company as to whether an internal transfer between a regulated and non-regulated partner would trigger the elimination of accumulated deferred income taxes that would need to be reflected on the books and records of the partnership.

In 2018 and 2019, assisted with the preparation of Expert testimony and a private letter ruling discussing the appropriate income tax treatment of a like-kind exchange between Oncor and Sharyland. The issue concerned whether the accumulated deferred income taxes relating to the exchanged assets could carry over or would need to be eliminated.

Provided assistance on rate case testimony for the following companies:

- Indianapolis Power & Light Company
- Dayton Power & Light Company
- Pacific Gas & Electric Company
- Iowa-Illinois Gas and Electric Company
- The Peoples Gas Light and Coke Company
- Northern Indiana Public Service Company
- Elizabethtown Gas Company
- New Mexico Gas Company
- GridLiance Corporation
- PPL Montana (contract dispute)
- Southern Bell Telephone Company
- Indiana Bell Telephone Company
- Iowa Power Company
- El Paso Electric Company
- Ameritech Corporation
- Central Illinois Light Company
- Central Illinois Public Service Company
- Tampa Electric Company/Peoples Gas Company
- Public Service Company of New Mexico
- Connecticut Light and Power Company
- Young Brothers, Limited
- Central Telephone Company of Florida
- Central Telephone Company of Texas
- Central Telephone Company of Nevada
- Integrys Energy Group, Inc.
- Dominion Energy Utah
- San Gabriel Valley Water Company
- Transco Pipeline

Provided regulatory consulting for the Panama Canal Company. Tariffs charged to transit the Panama Canal were based on a cost of service approach. Assisted the Panama Canal Company in determining test year costs. Tariffs were established based on these costs.

2012-2019. Led several projects to evaluate a rate case filing prior to filing validating the completeness, accuracy, consistency and support of the filing. As a result, adjustments and edits were made to the filing to increase the credibility of the utility's filing. Provided a similar role with respect to date request responses and rebuttal testimony.

FINANCIAL CONSULTING EXPERIENCE

Assisted two Chinese utility companies in registration filings to have their shares traded on the New York Stock Exchange. Huaneng Power International and Shandong Huaneng Power Company were the first two Chinese utilities to list on the NYSE. Process involved working with attorneys, company personnel and the Securities and Exchange Commission to file the equivalent of a Form S-1.

Assisted a number of companies in the preparation, review and filing of Registration Statements with the SEC to raise debt and equity capital.
Consulted with an electric transmission company on whether costs charged to generation companies based on specific costs are in accordance with the costs permitted by the Federal Energy Regulatory Commission.

Consulted with Ameritech Corporation on a number of projects involving cost allocations and compliance with the Federal Communications Commission separations rules.

Consulted with several entities in the preparation of a private letter ruling request to determine whether certain regulatory/ratemaking approaches would violate the Internal Revenue Service ("IRS") normalization rules. Provided the ratemaking aspect of the request when, combined with income tax consulting assistance formed the basis for a complete request, accepted by the IRS.

FINANCIAL AUDIT EXPERIENCE

- Allegheny Energy
- Ameritech Corporation
- Ameritech Cellular
- Ameritech New Media
- Louisville Gas and Electric Company
- Iowa-Illinois Gas and Electric Company
- Centel Corporation
- Constellation Energy
- Nicor, Inc.
- Peoples Energy
- Nisource
- Focal Communications
- Utilities, Inc.
- Chicago Skyway
- United Airlines

LECTURES AND SEMINARS

Speaker at Edison Electric Institute/American Gas Association Introductory, Intermediate and Advanced Accounting Seminar 1996-2019.

Speaker at SNL (Regulatory Research Associates) Utility Foundations Seminar 2013-2017

Speaker at Power Plan Associates annual conference (2012, 2010, 2008, 2006, 2004, 2002) on recent accounting, regulatory and SEC matters affecting utilities.

Developed and conducted Utilities Industry Basic Accounting and Ratemaking Seminar. This two-day seminar is conducted each year for Andersen, Huron and PwC personnel assigned to utility audits or projects. In addition, the seminar is periodically offered on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Developed and conducted Utility Income Taxes-Accounting and Ratemaking Issues. This two-and-a-half day seminar is conducted each year for Andersen, PwC and Huron personnel assigned to utility audits or income tax projects. In addition, the seminar is conducted annually on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites.

Developed and conducted Rate Case Experience Seminar and Utility Income Tax Seminar. The Rate Case Experience Seminar is week-long seminar is conducted each year on an open-registration basis for utility company personnel as well as offered and conducted for specific utility companies at their training sites. The Utility Income Tax Seminar is a two-day seminar focusing on the accounting, tax return/compliance and financial statement aspects of utility income taxes taking into consideration the consequences of ratemaking/revenue requirements. Specific examples of special training conducts for utility companies/regulators are as follows:

- Nicor
- Entergy
- Peoples Energy
- Sempra Energy
- Centerpoint
- Nisource, Inc.
- Cleco Corporation
- Consolidated Edison
- Duke Energy
- National Grid
- Dominion Resources
- Tucson Electric Power
- Portland General Electric
- Pepco Holdings, Inc.
- Ameritech Corporation
- Louisville Gas and Electric
- American Water Works
- Tampa Electric
- Natural Gas Pipeline Company of America
- Transco Pipeline
- Federal Energy Regulatory Commission
- Oklahoma Commission
- Arkansas Commission
- PPL Corporation
- Southern California Edison
- Sempra Energy
- Williams Pipeline
- Illinois Commerce Commission

- Sprint Corporation
- American Electric Power
- Consumers Power Company
- Arizona Public Service Company
- Qwest
- Northwest Pipeline
- Alaska Regulatory Commission
- Xcel Energy
- Exelon Corporation
- PG&E Corporation
- One Gas Corporation

PROFESSIONAL ASSOCIATIONS

American Institute of Certified Public Accountants

Illinois CPA Society

** The confidential version of this schedule will be provided after the execution of a Non-Disclosure Agreement

PRELIMINARY PUBLIC COPY

Schedule ADF-2

	2015	2016	2017	2018	2019 (Est.)	(A) Total 2015-2019	(B) Income Companies	(C) Loss Companies	(D) (B)/ Total(B) Income Company Percent of Income Companies Total	(E) Total(C) times (D) Allocate Total of Loss Companies to Income Companies based on Taxable Income Share
Taxable Income/(Loss):										
South Jersey Gas	**$ (16,501,655)**	**$ (153,374,901)**	**$ (83,008,088)**	**$ 29,469,426**	**63,585,720**	**$ (159,829,498)**	**$ -**	**$ (159,829,498)**	**0%**	**$ -**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

		Excess ADIT Liability Depreciation-related (ARAM)	Excess ADIT Asset NOL (RSGM)	Total Reg Liab	IIIIIII IIIIIII IIIIIII	Pre TCJA	Total with Pre TCJA
Balance at December 31, 2017, reported in 10-K (not grossed-up)		$ 198,471,424	$ (34,190,850)	$ 164,280,574	IIIIIII	$ 729,595	$ 165,010,169
Adjustments to 12/31/2017 opening balance:				$ -	IIIIIII		$ -
Q1 2018 14% NOL true-up			$ 5,068,146	$ 5,068,146	IIIIIII		$ 5,068,146
2017 Provision to Return true-ups		2,468,313	$ (2,447,439)	$ 20,874	IIIIIII		$ 20,874
Reclass from Protected to Unprotected (fixed asset basis differences)		$ (19,898,890)		$ (19,898,890)	IIIIIII		$ (19,898,890)
Returned to ratepayers through Rider H		$ -	$ -	$ -	IIIIIII	$ -	$ -
Excess ADIT Balance at December 31, 2017, as adjusted	**A**	**$ 181,040,847**	**$ (31,570,143)**	**$ 149,470,704**	**IIIIIII**	**$ 729,595**	**$ 150,200,299**
Monthly reversals, January-December 31, 2018:				$ -			$ -
Jan-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Feb-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Mar-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Apr-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
May-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Jun-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Jul-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Aug-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Sep-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Oct-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Nov-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
Dec-18		$ (181,448)	$ 79,643	$ (101,805)	IIIIIII	$ (10,147)	$ (111,952)
January-December 2018 reversal		$ (2,177,376)	$ 955,720	$ (1,221,656)	IIIIIII	$ (121,764)	$ (1,343,420)
Excess ADIT Balance at December 31, 2018		$ 178,863,471	$ (30,614,423)	$ 148,249,048	IIIIIII	$ 607,831	$ 148,856,879
Monthly reversals, January-December 2019							
Jan-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (10,147)	$ (127,130)
Feb-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (10,147)	$ (127,130)
Mar-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (10,147)	$ (127,130)
Apr-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (10,147)	$ (127,130)
May-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (10,147)	$ (127,130)
Jun-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (10,147)	$ (127,130)
Jul-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (6,088)	$ (123,071)
Aug-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (6,088)	$ (123,071)
Sep-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (6,088)	$ (123,071)
Oct-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (6,088)	$ (123,071)
Nov-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (6,088)	$ (123,071)
Dec-19		$ (196,626)	$ 79,643	$ (116,983)	IIIIIII	$ (6,088)	$ (123,071)
Estimated reversal, January-December 2019		$ (2,359,511)	$ 955,720	$ (1,403,791)	IIIIIII	$ (97,411)	$ (1,501,202)
Excess ADIT Balance December 31, 2019		$ 176,503,960	$ (29,658,703)	$ 146,845,257	IIIIIII	$ 510,420	$ 147,355,677
Monthly reversals, January-December 2020							
Jan-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Feb-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Mar-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Apr-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
May-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Jun-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Jul-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Aug-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Sep-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Oct-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Nov-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Dec-20		$ (256,963)	$ 79,643	$ (177,319)	IIIIIII	$ (6,088)	$ (183,408)
Estimated excess ADIT reversals 2020		$ (3,083,553)	$ 955,720	$ (2,127,833)	IIIIIII	$ (73,058)	$ (2,200,891)
Excess ADIT Balance December 31, 2020		$ 173,420,407	$ (28,702,983)	$ 144,717,424	IIIIIII	$ 437,361	$ 145,154,785
********* ******************	*****************	****************	****************	*****************	******	****************	***************
AMOUNTS INCLUDED IN RATE CASE FILING (PRO FORMA ADJUSTMENTS)							
Protected Excess ADIT reversal 7/1/2019-6/30/2020 (REVERSING IN TEST YEAR)	B	$ (2,721,532)	$ 955,720	$ (1,765,812)	IIIIIII	$ (73,058)	$ (1,838,870)
Reversal Prior to Test Year Delayed (1/1/2018-6/30/2019)	C	$ (3,357,132)	$ 1,433,580	$ (1,923,552)	IIIIIII	$ -	$ (1,923,552)
Five-Year amortization of delayed credit/recovery	(C divided by 5)=D	$ (671,426)	$ 286,716	$ (384,710)	IIIIIII	$ -	$ (384,710)
Rate Case Amortization for protected excess ADIT (PRO FORMA)	(B +D) =E	$ (3,392,958)	$ 1,242,436	$ (2,150,522)	IIIIIII	$ (73,058)	$ (2,223,581)
Protected Excess ADIT balance at June 30, 2020:							
Balance at December 31, 2017	A	$ 181,040,847	$ (31,570,143)	$ 149,470,704	IIIIIII	$ 729,595	$ 150,200,299
PRO FORMA Rate Case Amortization: January 1, 2018 through June 30, 2020	E	$ (3,392,958)	$ 1,242,436	$ (2,150,522)	IIIIIII	$ (73,058)	$ (2,223,581)
PRO FORMA Protected Excess ADIT Balance at June 30, 2020	A+E=F	$ 177,647,889	$ (30,327,707)	$ 147,320,182	IIIIIII	$ 656,537	$ 147,976,718

Schedule ADF-4

ARAM ILLUSTRATION

Line No.	Year	Asset Cost (A)	(B) 5-year MACRS Tax Rate	(A x B = C) Tax Depreciation	(A / 10 = D) Book Depreciation 10 yrs. S/L	(C - D = E) Tax over Book Difference	(F) Cumulative Tax Over Book Difference	(G) Tax Rate	(E x G = H) Originating Deferred	(E x G = I) ADIT Reversing Deferred	(F x G = J) ADIT Cumulative Balance	(K) Average Excess ADIT Rate	(E x K = L) Excess ADIT Reversing under ARAM	(M) Excess ADIT Cumulative Balance
1	2016	1,000,000	20.000%	200,000.00	100,000.00	100,000.00	100,000.00	35%	35,000.00		35,000			
2	2017		32.000%	320,000.00	100,000.00	220,000.00	320,000.00	35%	77,000.00		112,000			
2a	**Remeasurement at December 31, 2017**		-	-	-	-	**320,000.00**	**21%**	-		**67,200**			**44,800**
3	2018		19.200%	192,000.00	100,000.00	92,000.00	412,000.00	21%	19,320.00		86,520			44,800
4	2019		11.520%	115,200.00	100,000.00	15,200.00	427,200.00	21%	3,192.00		89,712			44,800
5	2020		11.520%	115,200.00	100,000.00	15,200.00	442,400.00	21%	3,192.00		92,904			44,800
6	2021		5.760%	57,600.00	100,000.00	(42,400.00)	400,000.00	21%	-	(8,904)	84,000	10.1266%	(4,294)	40,506
7	2022		0.000%	-	100,000.00	(100,000.00)	300,000.00	21%	-	(21,000)	63,000	10.1266%	(10,127)	30,380
8	2023		0.000%	-	100,000.00	(100,000.00)	200,000.00	21%	-	(21,000)	42,000	10.1266%	(10,127)	20,253
9	2024		0.000%	-	100,000.00	(100,000.00)	100,000.00	21%	-	(21,000)	21,000	10.1266%	(10,127)	10,127
10	2025		0.000%	-	100,000.00	(100,000.00)	-	21%	-	(21,000)	0	10.1266%	(10,127)	0
	Total			1,000,000.00	1,000,000.00	-			137,704.00	(92,904)			(44,800)	

(137,704)

$1,000,000 fixed asset placed in service on January 1, 2016
Book Depreciation using straight-line method, 10-year life, no half-year convention
Tax Depreciation using MACRS, five-year life

At the end of 2017, when the tax rate changes, the ADIT is remeasured at 21%. The remeasurement reclassifies a portion of the ADIT as Excess ADIT. (line 2a)
The remeasured ADIT reverses normally (i.e. the book tax difference times the current statutory rate) while the Excess ADIT reverses following ARAM

Average Rate (Column K) computed when the book-tax difference reverses (Column E-Year 2021). Computation is based on dividing the Excess ADIT balance at the time of reversal (44,800 in Column M) by the cumulative book-tax differences at the beginning of the year ($442,400 - the total originating differences in Column F). The average rate is 31.166 per cent, broken into 1) the statutory tax rate to apply to reversing book-tax differences (21 perecent) to clear the ADIT balance (Column I) and 2) the rate to apply to reversing book-tax differences to clear the Excess ADIT balance (Column L).

Ratemaking tax expense includes both the deferred tax expense (i.e originatind deferred or reversing defered) and rate base is reduced for both the Cumulative ADIT and Excess ADIT balances.

INSERT TAB:

D. WATSON

IN THE MATTER OF THE PETITION OF SOUTH JERSEY GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR20________

DIRECT TESTIMONY

OF

DANE A. WATSON, PE CDP

Partner,
Alliance Consulting Group

On Behalf Of
South Jersey Gas Company

Exhibit P-10

March 13, 2020

TABLE OF CONTENTS

SCHEDULES:

Exhibit P-10

SOUTH JERSEY GAS COMPANY
DIRECT TESTIMONY OF
DANE A. WATSON

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Dane A. Watson, and my business address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074. I am a Partner of Alliance Consulting Group. Alliance Consulting Group provides consulting and expert services to the utility industry.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("the Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I met all requirements and have become a Certified Depreciation Professional ("CDP").

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation and certain accounting-related studies for utilities in various industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I was the Industry Project Manager for the EEI/American Gas Association ("AGA") effort around the electric and gas industry adoption of FAS 143 and testified before FERC in the hearings leading up to the release of FERC Order 631. I was also the Project Leader for the EEI/AGA "Introduction to Depreciation" textbook update. I am a Registered Professional Engineer in the State of Texas and a Certified Depreciation Professional. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and served for several years as an officer of the Executive Board of the Dallas Section of IEEE as well as national and worldwide offices. I have served as President of the Society twice and teach as part of their annual training program as well as teaching depreciation in multiple venues for EEI/AGA.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES OR ANY OTHER STATE AND/OR REGULATORY COMMISSIONS?

A. Yes. I have testified before the New Jersey Board of Utilities and numerous other state and federal agencies in my 35-year career in performing depreciation studies. I have conducted depreciation studies, filed written testimony, and/or testified before the Commissions identified in Schedule DAW-1.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. I sponsor and support the depreciation study performed for South Jersey Gas ("SJG" or "Company"). The SJG depreciation study resulted in depreciation rates that are used to determine the Test Year depreciation expense for SJG's assets in this proceeding.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The SJG depreciation study and analysis that I have performed fully supports establishing depreciation rates at the level recommended in my testimony. The SJG depreciation study is attached to my testimony as Schedule DAW–2. The study shows that an overall increase in annual depreciation expense of approximately $4.1 million is needed to ensure that the appropriate amount of depreciation expense is collected by the Company. This amount was calculated by determining the depreciation expense difference between the currently effective depreciation rates for SJG and the proposed rates as shown in Schedule DAW-2, Appendix A, for assets at December 31, 2018. The primary drivers for the increase in the annual depreciation expense when compared to the existing rates are related to the additional net salvage accrual based on the Commission's approved methodology and changes in the reserve position for certain Distribution and General Plant accounts. There are a total of 37 accounts, of which six have life increase recommendations; nine accounts have life decrease recommendations; 20 accounts have no change; and two accounts where no comparison can be made. Company witness Brenda O'Brien is sponsoring the depreciation expense adjustment set forth in the Company's filing in this proceeding.

III. SJG DEPRECIATION STUDY

Q. DID YOU PREPARE THE SJG DEPRECIATION STUDY?

A. Yes. The study in Schedule DAW-2 analyzes the life and net salvage for all the depreciable property groups associated with SJG assets at December 31, 2018.

Q. WHAT PROPERTY IS INCLUDED IN THE DEPRECIATION STUDY?

A. There are five general classes, or functional groups, of depreciable property included in the study: the Liquefied Natural Gas ("LNG") Plant, Transmission Plant, Distribution Plant and General Plant depreciable and General Plant amortized property. The LNG Storage Plant functional group primarily consists of the structures, gas holders and purification equipment associated with LNG facilities. The Transmission Plant functional group primarily consists of lines and associated facilities used to move gas from the production or storage fields to the distribution system. The Distribution Plant functional group primarily consists of lines and associated facilities used to distribute gas to customers within the territory served by SJG. General Plant property is not location specific but is used to support the overall operations to distribute gas to its customers.

Q. HAVE YOU CALCULATED THE ANNUAL DEPRECIATION EXPENSE FOR SJG?

A. Yes. The proposed annual depreciation expense, based on plant balances at December 31, 2018, for SJG is $69.4 million. Using the existing approved rates for SJG accounts applied to December 31, 2018 balances, the existing annual depreciation expense would be $65.3 million. Comparing the existing and proposed rates would result in an increase of approximately $4.1 million in annual depreciation expense. The complete account comparison is shown in Schedule DAW-2, Appendix A. The calculation of the annual expense and rates are shown in Appendix B. A listing of the life and net salvage parameters used are shown in Appendix C.

Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR THE PURPOSES OF CONDUCTING A DEPRECIATION STUDY AND PREPARING YOUR TESTIMONY?

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the lives of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. I conducted the depreciation studies in four phases as shown in Schedule DAW-2. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the study, I collected historical data to be used in the analysis. After the data was assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, managerial personnel, was combined with the study results, and then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans should be applied. Using all of these resources, I then calculated the depreciation rate for each function.

Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE?

A. The straight-line, Average Life Group ("ALG") remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. This methodology that I used is consistent with the methodology used to develop the existing approved depreciation rates for SJG.

Q. HOW ARE DEPRECIATION RATES DETERMINED UNDER THE ALG PROCEDURE?

A. In this system, the annual depreciation expense for each group was computed by dividing the original cost of the asset, less allocated book depreciation reserve, less estimated net salvage, by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within an account were accumulated, and the total was divided by the original cost of all depreciable property within the account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual depreciation rates and remaining life calculations are shown in Appendix B of Schedule DAW-2.

Q. WHAT TIME PERIOD DID YOU USE TO DEVELOP THE PROPOSED DEPRECIATION RATES?

A. The account level depreciation rates were developed based on the depreciable property recorded on the Company's books at December 31, 2018.

Q. IN DEVELOPING THE PROPOSED DEPRECIATION RATES, DID YOU ALSO CONSIDER THE COMPANY'S CURRENT ASSET ACCOUNTING PRACTICES?

A. Yes. In developing the proposed depreciation rates, the depreciation study analysis focused not only on historical data but also considered the current asset accounting practices used by the Company. The results of this analysis confirmed that the historical accounting and operational data was generally representative of ongoing SJG practices.

Q. WHAT FACTORS INFLUENCE THE DEPRECIATION RATES FOR AN ACCOUNT?

A. The primary factors that influence the depreciation rate for an account are: 1. the remaining investment to be recovered in the account, 2. the depreciable life of the account, and 3. the net salvage for the account. In the case of SJG, account level net salvage is not recognized due to BPU requirements. However, a three year average net salvage amount is included in the overall depreciation expense accrual amount.

Q. WHAT METHOD DID YOU USE TO ANALYZE HISTORICAL DATA TO DETERMINE LIFE CHARACTERISTICS?

A. All accounts were analyzed using both the simulated plant record ("SPR") and the actuarial methods of life analysis. However, it was determined there is not enough aged retirement data (actuarial) to produce meaningful analyses in most of the accounts. Therefore, the SPR method of life analysis was relied upon to estimate the life of property. In much the same manner as human mortality is analyzed by actuaries, depreciation analysts use models of property mortality characteristics that have been validated in research and empirical applications. Further detail is found in the life analysis section of Schedule DAW-2.

Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life was used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated ratably over future periods.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR EACH ASSET GROUP?

A. The establishment of appropriate average service lives for each account was determined by using the SPR life analysis. The remaining life, by account, is shown in Appendix B of Schedule DAW-2. Graphs and tables supporting the SPR analysis and the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the Life Analysis section of Schedule DAW-2. A summary of the depreciable life for each account is shown in Schedule DAW-2, Appendix C.

Q. WHAT IS NET SALVAGE?

A. While discussed more fully in the study itself, net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Generally, salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of the addition versus the retirement. For example, a Distribution asset in FERC Account 376 Steel Mains with a current installed cost of $500 (2018) would have had an installed cost of $17.15[1] in 1950. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative 10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 292 percent removal cost for that asset ($50/$17.15). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

Q. HOW WOULD YOU TYPICALLY ANALYZE NET SALVAGE?

A. I would examine the experience realized by the Company by observing the actual net salvage amounts recorded for each year. The analysis also looks at various bands (or combinations) of these years, such as 2-year, 3-year etc., up to 10-years. Evaluating these moving averages allows the smoothing of the timing differences between when retirements, removal cost and salvage are booked. By looking at successive average bands ("rolling bands"), an analyst can also see trends in the data that would indicate the future

[1] Using the Handy-Whitman Bulletin No. 190, G-1, line 44, $17.15 = $500 x 32/933.

net salvage in the account. This examination, in combination with the feedback of Company engineers related to any changes in operations or maintenance that would affect the future net salvage of the asset, generally is the basis for the selection of the best estimate of future net salvage for each account.

Q. IS THE APPROACH YOU JUST DESCRIBED CONSISTENT WITH THE GENERALLY ACCEPTED APPROACH TO THE ANALYSIS OF NET SALVAGE IN THE INDUSTRY?

A. Yes, my approach is consistent with National Association of Regulatory Utility Commissioners' 1996 Public Utilities Depreciation Practices Manual and other authoritative texts. It is also the generally accepted methodology for the analysis of net salvage across most of the jurisdictions in the country.

Q. HAVE YOU USED THE NET SALVAGE APPROACH YOU JUST DESCRIBED IN YOUR STUDY IN THIS CASE?

A. No. I have not.

Q. WHY NOT?

A. Consistent with the stipulation in prior cases, net salvage is calculated by taking the average of the actual net salvage expense over an immediate prior period. While I and SJG disagree with this position, to avoid repeated litigation over the net salvage methodology, we used the approach approved by the BPU in prior cases.

Q. WHAT METHODOLOGY HAVE YOU USED IN THIS CASE?

A. I have utilized the average salvage expense for the most recently completed three year period 2016-2018. The Company directed me to use this most recent three-year average net salvage as the allowance. This calculation resulted in net salvage of $6,268,760, which will be added annually to the annual depreciation expense accruals for net salvage. This calculation is provided in Schedule DAW-2, Appendix D. The previous net salvage amount was stipulated at $4,659,755.

Q. WHAT IS CAUSING THE 3-YEAR AVERAGE TO INCREASE?

A. The costs of activities related to retirement costs (generally including cutting, capping, and purging of gas for the abandonment of pipe) have increased in part due to the cost of labor. Performing these activities today is more expensive than in the past and is definitely more expensive than the retirement costs reflected in the existing net salvage amount. Also, the use of the most recent 3-year average captures the level of accelerated infrastructure replacement program retirement activities that are occurring and expected to continue in the near term.

Q. IN YOUR JUDGMENT WHAT IS THE EFFECT OF UTILIZING THE AVERAGE OF RECENT YEAR'S NET SALVAGE EXPENSE TO CALCULATE NET SALVAGE?

A. It disregards the growth in net salvage percentage as plant ages and the growth in total removal cost required as larger portions of the asset base are retired – to some extent disregarding accrual accounting. As a result, it causes an intergenerational shift, whereby the burden of net salvage is shifted from today's customers and placed upon our children and grandchildren.

Q. IS THIS A REASONABLE METHOD FOR DETERMINING NET SALVAGE RATES?

A. Not in my opinion and not by the majority of utilities and state commissions who have utilized and adopted the traditional net salvage methodology. Additionally, there are authoritative texts[2] that also describe and support the traditional net salvage methodology.

IV. CONCLUSION

Q. WHAT ACCOUNT DEPRECIATION RATES ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The current depreciation rates and the rates I am now proposing are found in Schedule DAW-2. Detailed comparisons and calculations of these rates are found in Appendices A and B of Schedule DAW–2.

Q. MR. WATSON, DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The depreciation study and analysis performed under my supervision fully support setting depreciation rates at the level I have indicated in my testimony. The Company should continue to periodically review the annual depreciation rates for its property. In this way, all customers are charged for their appropriate share of the capital expended for their benefit. The depreciation study for SJG depreciable property as of December 31, 2018 describes the extensive analysis performed and the resulting rates that are now appropriate for Company property. The Company's depreciation rates should be set at my recommended amounts in order to recover the Company's total investment in property over the estimated remaining life of the assets.

---

[2] *The Estimation of Depreciation*, by Drs. Fitch, Wolf and Bissinger and the National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices*.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study
Tennessee	Tennessee Regulatory Authority	11-00144	Piedmont Natural Gas	2009	Gas Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

SOUTH JERSEY GAS

DEPRECIATION RATE STUDY

As of December 31, 2018

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

SOUTH JERSEY GAS
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

South Jersey Gas ("SJG" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's natural gas operations depreciable assets as of fiscal year end December 31, 2018.

