COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DELTA	**)**	
NATURAL GAS COMPANY, INC. FOR AN	**)**	**CASE NO. 2024-00346**
ADJUSTMENT OF GAS RATES	**)**	

TESTIMONY OF
JOHN B. BROWN
PRESIDENT
DELTA NATURAL GAS COMPANY, INC.

Filed: November 25, 2024

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Background

Q. Please state your name and business address.

A. My name is John B. Brown. My business address is 3617 Lexington Road, Winchester, Kentucky 40391.

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

A. I am employed by Delta Natural Gas Company, Inc. (“Delta” or “Company”) as its President. I am the chief officer in charge of Delta’s operations.

Q. For what period of time have you been so employed?

A. I was employed by Delta as Manager – Accounting & Finance in April of 1995. I was appointed Controller in March 1999 and promoted to Vice President – Controller and Assistant Secretary in November 2005. I was named Chief Financial Officer, Treasurer and Secretary in May 2007 and appointed Chief Operating Officer, Treasurer and Secretary in November 2015. I was named President, Secretary and Treasurer in September 2017. After the Essential acquisition in March 2020, I no longer have Treasury or Secretary responsibilities.

Q. Please describe your educational experience and professional history prior to joining Delta.

A. I attended Asbury College in Wilmore, Kentucky, from 1985 to 1989, receiving B.A. degrees in accounting and business management with a minor in computer science. I received an MBA degree from the University of Kentucky in 2000. I am a Certified Public Accountant in the state of Kentucky. I was employed by the accounting firm of Arthur Andersen LLP in its Louisville, Kentucky, office from 1989 to 1995, specializing in the utility industry and SEC registrants. I began auditing Delta in 1990 and was serving as

Acting Manager on the engagement in April 1995 when Delta hired me from Arthur Andersen LLP.

Q. What is the purpose of your testimony?

A. My testimony provides an overview of Delta's development, summarizes the need for the rate increase Delta is requesting, describes productivities and efficiencies the company has implemented since the last rate case, explains Delta's proposed changes to special charges, comments on the collection lag portion of the lead lag study and describes Delta's commitment to its customers with regard to economic development and supporting the communities in which we provide service. I am also sponsoring filing requirements that are part of Delta's application.

Q. Please summarize the development of Delta's business.

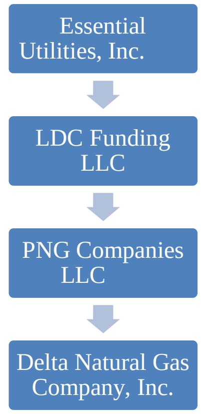
A. Delta is a Kentucky corporation with its principal office at 3617 Lexington Road in Winchester, Kentucky. In 1950, Delta completed its first distribution system, which served approximately 300 customers in Owingsville and Frenchburg. By 1977, Delta was serving 11,000 customers in relatively small communities in central Kentucky. In October 1977, we acquired Gas Service Company, Inc., Cumberland Valley Pipe Line Co., and Laurel Valley Pipe Line Company. These companies operated the distribution systems in London, Pineville, Middlesboro, Williamsburg and part of Barbourville, the transmission lines linking the towns, except London, and related gathering lines and gas storage facilities. At that point, Delta was serving an additional 8,500 customers and began utilizing locally produced natural gas and gas storage facilities. In January 1981, we acquired the assets of Peoples Gas Company of Kentucky, a subsidiary of The Wiser Oil Company, which added approximately 8,700 customers in Corbin, Barbourville, Manchester, Oneida, and Burning

Springs. In January 1982, we purchased approximately 57 miles of transmission lines from Wiser, which run generally from Manchester to Corbin and London. In 1989, we leased the TranEx pipeline, a 43-mile 8-inch diameter pipeline which extends from Manchester to Richmond and began operating it as a part of our transmission system. Delta expanded to Beattyville in 1992. In 1995-1996, we developed and began operating an underground storage field in Bell County. We acquired the City of North Middletown system in 1996. We purchased the TranEx pipeline, expanded into Fayette County, and acquired Annville Gas & Transmission in Jackson County in 1997. We purchased the Mt. Olivet gas system, located in Robertson and Mason Counties, in 1999.