The existing depreciation rates were based on the straight-line method, average life group ("ALG") procedure, and remaining-life technique and the same method, procedure, and technique are retained in this study. At the request of the Company, however, this study does not include a traditional net salvage approach. Instead, it includes a similar approach approved by the New Jersey Board of Public Utilities ("Board") in the last case. The approach being proposed in the study utilizes the development of an annual amount, based on the most recent three years, to be accrued as part of the depreciation expense. The net salvage accrual $6,268,760, is shown in Appendix A. Appendix D provides the calculation of the $6,268,760 net salvage amount. In total, this study recommends an increase of approximately $4.1 million in annual depreciation expense when compared to the depreciation rates currently in effect. Life estimates show the following changes: 6 accounts have an increase in life, nine accounts have a decrease in life, and 20 accounts remain unchanged. For the remaining 2 accounts, there is either no comparison possible.

The depreciation study Alliance conducted analyzed and developed depreciation recommendations at an account level resulting in annual depreciation accrual amounts and depreciation rates at that level. Appendix A demonstrates the change in depreciation expense.

SOUTH JERSEY GAS
DEPRECIATION RATE STUDY
As of December 31, 2018
Table of Contents

PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on SJG's books at December 31, 2018. The account-based depreciation rates were designed to recover the total remaining undepreciated investment, over the remaining life of SJG's property on a straight-line basis. Non-depreciable property and property that is amortized, such as intangible assets, were excluded from this study.

SJG provides local gas distribution service to approximately 398,000 customers in 113 municipalities over 2,500 square miles of service territory in southern New Jersey. Its assets currently consist of various liquefied natural gas ("LNG"), transmission, distribution, and general assets, with approximately 146 miles of transmission pipe, 6,551 miles of steel and plastic gas distribution mains, and 315,475 service lines that total 5,556 miles in length, which are located across the service area. The Company has seven receipt points, or city gates, throughout the system where gas enters the distribution system and is then delivered to customers for burner tip consumption.

STUDY RESULTS

The existing and current study of annual depreciation expense result from the use of Iowa Curve dispersion patterns with the straight-line method, average life group procedure and remaining-life technique, in the development of the study recommended depreciation rates. Detailed information for each of these factors will follow in this report.

Overall depreciation rates for SJG depreciable property are shown in Appendix A. The recommended rates translate into an annual depreciation accrual of approximately $69.4 million based on SJG's depreciable investment at December 31, 2018. The annual equivalent depreciation expense calculated by the same method using the currently approved rates is $65.3 million. The primary driver for the increase in the annual depreciation expense when compared to the existing is related to additional investment, reserve position, and net salvage accrual based on the Board's approved methodology, offset by increases in life for many of the accounts in the Transmission and Distribution Functions.

Appendix A presents a comparison of the composite existing rates versus the recommended study rates. Appendix B presents the development of the depreciation rates and annual accruals. Appendix C presents the mortality parameters by account. Appendix D presents the calculation for the net salvage annual accrual amount of $6,268,760.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

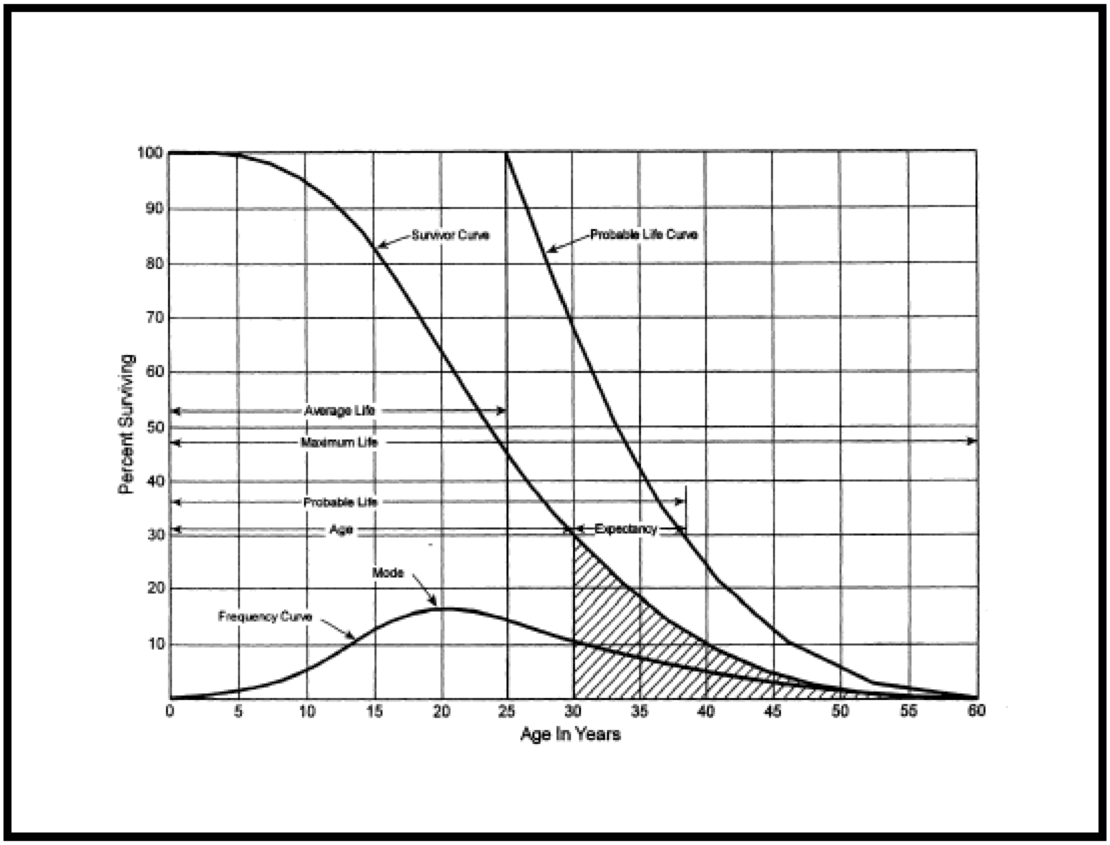
Basis of Depreciation Estimates

Annual and accrued depreciation were calculated in this study by the straight-line, broad group, remaining-life depreciation system. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset group less allocated depreciation reserve less estimated net salvage by its respective average remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group, and were computed in a direct weighting by multiplying each vintage or account balance times its remaining life and dividing by the plant investment in service as of December 31, 2018. The computations of the annual depreciation rates are shown in Appendix B and remaining life calculations are provided in the workpapers.

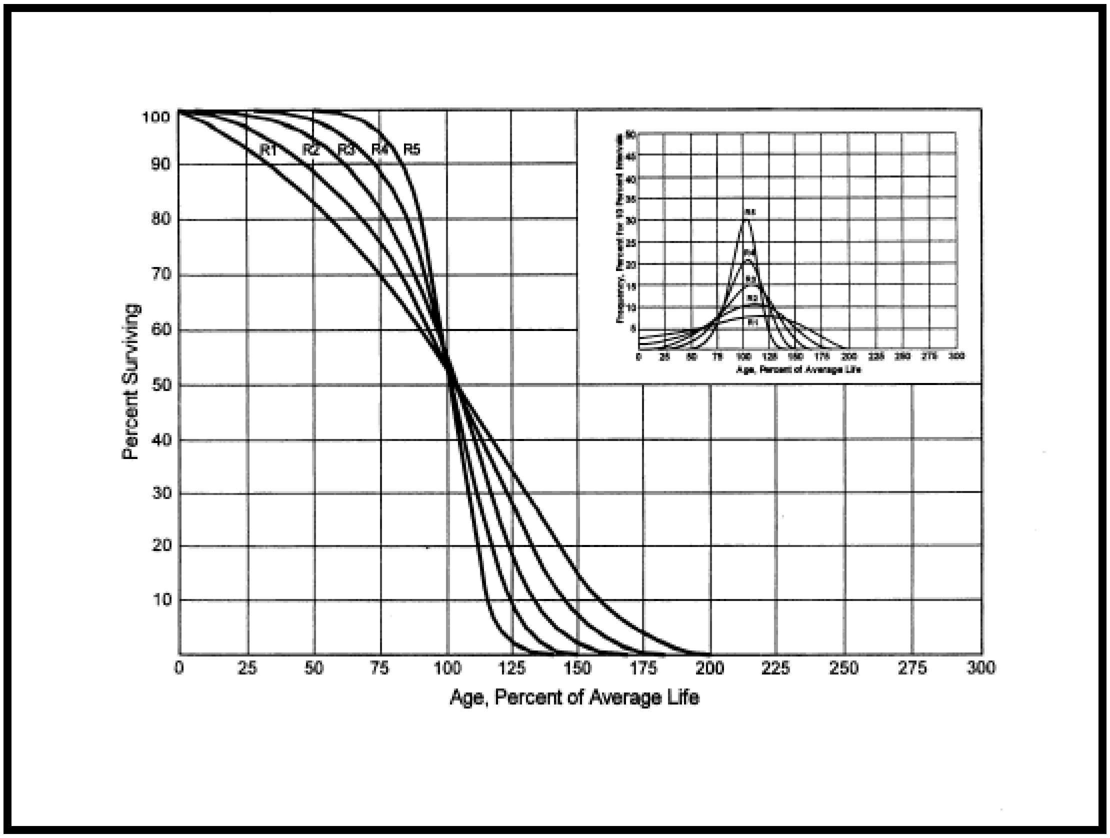
A variety of life estimation approaches were incorporated in the life analyses. Both Simulated Plant Record ("SPR") analysis and Actuarial Analysis are commonly used mortality analysis techniques for gas utility property. Historically, SJG has used SPR analysis to evaluate lives of its asset groups. The SPR balances approach was used for each account within a function where sufficient activity occurred within the account. Since some vintage information is available, actuarial analysis was performed on the largest accounts, primarily in the distribution function. For the accounts using actuarial analysis the experience bands varied depending on the amount of data. Judgment was used to a greater or lesser degree on all accounts. Each approach used in this study is more fully described in a later section.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Consistent with the prior study some accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. Matching data in observed life tables for each experience and placement band to an Iowa Curve requires visual examination. As stated in Depreciation Systems by Wolf and

Fitch, “the analyst must decide which points or sections of the curve should be given the most weight. Points at the end of the curve are often based on fewer exposures and may be given less weight than those points based on larger samples” (page 46). Some analysts chose to use mathematical fitting as a tool to narrow the population of curves using a least squares technique. Use of the least squares approach does not imply a statistical validity, however, because the underlying data does not meet criteria for independence between vintages and the same average price for property units through time. Thus, Depreciation Systems cautions, “… the results of mathematical fitting should be checked visually and the final determination of best fit made by the analyst” (page 48). This study uses the visual matching approach to match Iowa Curves, since mathematical fitting produces theoretically possible curve matches. Visual examination and experienced judgment allow the depreciation professional to make the final determination as to the best curve type.

Detailed information for each account is shown later in this study and in workpapers.

Simulated Plant Record Procedure (SPR)

The SPR - Balances approach is one of the commonly accepted approaches used to analyze mortality characteristics of utility property. SPR was applied to all accounts due to the unavailability of sufficient vintaged transactional data. In this method, an Iowa Curve and average service life are selected as a starting point of the analysis and its survivor factors are applied to the actual annual additions to give a sequence of annual balance totals. These simulated balances are compared with the actual balances by using both graphical and statistical analysis. Through multiple comparisons, the mortality characteristics (as defined by an average life and Iowa Curve) that are the best match to the property in the account can be found.

The Conformance Index (CI) is one measure used to evaluate SPR analyses. CIs are also used to evaluate the "goodness of fit" between the actual data and the Iowa Curve being referenced. The sum of squares difference (SSD) is a summation of the difference between the calculated balances and the actual balances for the band or test year being analyzed. This difference is squared and then summed to arrive at the SSD, where *n* is the number of years in the test band.

$$SSD = \sum_1^n (Calculated\ Balance_i - Observed\ Balance_i)^2$$

This calculation can then be used to develop other calculations, which the analyst feels might give a better indication for the “goodness of fit” for the representative curve under consideration. The residual measure (RM) is the square root of the average squared differences as developed above. The residual measure is calculated as follows:

$$RM = \sqrt{\left(\frac{SSD}{n}\right)}$$

The CI is developed from the residual measure and the average observed plant balances for the band or test year being analyzed. The calculation of conformance index is shown below:

$$CI = \frac{\sum_1^n Balances_i / n}{RM}$$

The retirement experience index (REI) gives an indication of the maturity of the account and is the percent of the property retired from the oldest vintage in the band at the end of the test year. Retirement indices range from 0 percent to 100 percent and a REI of 100 percent indicates that a complete curve was used. A retirement index less than 100 percent indicates that the survivor curve was truncated at that point. The originator of the SPR method, Alex Bauhan, suggests ranges of value for the CI and REI. The relationship for CI proposed by

Bauhan is shown below[1]:

CI	Value
Over 75	Excellent
50 to 75	Good
25 to 50	Fair
Under 25	Poor

The relationship for REI proposed by Bauhan[2] is shown below:

REI	Value
Over 75	Excellent
50 to 75	Good
33 to 50	Fair
17 to 33	Poor
17 and below	Valueless

Depreciation analysts have used these measures in analyzing SPR results for nearly 60 years, since the SPR method was developed. Both the CI and REI statistics provide the analyst with important information with which to make a comparison between a band of simulated or calculated balances and the observed or actual balances in the account being studied. It is important to understand that observing the pattern of best-fitting curves over various bands, as well as considering other company and asset-specific information, is important in the ultimate decision for the most appropriate live and curve combination that will reflect future retirements of each account.

Statistics are useful in analyzing mortality characteristics of accounts, as well as determining a range of service lives to be analyzed using the detailed graphical method. However, these statistics boil all the information down to one, or at most, a few numbers for comparison. Visual matching through comparison between actual and calculated balances expands the analysis by permitting the analyst to view many points of data at a time. The goodness of fit should be

1 Public Utility Depreciation Practices, p. 96.
2 Public Utility Depreciation Practices, p. 97.

visually compared to plots of other Iowa Curve dispersions and average lives for the selection of the appropriate curve and life. Detailed information for each account is shown later in this study and in workpapers.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. In these cases, it is rare for one factor to individually have a, substantial impact on the analysis. However, individual factors may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing upon which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the Liquefied Natural Gas, Transmission, Distribution and General accounts require judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the SPR balances and actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

At the request of SJG, this study continues to use the average life group depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG groups are defined by their respective account dispersion, life, and salvage estimates. A straight-line rate for each ALG group is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense, and dividing the annual depreciation expense by the surviving investment. The resultant rate for each ALG group is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net book cost over the life of each account by averaging many components.

Theoretical Depreciation Reserve

The book depreciation reserve is derived from Company records and is reallocated from a functional level to individual accounts. This Study uses a reserve model that relies on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current expectations were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The ALG method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line, remaining life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(\text{Average Remaining Life})}{(\text{Average Service Life})} * (1 - \text{Net Salvage Ratio})$$

In the workpapers, a theoretical reserve is computed for each account as of December 31, 2018, using the proposed life. The proration factor is computed by developing a ratio of the total book reserve to the total theoretical reserve for Storage, Transmission, Distribution, and General Plant. After each theoretical reserve is computed, each amount is then multiplied by the proration factor to re-establish the book reserve for each account for purposes of then determining proposed depreciation rates.

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also, as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis section, the salvage analysis section, and also in workpapers.

Phase 2 was where the SPR and Actuarial analysis was performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in Phase 2 to develop observed life tables for life analysis. These tables were visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 was the evaluation process that synthesized analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from Phase 2 was further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allowed the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in the final report. The calculation of accrual rates is found in Appendix B. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[3] documents the steps used in conducting this study. Depreciation Systems, page 289, documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, write logic supporting forecasts and estimation, and write final report.

[3] Introduction to Depreciation for Public Utilities and Other Industries, AGA EEI, 2013.

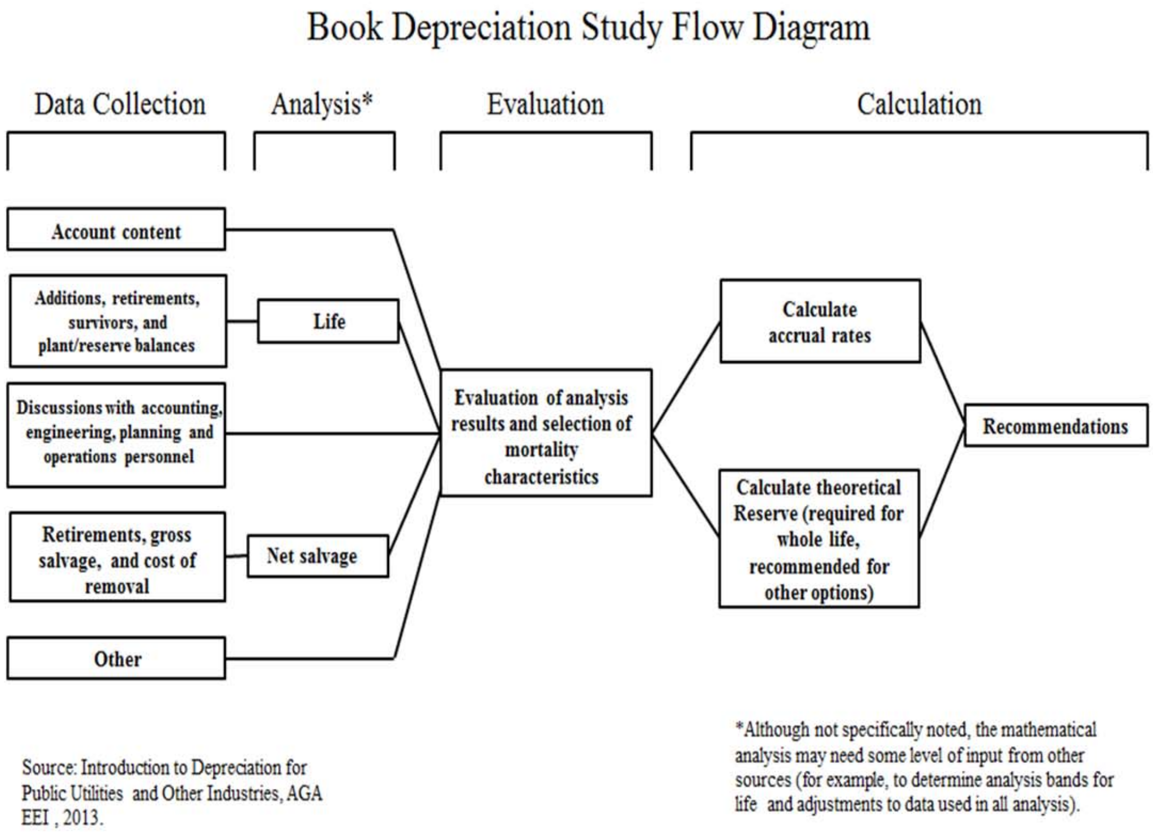


Figure 1

SJG DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable accounts of the Company were calculated by the straight line, average life group, remaining life system. With this approach, remaining lives were calculated according to standard ALG group expectancy techniques, using the Iowa Curves noted in the calculation. For each plant account, the difference between the surviving investment and adjusted for the book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix B.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using either the retirement rate actuarial or the SPR methods. After establishment of appropriate average service lives and retirement dispersion, remaining life was computed for each account. Theoretical depreciation reserve with zero net salvage was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the General Discussion section. The difference between plant balance and theoretical reserve was then spread over the ALG depreciation accruals. Remaining life is shown for each account in the workpapers.

Calculation Process

Annual depreciation expense amounts for all accounts were calculated by the straight line, remaining life procedure.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$\text{Annual Accrual Rate} = \frac{(100\% - \text{Net Salvage Percent})}{\text{Average Service Life}}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, average life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$\text{Composite Remaining Life} = \frac{\sum \text{Original Cost} - \text{Theoretical Reserve}}{\sum \text{Whole Life Annual Accrual}}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation.

$$\text{Annual Depreciation Expense} = \frac{\text{Original Cost} - \text{Book Reserve} - (\text{Original Cost}) * (1 - \text{Net Salvage \%})}{\text{Composite Remaining Life}}$$

Where the net salvage percent represents future net salvage.

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$\text{Annual Depreciation Rate} = \frac{\sum \text{Annual Depreciation Expense}}{\sum \text{Original Cost}}$$

These calculations are shown in Appendix B. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. Book depreciation reserves at an individual account level and the theoretical reserve computation was used to compute a composite remaining life for each account.

LIFE ANALYSIS

The SPR semi actuarial analysis method was applied to the majority of the accounts for SJG. For each account where this method was used, a simulated plant record method analysis was performed at intervals for the overall band and at various intervals (usually 10 and/or 5-year) within the overall balance period. In addition to reviewing the SPR analysis for each band and account, where possible, a graphical comparison between actual and simulated balances was performed.

The retirement rate actuarial analysis method was applied to those accounts where vintage retirement detail is available. Vintaged retirement detail by account is only available from 2003 forward. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Survivor Curves to obtain the most appropriate match. Those analyses are contained in the workpapers.

In the actuarial analysis, using the overall band (i.e., placement from earliest vintage year through 2018 and experience band from earliest available experience year, 2003, through 2018) for each account, the most recently approved survivor curves were used as a starting point. Then, using the same life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (e.g., L, S, or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall placement band, different placement bands were plotted and analyzed. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. Generally, the goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid-range of the plots. When adequate activity is present a graph of the observed life table versus the proposed life and curve is provided for each account where the actuarial life analysis was used. For assets with a long life, a period of ten years' experience was generally inconclusive for actuarial analysis and SPR was given more weight to detect historic trends.

These results are used in conjunction with all other factors that may influence asset lives.

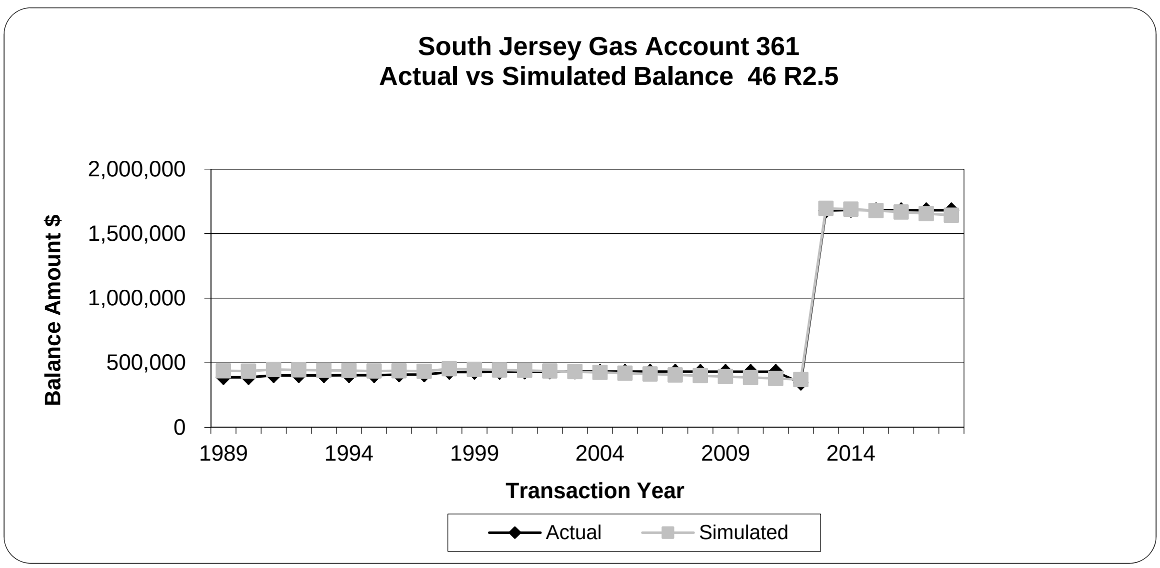
Liquefied Natural Gas Plant

Account 361 Structures and Improvements (46 R2.5)

This account consists of structures and various improvements associated with the natural gas plant. There is approximately $1.7 million in this account. The existing life is 46 R2.5. The average age of this account is 12.31 years.

Discussions with Company personnel indicated that there are five buildings and one shed in this account. With the exception of the original building, which houses the generators, all of these structures were built later. The original building has been re-coated and doors and windows have been replaced, but the skin and foundation are original.

When reviewing the SPR results, top ranked curves have REIs that are not in the excellent range and the CIs are in the poor range. When narrowing the curves to REIs of 90 and above for bands of 30 years and longer, the R2.5 curve is consistently the first choice. A life in the mid-40s is reasonable given that the steel building would last longer, but some of the sub systems would need to be replaced earlier. Based on the study analysis, type and age of assets, and judgment, the 46 R2.5 dispersion is retained. A comparison of actual versus simulated balances is shown below for the 46 R2.5.

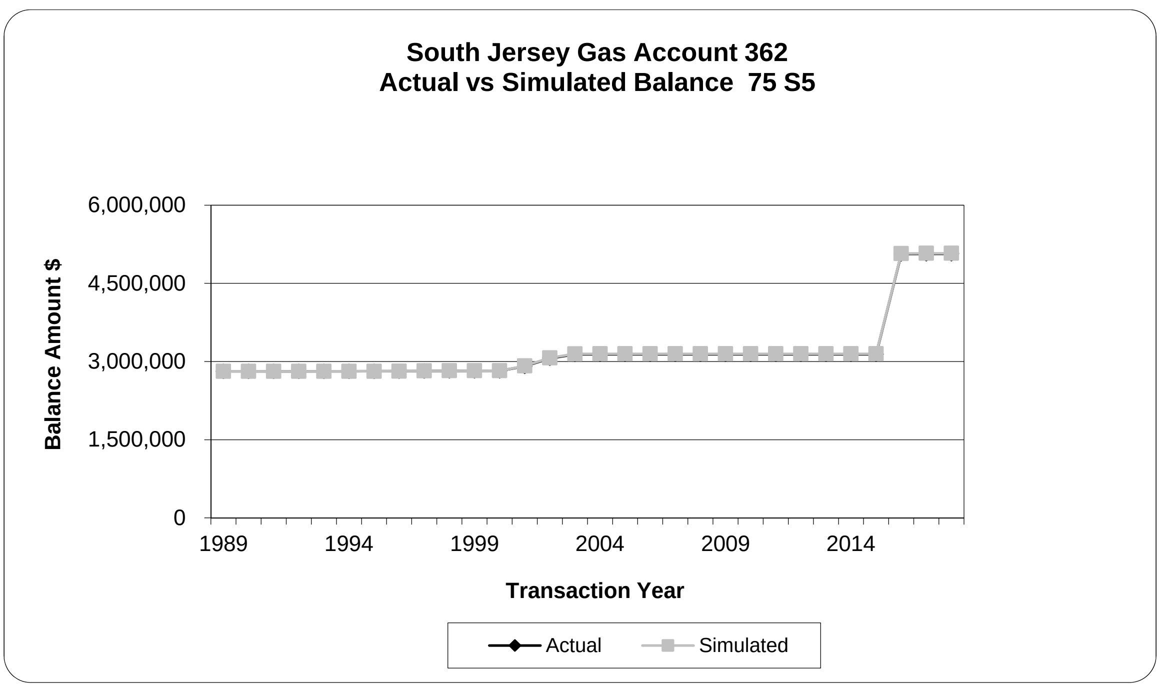


Account 362 Gas Holders (75 S5)

This account consists of gas holders used in connection with the storage of gas. There is approximately $5.1 million in this account. The existing life is 50 S5. The average age of this account is 26.87 years.

Discussions with Company personnel indicated that the tank is basically original equipment but was recoated around 20 years ago. Over time the Company has replaced heaters, replaced and automated sumps, automated lighting systems, upgraded level systems and relief valves, and upgraded overflow valve. Around half of the assets in this account are related to short-lived (20 year) assets such as coatings and automation, but the tank would last longer.

All the SPR runs show REIs of less than 1, in the valueless range. The CIs are all in the excellent range, but with life indications far beyond a range of reasonableness. This study recommends increasing the life of this account to 75 years and retaining the S5 dispersion. A comparison of actual versus simulated balances is shown below for the 75 S5.

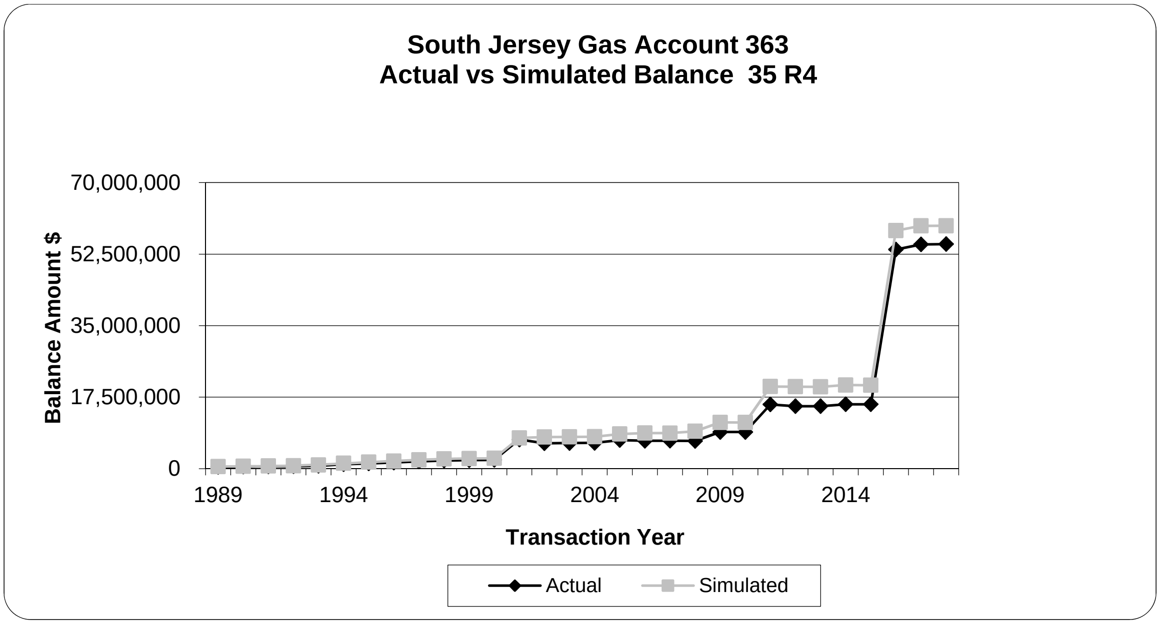


Account 363 Purification Equipment (35 R4)

This account consists of equipment used to remove impurities from gas and for conditioning gas. There is approximately $55.0 million in this account. The existing life is 30 R4. The average age of this account is 4.79 years.

Discussions with Company personnel indicated essentially all assets in this account have been replaced or modernized since original installation. Three vaporizers have been added over time, with the most recent replacement replaced at 29 years old in 2002. The third vaporizer is being evaluated for replacement at around 30 years old. The largest asset group in this account is the liquefier, which was recently replaced at around 30 years. There are two boil-off compressors, which run 24 hours a day. They are electric driven and have routine, smaller overhauls under O&M. The original compressors were replaced at around 30 years as well. Some of the software may have a 5-10 years life. The newer equipment may see a slightly longer life than the earlier generations of equipment. However, there are a number of other assets such as software, automation, etc., that would have much shorter life.

The SPR results show lives of 15 to 18 years, which is not a reasonable expectation for the type of assets. Based on the analysis, type of assets, discussions with Company personnel and judgment, this study recommends moving the life to 35 years but retaining the R4 dispersion. A comparison of actual versus simulated balances is shown below for the 35 R4.



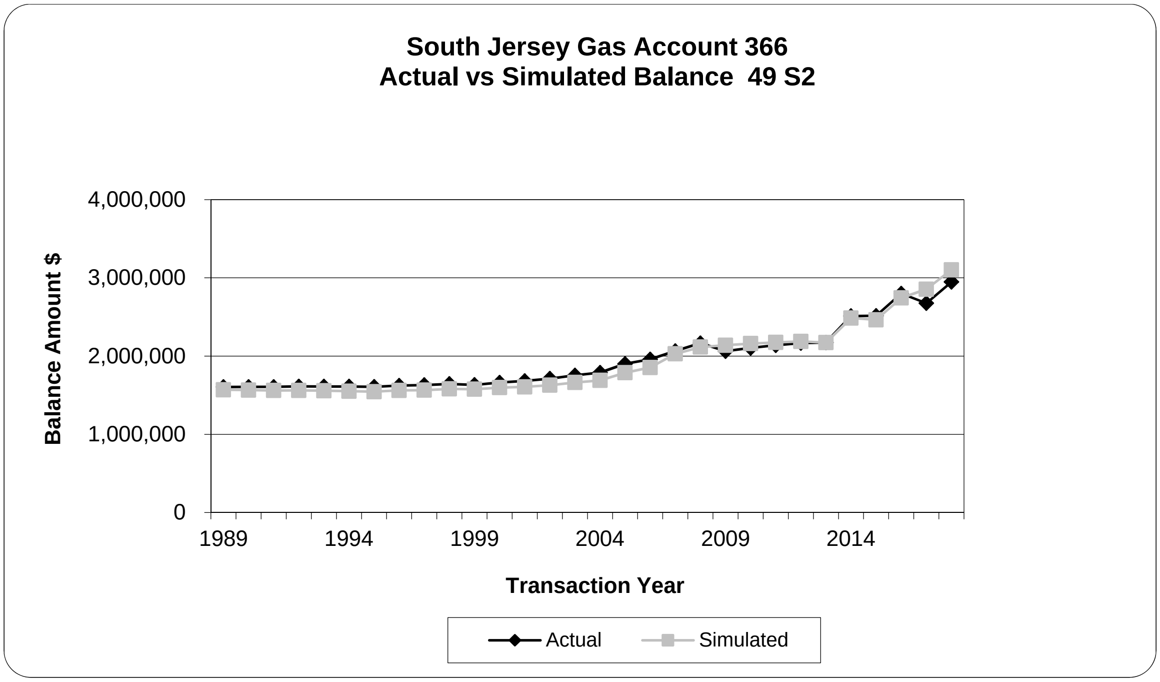
Transmission Plant

Account 366 Structures and Improvements (49 S2)

This account consists of structures and various improvements associated with the transmission plant. There is approximately $2.9 million in this account. The existing life is 50 R4. The average age of this account is 19.79 years.

Discussions with Company personnel indicated that a building life of 50 is reasonable. Some buildings are pre-constructed and others are masonry buildings. There are other assets, such as HVAC, that would have a shorter life.

In bands of 30 years and greater, SPR results show the top ranked curve as a 49 S2. The analyses indicate poor Cis but some excellent REIs. Given the type of investments in this account and discussions with Company personnel, this study recommends moving to a 49 year life with the S2 dispersion. A comparison of actual versus simulated balances is shown below for the 49 S2.

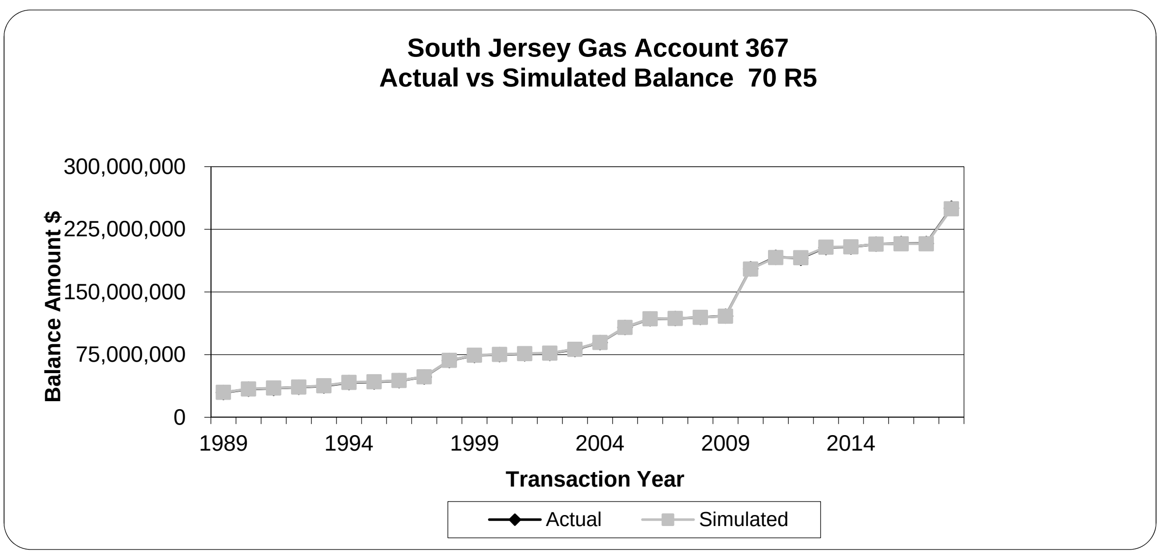

South Jersey Gas Account 366
Actual vs Simulated Balance 49 S2
Balance Amount $
4,000,000
3,000,000
2,000,000
1,000,000
0
1989
1994
1999
2004
2009
2014
Transaction Year
Actual
Simulated

Account 367 Mains (70 R5)

This account consists of the cost of steel mains and other miscellaneous assets used in connection with transmission operations. There is approximately $250.3 million in this account. The existing life is 68 R4. The average age of this account is 13.8 years.

Discussions with Company personnel indicated there are approximately 146 miles of steel transmission mains, all of which is cathodically protected. The existing 50 year life appears shorter than expected for the types of assets in this account, and a life of at least 60 years is a more reasonable expectation. None of the programs currently affect transmission mains. PHMSA will affect transmission mains, but at this point it is still in the planning stage. The Company expects that they may renew 40-50 miles of mains and retest the rest. In-line inspections are finding more problems that can be repaired before they become major issues, and the level of repair is increasing.

In bands of 30 years and greater, SPR results show the REIs in the valueless range and CIs in the excellent range. However, the life range for some of the top ranked curves is outside the range of reasonable. Based on experience with Account 376, which will be discussed later, this study recommends moving to a 70 year life with the R5 dispersion. A comparison of actual versus simulated balances is shown below for the 70 R5.



Account 368 Compressor Station Equipment (35 R4)

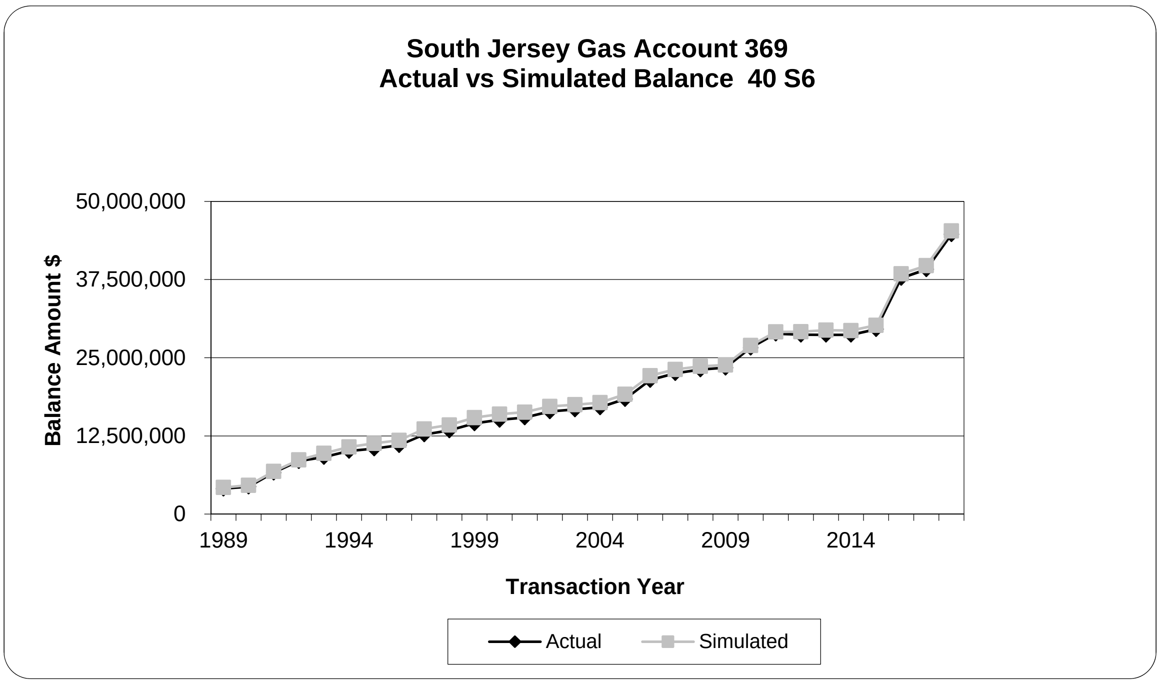
This account consists of compressor station equipment used in connection with transmission operations. Interviews with Company personnel indicated that there is currently no investment. One station is in the process of being constructed, and is scheduled to be in service around November 2020. There will be two units (15k HP total), both of which are centrifugal with electric drive. These units will run a small number of hours during the year. The Company would expect a life somewhere between 30 and 40 years to be reasonable. Based on Company expectations and industry expectations for this type of equipment, this study recommends 35 R4 and a whole life rate of 2.86% be approved and applied to investment when put in service.

Account 369 Measuring and Regulating Equipment (40 S6)

This account consists of the measuring and regulating station equipment used in connection with transmission operations. There is approximately $44.7 million in this account. The existing life is 30 S6. The average age of this account is 12.62 years.

Interviews with Company personnel indicated that the city gate is always a custody transfer point and that there are around 150 stations in total. Transmission stations tend to be larger and use control valves, all of which are SCADA driven with security equipment. Nearly all have pressure regulation, and regulators are repaired on site. The Company is rapidly growing and will upgrade regulators due to capacity needs. They have started using a new treatment, aluminum spray coatings, on above ground stations that will not corrode. Retirements are a result of parts wearing out and capacity increase needs. The Company believes the new stations, operationally, could last 40 years or more but that the older stations may only last 30 or less.

In bands of 30 years and greater, SPR results show the top ranked curve is an S6 33 with an excellent REI of 100 and the CI in the good range. Even though a lower life is indicated, moving the life longer is reasonable due to the replacement of older stations and newer coatings/technology. Based on the SPR results and Company input, this study recommends moving to a 40 year life and retaining the S6 dispersion. A comparison of actual versus simulated balances is shown below for the 40 S6.

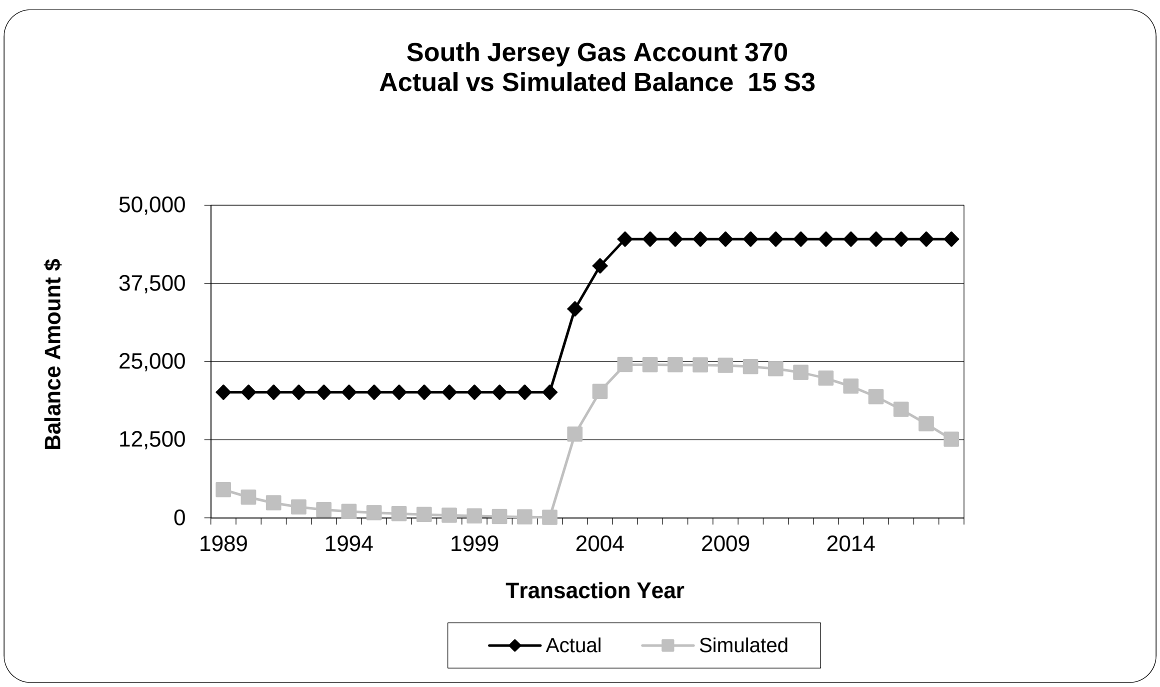


Account 370 Communication Equipment (15 S3)

This account consists of all communication equipment including mobile and fixed radio systems along with telephone, telemetering, and other miscellaneous communication equipment used in connection with transmission activities. There is approximately $44.6 thousand in this account. The existing life is 25 S3. The average age of this account is 29.11 years.

Discussions with Company personnel indicated that 25 years for transmitters and SCADA is long, especially with newer technology and electronics in the field.

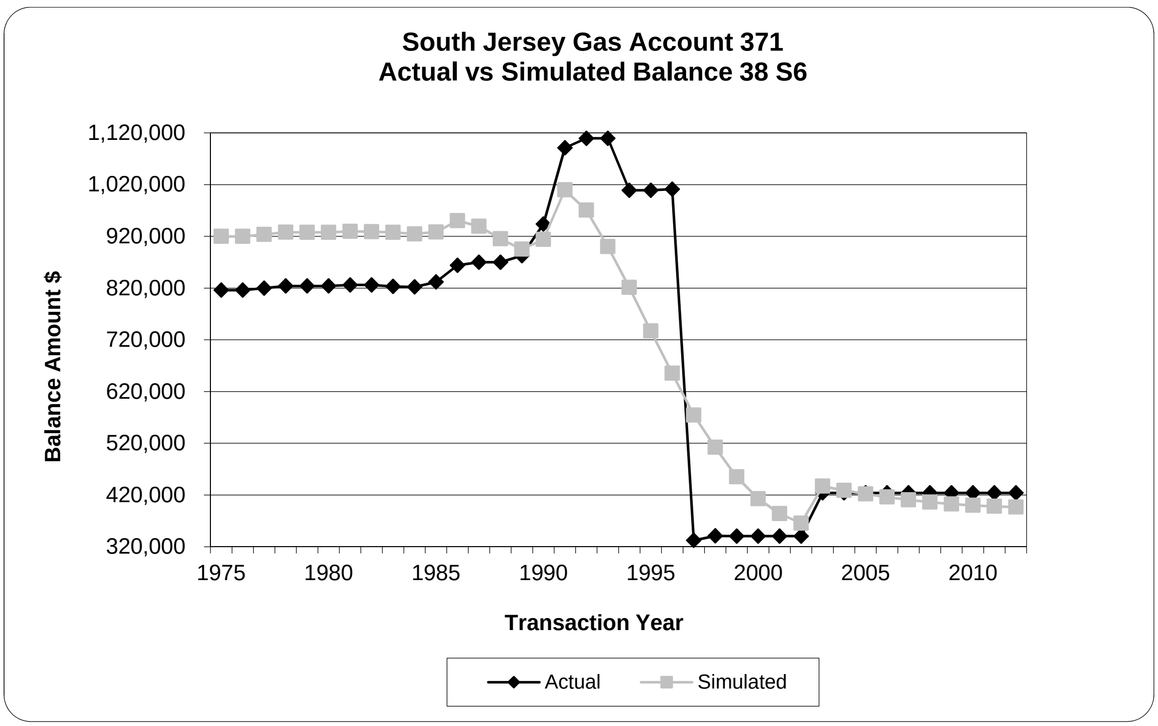
Because retirements have been very limited in this account, the SPR analysis does not produce any meaningful results. Giving consideration to the historical activity, the type of assets, and the impact of software technology, this study proposes to move the life of the account to 15 years and retain the existing S3 dispersion. A comparison of actual versus simulated balances is shown below for the 15 S3.



Account 371 Other Equipment (38 S6)

This account consists of the cost of various other equipment used in connection with transmission assets and activities. There is approximately $184.1 thousand in this account. The existing life is 38 S6. The average age of this account is 26.44 years.

The top ranked curve with an REI of 100 in bands of 20 years and longer is the S6 dispersion. Given the age of the assets, this study proposes to retain the 38 year life and the S6 dispersion. A comparison of actual versus simulated balances is shown below for the 38 S6.

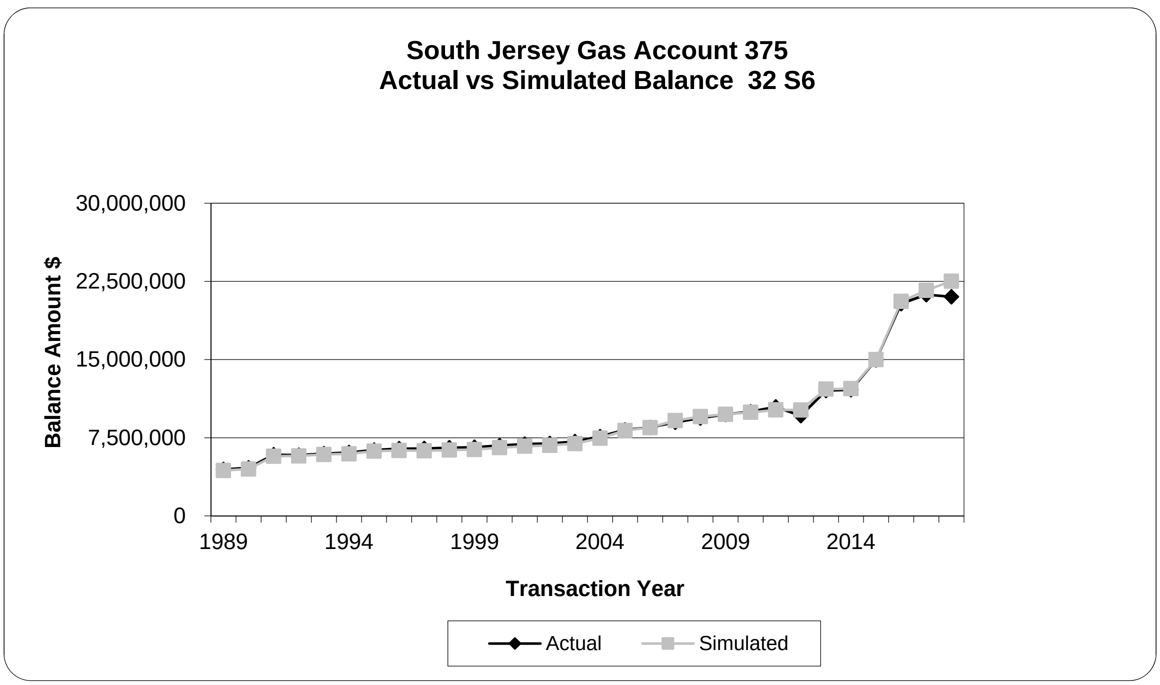


Distribution Plant

Account 375 Structures and Improvements (32 S6)

This account consists of structures and various improvements associated with the distribution plant. There is approximately $20.9 million in this account. The existing life is 34 L5. The average age of this account is 9.73 years.

For bands of 20 years and longer, SPR analysis shows the S6 dispersion curve as the top ranked with an REI of 100 but with fair to poor CIs. Besides long-lived assets such as buildings, there are many short lived items in this account such as lighting, pumps, roofs, and other items. Based on the mix of assets in this account and SPR results, this study recommends moving to a 32 year life with the S6 dispersion. A comparison of actual versus simulated balances is shown below for the 32 S6.

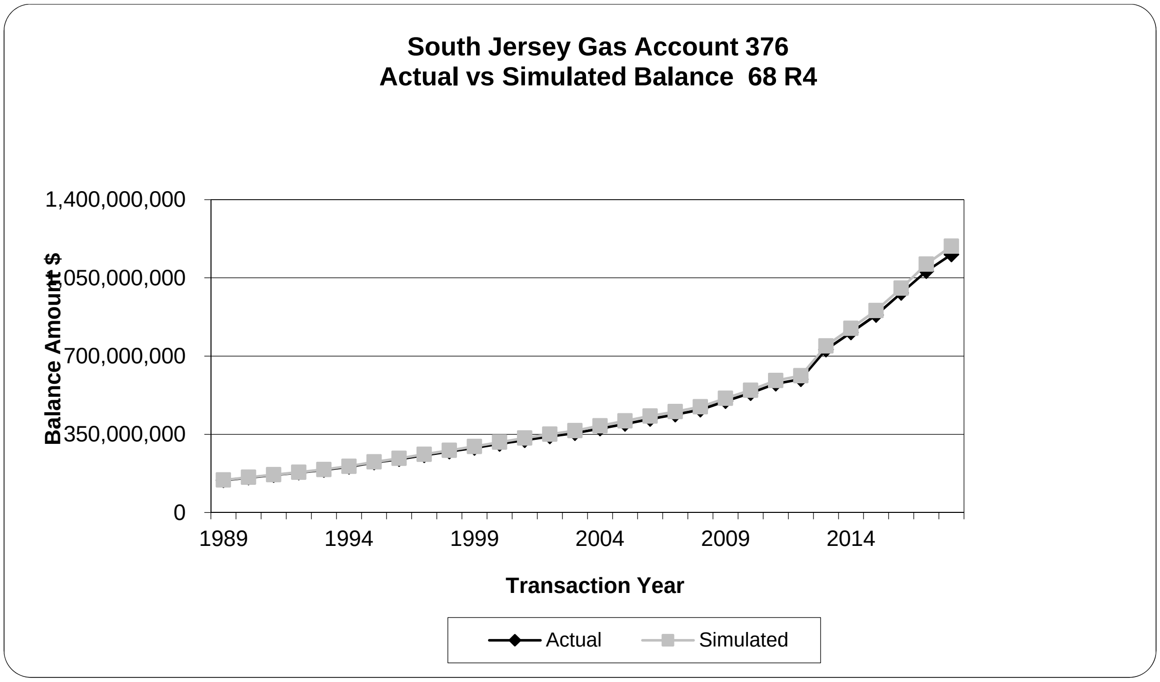


Account 376 Mains (68 R4)

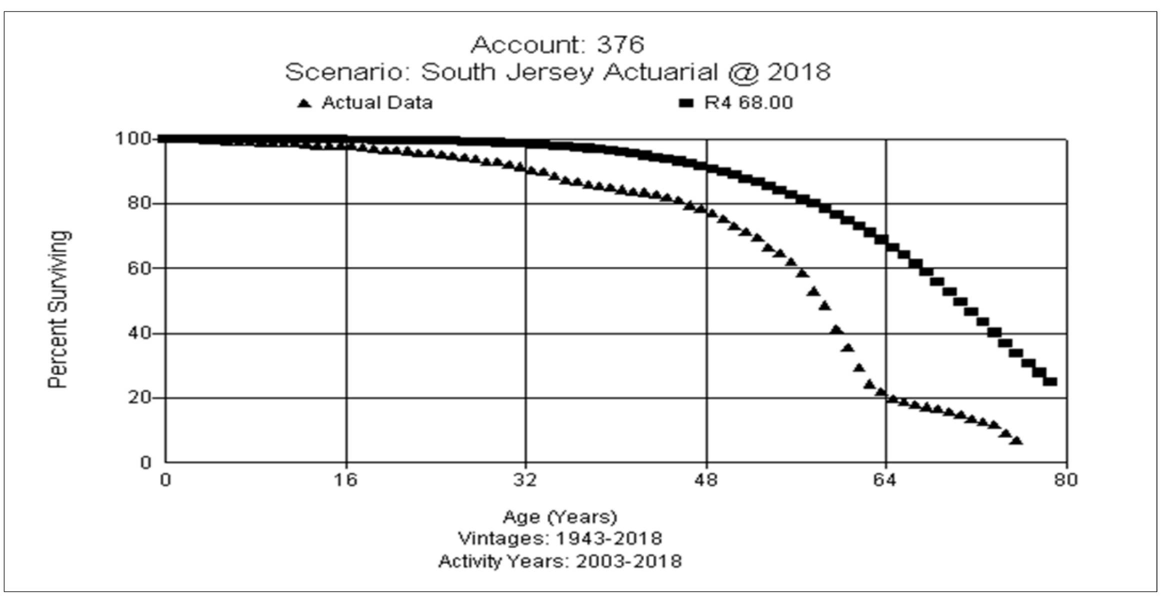
This account consists of the cost of steel mains and other miscellaneous assets used in connection with distribution operations. There is nearly $1.2 billion in this account. The existing life is 68 R4. The average age of this account is 12.28 years.