In 2017, all of Delta's common stock was acquired by PNG Companies LLC ("PNG"). This transaction allowed Delta to be part of a larger natural gas utility system. In 2020, Aqua America, Inc, acquired PNG and its subsidiaries, including Delta. Aqua subsequently changed its name to Essential Utilities Inc. ("Essential") to better reflect the range of services it provides customers. In April 2021, ownership of Peoples Gas of Kentucky LLC ("PKY"), a farm tap affiliate of Delta's owned by PNG Companies LLC, was transferred to Delta. Delta merged PKY's operations into Delta, which consists of approximately 3,000 farm tap customers in southeastern Kentucky, and the service territory for these customers abuts Delta's existing service area.

Delta has continued to look for opportunities to grow. In 2022, Delta began serving customers in Lincoln County, and is in the process of expanding to unserved portions of Rockcastle County.

As a result of these acquisitions, Delta's current organizational structure is as follows:



Q. Please provide an overview of Essential, Delta's ultimate parent.

A. Essential is the largest publicly traded regulated water, wastewater, and natural gas provider in the United States, with operations dating back to 1886. It serves approximately 5.5 million people across nine states through the Aqua water and wastewater segment and PNG natural gas segment, to which Delta belongs. Since 2020, Essential has invested over $4 billion in infrastructure.

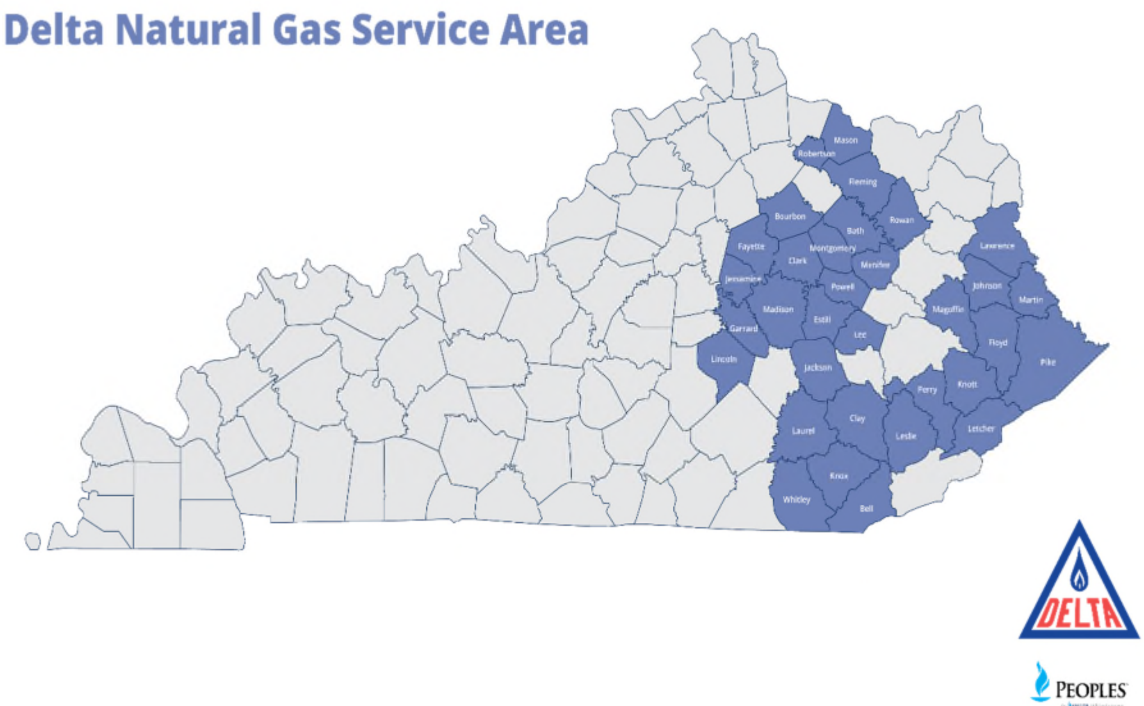
Q. Please provide an overview of PNG, Delta's immediate parent.