Discussions with Company personnel indicated that there is approximately 6,000 miles of mains. All cast iron has been removed from the system and bare steel is expected to be entirely removed by late 2020 or mid-2021. The pipe replacements are plastic and are expected to have as long a life as the steel being replaced or longer. Unless there is a pressure issue, steel will be replaced with plastic. The primary cathodic protection is anodes on wrapped steel, which are expected to last 15-20 years. The wells for the rectifiers will last around 25 years. The Company has renewed a significant amount of pipe, and the renewals may be affecting the historical life analysis as the programs were retiring some pipe earlier than the projected life. Approximately 74% of distribution is plastic and of that, 25% is Aldel-A. The Company does not currently have a program to replace Aldel-A.

For Account 376 SPR analysis, bands of 40 years and longer show the R4 dispersion curve as one the top four ranked with an REI of 100 and an excellent CI. However, the life associated with the R4 is 53 years, which is less than the existing 68 R4. Leaving the life at 68 years is reasonable until or if the Company starts a early generation plastic replacement program. Once the current replacement program nears completion, the dispersion, and eventually the life, will begin to increase back to the expected level. Based on the discussions with Company personnel, the mix of assets, and the analysis, this study recommends retention of the 68 R4 dispersion. A comparison of actual versus simulated balances is shown below for the 68 R4.



In the 10 years of actuarial data (2003-2012) available for analysis, the widest placement band and experience band produce a curve that goes to 20 percent surviving. Although the level may not rise to a statistically valid sample, as with the SPR analysis, the actuarial analysis also indicates a life less than the existing and movement to a slightly flatter dispersion. A graph of the account observed life table versus the proposed life and curve is shown below.

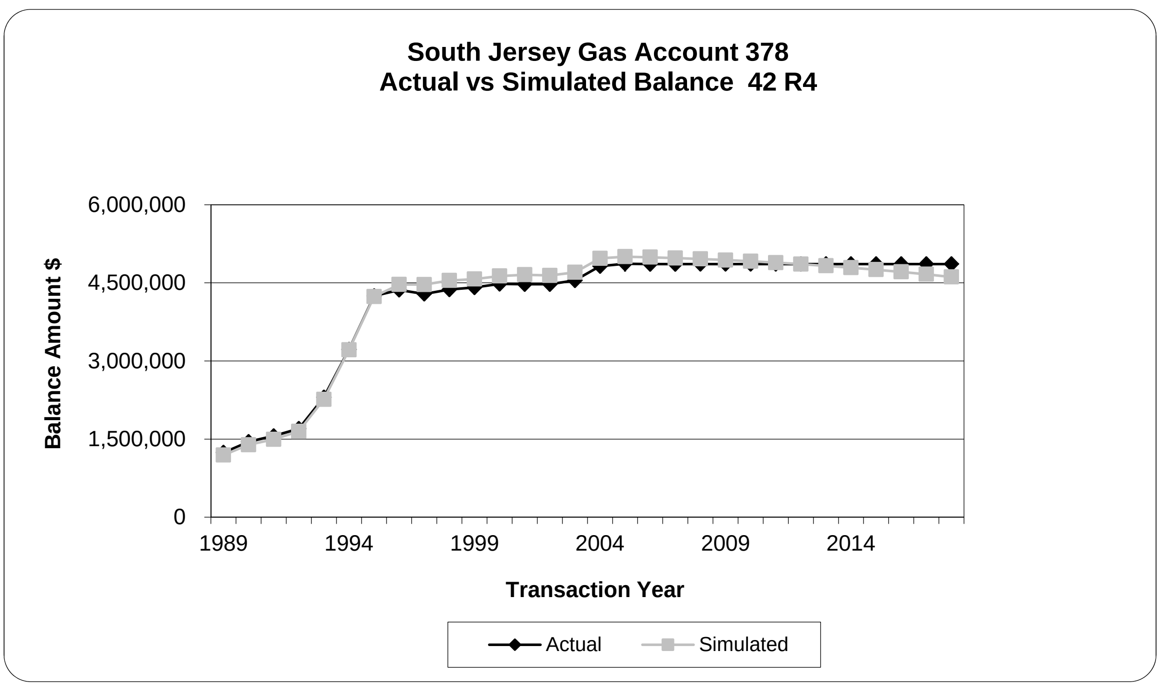


Account 378 Measuring and Regulating Station Equipment- General (42 R4)

This account consists of the measuring and regulating station equipment used in connection with general distribution operations. There is approximately $4.9 million in this account. The existing life is 38 R4. The average age of this account is 26.78 years.

Discussions with Company personnel indicated that they do not expect the "MegaRule" to materially affect the level of retirements in this account. They do not see any specific reason that the life would materially increase or decrease and believe the existing 38 years or slightly longer would be reasonable.

For SPR analysis, the top ranked curve with excellent REI and fair CI is the S6 dispersion. About half-way down the ranking, the R4 dispersion has a REI of 100 but the CI is in the poor range. Keeping the same dispersion as existing, giving consideration to the discussions with Company personnel, and using judgment, this study recommends moving to a 42 year life and retaining the R4 dispersion. A comparison of actual versus simulated balances is shown below for the 42 R4.

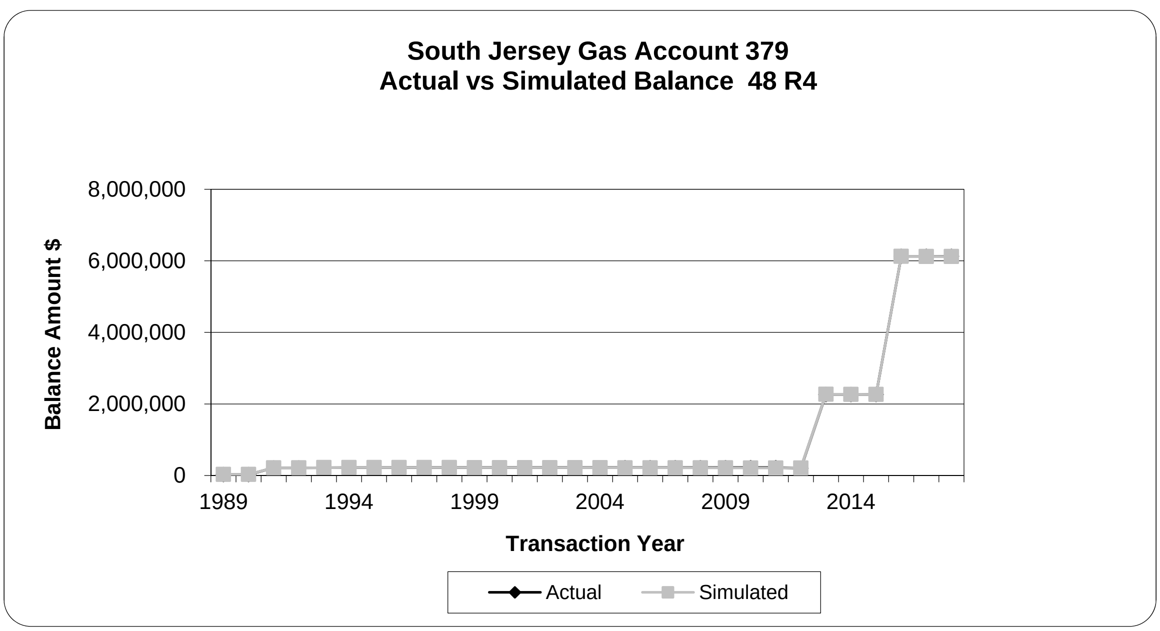


Account 379 Measuring and Regulating Station Equipment- City Gate (48 R4)

This account consists of the measuring and regulating station equipment used in connection with City Gate distribution operations. There is approximately $6.1 million in this account. The existing life is 38 R4. The average age of investment is 5.38 years.

Discussions with Company personnel indicated that there is a small sample size, with only seven city gates. They may replace control valves or heaters, but they do not generally replace stations. The gates are in buildings (for noise reasons) so they are more protected from the environment. The Company expects, operationally, that there should be some difference in life between a DRS (378) and a city gate, with the city gates having a slightly longer life.

The SPR analysis produces both excellent REI and CI with the R4 dispersion and a life of 48 years. This supports the discussions with Company personnel and a move toward a slightly longer life in both Account 378 and 379. This study recommends moving to a 48 year life and retaining the R4 dispersion. A comparison of actual versus simulated balances is shown below for the 48 R4.

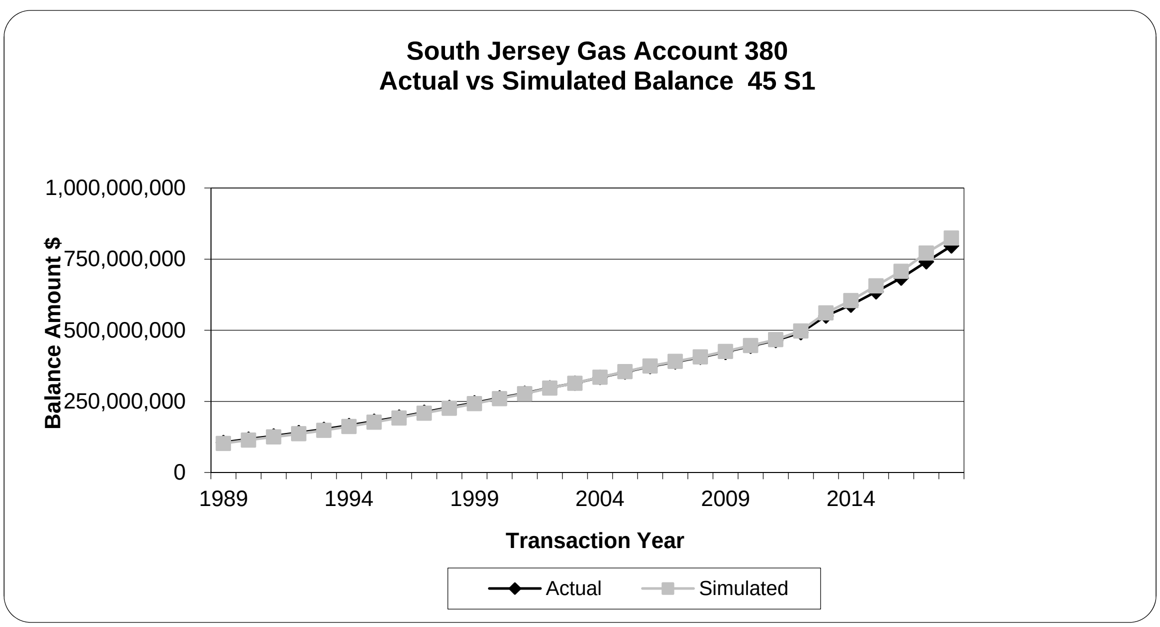


Accounts 380 Services (45 S1)

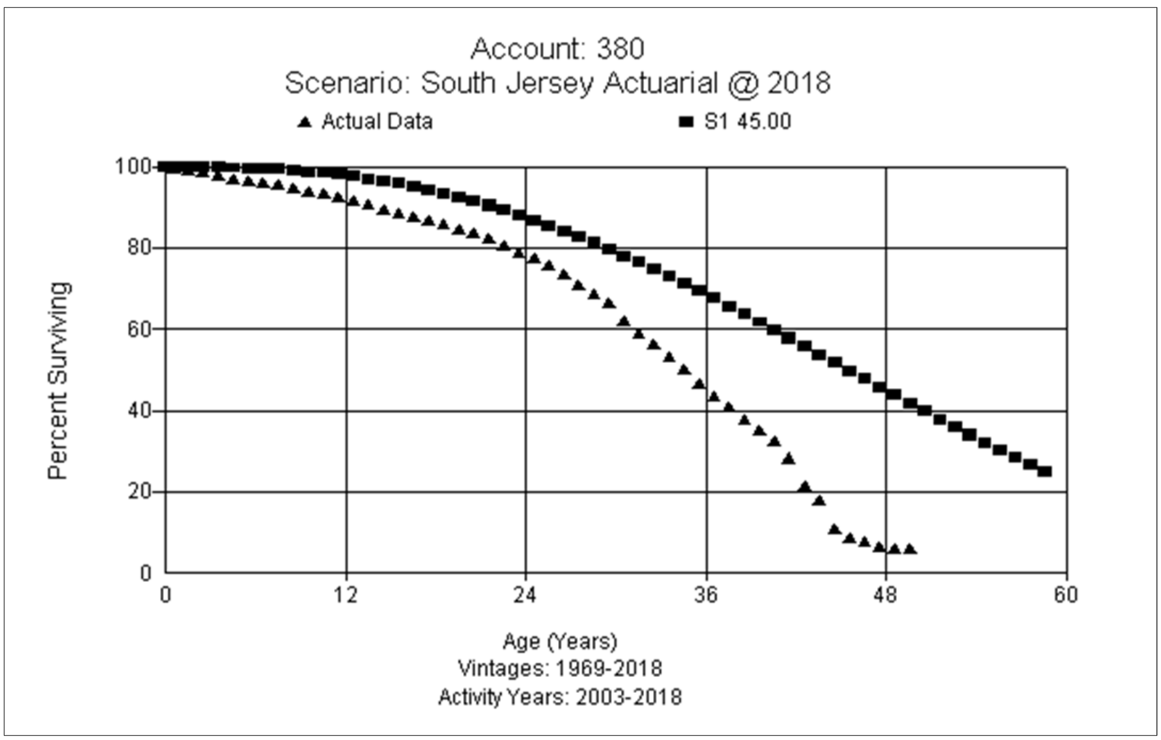
This account consists of the cost of all types of services associated with the distribution operations. There is approximately $796.7 million in the account. The existing life is 45 S1. The current average age of investment is approximately 9.62 years.

Discussions with Company personnel indicate EFVs are one of the triggers of replacement of services (SHARP Program). Risers are part of the service. Main replacement work also includes replacing some services. Service line lives may be shorter than in the past due to the concurrent replacement with mains, among other reasons. Any steel service will be replaced with plastic when there is mains work. After the steel main program is over, service life as seen in the analysis may begin to increase.

The top ranked curves in the SPR analysis produces are signaling lives that are below the existing lives. Generally, the REIs are excellent and the Cis are fair to good. Considering the replacement activity is depressing the life shown in the analysis, this Study retains the existing life rather than to decrease it. A comparison of actual versus simulated balances is shown below for the 45 S1.



There is just over ten years of actuarial data from 2003-2012 available for analysis. Generally, the life indications, from a short experience band, appear to be noting the effects of the recent replacement programs in the life characteristics. In this case, the stub curve goes to near zero percent surviving. Similar to the SPR analysis, the best fits indicate a life about 10 years less than the existing life and do not match the future life expectations after the replacement programs. The life indications suggest a decrease (similar to mains). Given the large effort to replace aging infrastructure, neither SPR analysis nor actuarial analysis may yield life characteristics applicable to the long-term projection for current investment. With these considerations, this study recommends retaining the existing 45 S1. A graph of the account observed life table versus the proposed life and curve is shown below.

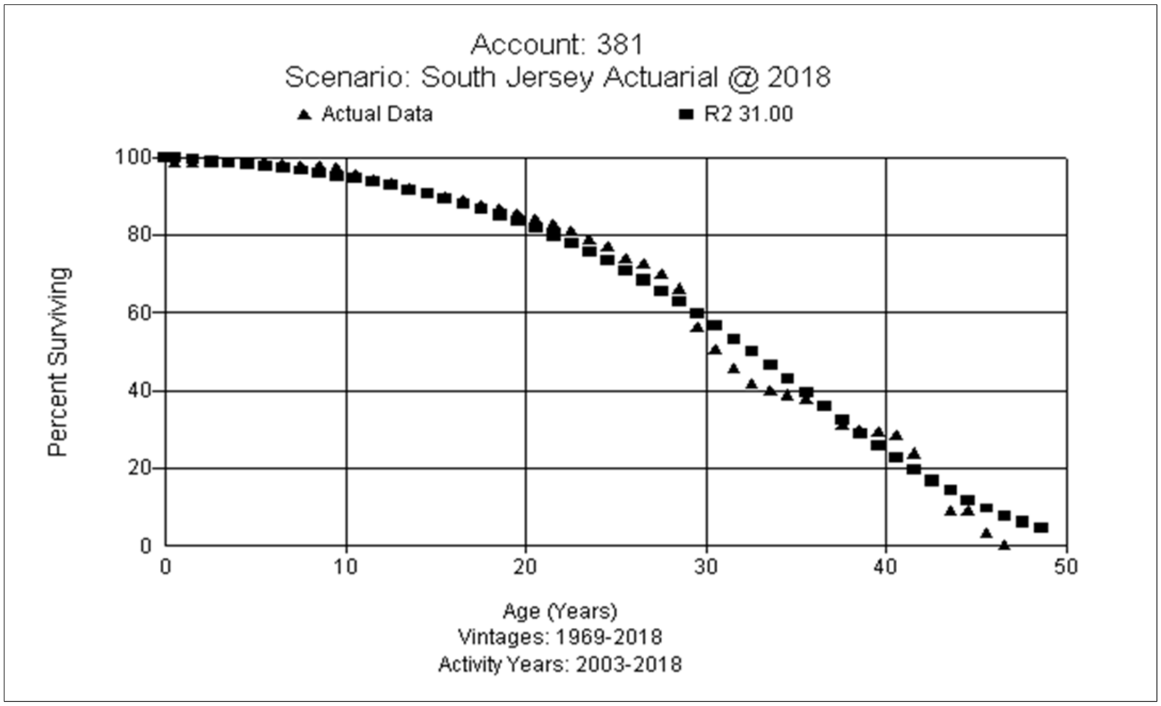


Account 381 Meters (31 R2)

This account consists of the cost of meters associated with distribution operations. There is approximately $66.5 million in the account. The existing life is 39 S0. The current average age of investment is approximately 8.11 years.

Discussions with Company personnel indicated they no longer repair residential meters. This change will have the effect of lowering the life of meters since repairing meters and keeping them in service will extend the useful life of those meters. They will test and, if possible, repair commercial meters. Currently, there are nearly 400,000 meters on the system. Larger meters (over 500 CFH) are subject to mandatory replacement every 10 years, which is about 5-6% per year. Smaller meters are targeted for replacement when they reach 15-20 years, although there is no mandate and it does not always happen. The State sampling criteria is tightening in 2020 and it may trigger a higher level of meter replacements going forward. The Company replaced 40-45 thousand meters due to Hurricane Sandy.

Both the SPR and actuarial analysis were performed. The SPR analysis produces excellent REIs but poor to fair CIs in the fuller bands. In this account, the actuarial analysis was useful in projecting future life characteristics since the life-cycle for these assets is shorter than seen in Mains or Services and there were sufficient transactional activity. The actuarial analysis produced a great fit in the fuller placement 1969-2018 and experience band 2003-2018 with the 31 R2. Based upon the analyses, the changing sampling requirements, and general expectation for meters to have a shorter, not longer, life, this study recommends moving to a 31 year life and the R2 dispersion. A graph of the account observed life table versus the proposed life and curve is shown below.

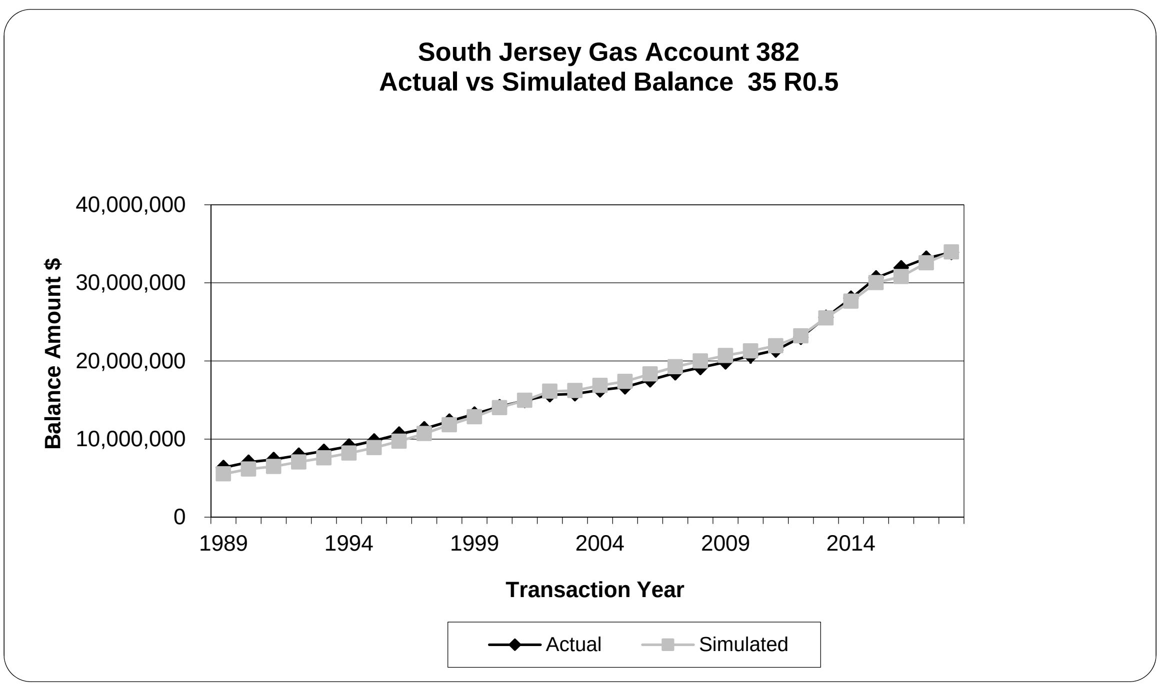

Account: 381
Scenario: South Jersey Actuarial @ 2018
Actual Data
R2 31.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1969-2018
Activity Years: 2003-2018

Account 382 Meter Installations (35 R0.5)

This account consists of the cost of meter installations associated with distribution operations. There is approximately $33.9 million in the account. The existing life is 34 R0.5. The current average age of investment is approximately 9.75 years.

Discussions with Company personnel indicated that they are currently using a pre-fabricated meter bar, and began using these at least 15 years ago. The meter bar does not include the riser. Company personnel indicated that 75% of the time when a meter is pulled the meter bar is replaced as well. This would suggest the life of this account should be reasonably close to the 31 years life of the meters.

In the SPR analysis, the focus was on curves that produce an REI of 100, but the CIs are in the poor to fair range. The 35 R0.5 is the top ranked curve with an excellent REI of 100 in the 30 year band and is 35.6 across all the other bands. A comparison of actual versus simulated balances is shown below for the 35 R0.5.

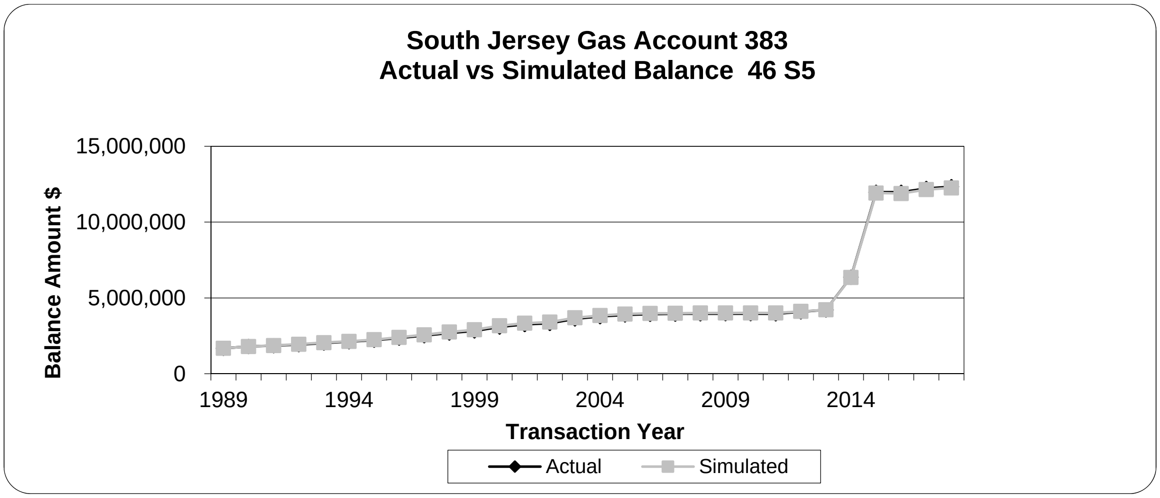


Account 383 House Regulators (46 S5)

This account consists of the cost of house regulators associated with distribution operations. There is approximately $12.3 million in this account. The existing life is 45 R4. The current average age of investment is approximately 9.96 years.

Discussions with Company personnel indicated that since the implementation of Maximo in 2014 they are doing a more accurate job at retiring regulators, which is expected to decrease the life indications going forward. There have been enough years of the higher level of transactions to materially affect the life analysis at this point.