A. PNG is comprised of gas operations in Kentucky (Delta) and Pennsylvania (Peoples Natural Gas Company LLC ("Peoples")). Peoples, as the largest natural gas distribution company in Pennsylvania, serves more than 743,000 customers. PNG is committed to safe operations, and PNG has had an over 80% reduction in outstanding gas leaks since 2019.

Q. Please describe Delta's current service territory.

A. Delta has grown to a system of approximately 40,000 customers in primarily rural areas of Kentucky where there is no large concentration of customers. We serve areas in central and southeastern Kentucky that were otherwise not served and have continued to look for opportunities to bring gas service to additional unserved areas.

Delta owns and operates 6 district offices, two warehouses, an underground natural gas storage facility with approximately 5 Bcf of capacity and 2 Bcf of working capacity, a natural gas liquids processing plant, and approximately 2,700 miles of transmission, distribution, service and gathering pipeline in 33 counties in central and southeastern Kentucky. Below is the geographic footprint of Delta's operations:



Q. Please describe Delta's current management structure.

A. Delta's management team consists of persons with a great deal of institutional and utility knowledge. I have been with Delta since 1995. Jonathan Morphew is the Director of Operations and has been with Delta since 1987. Danny Shelley is the Director of Gas Control and Transmission and has been with Delta since 1986. Abdul-Azeez Odusanya joined Delta as the Controller in 2023.

Q. Please state which filing requirements you are sponsoring in this case.

A. I am sponsoring the following filing requirements:

807 KAR 5:001 Section 14	Application requirements
807 KAR 5:001 Section 16(1)(b)(1)	A statement of the reason the adjustment is required.
807 KAR 5:001 Section 16(1)(b)(2)	A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.
807 KAR 5:001 Section 16(1)(b)(3)	New or revised tariff sheets
807 KAR 5:001 Section 16(1)(b)(4)	Comparison of current and proposed tariffs
807 KAR 5:001 Section 16(1)(b)(5)	Statement that notice has been given in compliance with Section 17 of this administrative regulation, with a copy of the notice.
807 KAR 5:001 Section 16(2)	Notice of Intent
807 KAR 5:001 Section 16(7)(a)	Written testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program
807 KAR 5:001 Section 16(7)(c)	Factors used to prepare forecast
807 KAR 5:001 Section 16(7)(e)	Attestation by utility's chief officer in Kentucky regarding forecast's reasonableness/reliability, affirming forecast's assumptions/ methodologies used in forecast prepared for management, and inclusion of productivity and efficiency gains in forecast
807 KAR 5:001 Section 16(7)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: subsections (1), (2), (3), (4), (11) and (12)
807 KAR 5:001 Section 16(7)(h)(5)	Load forecast including energy and demand (electric)
807 KAR 5:001 Section 16(7)(h)(6)	Access line forecast (telephone)
807 KAR 5:001 Section 16(7)(h)(7)	Mix of generation (electric)

807 KAR 5:001 Section 16(7)(h)(8)	Mix of gas supply (gas)
807 KAR 5:001 Section 16(7)(h)(9)	Employee level
807 KAR 5:001 Section 16(7)(h)(10)	Labor cost changes
807 KAR 5:001 Section 16(7)(h)(11)	Capital structure requirements
807 KAR 5:001 Section 16(7)(h)(13)	Gallons of water projected to be sold (water)
807 KAR 5:001 Section 16(7)(h)(14)	Customer forecast (gas, water)
807 KAR 5:001 Section 16(7)(h)(15)	Sales volume forecasts - cubic feet (gas)
807 KAR 5:001 Section 16(7)(h)(16)	Toll and access forecast of number of calls and number of minutes (telephone)
807 KAR 5:001 Section 16(7)(h)(17)	A detailed explanation of any other information provided
807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports
807 KAR 5:001 Section 16(7)(u)	Amounts charged or allocated to it by an affiliate or general or home office
807 KAR 5:001 Section 16(7)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as directed by PSC
807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes
807 KAR 5:001 Section 17	Notice Content

Q. Who is sponsoring direct testimony on behalf of Delta in this proceeding?

A. In addition to myself, the following individuals are sponsoring direct testimony:

- Jonathan W. Morphew, Director of Operations, Delta Natural Gas Company, Inc.
- William C. Packer, Vice President, Regulatory Accounting and Regional Controller, Essential Utilities, Inc.
- Azeez Odusanya, Controller, Delta Natural Gas Company, Inc.
- Paul Moul, Managing Consultant, P. Moul & Associates
- Larry Feltner, Managing Partner of The Prime Group LLC
- Jeff Wernert, Principal, The Prime Group LLC

<u>**Proposed Revenue Increases and Bill Impacts**</u>

Q. Please explain why Delta is requesting a rate increase at this time.

A. Delta is requesting a rate increase to recover its capital investments that are necessary to providing safe and reliable natural gas distribution service to our customers. Delta last requested a base rate adjustment in 2021.[1] Since that time, and as described in Mr. Morphew's testimony, Delta has been focused on improving service for existing customers, as well as expanding its operations to offer natural gas distribution service to unserved areas. Delta's investments have been significant. For example, Delta's rate base has increased by 35% since its last rate case in 2021. The corresponding increase to depreciation is roughly the same.

Delta has also experienced an increase in O&M expenses, which are attributable to the overall economic environment and the compensation adjustments that arose from the collective bargaining agreement Delta executed with its union employees following the employees' decision to unionize.

Q. Is Delta earning a fair rate of return on equity at its current rates?

A. No. At current rates, Delta is projected to earn only 3.06% in the forecast period. As further described in Mr. Moul's testimony, these returns are drastically below market expectations for a gas utility of Delta's size and risk profile.

Q. Can you please describe the risks that are facing the gas industry and Delta?

A. Certainly. Delta has direct competition in its service territory from many alternate energy suppliers—electric, coal, oil, propane, and solar. Our customers can transition to another energy source and supplier at any time. Moreover, in 2023, 87% of Delta's overall

[1] Case No. 2021-00185, In the Matter of: Electronic Application of Delta Natural Gas Company, Inc. for an Adjustment of Its Rates and a Certificate of Public Convenience and Necessity.

throughput was to transportation customers that obtain their gas supplies from producers and marketers. Service to these customers is especially vulnerable in this economic environment. Large volume users, which have traditionally used transportation service, also have the ability to bypass Delta's system. Indeed, Delta has lost customers to bypass in the past. At the same time, there is significant discussion at the national level regarding the reduction of fossil fuels and hydrocarbons. As explained by witness Mr. Moul, these competitive factors increase the amount of Delta's risk.

Q. Please briefly describe the revenue increase Delta is requesting.

A. Delta is requesting an approximately 19.02% or $10,909,513 increase in its annual revenue. If the Commission approves the proposed base rates, the average monthly bill increase due to the proposed gas base rates will be 22.18%, or approximately $15.75, for a residential customer using an average of 4.56 Mcf of gas. Typical bill calculations for various levels of consumption are shown in the Section 16(8)(n) filing requirement.

Q. Please summarize the test period Delta is utilizing in this case.

A. Delta is utilizing a forecasted test period in this case. It is comprised of a base period ending February 28, 2025. The base period utilizes actual information for six months, from March 2024 to August 2024, with six months of estimated information from September 2024 to February 2025. The forecasted period will be the twelve months ending June 30, 2026.