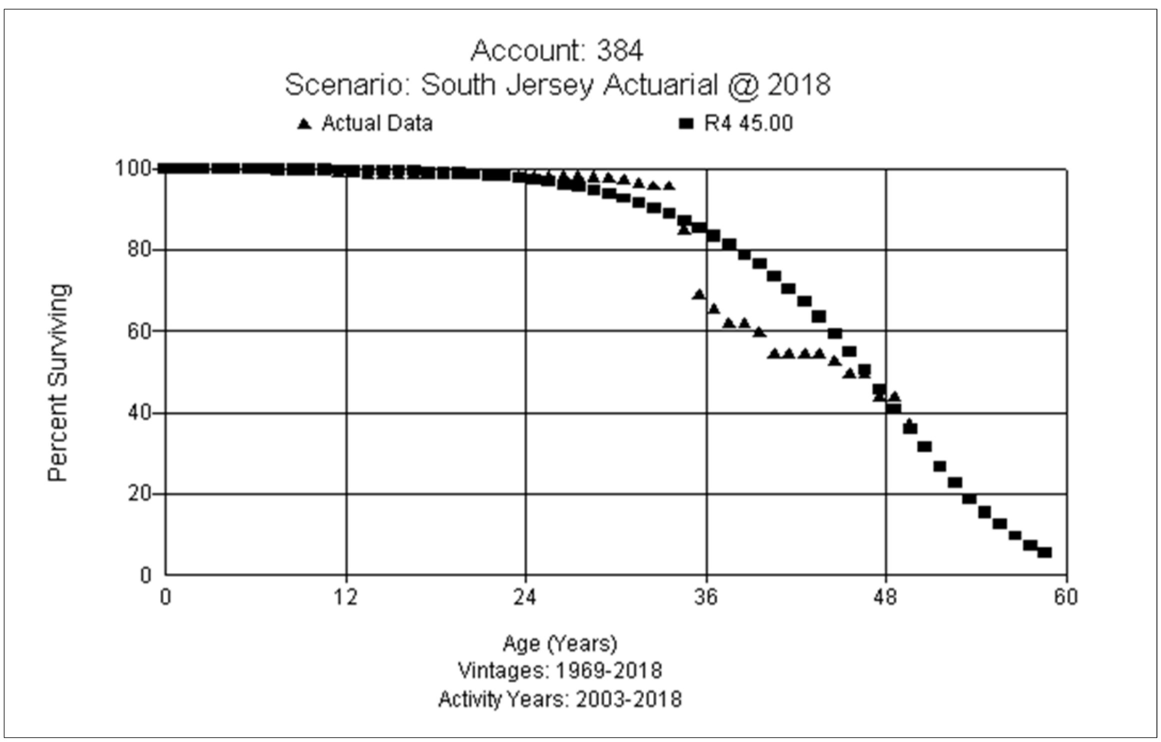
Both the SPR and actuarial analysis were performed. However, with the limited experience band (2003-2018), the actuarial analysis produced life indications beyond what would reasonably be expected. In the SPR analysis, some curves produce an excellent REI and CI. However, the top ranked curves in the fuller bands have excellent CIs and fair REIs. The steeper dispersion patterns yield the best REI and CI. The 30 year band has the S5 ranked in the middle and has an excellent CI and REI with a life of 46 years. The CI declines to good in fuller bands analyzed. Due to the existing life, only bands of 30 years or longer were evaluated. Based upon the analyses, this study recommends moving to a 46 year life and the S5 dispersion. A comparison of actual versus simulated balances is shown below for the 46 S5.



Account 384 House Regulator Installations (45 R4)

This account consists of the cost of the installation of house regulators associated with distribution operations. There is approximately $52.0 million in this account. The existing life is 45 R3. The current average age of investment is 5.65 years.

Both the SPR and actuarial analysis were performed. In the SPR analysis, the top ranked curves produce an excellent REI and CI with the 40 S6. The other bands produce similar results, which indicates a life lower than approved and lower than expected. However, the actuarial analysis provides a good fit in the fuller bands (e.g. placement 1969-2018 and experience 2003-2018) with the 45 R4. Based on type of assets, the analyses and judgment, this study recommends retention of the existing 45 year life, but moving from the R3 to R4 dispersion. A graph of the account observed life table versus the proposed life and curve is shown below.



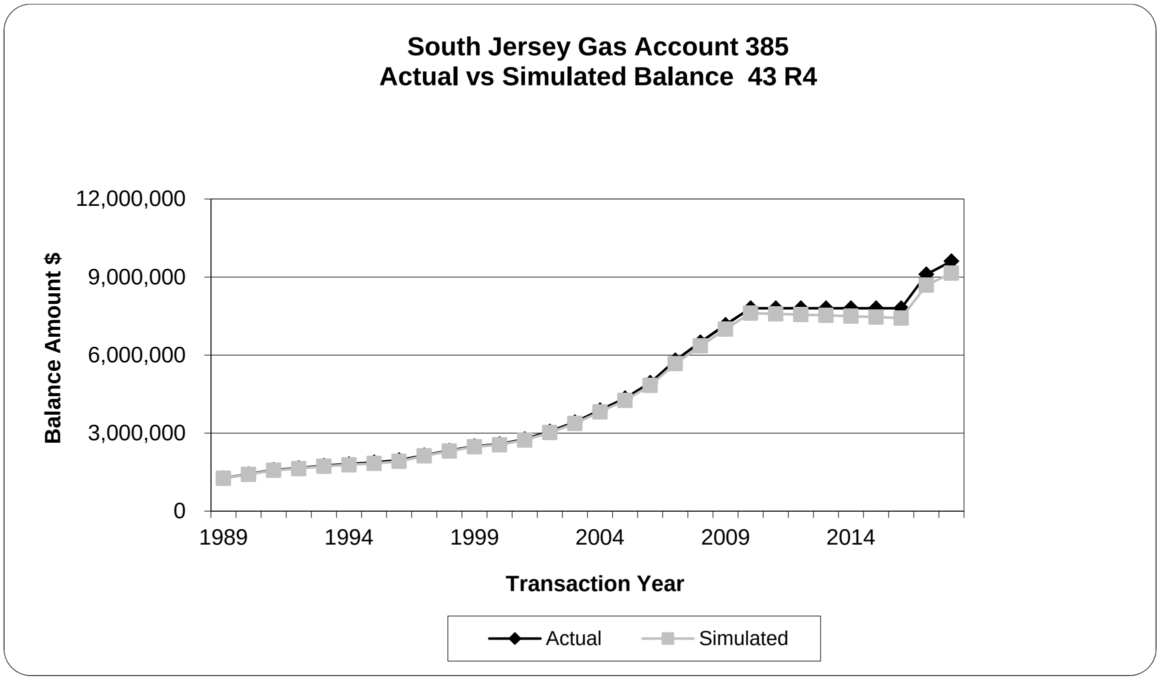
Account 385 Industrial Measuring and Regulating Equipment (43 R4)

This account consists of the cost of industrial measuring and regulating equipment associated with distribution operations. There is approximately $9.6 million in this account. The existing life is 30 R1. The current age of surviving investment is 15.73 years.

Discussions with Company personnel indicated that their expectation from an operational standpoint isthat these would have a life-cycle close to that of DRS. From a life standpoint, the life would be similar to an above ground DRS, but the assets much more susceptible to changes in customer capacity demands since the current assets are installed at industrial and commercial customers' locations across the system. There may be some differential in life between a DRS, but parity with DRS would also be reasonable.

In the SPR analysis, the CI is in the good range and the REIs are in the excellent range. However, the life is significantly longer than existing and even longer than the life proposed for DRS in Account 378. The top ranked dispersion pattern in the 30 year or more bands is the SQ with a 51 year life. The SQ dispersion is not representative of a typical retirement pattern for this type of equipment in the industry since it would suggest all assets retire at that same time.

Given the indications in the analysis, discussions with Company personnel, similarity of assets, and judgment, this study recommends moving toward the life proposed for Accounts 378. The study recommendation is a 43 R4, which is just one year longer than Account 378, but using the same R4 dispersion. A comparison of actual versus simulated balances is shown below for the 43 R4.

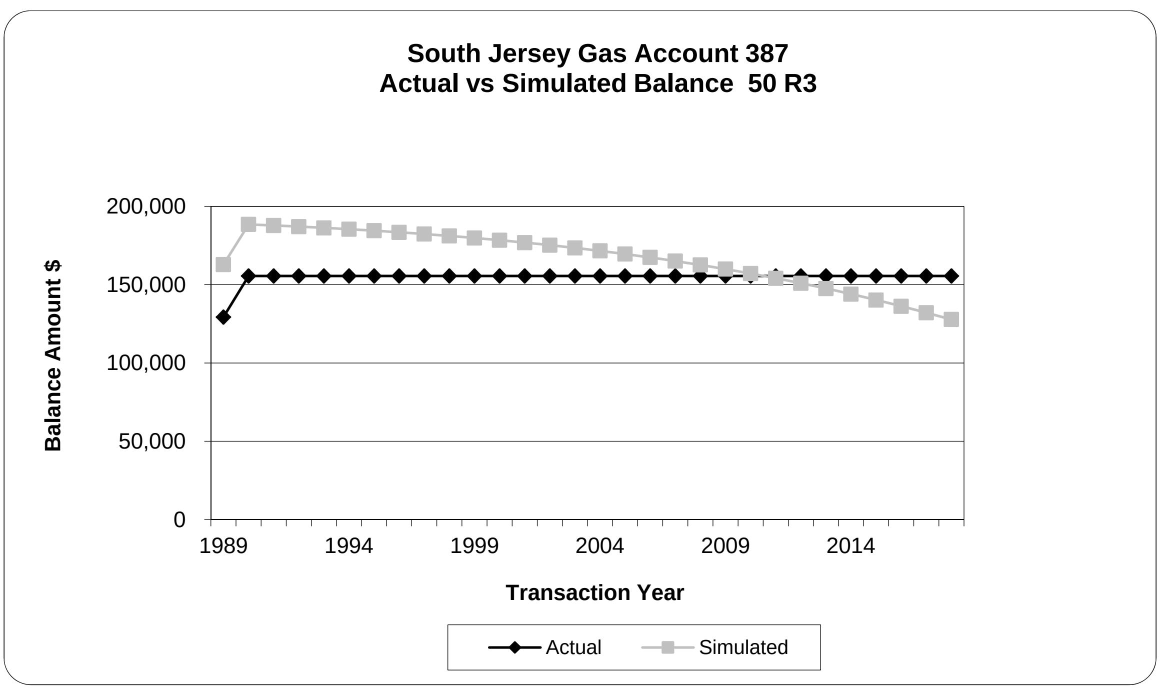

South Jersey Gas Account 385
Actual vs Simulated Balance 43 R4
Balance Amount $
12,000,000
9,000,000
6,000,000
3,000,000
0
1989
1994
1999
2004
2009
2014
Transaction Year
Actual
Simulated

Account 387 Other Equipment (50 R3)

This account consists of the cost related to various other equipment associated with distribution operations. There is approximately $156.0 thousand in this account. The existing life is 45 R3. The current average age of surviving investment is approximately 46.99 years.

Discussions with Company personnel indicated that the cost is mostly parking lots and roads. They noted that 45 years seems a somewhat long, but the practice of incrementally adding layers to roads in many cases rather than replacing them might push the life longer.

Investment in this account has remained constant which limits the usefulness of the SPR analysis. The top ranked curves in the SPR analysis have poor CIs and fair REIs. The lower ranked curves have better indices. The existing R3 is ranked in the middle with a life of 50 years. This account is fully depreciated. Based on judgment, this study recommends moving the life to 50 years, but retaining the R3 dispersion and a whole life rate of 2.22% if assets are added in the future. A comparison of actual versus simulated balances is shown below for the 50 R3.



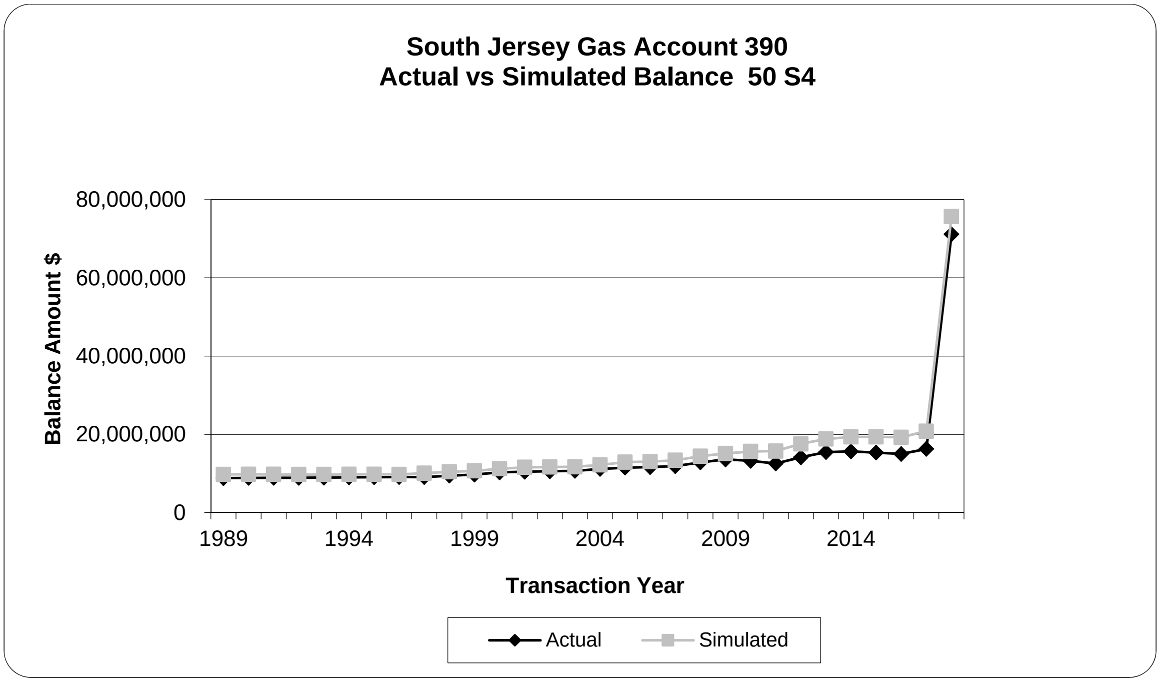
General Plant – Depreciated

Account 390 Structures and Improvements (50 S4)

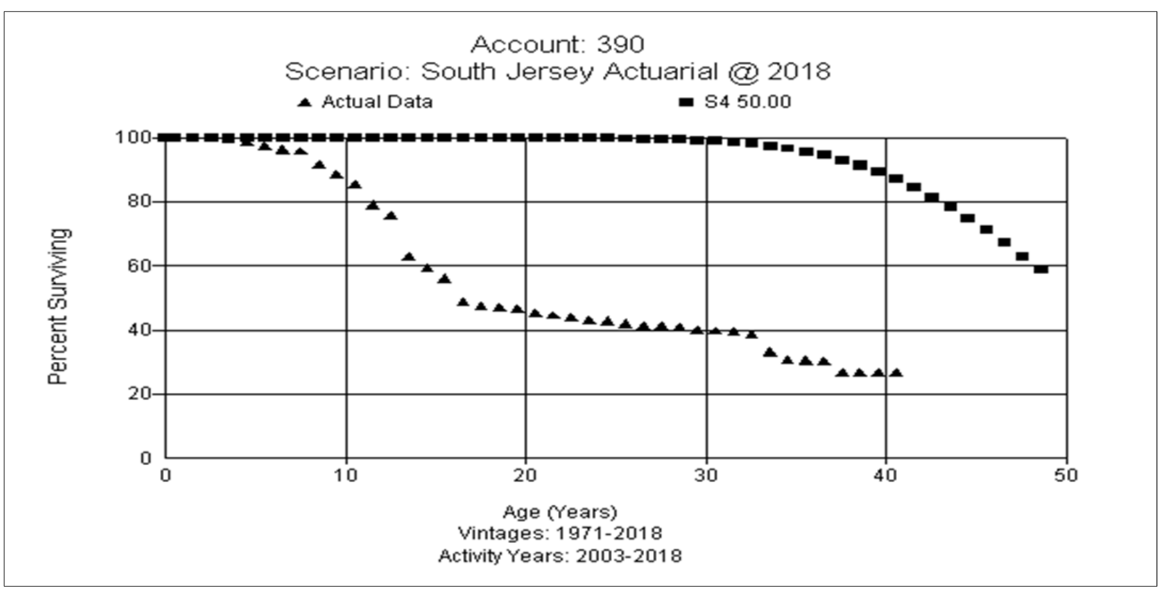
This account consists of structures and various improvements associated with the general plant. There is approximately $65.3 million in this account. The existing life is 31 S4. The current average age of surviving investment is approximately 4.37 years.

Discussions with Company personnel indicated that the new Atlantic City Headquarters (“HQ”), built in 2018, is the largest asset in this account. There are six operating division buildings in this account as well, all six of which have been in service for at least 50 years. Although many of the assets related to the building have been replaced, the structure of the buildings could last up to 70 years. Four of the operating division buildings are good for another 5-10 year period, while one, Pleasantville, could be considered for replacement due to capacity and location. Another operating division building, Glassboro, could be considered for replacement due to capacity and training needs, which will likely result in the Company adding to that facility. There are various other assets with shorter lives such as: 20 years for HVAC (less due to salt for HQ); 10 years for Roofs (20 for HQ); a 15 year cycle to reseal for Parking Lots, but no retirement until the lot fails completely, and Remodeling would occur as needed, possibly in a 15 year cycle range; 20-25 years for Generators.

Both the SPR and actuarial analysis were performed. In the SPR analysis, the 31 S4 is in the top five ranked curves with poor to fair CIs and REIs of 100 for the periods analyzed. The life indications are all in the 30 year range, which is significantly lower than what would be expected for the majority of the investment. A comparison of actual versus simulated balances is shown below for the 50 S4.



The actuarial analysis provided similar indications of a lower life than what is expected and is not reasonable for the mix of assets. Giving consideration to the analyses and the significance of recent investment, such as the HQ building that was added in 2018, a longer life is reasonable. The study recommendation is to move the life to 50 years, but retain the S4 dispersion. A graph of the account observed life table versus the proposed life and curve is shown below.

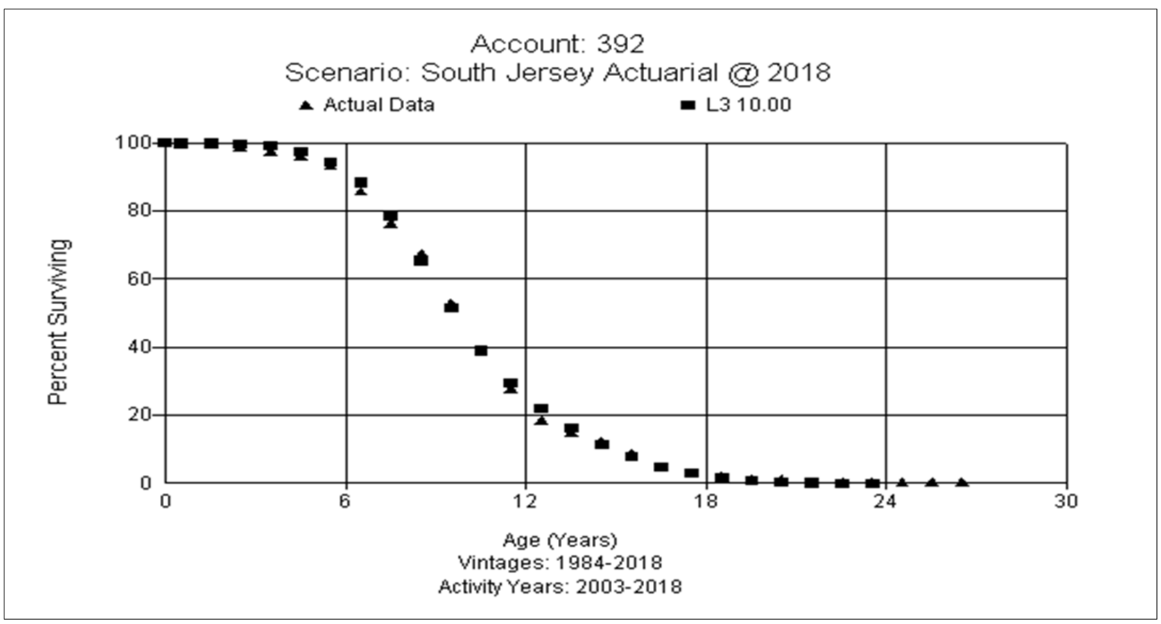


Account 392 Transportation Equipment (10 L3)

This account consists of various types of transportation equipment including car and trucks. There is approximately $19.2 million in this account. The existing life is 10 L2.5. The current average age of the investment is 5.64 years.

Discussions with Company personnel indicated that the larger trucks costs are between $100 and $150 thousand. These trucks can run 100,000 miles or more, and most are replaced around 165,000 miles. There are a few vehicles in this account that will generally last 6, 7, 8, and 9 years, but they are a small part of the overall fleet. The Company believes that a 10 average for the group is appropriate.

Actuarial analysis was used for this account and produced multiple fits with varying dispersion but all at 10 years. The best and excellent fit was made in the placement 1984-2018 and experience band 2003-2018 with the 10 L3. Based on the actuarial analysis and discussions with Company, this study recommends retention of the 10 year life and moving to a slightly steeper L3 dispersion. A graph of the account observed life table versus the proposed life and curve is shown below.

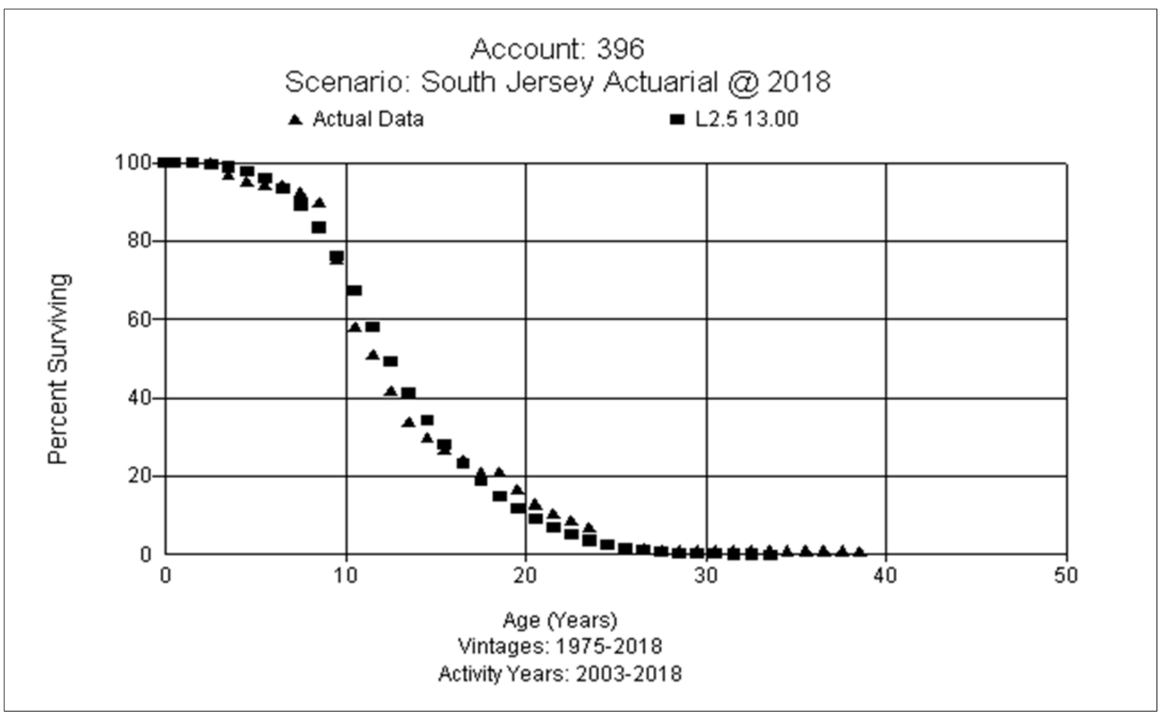


Account 396 Power Operated Equipment (13 L2.5)

This account consists of the cost of power operated equipment associated with the general plant. There is approximately $2.3 million in this account. The existing life is 13 L3. The current average age of investment is approximately 7.27 years.

From an operational standpoint, Company personnel are comfortable that the existing life is indicative of their expectations. Trailers are generally sold with the equipment they are carrying. There is some concern on the part of Company personnel that the life would be slightly less since the quality and durability of the equipment is lower than in the past.

Since the existing life is close to the number of experience years, actuarial analysis was relied upon for this account. The fits indicated a life between 12 and 13 years with various L patterns. The best fit was in the placement 1975-2018 and experience band 2003-2018 with a 13 L2.5. Based on the actuarial analysis and discussions with Company, the study recommends retaining the life of 13 years but moving to a flatter L2.5 dispersion. A graph of the account observed life table versus the proposed life and curve is shown below.



General Plant - Amortized

The Company has previously segregated these accounts into pre-2005 vintage assets and post-2004 vintage assets. Pre-2005 assets are depreciated compared to post-2004 assets which are amortized. No additional investment is going into the pre-2004 asset groups. This study consolidates the two groups of assets into a single account for amortization going forward.

Account 391.00 Office Furniture and Equipment (20 SQ)

This account consists of miscellaneous office furniture such as desks, chairs, filing cabinets, and tables used for general utility service. There is approximately $5.2 million in this account after retirements for implementation of FERC AR-15. The existing life is 20 SQ. Newer furniture has a shorter life than in the past, both from construction, design, and the embedding of electronics in some assets. Some of the older furniture might have up to a 30 year life when the newer furniture (e.g., the furniture in HQ) may only have a 15 year life. The existing 20 SQ is retained.

Account 391.358 - Computer Equipment (5 SQ)

This account consists of the cost of computers associated with general plant facilities. There is $16.6 million of investment in this account after retirements for implementation of FERC AR-15. The existing life is 5 SQ.

Discussions with Company personnel indicated that the Company's PCs are on a four-year replacement cycle; in the fifth and occasionally the sixth year, some are used as spares. Toughbooks are in the process of being replaced between 5-7 years and are being replaced with Windows Tablets (which will likely have a shorter life). Servers, which were formerly Dell servers, are on a five-year cycle. The Company is now using a Cisco virtual server "farm" but do not expect the life-cycle to change materially. Networking equipment, such as routers, switches, connections, is all Cisco equipment and is all expected to last 5 year. Given the mix of assets in this account and their life-cycles, the existing 5

SQ is retained.

Account 391.356 Major Software Systems Implementation (15 SQ)

This is a new account that will consist of the cost of major software and systems and implementation associated with general plant facilities. There is approximately $108.5 million in this account.

Discussions with Company personnel indicated that software, such as ERP, CIS, Hyperion, and Oracle, will likely have around a 15 year-cycle. The CIS and WMS systems were replaced in 2014 and 2013, respectively. The Company is also upgrading CC&B and Maximo. All of these are long-term applications and this study recommends a life of 15 SQ with general plant amortization.

Account 393 Stores Equipment (25 SQ)

This account consists of various costs associated with stores equipment. There is approximately $6.2 thousand in this account after retirements for implementation of FERC AR-15. This is mostly shelving and the existing life 25 SQ is reasonable and retained.

Account 394.00 Tools, Shop, and Garage Equipment (15 SQ)

This account consists of other miscellaneous tools, shop, and garage equipment associated with the general plant. There is approximately $11.7 million in this account after retirements for implementation of FERC AR-15. The existing life is 20 SQ. Discussions with Company personnel indicated electronic tools have a shorter life, while the “steel” tools have a longer life. However, for the majority of the tools, they break or are lost long before 20 years, making 20 years unreasonable. The study recommends moving the life to 15 SQ.

Account 395 Laboratory Equipment (20 SQ)

This account consists of various costs associated with laboratory equipment. There is no investment in this account after retirements for implementation of FERC AR-15. The existing life 20 SQ is retained for any future investment.

Account 397.00 Communication Equipment (15 SQ)

This account consists of all communication equipment including mobile and fixed radio systems along with telephone, telemetering, and other miscellaneous communication equipment used in connection with the general plant. There is a balance of approximately $2.8 million in this account after retirements for implementation of FERC AR-15. The existing life is 15 SQ.

Discussions with Company personnel indicated that the assets are private network radios in trucks, many of which were upgraded in 2012 due to the narrow banding. The bulk of mobile radios were upgraded within the last five years. The base station equipment is probably 10 years old. Telephone equipment at all locations is now VOIP, which occurred approximately 3 years ago. Overall the life expectation for the account is between 10-15 years. This study retains the existing 15 SQ.

Account 398.00 Miscellaneous Equipment (20 SQ)

This account includes the cost of miscellaneous equipment associated with the general plant. There is approximately $67.2 thousand in this account, after retirements for implementation of FERC AR-15. The existing life is 20 SQ and is retained.

SALVAGE ANALYSIS

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the salvage and removal costs stated in current dollars by the original installed cost of the asset stated in dollars when the plant went into service. Some plant assets can experience significant negative removal cost percentages due to the timing of the original addition versus the retirement. For example, a Distribution asset in FERC Account 376 Steel Mains with a current installed cost of $500 (2018) would have had an installed cost of $17.15[4] in 1950. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative 10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 292 percent removal cost for that asset ($50/$17.15). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

The normal net salvage analysis that is performed uses the history of the individual accounts to estimate the future net salvage that a company can expect in its operations. As a result, the analysis not only looks at the historical experience but also takes into account recent and expected changes in operations that could reasonably lead to different future expectations for net salvage than were experienced in the past. Generally, recent experience is more heavily weighted in making net salvage recommendations than experience older than 10 years. Is discussed below, this approach was not used for South Jersey

[4] Using the Handy-Whitman Bulletin No. 190, G-1, line 44, $17.15 = $500 x 32/933.

Gas.

Salvage Characteristics

In the traditional net salvage analysis, we take historical data for each account, including data for retirements, gross salvage, and cost of removal for as far back as available. A minimum of 10 years is desired. Moving averages, which remove timing differences between retirement and salvage and removal cost, would be analyzed over periods varying from one to 2 to 10 years. These are then evaluated in making the net salvage recommendations for the study. However, the Board of Public Utilities' past orders have supported the Division of Rate Counsel position that an average of net salvage expense should be used to calculate net salvage and included in the overall depreciation expense of the Company. Therefore, while neither the Company nor Alliance agrees with this position, the Company wished to avoid significant controversy on this issue and directed Alliance to follow this methodology.

As a result, it was agreed that we would use an average of recent historical net salvage experience. For reasons set forth in the testimony accompanying this report, the most recently completely three year period was used to calculate the average. As a result, a net salvage amount of $6,268,760 was developed and has been incorporated into the total annual accrual amount for the Company as shown on Appendix A. Appendix D provides the calculation of the $6.3 million used for the annual net salvage accrual amount.

APPENDIX A - Comparison of Approved and Proposed Rates

SOUTH JERSEY GAS COMPANY
COMPARISON OF APPROVED AND PROPOSED ACCRUAL RATES
AS OF DECEMBER 31, 2018

Account and Description (1)	Original Plant Cost 12/31/2018 (2)	Current Accrual Rate (3)	Current Accrual Amount (4)= (2) x (3)	Proposed Accrual Rate (5)	Proposed Accrual Amount (6) = (2) x (5)	Difference (7)= (6) - (4)
Liquefied Natural Gas Plant						
361 Structures and Improvements	1,681,795	0.67%	11,268	2.00%	33,657	22,389
362 Gas Holders	5,067,188	0.07%	3,547	1.13%	57,281	53,734
363 Purification Equipment	54,965,869	3.37%	1,852,350	2.74%	1,506,111	(346,238)
Total Liquefied Natural Gas Plant	61,714,852	3.03%	1,867,165	2.59%	1,597,050	(270,115)
Transmission Plant						
366 Structures and Improvements	2,947,681	2.13%	62,786	1.62%	47,894	(14,892)
367 Mains	250,295,862	1.29%	3,228,817	1.30%	3,243,918	15,101
368 Compressor Equipment		0.00%	0	2.86% *	0	0
369 Measuring and Regulating Equipment	44,743,785	3.38%	1,512,340	2.10%	939,585	(572,754)
370 Communication Equipment	44,562	0.00%	0	0.00%	0	0
371 Other Equipment	184,096	0.00%	0	1.67%	3,079	3,079
Total Transmission Plant	298,215,986	1.61%	4,803,942	1.42%	4,234,476	(569,466)
Distribution Plant						
375 Structures and Improvements	20,868,796	3.80%	793,014	3.15%	656,996	(136,018)
376 Mains	1,154,736,695	1.37%	15,819,893	1.48%	17,051,034	1,231,141
378 Measuring & Regulating Station Equipment - General	4,860,675	1.69%	82,145	2.45%	118,983	36,837
379 Measuring & Regulating Station Equipment - City Gate	6,124,925	1.26%	77,174	2.09%	127,905	50,731
380 Services	796,714,103	2.01%	16,013,953	2.23%	17,788,407	1,774,454
381 Meters	66,466,808	2.38%	1,581,910	3.24%	2,155,087	573,177
382 Meter Installations	33,889,445	2.69%	911,626	2.87%	971,976	60,350
383 House Regulators	12,332,106	1.82%	224,444	2.19%	269,460	45,015
384 House Regulator Installations	51,967,135	2.09%	1,086,113	2.23%	1,157,720	71,607
385 Industrial Measuring and Regulating Equipment	9,611,695	3.09%	297,001	2.35%	225,681	(71,320)
387 Other Equipment	155,583	0.00%	0	2.12%	3,295	3,295
Total Distribution Plant	2,157,727,966	1.71%	36,887,275	1.88%	40,526,543	3,639,269
General Plant Depreciated						

SOUTH JERSEY GAS COMPANY
COMPARISON OF APPROVED AND PROPOSED ACCRUAL RATES
AS OF DECEMBER 31, 2018

Account and Description (1)		Original Plant Cost 12/31/2018 (2)	Current Accrual Rate (3)	Current Accrual Amount (4)= (2) x (3)	Proposed Accrual Rate (5)	Proposed Accrual Amount (6) = (2) x (5)	Difference (7)= (6) - (4)
390	Structures and Improvements	65,327,593	4.98%	3,253,314	2.09%	1,366,256	(1,887,058)
392	Transportation Equipment	19,227,782	10.87%	2,090,060	17.29%	3,325,366	1,235,306
396	Power Operated Equipment	2,310,376	6.43%	148,557	12.33%	284,952	136,395
	Total General Depreciated	86,865,751	6.32%	5,491,931	5.73%	4,976,575	(515,356)
General Plant Amortized Consolidated - After AR 15 Retirements							
391.00	Office Furniture and Equipment	5,249,031	5.00%	262,452	5.00%	262,452	0
391.36	PC, Laptop, Tougbook Equipment	0			25.00% *		
391.36	Network/Server Hardware	0			16.67% *		
391.36	PC, Laptop, Non Enterprise Software	0			20.00% *		
391.36	Network/Server Software	0			33.33% *		
391.356	Major Software Systems Implementation	108,480,063	6.67%	7,232,004	6.67%	7,232,004	0
391.580	Computer Equipment	16,573,219	20.00%	3,314,644	20.00%	3,314,644	0
393.00	Stores Equipment	6,203	0.00%	0	4.00%	248	248
394.00	Tools, Shop and Garage Equipment	11,708,838	5.00%	585,442	6.67%	780,589	195,147
395.00	Laboratory Equipment	0	5.00%	0	5.00%	0	0
397.00	Communication Equipment	2,840,316	6.67%	189,449	6.67%	189,449	0
398.00	Miscellaneous Equipment	67,224	5.00%	3,361	5.00%	3,361	0
	Subtotal General Amortized	144,924,895	8.00%	11,587,352	8.13%	11,782,747	195,395
	Total Depreciable and Amortized	2,749,449,451	2.21%	60,637,665	2.30%	63,117,391	2,479,726
	Three Year Average Annual Net Salvage Amount			4,659,755		6,268,760	1,609,005
	Total Study	2,749,449,451	2.37%	65,297,420	2.52%	69,386,151	4,088,731

*Account segregations are for new investment.

Notes: The following proforma retirements recorded at 12/31/19 were incorporated into the study:

305100 - Structures & Improvements Total	258,487.70

SOUTH JERSEY GAS COMPANY
COMPARISON OF APPROVED AND PROPOSED ACCRUAL RATES
AS OF DECEMBER 31, 2018

	Original	Current		Proposed		
	Plant Cost	Accrual	Accrual	Accrual	Accrual	
Account and Description	12/31/2018	Rate	Amount	Rate	Amount	Difference
(1)	(2)	(3)	(4)= (2) x (3)	(5)	(6) = (2) x (5)	(7)= (6) - (4)
311000 - Liquefied Petroleum Gas	2,280.09					
371000 - Other Equipment Total	239,982.75					
375000 - Structures & Improvements Total	148,694.00					
377000 - Compressor Station Equipme Total	14,678.37					
390000 - Structures & Improvements Total	5,821,582.00					
395050 - Laboratory Equipment - Post	1,538.89					
	6,487,243.80					

APPENDIX B - Computation of Depreciation Accrual Rate

SOUTH JERSEY GAS COMPANY
COMPUTAT ION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Account Description	Original Plant Cost at 12/31/2018	Allocated Book Reserve	Net Salvage Percent	Net Salvage Amount	Unaccrued Balance	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)	(2)	(3)	(4)	(5) = (4) x (2)	(6) = (2) - (3)- (5)	(7)	(8)=(6)/(7)	(9) = (8)/(2)
Liquefied Natural Gas Plant								
361 Structures and Improvements	1,681,795	482,741	0.00%	0.00	1,199,054	35.63	33,657	2.00%
362 Gas Holders	5,067,188	2,309,865	0.00%	0.00	2,757,323	48.14	57,281	1.13%
363 Purification Equipment	54,965,869	9,319,124	0.00%	0.00	45,646,745	30.31	1,506,111	2.74%
Total Liquefied Natural Gas Plant	61,714,852	12,111,729		0.00	49,603,123		1,597,050	
Transmission Plant								
366 Structures and Improvements	2,947,681	1,417,196	0.00%	0.00	1,530,484	31.96	47,894	1.62%
367 Mains	250,295,862	67,711,880	0.00%	0.00	182,583,982	56.29	3,243,918	1.30%
369 Measuring and Regulating Equipment	44,743,785	18,810,275	0.00%	0.00	25,933,510	27.60	939,585	2.10%
370 Communication Equipment	44,562	44,562	0.00%	0.00	0	1.60	0	0.00%
371 Other Equipment	184,096	143,816	0.00%	0.00	40,280	13.08	3,079	1.67%
Total Transmission Plant	298,215,986	88,127,728		0.00	210,047,977		4,234,476	
Distribution Plant								
375 Structures and Improvements	20,868,796	5,733,877	0.00%	0.00	15,134,918	23.04	656,996	3.15%
376 Mains	1,154,736,695	200,190,797	0.00%	0.00	954,545,898	55.98	17,051,034	1.48%
378 M&R Station Equip. - General	4,860,675	2,838,566	0.00%	0.00	2,022,109	17.00	118,983	2.45%
379 M&R Station Equip. - City Gate	6,124,925	663,788	0.00%	0.00	5,461,137	42.70	127,905	2.09%
380 Services	796,714,103	154,980,959	0.00%	0.00	641,733,144	36.08	17,788,407	2.23%
381 Meters	66,466,808	13,800,735	0.00%	0.00	52,666,073	24.44	2,155,087	3.24%
382 Meter Installations	33,889,445	5,549,214	0.00%	0.00	28,340,230	29.16	971,976	2.87%
383 House Regulators	12,332,106	2,553,955	0.00%	0.00	9,778,151	36.29	269,460	2.19%
384 House Regulator Installations	51,967,135	5,913,742	0.00%	0.00	46,053,393	39.78	1,157,720	2.23%
385 Industrial Measuring and Regulating Equip.	9,611,695	3,160,766	0.00%	0.00	6,450,929	28.58	225,681	2.35%
387 Other Equipment	155,583	115,278	0.00%	0.00	40,305	12.23	3,295	2.12%
Total Distribution Plant	2,157,727,966	395,501,678		0.00	1,762,226,288		40,526,543	1.88%
General Plant Depreciated								
390 Structures and Improvements	65,327,593	1,030,900	0.00%	0.00	64,296,693	47.06	1,366,256	2.09%
392 Transportation Equipment	19,227,782	2,576,829	0.00%	0.00	16,650,953	5.01	3,325,366	17.29%
396 Power Operated Equipment	2,310,376	280,297	0.00%	0.00	2,030,079	7.12	284,952	12.33%
Total General Depreciated	86,865,751	3,888,025		0.00	82,977,726		4,976,575	5.73%
GENERAL PLANT CONSOLIDATED - AMORTIZED								
After Retirements of Assets With Age > Average Service Life								
391.000 Office Furniture and Equipment	5,249,031	1,211,204	0.00%	0.00	4,037,827		262,452	5.00%
391.359 PC, Laptop, Tougbook Equipment	0	0	0.00%	0.00	0		0 *	25.00%

SOUTH JERSEY GAS COMPANY
COMPUTAT ION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Account	Description		Original Plant Cost at 12/31/2018	Allocated Book Reserve	Net Salvage Percent	Net Salvage Amount	Unaccrued Balance	Composite Remaining Life	Calculated Annual Accrual Amount		Calculated Annual Accrual Rate
391.360	Network/Server Hardware		0	0	0.00%	0.00	0		0	*	16.67%
391.361	PC, Laptop, Non Enterprise Software		0	0	0.00%	0.00	0		0	*	20.00%
391.362	Network/Server Software		0	0	0.00%	0.00	0		0	*	33.33%
391.36	Major Software Systems Implementation		108,480,063	28,121,475	0.00%	0.00	80,358,588		7,232,004		6.67%
391.58	Computer Equipment	#	16,573,219	8,080,285	0.00%	0.00	8,492,935		3,314,644		20.00%
393.00	Stores Equipment		6,203	5,335	0.00%	0.00	868		248		4.00%
394.00	Tools, Shop and Garage Equipment		11,708,838	1,810,926	0.00%	0.00	9,897,912		780,589		6.67%
395.00	Laboratory Equipment		0	0	0.00%	0.00	0		0		5.00%
397.00	Communication Equipment		2,840,316	1,760,458	0.00%	0.00	1,079,858		189,354		6.67%
398.00	Miscellaneous Equipment		67,224	19,620	0.00%	0.00	47,604		3,361		5.00%
	Total General Plant Amortized		144,924,895	41,009,302		0.00	103,915,593		11,782,653		
	Total General Plant Depreciated & Amortized		231,790,647	44,897,328		0.00	186,893,319		16,759,227		
	Three Year Average Annual Net Salvage Amount								6,268,760		
	Total Study Depreciable (Excl ARO, Land and ROW)		2,749,449,451	540,638,464		$ -	2,208,770,707		69,386,056		

*Account segregations are for new investment.

Excluded from Study Amounts:		
301000 - Organization	138,013	
302000 - Franchise & Consents	43,395	
303100 - Misc. Intangible Plant	47,212	4,062
304100 - Land	24,146	96
304200- Gas Production Land Rights		(96)
320400 - Miscellaneous	0	(1,718)
350100 - Land	25,586	0
354000 - Compressor Station Equipme Total		(126,287)
357001 - ARO Other Equipment	9,284	6,659
360100 - Land	18,975	
365110 - Land	297,213	
365120 - Land Rights	3,064,947	
365200 - Rights of Way	4,402,053	
374100 - Land	516,658	0
374200 - Land Rights	156,331	
376001 - ARO Mains-Distribution	9,162,686	2,058,749
380001-ARO Services	45,328,289	3,819,799
389100 - Land	3,100,131	
390001 - ARO Structures & Impr	38,736	32,808
Total Excluded	66,373,657	5,794,072

SOUTH JERSEY GAS COMPANY
COMPUTAT ION OF DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Account Description	Original Plant Cost at 12/31/2018	Allocated Book Reserve	Net Salvage Percent	Net Salvage Amount	Unaccrued Balance	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
Total Plant	2,815,823,107	546,432,536						
GL w/ARO	2,822,663,653	553,268,203						
Difference	(6,840,545)	(6,835,667)						
PROFORMA ADJUSTMENTS								
305100 - Structures & Improvements	258,488	432,368						
311000 - Liquefied Petroleum Gas	13,446	(165,313)						
371000 - Other Equipment	239,983	239,983						
375000 - Structures & Improvements (Folsom)	148,694	148,694						
37700 - Compressor Station Equipment	14,678	14,678						
39000 - Structures & Improvements (Folsom)	5,821,582	5,821,582						
395.05-Laboratory Equipment Post 12/04	1,539	1,539						
Total Proforma/Adjustments	6,498,409	6,493,531						
Reconciled Difference	(342,136)	(342,136)						
AR 15	342,136	342,136						
	(0)	(0)						

APPENDIX C - Comparison of Parameters

SOUTH JERSEY GAS COMPANY
COMPARISON OF EXISTING VS PROPOSED DEPRECIATION PARAMETERS
AS OF DECEMBER 31, 2018

Account	Description	Current Life	Current Net Salvage	Proposed Life	Proposed Curve	Proposed Net Salvage
Production Plant						
305	Structures and Improvements	30-R4	0.00%	46	R2.5	0.00%
311	Liquefied Petroleum Gas Equipment	28-R2.5	0.00%	46	R2.5	0.00%
Underground Storage Plant						
351	Structures and Improvements	47 S6	0.00%	47	S6	0.00%
355	Measuring and Regulating Equipment	30-R2.5	0.00%	47	S6	0.00%
LNG Plant						
361	Structures and Improvements	46 R2.5	0.00%	46	R2.5	0.00%
362	Gas Holders	50 S5	0.00%	75	S5	0.00%
363	Purification Equipment	30 R4	0.00%	35	R4	0.00%
Transmission Plant						
366	Structures and Improvements	50 R4	0.00%	49	S2	0.00%
367	Mains	68 R4	0.00%	70	R5	0.00%
368	Compressor Equipment (New Construction)			35	R4	0.00%
369	Measuring and Regulating Equipment	30 S6	0.00%	40	S6	0.00%
370	Communication Equipment	25 S3	0.00%	15	S3	0.00%
371	Other Equipment	38 S6	0.00%	38	S6	0.00%
Distribution Plant						
375	Structures and Improvements	34 L5	0.00%	32	S6	0.00%
376	Mains	68 R4	0.00%	68	R4	0.00%
377	Compressor Station Equipment	45 R0.5	0.00%	45	R0.5	0.00%
378	Measuring & Regulating Station Equipment - General	38 R4	0.00%	42	R4	0.00%
379	Measuring & Regulating Station Equipment - City Gate	38 R4	0.00%	48	R4	0.00%
380	Services	45 S1	0.00%	45	S1	0.00%
381	Meters	39 S0	0.00%	31	R2	0.00%
382	Meter Installations	34 R0.5	0.00%	35	R0.5	0.00%
383	House Regulators	45 R4	0.00%	46	S5	0.00%
384	House Regulator Installations	45 R3	0.00%	45	R4	0.00%
385	Industrial Measuring and Regulating Equipment	30 R1	0.00%	43	R4	0.00%
387	Other Equipment	45 R3	0.00%	50	R3	0.00%
General Plant						
390	Structures and Improvements	31 S4	0.00%	50	S4	0.00%
391	Office Furniture and Equipment	20 SQ	0.00%	20	SQ	0.00%
391.051	Office Furniture and Equipment	20 SQ	0.00%	20	SQ	0.00%
391.250	Office Furniture and Equip- Computers Post 12/04	5 SQ	0.00%	5	SQ	0.00%
391.357	Computer Equipment ADS	NA	NA	5	SQ	0.00%
391.358	Office Furniture and Equip- Computers Post 12/04	5 SQ	0.00%	5	SQ	0.00%
391.356	Major Software Systems Implementation	NA	NA	15	SQ	0.00%
392	Transportation Equipment	10 L2.5	0.00%	10	L3	0.00%
393	Stores Equipment	25-SQ	0.00%	25	SQ	0.00%
394	Tools, Shop and Garage Equipment	20-SQ	0.00%	15	SQ	0.00%
395	Laboratory Equipment	20-SQ	0.00%	20	SQ	0.00%
396	Power Operated Equipment	13 L3	0.00%	13	L2.5	0.00%
397	Communication Equipment	15-SQ	0.00%	15	SQ	0.00%
398	Miscellaneous Equipment	20-SQ	0.00%	20	SQ	0.00%

*Account segregations are for new investment.

Account	Description	Current Life	Current Net Salvage	Proposed Life	Proposed Curve	Proposed Net Salvage
391.359	PC, Laptop, Tougbook Equipment			4	SQ	0.00%
391.360	Network/Server Hardware			6	SQ	0.00%
391.361	PC, Laptop, Non Enterprise Software			5	SQ	0.00%
391.362	Network/Server Software			3	SQ	0.00%

APPENDIX D - Cost of Removal and Salvage

South Jersey Gas Company
Three Year Cost of Removal and Salvage

Date	*Acct 108103* Actual COR	*Acct 108104* Actual Salv
1/1/16 -12/31/16	$ 6,107,234.65	$ (361,615.94)
1/1/17 -12/31/17	7,062,228.20	(421,879.02)
1/1/18 -12/31/18	6,899,062.72	(478,751.71)
Total 3 Year	**20,068,525.57**	**(1,262,246.67)**
Net Salvage Total 2016 thru 2018	**18,806,279**	
Average over 3 Years	**$ 6,268,759.63**	

INSERT TAB:

D. YARDLEY

IN THE MATTER OF THE PETITION OF SOUTH JERSEY GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE, CHANGES TO DEPRECIATION RATES AND OTHER TARIFF REVISIONS

BPU DOCKET NO. GR20________

DIRECT TESTIMONY

OF

DANIEL P. YARDLEY

On Behalf Of
South Jersey Gas Company

Exhibit P-11

March 13, 2020

TABLE OF CONTENTS

SOUTH JERSEY GAS COMPANY
DIRECT TESTIMONY OF
DANIEL P. YARDLEY

I. INTRODUCTION

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 South Jersey Gas Company ("South Jersey Gas" or the "Company").

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have been employed as a consultant to the natural gas industry for over 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 AND OTHER REGULATORY BODIES?

A. Yes. Over the last 20 years, I have testified before the New Jersey Board of Public Utilities (the "BPU") on various ratemaking and regulatory matters including rate unbundling, cost allocation, service design, rate design, revenue decoupling, cost recovery mechanisms and tariff design. My testimony in various proceedings has been presented on behalf of South

Jersey Gas, Elizabethtown Gas Company, and New Jersey Natural Gas Company, including testimony on behalf of South Jersey Gas in its previous base rate proceedings. I have also testified in proceedings before several other state utility regulatory commissions, the Federal Energy Regulatory Commission, and the Canada Energy Regulator on a variety of rate and regulatory topics.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by South Jersey Gas 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 it provides, as well as important rate design objectives. In this regard, my testimony addresses two topics. First, I will review important public policy and industry developments that are guiding important changes in the way regulatory agencies and LDCs are approaching rate design matters. Second, I will support the derivation of specific rates and charges for distribution services that fairly apportion the Company's 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 five principal conclusions of my testimony are as follows:

(1) **South Jersey Gas' Conservation Incentive Program ("CIP") provides an appropriate foundation for the Company's rate structure.** The CIP aligns the financial interests of South Jersey Gas and its customers with respect to energy consumption by adjusting margin recoveries for changes in customer use. This rate mechanism promotes important rate design goals and recognizes the important role

of utilities in promoting the most efficient use of energy by customers. As such, South Jersey Gas' rate design, which incorporates the CIP, contributes to longer-term consumer and environmental benefits.

(2) **Existing monthly fixed customer charges for the majority of the Company's customers are substantially below cost-based levels:** The customer charges for residential customers are less than 20% of corresponding customer-related costs. Similarly, customer charges for general service customers are less than 40% 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 customers within a class.

(3) **The cost of distribution service provided to South Jersey Gas' residential customers remains subsidized by prices paid by commercial and industrial customers:** The results of the ACOSS demonstrate that the Company is currently providing service to residential customers at below-average returns. The below-average returns for the residential class are the primary driver of the Company's need to increase its distribution prices because the residential class is by far the largest class on the system, representing over 90% of customers and over 50% of firm throughput.

(4) **Within the residential class, non-heating customers receive the greatest level of subsidy by other customers:** The prices for service to residential non-heating customers do not provide adequate revenue recovery based upon the consumption patterns of residential non-heating customers.

(5) **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 natural gas vehicle customers are well below the rates of return for all other classes of customers. By applying the largest proportion of the revenue increase to these rate classes, the proposed class-specific revenue requirements promote fairness among the various customers that South Jersey Gas serves.

Q. ARE YOU SUPPORTING ANY SCHEDULES THAT ACCOMPANY YOUR TESTIMONY?

A. Yes. I am sponsoring the following four schedules, which was prepared under my direction and supervision and will be explained later in my testimony:

Schedule DPY-1: Allocated Cost of Service Study;

Schedule DPY-2: Summary of Existing and Proposed Rates and Revenues;

Schedule DPY-3: Pro Forma Revenue Adjustment Attributable to Updating CIP Tariff Factors; and

Schedule DPY-4: Derivation of Updated CIP Baseline Use per Customer Factors.

II. <u>RATE DESIGN POLICY BACKGROUND</u>

Q. HOW DOES RATE DESIGN AFFECT THE ACHIEVEMENT OF ENERGY POLICY OBJECTIVES?

A. From a public policy perspective, rate design is a critically important tool for achieving specific energy policy goals that influence the quality of life for New Jersey's citizens and the State's competitive position. Policy goals affected by rate design include end-use fuel mix, energy efficiency and the resulting environmental and cost impacts of energy consumption. Therefore, the form of a utility's rate structure is an important building block that can contribute to achieving important energy policy goals.

The nexus between rate design and energy policy objectives continues to receive attention throughout the U.S., due in large part to the prevalence of usage-based rate designs. Usage-based rate designs recover a substantial portion of LDC fixed-cost revenue requirements through volumetric charges applied to the amount of natural gas consumed by customers. The inherent operating incentives under this form of rate structure are for the LDC to promote increased consumption by its existing customers. However, it is essential for utilities to actively support more efficient use of their product by customers in order to achieve public policy goals that favor energy conservation and reductions in customer energy bills. LDCs such as South Jersey Gas are promoting increased energy efficiency to their customers. The form of rate design is essential to LDCs' fully embracing the energy efficiency imperative while also meeting fiduciary responsibilities to shareholders, regulators and customers alike.

Q. HOW WOULD YOU CHARACTERIZE SOUTH JERSEY GAS' EXISTING RATE DESIGN?

A. Base rates are intended to recover a utility's cost of service, excluding purchased gas and other tracked costs. The costs recovered through base rates are fixed costs. The Company's rate design reflects a throughput-based approach. A throughput-based rate design recovers a substantial portion of an LDC's fixed-cost revenue requirements through volumetric charges applied to the amount of natural gas consumed by customers. While the rates for customers include a combination of fixed monthly charges and throughput-based or variable charges, base revenues from variable charges account for nearly 70% of the Company's total base revenue recoveries. This indicates a significant dichotomy between the manner in which South Jersey Gas incurs costs and how costs are recovered from customers.

Q. DOES THE CIP REPRESENT A RATE DESIGN APPROACH THAT ADDRESSES THIS DICHOTOMY BETWEEN COST INCURRENCE AND COST RECOVERY?

A. Yes. A fundamental tenet of the CIP Tariff is alignment of the financial interests of South Jersey Gas 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 enables South Jersey Gas to recover fixed costs through a variable or usage-based rate structure without negative consequences. Customers continue to 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.

Elimination of the disincentives to promoting customer conservation enables South Jersey Gas to embrace new and complementary initiatives to those required by New Jersey's Clean Energy Program ("NJCEP") that capitalize on various channels for promoting conservation by customers. Energy efficiency and renewable energy resources are two of the building blocks to ensuring a secure energy future for New Jersey. These resources play an important role in achieving environmental policy goals of reducing carbon emissions that pose environmental risks.