Budgeting Process

Q. Why has Delta utilized a forecasted test period in this case?

A. Our decision to utilize a forecasted test period was based on several factors. First, the forecasted period will reduce regulatory lag by more accurately matching the revised rates to Delta's anticipated costs and expenses. Second, since joining the Essential family of utilities, Delta has synchronized its budgeting process to align with its affiliates, many of which also utilize forecasted test periods for rate increases.

Q. Can you please describe the budgeting process Delta has utilized?

A. Certainly. Delta's local management team directs the development of Delta's budget. It is a bottom-up process, in which our team analyzes the priorities, needs, and expectations for Delta and our customers. Delta has utilized this budget process to prepare the forecasted test year information in this case.

There are five major inputs in the financial budgeting process: (1) capital budget; (2) expense budget; (3) revenue budget; (4) financing and interest requirements; and (5) depreciation. I am primarily involved with the capital budget and revenue budget. Please see Mr. Odusanya's testimony for more information regarding development of the other major budget inputs. With respect to the capital budget, Delta prepares and ranks the projects within its capital requirements. The projects are largely generated by Delta's operations and IT departments, which have firsthand knowledge of system needs. Once the recommendations are reviewed and approved, monthly capital budgets are loaded into SAP to allow for efficient monthly monitoring and reporting. The revenue budget is developed by preparing key assumptions regarding customer growth and usage by class. Once complete and approved by senior leadership, a monthly revenue and volume plan is loaded into SAP.

Productivities and Efficiencies

Q. Does Delta have programs in place to achieve improvements in efficiency and productivity?

A. Yes. As President, I expect our management team to implement and execute programs and initiatives that allow us to improve our efforts at operating efficiently and productively.

Q. Can you describe technology-related programs that are aimed at improving efficiency and productivity that have been implemented since the last rate case?

A. Certainly. Delta has implemented several technology-related programs since 2021 that result in greater efficiency and productivity. For example, Delta now offers an e-account portal for customers that allows customers to pay their bill or initiate service online. This allows customers to perform these actions at their convenience, instead of during limited business hours. In addition to this significant enhancement, Delta upgraded its computer and telecommunications infrastructure to the Essential network. This allows Delta employees to seamlessly collaborate across the Essential footprint, whether the employee be in Corbin or Winchester, Kentucky or Pittsburgh or Bryn Mawr, Pennsylvania. Not only did this upgrade greatly enhance efficiency and effectiveness, it also brought Delta's system under the protection of Essential's cybersecurity team, which is vitally important to our operations and our customers' data. Essential's threat detection review examines all interactions with the Company's servers and escalates any concerns through a formal process, regularly benchmarked against best practices. Third, Delta transitioned to a Bring Your Own Device policy for all non-union employees. Under this policy, Delta no longer provides employees with a work phone and employees instead use their personal devices. Delta is also completing a data migration project that is moving certain of its important operations information currently housed in smaller home-grown systems to the SAP platform, where it can be readily supported with the rest of the Company's data.

Q. Please describe other programs that have been implemented since the last rate case to improve efficiency and productivity.

A. In addition to these three technology-related efficiencies, Delta has implemented several other initiatives aimed at improving productivity. The most significant of these pertain to customer service. As the number of customers who paid in person continued to decline, Delta determined it was prudent to close 5 of its business offices in 2023. At the same time, Delta began using a centralized contact center for customer inquiries that it shares with Peoples. Delta has also shifted certain billing, remittance, credit, and collection tasks to a centralized center.

In addition to these efficiencies, in 2024 Delta added an additional contractor for construction services, which helps ensure Delta is receiving the most competitive rate from reliable vendors. Third, Delta completed the integration of PKY into Delta and dissolved the PKY legal entity. This allowed Delta to terminate the lease for office space that PKY had previously been utilizing. Formally dissolving PKY reduced several administrative tasks, including tax and other corporate filings.

Delta has continued to look for additional opportunities to utilize central purchasing and the benefit of Essential's leverage in buying power when doing so is beneficial to Delta and its customers. For example, Delta now has access to national fleet pricing for vehicles and a national auction house for used vehicles and equipment. Related to transportation, Delta has moved from purchasing ½ ton trucks to 4-cylinder turbo models to improve miles per gallon performance and vehicle longevity.