Q. PLEASE COMMENT ON THE RELATIONSHIP BETWEEN SOUTH JERSEY GAS' CIP AND THE APPROPRIATE RATE DESIGN IN THIS PROCEEDING.

A. The CIP represents an appropriate means of separating the Company's margin revenue recoveries from customer usage. The CIP is essential to aligning the interests of South Jersey Gas and its customers with respect to energy consumption. Removing the link between throughput and margins through the CIP allows the Company 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 South Jersey Gas' overall rate structure.

III. SOUTH JERSEY GAS DISTRIBUTION RATE DESIGN

Q. PLEASE DESCRIBE THE SPECIFIC RATE DESIGN GOALS THAT GUIDED THE DEVELOPMENT OF NEW RATES AND TARIFFS FOR SOUTH JERSEY GAS IN THIS PROCEEDING?

A. The rate design approach I am recommending seeks to achieve the following six 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 South Jersey Gas, and (iii) among customers taking service under a common rate schedule.

(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 the Company'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** – Reducing energy consumption through energy efficiency and conservation supports policy objectives that benefit customers and the environment.

(6) **Simplicity** – Simplicity means a rate structure that is easy for customers to understand and straightforward to administer.

Q. PLEASE DESCRIBE THE COMPANY'S EXISTING RATE SCHEDULES.

A. South Jersey Gas' existing rate schedules are segregated by sector, nature of service (firm or interruptible) and by customer size. Firm service is primarily provided under one Residential Service ("RSG") and two size-based general service rate schedules. General service customers with less than 100,000 annual therms are served under the General Service ("GSG") rate schedule and larger customers are served under the General Service – Large Volume ("GSG-LV") rate schedule.

Firm service is also provided to any commercial or industrial electric generating customer including distributed generation and combined heat and power loads pursuant to the Electric Generation Service (“EGS”) rate schedule for customers below 200 Mcf per Day or the Electric Generation Service – Large Volume (“EGS-LV”) rate schedule for larger customers. A limited number of large customers take firm service under either the Comprehensive Transportation Service (“CTS”) or the Large Volume Service (“LVS”) rate schedules. CTS requires a minimum contract demand of 100 Mcf/day and LVS requires a minimum contract demand of 200 Mcf/day. The Company also provides firm service to customers using natural gas as a motor vehicle fuel pursuant to its Natural Gas Vehicle (“NGV”) rate schedule.

Interruptible customers are either served under the Interruptible Gas Service (“IGS”) or Interruptible Transportation Service (“ITS”) rate schedules. Lastly, gas lighting service is provided pursuant to the Yard Lighting Service (“YLS”) and Street Lighting Service (“SLS”) rate schedules.

Q. WHAT RATES AND CHARGES ARE INCORPORATED INTO THE RSG AND GSG RATE SCHEDULES?

A. The existing rate design for these customers is similar and includes two types of base rate charges that are intended to recover South Jersey Gas’ non-gas revenue requirements. The RSG base rates consist of a \$9.50 customer charge and a flat distribution or throughput charge that is \$0.678051 per therm.[1] Customer charges are applied per customer per month and distribution charges are applied to each customer’s monthly therm usage. Under this rate structure, all residential customers pay a minimum amount to South Jersey Gas equal

[1] All prices noted in this testimony and supporting schedules exclude the New Jersey Sales and Use Tax (“SUT”). The SUT rate is 6.625% as of January 1, 2018.

to the 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 distribution charge. The distribution charge is considered a variable charge because all of the associated revenues are linked to customer usage or throughput. The existing rate design for GSG customers is similar to that for residential customers. The monthly customer charge for GSG customers is $29.97 and the distribution charge is $0.566312 per therm.

Q. DO THE REMAINING RATE SCHEDULES EMPLOY THE SAME TYPE OF RATE DESIGN?

A. The rate structures for larger commercial and industrial customers taking service under South Jersey Gas' other rate schedules employ a fixed monthly demand charge in addition to monthly customer and distribution charges. The demand charge is an important means of recovering fixed peak-related costs from customers in an equitable manner.

Q. ARE THERE SEPARATE CHARGES FOR GAS SUPPLY?

A. Yes. Sales customers that purchase their gas supply from South Jersey Gas pay a volumetric Basic Gas Supply Service ("BGSS") rate for gas supply. The BGSS rate recovers the costs of purchased gas and upstream pipeline capacity and storage resources necessary to ensure firm delivery to customers throughout the year, and is adjusted periodically to track changes in the delivered cost of gas supply. The BGSS rate for residential customers may be adjusted three or more times per year and for non-residential customers with greater than 5,000 annual therms is adjusted monthly.

Many customers are transportation-only customers, and pay South Jersey Gas to deliver gas supply that they have purchased from various Third Party Suppliers ("TPSs") that may offer competitive pricing or other terms. The gas supply price for a firm transportation customer is negotiated in a competitive marketplace between the customer and the TPS. Transportation customers also have the option of returning to sales service at any point in the future, subject to certain notice requirements.

Q. DID YOU PERFORM A TRADITIONAL 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 guides the development of price changes. In particular, the ACOSS that I performed for South Jersey Gas 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 one factor to consider in the apportionment of the revenue requirements among all of South Jersey Gas' 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. A full description of the South Jersey Gas ACOSS and detailed results are presented in Schedule DPY-1.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ACOSS AND HOW THESE RESULTS GUIDED THE DEVELOPMENT OF THE PROPOSED BASE RATES FOR SOUTH JERSEY GAS.

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 and NGV classes are less than the system-average rate of return at present rates. The rate of return for all other classes is above the system-average, to varying degrees. Table 1 provides a summary of the rate of return by class and total existing base revenues.

Table 1

Rate of Return by Class and Existing Base Revenues ($ million)

	ACOSS Rate of Return	Unitized Return	Existing Base Revenues
Residential Heating	2.5%	0.5	$227.4
Residential Non-Heating	(3.5%)	(0.7)	$3.2
GSG	20.6%	4.0	$77.3
GSG-LV	18.7%	3.7	$11.2
CTS	19.2%	3.8	$6.4
LVS	11.1%	2.2	$6.7
EGS	16.6%	3.3	$0.3
EGS-LV	9.9%	1.9	$1.0
NGV	(6.5%)	(1.3)	$0.7
Overall	5.1%	1.0	$334.1

With respect to unit costs, the ACOSS indicates that the system-wide average customer cost is $60.41 per month, and the cost generally varies with the size of the customer. The lowest average customer cost of $57.20 per month is indicated for the residential non-heating class and the highest is $3,036 per month for the EGS-LV 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
Residential Heating	$9.50	$58.83
Residential Non-Heating	$9.50	$57.20
GSG	$29.97	$77.40
GSG-LV	$150.00	$217.33
CTS	$600.00	$1,506.34
LVS	$900.00	$1,667.33
EGS	$63.38	$283.74
EGS-LV	$428.32	$3,036.09
NGV (5,000- 24,999 CFH)	$200.00	$409.89

The significant variance between monthly customer-related costs and customer charges is taken into consideration when designing the intra-class rate design.

Q. WHAT STEPS DID YOU EMPLOY TO ESTABLISH THE SPECIFIC BASE 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, where appropriate, to recover a greater proportion of customer-related costs through customer charges. Lastly, I established the appropriate rate structure and rate levels to recover the remaining portion of class revenue requirements.

Q. HOW DID YOU DEVELOP THE CLASS-BY-CLASS REVENUE REQUIREMENTS?

A. The development of the class-by-class revenue requirements is a two-step process. The first step entails estimating the rate change that will occur pursuant to the Company's existing Storm Hardening and Reliability Program ("SHARP II") and its Accelerated Infrastructure Replacement Program ("AIRP II") rate mechanisms. The costs associated with the SHARP and AIRP programs are reflected in rates each October 1st through an adjustment to base rates. Based on current cost estimates, the revenue requirement impact of the next SHARP adjustment is $3.4 million and of the next AIRP II adjustment is $6.3 million. Since these adjustments will occur independently of the base rate adjustments resulting from this rate case, I estimated the revenue requirement impact to each class of the combined adjustment based on the percentage of existing base revenues for each class.

Next, I determined the appropriate additional base revenue change for each rate class resulting from the Company's requested revenue increase of $75.3 million. Specifically, the base revenue requirements by rate class are based upon the existing base revenues and the results of the ACOSS. Specifically, those classes demonstrating an existing rate of return that is above the system-average receive a lower percentage increase in base revenues than do rate classes demonstrating an existing rate of return that is below the system-average rate of return. In particular, the GSG, GSG-LV, CTS and EGS rate classes receive an increase that is equal to one-half of the average percentage change in base revenues. The rates of return for these four rate classes are more than twice the proposed rate of return. The LVS and EGS-LV, whose existing rates of return are between one and two times the proposed rate of return, receive an increase that is equal to the average percentage change in base revenues. The remaining increase is applied to the RSG and NGV rate classes. All rate classes receive a base rate increase in order to mitigate the impact of the rate change upon rate classes that receive a larger-than-average base rate increase.

Q. WHY IS THE LEVEL OF THE CUSTOMER CHARGE IMPORTANT?

A. The level of the monthly fixed customer charge is important for a variety of reasons that relate to the Company's rate design goals I described earlier. First, the monthly fixed customer charge provides customers with an important price signal concerning the impact of connecting to South Jersey Gas' distribution system. Second, recovering customer-related costs through monthly fixed 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 are created as larger customers pay a disproportionate share of customer-related costs. Third, the fixed monthly 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 FIXED CHARGES INCLUDING MONTHLY CUSTOMER CHARGES AS WELL AS ANY APPLICABLE DEMAND CHARGES.

A. I am proposing changes to the fixed charges applicable to all rate schedules including changes to the monthly customer charges for most customers. It is desirable to recover a greater proportion of the class revenue requirement increase through the customer charge, so that individual rate elements move closer to cost-based levels. For the RSG class, the proposed monthly customer charge is $12.75 per month. The proposed 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 RSG monthly customer charge reduces the increases needed to volumetric charges in order to recover the class-specific revenue requirements. Even with the increase to the residential customer charge, 80% of the target revenue requirements of the class are recovered through the volumetric charge under the proposed RSG rates.

I am proposing to increase the monthly customer charge for the GSG class to $34.75, for the GSG-LV class to $225.00, for the CTS class to $750.00, for the LVS class to $1,050.00, for the EGS class to $79.00, for the EGS-LV class to $750.00, for the NGV class for meters from 5,000 to 24,999 CFH to $220.00, and for the NGV class for meters above 25,000 CFH to $925.00. Additionally, I am proposing to reflect a portion of the revenue increase for the GSG-LV, CTS, LVS, EGS and EGS-LV classes through an increase to the applicable monthly demand charge for each of these classes. These increases to fixed monthly 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 NEXT STEP IN THE RATE DESIGN PROCESS.

A. Once the monthly customer and demand charges are established, the next step in the rate design process is to design the remaining rate elements for each class to recover the total target revenue requirements less the revenues recovered through the customer charge. For all rate classes, I have derived appropriate volumetric distribution base rates to yield the target revenue requirements assigned to each class.

Q. HAVE YOU PREPARED A SUMMARY OF THE PROPOSED RATE CHANGES?

A. Yes. The existing and proposed rates for each class are compared in Schedule DPY-2. This schedule reflects the two-step process necessary to establish class-by-class revenue requirements discussed earlier in my testimony. The last column of Schedule DPY-2 provides the percentage increases in base and total revenues by class. In addition, Schedule DPY-2 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 South Jersey Gas' recovery of its overall costs of providing service to customers.

A. The proposed rates reflect class-differentiated changes in base rates that reduce existing subsidies indicated by the ACOSS. At the same time, all rate classes receive a base revenue increase, mitigating the rate increase to the residential class. The moderate increases in the fixed customer charges result in charges that are closer to cost-based levels. The estimated return on rate base investment by rate class at existing and proposed rates is provided in Table 3.

Table 3

Estimated Return on Rate Base Investment

Rate Schedule	Existing Rates	Proposed Rates
Residential Heating	2.5%	5.1%
Residential Non-Heating	(3.5%)	(2.3%)
GSG	20.6%	19.6%
GSG-LV	18.7%	21.9%
CTS	19.2%	22.3%
LVS	11.1%	15.2%
EGS	16.6%	19.3%
EGS-LV	9.9%	13.6%
NGV	(6.5%)	(0.6%)
Overall	5.1%	7.3%

While the proposed rates do not 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 the continuation of the Company's CIP.

Q. WHAT ELEMENTS OF THE CIP TARIFF ARE UPDATED IN A BASE RATE CASE?

A. Aspects of the CIP tariff that interrelate with South Jersey Gas base rate revenue recoveries must be updated when new base rates are determined in a base rate case. Specifically, the Margin Revenue Factors and the monthly Baseline Usage per Customer ("BUC") set forth in the CIP tariff must be updated in order to align these aspects of the CIP with the BPU's approval of new rates in a base rate proceeding. In conjunction with updating the BUC, the date for determining incremental large customers set forth in Section (h)(viii) of the CIP Tariff should be changed to July 1, 2020, the first day following the end of the test year.

Updating the BUC levels also affects projected test period revenues. A component of test period revenues are the revenues, positive or negative, associated with the difference between the BUC and actual customer use. Any CIP revenues included in the test period are eliminated on a *pro forma* basis with the resetting of the BUC to the test period throughput level. Schedule DPY-3 provides the CIP revenues that are eliminated from the test period. In addition, Schedule DPY-4 provides the derivation of updated BUC factors to be effective upon implementation of new rates. These BUC factors reflect the billing determinants relied upon to derive the proposed rates in Schedule DPY-4.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SOUTH JERSEY GAS COMPANY
ALLOCATED COST OF SERVICE STUDY

I. PURPOSE AND GUIDING PRINCIPLES

South Jersey Gas Company ("South Jersey Gas") 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 with 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 South Jersey Gas' 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 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 South Jersey Gas system. For example, the principle of cost causation requires that the costs incurred by the Company for meter reading be apportioned to classes on the basis of the number of meter readings in each class.

II. Specification of South Jersey Gas ACOSS

A. Overview

The ACOSS follows a three-part process, which consists of the functionalization, classification and allocation of South Jersey Gas' 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 South Jersey Gas' 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 nine customer classes, which are: Residential Heating, Residential Non-Heating, General Service ("GSG"), General Service – Large Volume ("GDS-LV"), Comprehensive Transportation Service ("CTS"), Large Volume Service ("LVS"), Electric Generation Service ("EGS"), Electric Generation Service – Large Volume ("EGS-LV") and Natural Gas Vehicle Service ("NGV").

The Residential Heating and Residential Non-Heating customers are served under the same rate schedule, Residential Service ("RSG"); however, the two types of customers are studied separately to guide the design of the customer and delivery rates that apply to RSG 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 have much lower use 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 two types of customers in the ACOSS.

C. 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 South Jersey Gas' 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 2019 through June 2020. This is South Jersey Gas' test year, which is the period for which rates are to be determined.

D. 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 South Jersey Gas' 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 South Jersey Gas' 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.

E. Cost Classification

Classification is the apportionment of costs among demand, customer and commodity categories. Each of South Jersey Gas' 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 of transmission facilities. 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 South Jersey Gas' 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, 49% of South Jersey Gas' distribution mains investment is classified as customer-related.

F. 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 South Jersey Gas' 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 sales 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.

- *Service Investment Study:* South Jersey Gas' 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.

- *Industrial Customer Investment Study:* The industrial customer investment study examines the Company's investments in services, meters and regulators to serve the largest customers on the system.

- *Working Capital Study:* The working capital study examines the components of South Jersey Gas' proposed working capital allowance. A composite allocator is derived from the allocation of each component within the ACOSS.

- *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 represent a significant proportion of the Company's overall O&M

expense. Gas costs are allocated among South Jersey Gas' rate classes on the basis of Basic Gas Supply Service ("BGSS") 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 1. 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 for the Residential Heating, Residential Non-Heating, and NGV customers are less than the system-average rate of return of 5.10% at present rates. The residential class is by far South Jersey Gas' largest class. The rate of return for all other classes is above the system-average, indicating that these classes are subsidizing the prices for residential customers.

Monthly customer costs are derived from the costs that are classified as customer-related and the apportionment of these costs to South Jersey Gas' various customer classes. The system-wide average monthly customer cost is $60, and the cost generally varies with the size of the customer. The lowest average customer cost of $57 per month is associated with serving the Residential Non-Heating class.

The results of the ACOSS indicates that class-differentiated base rate revenue increases would be appropriate given the wide disparity in rates of return by customer class. In addition, the monthly customer-related costs should be taken into consideration in the development of proposed modifications to existing customer charges.

South Jersey Gas Company
Income and Rate of Return at Present Rates

	Total System	Residential Heating	Residential Non-Heating	General Service GSG	General Service GSG-LV	CTS	LVS	EGS	EGS-LV	NGV
REVENUES										
Margin Revenues	$ 334,122,866	$ 227,379,690	$ 3,183,953	$ 77,283,063	$ 11,194,507	$ 6,385,509	$ 6,703,330	$ 314,174	$ 973,635	$ 705,004
Rider Revenues	275,358,650	187,430,787	1,371,864	60,448,728	9,844,516	5,159,149	8,446,833	715,704	1,355,547	585,522
Miscellaneous Revenues	5,833,219	4,732,768	119,651	684,667	111,076	63,019	95,402	3,471	14,937	8,228
Total	**$ 615,314,735**	**$ 419,543,245**	**$ 4,675,468**	**$ 138,416,458**	**$ 21,150,099**	**$ 11,607,677**	**$ 15,245,565**	**$ 1,033,349**	**$ 2,344,119**	**$ 1,298,755**
OPERATING EXPENSES										
Operations and Maintenance	$ 394,248,316	$286,443,646	$3,903,470	$73,055,609	$11,517,683	$5,951,938	$9,667,122	$758,820	$1,527,999	$1,422,028
Depreciation and Amortization	78,634,560	64,260,892	1,707,601	8,999,150	1,276,073	796,141	1,131,653	40,883	186,889	235,277
Taxes Other Than Income Taxes	5,051,306	4,306,724	113,661	604,283	87,356	47,586	73,306	2,628	11,275	(195,514)
Total	**$ 477,934,181**	**$ 355,011,262**	**$ 5,724,732**	**$ 82,659,042**	**$ 12,881,112**	**$ 6,795,665**	**$ 10,872,082**	**$ 802,331**	**$ 1,726,164**	**$ 1,461,792**
OPERATING INCOME BEFORE TAXES	**$ 137,380,554**	**$ 64,531,983**	**$ (1,049,265)**	**$ 55,757,416**	**$ 8,268,988**	**$ 4,812,012**	**$ 4,373,483**	**$ 231,018**	**$ 617,955**	**$ (163,037)**
INCOME TAXES										
Federal Income Taxes	$ 16,859,312	$ 13,678,762	$ 345,818	$ 1,978,841	$ 321,034	$ 182,140	$ 275,732	$ 10,032	$ 43,171	$ 23,781
State Income Taxes	8,987,234	7,291,771	184,346	1,054,866	171,135	97,094	146,985	5,348	23,013	12,677
Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-
Total	**$ 25,846,546**	**$ 20,970,533**	**$ 530,164**	**$ 3,033,707**	**$ 492,169**	**$ 279,234**	**$ 422,717**	**$ 15,379**	**$ 66,184**	**$ 36,459**
RATEMAKING ADJUSTMENTS	**$ (163,179)**	**($132,395)**	**($3,347)**	**($19,153)**	**($3,107)**	**($1,763)**	**($2,669)**	**($97)**	**($418)**	**($230)**
NET INCOME	**$ 111,370,829**	**$ 43,429,056**	**$ (1,582,775)**	**$ 52,704,556**	**$ 7,773,711**	**$ 4,531,014**	**$ 3,948,097**	**$ 215,542**	**$ 551,353**	**$ (199,726)**
RATE BASE	**$ 2,183,729,657**	**$1,771,763,793**	**$44,792,609**	**$256,312,614**	**$41,582,510**	**$23,592,009**	**$35,714,649**	**$1,299,347**	**$5,591,797**	**$3,080,330**
RATE OF RETURN AT PRESENT RATE	**5.10%**	**2.45%**	**-3.53%**	**20.56%**	**18.69%**	**19.21%**	**11.05%**	**16.59%**	**9.86%**	**-6.48%**

South Jersey Gas Company
Income and Rate of Return at Proposed Rates

	Total System	Residential Heating	Residential Non-Heating	General Service GSG	General Service GSG-LV	CTS	LVS	EGS	EGS-LV	NGV
REVENUES										
Margin Revenues	$ 402,999,258	$ 290,474,812	$ 4,129,386	$ 77,208,865	$ 12,878,037	$ 7,327,041	$ 8,477,088	$ 360,500	$ 1,231,267	$ 912,263
Rider Revenues	275,358,650	187,430,787	1,371,864	60,448,728	9,844,516	5,159,149	8,446,833	715,704	1,355,547	585,522
Miscellaneous Revenues	6,462,554	5,243,378	132,560	758,534	123,060	69,818	105,694	3,845	16,548	9,116
Total	**$ 684,820,462**	**$ 483,148,977**	**$ 5,633,810**	**$ 138,416,127**	**$ 22,845,613**	**$ 12,556,008**	**$ 17,029,615**	**$ 1,080,049**	**$ 2,603,363**	**$ 1,506,902**
OPERATING EXPENSES										
Operations and Maintenance	$ 395,394,984	$287,491,577	$3,915,331	$73,125,001	$11,528,220	$5,957,745	$9,667,122	$759,312	$1,527,999	$1,422,676
Depreciation and Amortization	78,634,560	64,260,892	1,707,601	8,999,150	1,276,073	796,141	1,131,653	40,883	186,889	235,277
Taxes Other Than Income Taxes	5,241,446	4,460,994	117,561	626,600	90,976	49,640	76,416	2,741	11,762	(195,245)
Total	**$ 479,270,989**	**$ 356,213,462**	**$ 5,740,493**	**$ 82,750,751**	**$ 12,895,270**	**$ 6,803,526**	**$ 10,875,192**	**$ 802,936**	**$ 1,726,651**	**$ 1,462,708**
OPERATING INCOME BEFORE TAXES	**$ 205,549,473**	**$ 126,935,515**	**$ (106,684)**	**$ 55,665,376**	**$ 9,950,343**	**$ 5,752,482**	**$ 6,154,423**	**$ 277,113**	**$ 876,712**	**$ 44,194**
INCOME TAXES										
Federal Income Taxes	$ 29,886,767	$ 24,248,556	$ 613,037	$ 3,507,923	$ 569,103	$ 322,883	$ 488,795	$ 17,783	$ 76,530	$ 42,158
State Income Taxes	15,122,613	12,269,696	310,195	1,774,998	287,964	163,378	247,329	8,998	38,724	21,332
Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-
Total	**$ 45,009,380**	**$ 36,518,252**	**$ 923,231**	**$ 5,282,921**	**$ 857,067**	**$ 486,261**	**$ 736,123**	**$ 26,781**	**$ 115,254**	**$ 63,489**
RATEMAKING ADJUSTMENTS	**$ (163,179)**	**($132,395)**	**($3,347)**	**($19,153)**	**($3,107)**	**($1,763)**	**($2,669)**	**($97)**	**($418)**	**($230)**
NET INCOME	**$ 160,376,914**	**$ 90,284,868**	**$ (1,033,262)**	**$ 50,363,302**	**$ 9,090,168**	**$ 5,264,458**	**$ 5,415,631**	**$ 250,234**	**$ 761,041**	**$ (19,526)**
RATE BASE	**$ 2,183,729,657**	**$1,771,763,793**	**$44,792,609**	**$256,312,614**	**$41,582,510**	**$23,592,009**	**$35,714,649**	**$1,299,347**	**$5,591,797**	**$3,080,330**
RATE OF RETURN AT PROPOSED RAT	**7.34%**	**5.10%**	**-2.31%**	**19.65%**	**21.86%**	**22.31%**	**15.16%**	**19.26%**	**13.61%**	**-0.63%**

South Jersey Gas Company
Rate Base

	Total System	Residential Heating	Residential Non-Heating	General Service GSG	General Service GSG-LV	CTS	LVS	EGS	EGS-LV	NGV
I. PLANT IN SERVICE										
Demand	$ 1,051,028,023	$ 697,674,643	$ 3,307,950	$199,087,184	$60,443,033	$28,132,087	$49,380,202	$1,549,191	$6,727,009	$4,726,724
Customer	2,191,222,356	1,930,406,612	63,166,174	178,324,431	1,855,352	9,219,043	5,504,480	379,039	2,059,392	307,833
Commodity	1,401,979	954,297	6,985	307,773	50,123	26,268	43,007	3,644	6,902	2,981
	$ 3,243,652,358	$2,629,035,553	$66,481,109	$377,719,388	$62,348,507	$37,377,398	$54,927,689	$1,931,873	$8,793,302	$5,037,538
II. ACCUMULATED RESERVE FOR DEPRECIATION										
Demand	$ 210,899,033	$ 139,730,213	$ 662,516	$39,873,163	$12,105,525	$5,634,292	$9,889,862	$310,272	$1,347,285	$1,345,906
Customer	402,792,843	352,358,810	11,529,564	32,669,528	340,848	3,098,963	1,897,485	107,315	684,849	105,482
Commodity	357,191	243,133	1,780	78,413	12,770	6,692	10,957	928	1,758	760
	$ 614,049,068	$492,332,156	$12,193,859	$72,621,104	$12,459,143	$8,739,947	$11,798,305	$418,515	$2,033,892	$1,452,148
III. NET PLANT IN SERVICE										
Demand	$ 840,128,990	$ 557,944,430	$ 2,645,434	$159,214,021	$48,337,508	$22,497,796	$39,490,340	$1,238,919	$5,379,724	$3,380,817
Customer	1,788,429,512	1,578,047,802	51,636,611	145,654,903	1,514,504	6,120,080	3,606,995	271,724	1,374,543	202,351
Commodity	1,044,788	711,165	5,205	229,359	37,353	19,575	32,050	2,716	5,143	2,222
	$ 2,629,603,290	$2,136,703,397	$54,287,250	$305,098,284	$49,889,364	$28,637,450	$43,129,385	$1,513,359	$6,759,411	$3,585,390
IV. RATE BASE ADDITIONS										
Demand	$ 41,111,948	$ 31,728,364	$ 600,766	$6,676,998	$955,899	$330,553	$585,110	$51,077	$87,579	$95,602
Customer	60,570,986	47,591,691	1,136,127	8,805,092	1,163,786	539,617	955,393	60,700	146,918	171,660
Commodity	35,409	27,770	658	5,183	689	319	566	36	87	101
	$ 101,718,344	$79,347,826	$1,737,552	$15,487,273	$2,120,375	$870,490	$1,541,068	$111,813	$234,585	$267,363
V. RATE BASE DEDUCTIONS										
Demand	$ (176,676,544)	$ (118,221,189)	$ (650,818)	($33,258,841)	($9,882,642)	($4,576,766)	($8,034,570)	($258,626)	($1,096,118)	($696,974)
Customer	(370,698,868)	(325,918,095)	(10,580,200)	(30,967,079)	(536,960)	(1,335,177)	(914,695)	(66,647)	(305,032)	(74,984)
Commodity	(216,564)	(148,146)	(1,175)	(47,023)	(7,627)	(3,989)	(6,539)	(552)	(1,049)	(466)
	$ (547,591,976)	($444,287,430)	($11,232,193)	($64,272,943)	($10,427,229)	($5,915,931)	($8,955,804)	($325,824)	($1,402,199)	($772,423)
VI. TOTAL RATE BASE										
Demand	**$ 704,564,394**	**$ 471,451,606**	**$ 2,595,383**	**$132,632,178**	**$39,410,765**	**$18,251,582**	**$32,040,880**	**$1,031,369**	**$4,371,185**	**$2,779,446**
Customer	**1,478,301,631**	**1,299,721,398**	**42,192,538**	**123,492,916**	**2,141,330**	**5,324,520**	**3,647,693**	**265,778**	**1,216,430**	**299,027**
Commodity	**863,633**	**590,789**	**4,688**	**187,520**	**30,415**	**15,906**	**26,077**	**2,200**	**4,182**	**1,857**
	$ 2,183,729,657	**$1,771,763,793**	**$44,792,609**	**$256,312,614**	**$41,582,510**	**$23,592,009**	**$35,714,649**	**$1,299,347**	**$5,591,797**	**$3,080,330**