<u>Tariff Changes</u>

Q. Is Delta proposing to change any of its special charges?

A. Yes, Delta is proposing to return its collection charge and reconnection charge to the amounts it previously assessed. In Case No. 2007-00089, the Commission authorized Delta to assess $20.00 for a collection charge, which is incurred for each trip to premises that Delta makes for purpose of terminating service. In the same 2007 proceeding, the Commission also approved a $60.00 reconnection charge, which is applied to all service reconnections, except for the $25.00 reconnection charge for farm tap customers that is mandated by Commission regulation.

Delta did not propose changes to its collection and reconnection charges in Case No. 2021-0085, but the Commission reduced the collection charge to $5.00 and the reconnection charge to $9.00.

Q. Why did the Commission reduce the collection and reconnection charges so significantly?

A. The Commission stated that in *Case No. 2021-00141, Electronic Application of Hyden-Leslie County Water District for an Alternative Rate Adjustment* (Ky. PSC Nov. 6, 2020), "the Commission found that the calculation of non-recurring charges should be revised because only the marginal costs related to the service should be recovered through special non-recurring charges for service provided during normal work hours."[2] The Commission then reduced the charges to the amounts it deemed were the marginal costs of those charges.

Q. Why is Delta seeking to revert the collection and reconnection charges to the amounts assessed from 2007 to 2021?

A. Delta does not have a dedicated employee whose job responsibilities center on collection and reconnection. While Delta expects that its employees can perform a limited number of these actions in their standard working day, any material increase in our employees' time in performing these tasks burdens our capacity, leading to less time devoted to the

[2] Case No. 2021-00185, In the Matter of: Electronic Application of Delta Natural Gas Company, Inc. for an Adjustment of Its Rates and a Certificate of Public Convenience and Necessity (Ky. PSC Jan. 3, 2022).

employees' primary responsibilities. The number of line locates continue to increase substantially and Delta looks for any opportunity to increase efficiency in order to accommodate the increased workload without adding to our headcount or incurring overtime. Reducing the number of disconnections and reconnections can help with this challenge.

As the Commission noted in its Final Order reducing the charges, the Commission's decisions are premised on "ensuring that rates reflect, to a reasonable degree, the principle of cost causation." The increased workload is caused by those actions, and in keeping with the Commission's longstanding practice, the cost causers—as opposed to all customers—should bear those costs.

Lead-Lag Study

Q. Has Delta submitted a lead-lag study in this proceeding?

A. Yes, which was performed by Mr. Wernert and is described in his direct testimony. The lead-lag study is a statistical analysis that utilizes historical payment data to calculate lead days and lag days. The Commission has recently utilized lead-lag studies to calculate a utility's cash working capital needs.

Q. Is Delta proposing a different collection lag than is calculated in the lead-lag study?

A. Yes. As described in Mr. Wernert's testimony, the revenue lag measures the number of days from the date service was rendered by Delta until the payment is received from customers and available to Delta. One of the components of the revenue lag is the collection lag, which is the period from when the bill is invoiced to when the customer payment is received.

In Case No. 2021-00185, the collection lag, which was based on 2020 data, was 10.72 days. The collection lag in Mr. Wernert's current study, which is based on 2023 data, is 31.33 days. This is a material increase in collection days since the last study. The impact of the increase in collection days contributes to a greater cash working capital requirement.

Q. Why has the collection lag materially increased from the 2020 to 2023?

A. Delta experienced unusually high accounts receivable balances during 2023. For comparison, Delta's average accounts receivable in 2020 was $1,160,563. In 2023, the average had grown to $3,630,661. There were several reasons for this. First, many of the payment plans Delta entered during the Covid pandemic had atypically long payback periods, given that Delta wanted to assist customers who were struggling during the pandemic. Even after these payment plans ended, Delta continued to experience the related uptick in accounts receivable. Second, the accounts receivable balances increased during the transition to use of a shared customer contact center with Peoples.