South Jersey Gas Company
O&M Expense

	Total System	Residential Heating	Residential Non-Heating	General Service GSG	General Service GSG-LV	CTS	LVS	EGS	EGS-LV	NGV
I. PRODUCTION EXPENSE										
Demand	$ -	$ -	$ -	$0	$0	$0	$0	$0	$0	$0
Customer	-	-	-	-	-	-	-	-	-	-
Commodity	256,377,051	174,510,415	1,277,296	56,281,750	9,165,893	4,803,508	7,864,558	666,367	1,262,104	545,160
	$ 256,377,051	$174,510,415	$1,277,296	$56,281,750	$9,165,893	$4,803,508	$7,864,558	$666,367	$1,262,104	$545,160
II. STORAGE EXPENSE										
Demand	$ 483,334	$ 321,971	$ 1,527	$ 91,877	$ 27,894	$ 12,983	$ 22,789	$ 715	$ 3,104	$ 475
Customer	-	-	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-	-	-
	$ 483,334	$321,971	$1,527	$91,877	$27,894	$12,983	$22,789	$715	$3,104	$475
III. TRANSMISSION EXPENSE										
Demand	$ 8,988,538	$ 5,987,678	$ 28,390	$ 1,708,633	$ 518,742	$ 241,439	$ 423,797	$ 13,296	$ 57,733	$ 8,830
Customer	-	-	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-	-	-
	$ 8,988,538	$5,987,678	$28,390	$1,708,633	$518,742	$241,439	$423,797	$13,296	$57,733	$8,830
IV. DISTRIBUTION EXPENSE										
Demand	$ 5,786,944	$ 3,425,868	$ 16,243	$977,599	$296,800	$138,140	$242,477	$7,607	$33,032	$649,176
Customer	21,516,830	18,564,715	605,500	2,287,808	34,659	13,223	5,944	1,364	3,267	350
Commodity	-	-	-	-	-	-	-	-	-	-
	$ 27,303,774	$21,990,583	$621,743	$3,265,408	$331,459	$151,363	$248,421	$8,971	$36,299	$649,527
V. CUSTOMER ACCOUNTS EXPENSE										
Demand	$ 4,459,172	$ 4,075,202	$ 46,124	$ 269,851	$ 40,979	$ 22,582	$ -	$ 1,913	$ -	$ 2,521
Customer	23,342,291	21,182,445	510,821	1,496,996	91,889	49,005	898	4,464	173	5,600
Commodity	5,466	4,995	57	331	50	28	-	2	-	3
	$ 27,806,929	$25,262,642	$557,001	$1,767,177	$132,918	$71,615	$898	$6,380	$173	$8,124
VI. CUSTOMER SERVICE AND SALES EXPENSE										
Demand	$ 168,505	$ 112,249	$ 532	$ 32,031	$ 9,725	$ 4,526	$ 7,945	$ 249	$ 1,082	$ 166
Customer	1,762,171	1,591,549	52,167	117,275	744	205	113	57	22	39
Commodity	15,952,152	10,858,291	79,475	3,501,932	570,315	298,881	489,344	41,462	78,530	33,921
	$ 17,882,828	$ 12,562,089	$ 132,175	$ 3,651,238	$ 580,784	$ 303,612	$ 497,402	$ 41,768	$ 79,634	$ 34,125
VII. ADMINISTRATIVE AND GENERAL EXPENSE										
Demand	$ 12,499,475	$ 8,222,016	$ 39,354	$2,344,265	$710,840	$330,753	$580,574	$18,241	$79,097	$174,335
Customer	43,793,019	38,457,179	1,256,549	3,957,570	50,394	37,601	20,706	2,899	8,574	1,548
Commodity	260,036	177,004	1,296	57,083	9,296	4,872	7,976	676	1,280	553
	$ 56,552,530	$46,856,198	$1,297,199	$6,358,917	$770,530	$373,226	$609,257	$21,816	$88,951	$176,436
VIII. TOTAL O&M EXPENSE										
Demand	**$ 32,385,967**	**$ 22,144,982**	**$ 132,170**	**$ 5,424,256**	**$ 1,604,980**	**$ 750,423**	**$ 1,277,582**	**$ 42,022**	**$ 174,050**	**$ 835,502**
Customer	**90,414,312**	**79,795,889**	**2,425,037**	**7,859,649**	**177,686**	**100,034**	**27,661**	**8,783**	**12,035**	**7,538**
Commodity	**272,594,705**	**185,550,706**	**1,358,123**	**59,841,096**	**9,745,555**	**5,107,288**	**8,361,879**	**708,508**	**1,341,914**	**579,637**
	$ 395,394,984	**$ 287,491,577**	**$ 3,915,331**	**$ 73,125,001**	**$ 11,528,220**	**$ 5,957,745**	**$ 9,667,122**	**$ 759,312**	**$ 1,527,999**	**$ 1,422,676**

South Jersey Gas Company
Total Revenue Requirements

	Total System	Residential Heating	Residential Non-Heating	General Service GSG	General Service GSG-LV	CTS	LVS	EGS	EGS-LV	NGV
I. O&M EXPENSE										
Demand	$ 32,385,967	$ 22,144,982	$ 132,170	$ 5,424,256	$ 1,604,980	$ 750,423	$ 1,277,582	$ 42,022	$ 174,050	$ 835,502
Customer	90,414,312	79,795,889	2,425,037	7,859,649	177,686	100,034	27,661	8,783	12,035	7,538
Commodity	272,594,705	185,550,706	1,358,123	59,841,096	9,745,555	5,107,288	8,361,879	708,508	1,341,914	579,637
	$ 395,394,984	$ 287,491,577	$ 3,915,331	$ 73,125,001	$ 11,528,220	$ 5,957,745	$ 9,667,122	$ 759,312	$ 1,527,999	$ 1,422,676
II. DEPRECIATION										
Demand	$ 21,244,177	$ 14,013,973	$ 66,446	$ 3,999,002	$ 1,214,100	$ 565,080	$ 991,885	$ 31,118	$ 135,123	$ 227,449
Customer	57,283,396	50,174,095	1,640,623	4,976,662	58,148	229,056	136,486	9,487	51,239	7,600
Commodity	106,986	72,823	533	23,486	3,825	2,005	3,282	278	527	227
	$ 78,634,560	$ 64,260,892	$ 1,707,601	$ 8,999,150	$ 1,276,073	$ 796,141	$ 1,131,653	$ 40,883	$ 186,889	$ 235,277
III. TAXES OTHER THAN INCOME										
Demand	$ 1,308,713	$ 1,006,280	$ 5,093	$ 285,450	$ 85,896	$ 39,897	$ 70,035	$ 2,221	$ 9,546	$ (195,705)
Customer	3,920,456	3,446,355	112,406	338,457	4,641	9,514	6,005	488	2,156	433
Commodity	12,277	8,360	62	2,693	439	230	376	32	60	26
	$ 5,241,446	$4,460,994	$117,561	$626,600	$90,976	$49,640	$76,416	$2,741	$11,762	($195,245)
IV. DEFERRED INCOME TAXES										
Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	-	-	-	-	-	-	-	-	-	-
Commodity	-	-	-	-	-	-	-	-	-	-
	$ -	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. RATEMAKING ADJUSTMENTS										
Demand	$ 52,648	$ 35,229	$ 194	$ 9,911	$ 2,945	$ 1,364	$ 2,394	$ 77	$ 327	$ 208
Customer	110,466	97,121	3,153	9,228	160	398	273	20	91	22
Commodity	65	44	0	14	2	1	2	0	0	0
	$ 163,179	$132,395	$3,347	$19,153	$3,107	$1,763	$2,669	$97	$418	$230
VI. RETURN										
Demand	$ 53,039,488	$ 35,490,797	$ 195,380	$ 9,984,528	$ 2,966,836	$ 1,373,976	$ 2,412,032	$ 77,641	$ 329,062	$ 209,236
Customer	111,286,297	97,842,807	3,176,247	9,296,526	161,199	400,829	274,598	20,008	91,573	22,511
Commodity	65,014	44,474	353	14,116	2,290	1,197	1,963	166	315	140
	$ 164,390,799	$133,378,078	$3,371,980	$19,295,170	$3,130,324	$1,776,002	$2,688,593	$97,815	$420,950	$231,887
VII. INCOME TAXES										
Demand	$ 14,521,947	$ 9,717,203	$ 53,494	$ 2,733,714	$ 812,305	$ 376,188	$ 660,402	$ 21,258	$ 90,096	$ 57,288
Customer	30,469,632	26,788,872	869,641	2,545,342	44,135	109,745	75,183	5,478	25,072	6,163
Commodity	17,801	12,177	97	3,865	627	328	537	45	86	38
	$ 45,009,380	$36,518,252	$923,231	$5,282,921	$857,067	$486,261	$736,123	$26,781	$115,254	$63,489
VIII. TOTAL REVENUE REQUIREMENTS										
Demand	**$ 122,552,941**	**$ 82,408,464**	**$ 452,777**	**$ 22,436,861**	**$ 6,687,062**	**$ 3,106,929**	**$ 5,414,330**	**$ 174,336**	**$ 738,204**	**$ 1,133,978**
Customer	**293,484,558**	**258,145,139**	**8,227,107**	**25,025,864**	**445,970**	**849,575**	**520,207**	**44,264**	**182,165**	**44,268**
Commodity	**272,796,848**	**185,688,584**	**1,359,168**	**59,885,271**	**9,752,737**	**5,111,049**	**8,368,039**	**709,029**	**1,342,902**	**580,068**
	$ 688,834,347	**$526,242,187**	**$10,039,052**	**$107,347,996**	**$16,885,769**	**$9,067,552**	**$14,302,576**	**$927,629**	**$2,263,272**	**$1,758,314**

South Jersey Gas Company
Monthly Customer Cost Detail

	Total System	Residential Heating	Residential Non-Heating	General Service GSG	General Service GSG-LV	CTS	LVS	EGS	EGS-LV	NGV
I. AVERAGE CUSTOMER COSTS										
Customer-Related Revenue Req.	$ 293,484,558	$ 258,145,139	$ 8,227,107	$ 25,025,864	$ 445,970	$ 849,575	$ 520,207	$ 44,264	$ 182,165	$ 44,268
Average Customers	404,844	365,645	11,985	26,943	171	47	26	13	5	9
Average Monthly Customer Cost	**$ 60.41**	**$ 58.83**	**$ 57.20**	**$ 77.40**	**$ 217.33**	**$ 1,506.34**	**$ 1,667.33**	**$ 283.74**	**$ 3,036.09**	**$ 409.89**
II. MONTHLY CUSTOMER COST DETAIL										
O&M Expense										
Mains and Services Expense	$ 1.93	$ 1.92	$ 1.92	$ 2.00	$ 2.00	$ 19.77	$ 15.66	$ 7.08	$ 47.19	$ 2.00
Meter & Regulator Expense	1.14	0.99	0.97	3.21	11.10	-	-	-	-	-
Meter Reading Expense	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Customer Records and Collections	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
Uncollectible Accounts	1.60	1.62	0.56	1.46	34.84	69.86	-	21.40	-	40.72
All Other O&M	11.06	10.77	10.53	14.76	35.77	84.86	70.12	24.95	150.51	24.19
Total O&M	$ 18.61	$ 18.19	$ 16.86	$ 24.31	$ 86.59	$ 177.36	$ 88.66	$ 56.30	$ 200.58	$ 69.79
Depreciation										
Mains	$ 2.53	$ 2.53	$ 2.53	$ 2.53	$ 2.53	$ 2.53	$ 2.53	$ 2.53	$ 2.53	$ 2.53
Services	4.47	4.44	4.44	4.72	4.72	63.73	50.09	21.57	154.82	4.72
Measuring and Regulating	1.25	1.03	1.01	3.32	11.50	318.55	364.79	30.09	650.87	58.77
All Other Depreciation	3.54	3.44	3.43	4.82	9.59	21.32	20.06	6.63	45.77	4.36
Total Depreciation	$ 11.79	$ 11.44	$ 11.41	$ 15.39	$ 28.34	$ 406.13	$ 437.46	$ 60.81	$ 853.99	$ 70.37
Taxes Other Than Income Taxes	$ 0.81	$ 0.79	$ 0.78	$ 1.05	$ 2.26	$ 16.87	$ 19.25	$ 3.13	$ 35.93	$ 4.01
Deferred Income Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ratemaking Adjustments	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.08	$ 0.71	$ 0.87	$ 0.13	$ 1.51	$ 0.21
Rate Base-Related (Return and Income Taxes)										
Mains	$ 13.35	$ 13.35	$ 13.35	$ 13.35	$ 13.35	$ 13.35	$ 13.35	$ 13.35	$ 13.35	$ 13.35
Services	16.22	14.83	14.83	15.75	15.75	212.74	167.19	71.99	516.79	15.75
Meters and Regulators	3.50	2.88	2.83	9.32	32.29	786.08	900.17	74.25	1,606.12	145.02
All Other Rate Base-Related	(3.89)	(2.65)	(2.88)	(1.80)	38.68	(106.89)	40.39	3.78	(192.18)	91.39
Total Rate Base-Related	$ 29.18	$ 28.40	$ 28.13	$ 36.63	$ 100.07	$ 905.27	$ 1,121.09	$ 163.37	$ 1,944.08	$ 265.50
Total Average Monthly Customer Cost	**$ 60.41**	**$ 58.83**	**$ 57.20**	**$ 77.40**	**$ 217.33**	**$ 1,506.34**	**$ 1,667.33**	**$ 283.74**	**$ 3,036.09**	**$ 409.89**

South Jersey Gas Company
Base and Total Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Rate	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase
			RSG		RSG		RSG		
Residential Service									
Customer Charge	4,531,567	Bills	$ 9.50	$ 43,049,890	$ 9.50	$ 43,049,890	$ 12.75	$ 57,777,484	
Distribution Charge	276,548,155	Therms	0.678051	187,513,753	0.702706	194,332,048	0.856372	236,828,096	
CIP Revenues				(5,472,678)		(5,472,678)		-	
Total Base Revenues				**$ 225,090,965**		**$ 231,909,260**		**$ 294,605,581**	**27.0%**
		Rider Revenues		**$ 159,248,510**		**$ 159,248,510**		**$ 159,248,510**	
		Total Class Revenues		**$ 384,339,475**		**$ 391,157,770**		**$ 453,854,091**	**16.0%**
			GSG		GSG		GSG		
General Service (0-100,000 Annual Therms)									
Customer Charge	323,321	Bills	$ 29.97	$ 9,689,918	$ 29.97	$ 9,689,918	$ 34.75	$ 11,235,391	
Distribution Charge	119,356,723	Therms	0.566312	67,593,145	0.583388	69,631,280	0.552743	65,973,593	
CIP Revenues				(9,995,628)		(9,995,628)		-	
Total Base Revenues				**$ 67,287,435**		**$ 69,325,570**		**$ 77,208,984**	**11.4%**
		Rider Revenues		**$ 59,229,860**		**$ 59,229,860**		**$ 59,229,860**	
		Total Class Revenues		**$ 126,517,295**		**$ 128,555,430**		**$ 136,438,844**	**6.1%**

South Jersey Gas Company
Base and Total Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Rate	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase
			GSG-LV		GSG-LV		GSG-LV		
General Service Large Volume (100,000 + Annual Therms)									
Customer Charge	2,053	Bills	$ 150.00	$ 307,950	$ 150.00	$ 307,950	$ 225.00	$ 461,925	
Demand Charge	231,528	Mcf	9.6086	2,224,660	9.6086	2,224,660	12.2500	2,836,218	
Distribution Charge	30,549,982	Therms	0.283532	8,661,897.41	0.294660	9,001,858	0.313582	9,579,924	
CIRT Revenues				28,681		28,681		-	
Total Base Revenues				**$ 11,223,188**		**$ 11,563,148**		**$ 12,878,067**	**11.4%**
		Rider Revenues		**$ 7,989,473**		**$ 7,989,473**		**$ 7,989,473**	
		Total Class Revenues		**$ 19,212,661**		**$ 19,552,621**		**$ 20,867,540**	**6.7%**
			CTS		CTS		CTS		
Comprehensive Firm Transportation Service									
Customer Charge	560	Bills	$ 600.00	$ 336,000	$ 600.00	$ 336,000	$ 750.00	$ 420,000	
Demand Charge	170,624	Mcf	28.6555	4,889,316	28.6555	4,889,316	31.7500	5,417,312	
Distribution Charge	16,869,883	Therms	0.068773	1,160,192	0.080239	1,353,623	0.088309	1,489,763	
Total Base Revenues				**$ 6,385,509**		**$ 6,578,939**		**$ 7,327,075**	**11.4%**
		Rider Revenues		**$ 4,202,019**		**$ 4,202,019**		**$ 4,202,019**	
		Total Class Revenues		**$ 10,587,528**		**$ 10,780,958**		**$ 11,529,094**	**6.9%**

South Jersey Gas Company
Base and Total Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Rate	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase
			LVS		LVS		LVS		
Large Volume Service									
Customer Charge	306	Bills	$ 900.00	$ 275,400	$ 900.00	$ 275,400	$ 1,050.00	$ 321,300	
Demand Charge	299,496	Mcf	15.9588	4,779,597	15.9588	4,779,597	19.7500	5,915,046	
Distribution Charge	32,287,343	Therms	0.051052	1,648,333	0.057341	1,851,389	0.069401	2,240,774	
Total Base Revenues				**$ 6,703,330**		**$ 6,906,385**		**$ 8,477,120**	**22.7%**
		Rider Revenues		**$ 6,879,770**		**$ 6,879,770**		**$ 6,879,770**	
		Total Class Revenues		**$ 13,583,100**		**$ 13,786,155**		**$ 15,356,890**	**11.4%**
			EGS		EGS		EGS		
Electric Generation Service									
Customer Charge	156	Bills	$ 63.38	$ 9,887	$ 63.38	$ 9,887	$ 79.00	$ 12,324	
Demand Charge	9,396	Mcf	7.8432	73,695	7.8432	73,695	8.2500	77,517	
Distribution Charge (Nov - Mar.)	907,290	Therms	0.135163	122,632	0.140084	127,097	0.155881	141,429	
Distribution Charge (Apr - Oct.)	1,026,600	Therms	0.105163	107,960	0.110084	113,012	0.125881	129,229	
Total Base Revenues				**$ 314,174**		**$ 323,691**		**$ 360,500**	**11.4%**
		Rider Revenues		**$ 582,926**		**$ 582,926**		**$ 582,926**	
		Total Class Revenues		**$ 897,100**		**$ 906,617**		**$ 943,425**	**4.1%**

South Jersey Gas Company
Base and Total Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Rate	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase
			EGS-LV		EGS-LV		EGS-LV		
Electric Generation Service - Large Volume									
Customer Charge	60	Bills	$ 428.32	25,699	$ 428.32	$ 25,699	$ 750.00	$ 45,000	
Demand Charge	40,800	Mcf	23.233717	947,936	23.956564	977,428	29.075282	1,186,272	
Total Base Revenues				**$ 973,635**		**$ 1,003,127**		**$ 1,231,272**	**22.7%**
		Rider Revenues		**$ 1,104,065**		**$ 1,104,065**		**$ 1,104,065**	
		Total Class Revenues		**$ 2,077,700**		**$ 2,107,192**		**$ 2,335,337**	**10.8%**

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Existing Adjusted Rate	Existing Adjusted Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase
			NGV		NGV		NGV		
Natural Gas Vehicle Service									
Cust. Charge 0-999 CFH	12	Bills	$ 37.50	$ 450	$ 37.50	$ 450	$ 37.50	$ 450	
Cust. Charge 1,000-4,999 CFH	-	Bills	75.00	-	75.00	-	75.00	-	
Cust. Charge 5,000-24,999 CFH	12	Bills	200.00	2,400	200.00	2,400	220.00	2,640	
Cust. Charge 25,000+ CFH	84	Bills	703.47	59,091	703.47	59,091	925.00	77,700	
Distribution Charge	1,888,852	Therms	0.196474	371,110	0.203419	384,228	0.257299	486,000	
Subtotal Distribution				$ 433,052		$ 446,170		$ 566,790	
Compression Charge	495,620	Therms	0.548712	271,952	0.548712	271,952	0.697060	345,477	
Total Base Revenues				**$ 705,004**		**$ 718,122**		**$ 912,266**	**27.0%**
		Rider Revenues		**$ 476,896**		**$ 476,896**		**$ 476,896**	
		Total Class Revenues		**$ 1,181,900**		**$ 1,195,018**		**$ 1,389,162**	**16.2%**

South Jersey Gas Company
Base and Total Revenues at Present and Proposed Rates

Component	Amount	Units	Present Rates Rate	Present Rates Revenue	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Rate	Exsting Rates Adjusted for Projected October 1, 2020 SHARP and AIRP II Roll-In Revenue	Proposed Rates Rate	Proposed Rates Revenue	Increase
			GLS		GLS		GLS		
Gas Lights Service									
Yard Lights	48	Mantles	$ 8.818524	$ 5,079	$ 9.085644	$ 5,233	$ 11.152022	$ 6,424	
Street Lights	36	Mantles	$ 9.506499	4,107	$ 9.794458	4,231	$ 12.022044	5,194	
Total Base Revenues				**$ 9,186**		**$ 9,465**		**$ 11,617**	**22.7%**
		Rider Revenues		**$ 34,114**		**$ 34,114**		**$ 34,114**	
		Total Class Revenues		**$ 43,300**		**$ 43,578**		**$ 45,731**	**4.9%**
TOTAL SYSTEM BASE DISTRIBUTION REVENUES				***$ 318,692,426***		***$ 328,337,707***		***$ 403,012,481***	***22.7%***
Other Revenues									
Rider Revenues				**$ 239,747,632**		**$ 239,747,632**		**$ 239,747,632**	
Special Contracts				**3,687,306**		**3,687,306**		**3,687,306**	
Service Charges				**2,136,448**		**2,136,448**		**2,763,631**	
Total Other Revenues				**$ 245,571,387**		**$ 245,571,387**		**$ 246,198,570**	
TOTAL SYSTEM INCLUDING OTHER REVENUES				***$ 564,263,813***		***$ 573,909,094***		***$ 649,211,051***	***13.1%***

Increase	**$ 75,301,957**
Target	**75,302,112**
Difference	**($155)**

SOUTH JERSEY GAS COMPANY
Pro Forma Adjustment to June 30, 2020
Summary of CIP Revenue Adjustment

Description	Actual 2019 July	Actual 2019 August	Actual 2019 September	Actual 2019 October	Actual 2019 November	Actual 2019 December	Projected 2020 January	Projected 2020 February	Projected 2020 March	Projected 2020 April	Projected 2020 May	Projected 2020 June	Test Year Total
CIP Revenue Adjustment													
CIP Group 1 - RSG non-Heat	($6,063)	($2,107)	$11,451	$26,262	$43,959	$76,641	($22,540)	($25,825)	$2,766	($238)	$11,691	($9,257)	$106,740
CIP Group 2 - RSG Heat	($55,615)	$1,332,528	($529,892)	$1,440,189	$3,634,254	($1,937,820)	$1,340,670	$662,029	($601,716)	($966,863)	$401,601	$582,817	$5,302,181
CIP Group 3 - GSG	$35,573	$521,321	($117,209)	$817,295	$1,202,435	($561,092)	($603,342)	$1,587,390	$820,778	$1,441,585	$2,600,335	$2,232,176	$9,977,245
CIP Group 4 - GSG-LV	($97,543)	$70,518	$84,949	$61,447	$91,260	($42,615)	($134,320)	$4,493	($107,862)	$73,052	($120,480)	$86,058	($31,042)
Total Revenue	($123,647)	$1,922,260	($550,702)	$2,345,193	$4,971,908	($2,464,885)	$580,467	$2,228,087	$113,966	$547,536	$2,893,148	$2,891,794	$15,355,124
Weather Related Dollars	$0	$0	$0	($3,591,424)	$5,704,020	($2,197,097)	$0	$0	$0	$0	$0	$0	($84,501)
Total Non-Weather Related Dollars	($123,647)	$1,922,260	($550,702)	$5,936,617	($732,112)	($267,788)	$580,467	$2,228,087	$113,966	$547,536	$2,893,148	$2,891,794	$15,439,625

South Jersey Gas Company
Derivation of CIP Baseline Use-per-Customer
6 + 6 Update

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Total
Group 1: RSG Non-Heat													
Customers	11,564	11,553	11,538	11,489	11,480	11,466	11,583	11,612	11,655	11,695	11,729	11,769	139,133
Therms	112,114	100,743	114,501	151,322	266,879	466,186	313,114	319,517	284,981	189,077	145,058	126,428	2,589,920
Baseline Use per Cust.	**9.70**	**8.72**	**9.92**	**13.17**	**23.25**	**40.66**	**27.03**	**27.52**	**24.45**	**16.17**	**12.37**	**10.74**	**223.70**
Group 2: RSG Heat													
Customers	355,602	355,501	355,777	356,438	357,814	359,223	359,498	360,284	360,740	360,999	361,151	361,154	4,304,181
Therms	4,715,241	5,067,607	4,807,725	12,322,564	25,061,283	44,633,568	56,477,843	47,705,885	36,195,907	18,213,226	8,753,687	5,301,511	269,256,047
Baseline Use per Cust.	**13.26**	**14.25**	**13.51**	**34.57**	**70.04**	**124.25**	**157.10**	**132.41**	**100.34**	**50.45**	**24.24**	**14.68**	**749.10**
Group 3: GSG													
Customers	25,614	25,505	25,498	25,613	25,875	26,083	26,140	26,270	26,424	26,468	26,478	26,481	312,449
Therms	2,889,219	3,194,586	3,042,258	5,408,674	8,842,701	15,252,075	16,915,772	17,753,263	15,306,596	9,698,918	8,957,422	7,140,704	114,402,187
Baseline Use per Cust.	**112.80**	**125.25**	**119.31**	**211.17**	**341.75**	**584.75**	**647.13**	**675.80**	**579.26**	**366.44**	**338.30**	**269.66**	**4,371.62**
Group 4: GSG-LV													
Customers	170	171	170	170	170	170	172	172	172	172	172	172	2,053
Therms	836,487	1,035,121	917,111	2,097,699	2,835,856	4,174,974	5,351,489	4,589,154	3,844,192	2,466,183	1,201,319	1,200,396	30,549,982
Baseline Use per Cust.	**4,920.51**	**6,053.34**	**5,394.77**	**12,339.41**	**16,681.51**	**24,558.67**	**31,113.31**	**26,681.13**	**22,349.95**	**14,338.27**	**6,984.41**	**6,979.05**	**178,394.33**