Q. Do you believe the level of accounts receivables in 2023 is representative of the balances that will be experienced during the forecast test period?

A. No, as Delta has focused significant attention in reducing the accounts receivable and our efforts are succeeding. Delta has counseled the customer service representatives regarding appropriate budget payment plan terms and is ensuring that the proper timelines for missed payments and disconnections are being followed. As a result of Delta's internal efforts, collection lag using data from the twelve-months ending August 2024 resulted in a collection lag of 25.74 days, a roughly 18% reduction.

Q. Do you believe that the collection lag days will continue to decrease?

A. Yes, to an extent. The collection lag Delta experienced in 2020 was atypically low because of the various customer support efforts that were utilized during the pandemic, such as the

the increased use of payment plans. Thus, I do not expect the accounts receivable balance to decline to 2020 levels. That being said, Delta's current internal efforts to reduce accounts receivable are working, and I expect the collection lag to further decrease as the impacts of our efforts are fully realized.

Q. What collection lag is Delta is proposing to utilize in the lead lag study in this case?

A. Delta is proposing to utilize a collection lag of 15 days. I made this recommendation to Mr. Wernert after analyzing the 2023 data and studying the accounts receivable data. A collection lag of 15 days is likely more representative of the lag that will be experienced during the forecast test period. By reducing the collection lag, the amount of cash working capital necessary to fund Delta's operations is likewise decreased. This benefits our customers from a rate perspective.

Customer Notice

Q. Please describe the methods by which Delta informed customers of the proposed gas rate adjustments.

A. Delta delivered a copy of the rate case notice prescribed by the Commission's regulations to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication in the applicable newspapers once a week for three consecutive weeks beginning the week of November 18, 2024. Delta also posted the notice at their offices and posted a copy on the website.

Community Support

Q. Please explain Delta's commitment to the communities it serves.

A. Delta's commitment to the communities in which it has the privilege to provide gas service is longstanding. Our customers are primarily located in rural areas, and because of our relatively small size, Delta truly knows its customers, and works to aid customers that are experiencing difficulties. Delta looks for opportunities to aid its customers. As an example, Delta is one of the only utilities in Kentucky that has never had a late fee, which reduces the delinquency facing a customer that is working to repay their gas bill.

Q. Please describe Delta's HEA program.

A. Delta's HEA is supported by an annual $45,000 shareholder contribution and a customer charge of $0.30 per month. Through increasing awareness through website popups and local media interviews, enhanced customer reminders and flyers by the local offices, and sharing of best practices within the Essential family of utilities, Delta was able to provide 341 customers with a $150 monthly benefit for the heating season.

Q. Does Delta support the communities it serves in other ways?

A. Certainly. To celebrate Earth Day this year, over 30 employees cleaned headstones at the Camp Nelson National Cemetery, which is located within our service territory in Nicholasville. Last year, we cleaned up litter in Floyd for our Earth Day celebration. In April 2024, we also participated in the Berea Urban Farm Victory Garden Blitz, which increases food security, builds community, and improves nutrition and health by providing raised garden beds at low cost primarily to low-income households. The event relies on volunteers who come together to build the beds, deliver them, and fill them with a mixture of compost and soil designed specifically for raised beds.

In addition to our community service, we also support food pantries throughout the communities we serve, providing $2,000 in shareholder contributions to six pantries located in Berea, Corbin, Middlesboro, Nicholasville, Owingsville, and Prestonsburg. In addition, just this month we sent a team to Frenchburg in Menifee County to help distribute groceries at the local food pantry.

Q. Please explain how Delta's commitment to its customers is consistent with its proposed rate increase.

A. Delta strives every day to provide safe, reliable, and economical gas service to our customers, as well as an excellent customer-service experience. The decision to file for a rate increase is a serious matter—we understand it will impact all customers. In particular, we understand the needs of low and fixed-income customers through our relationships with these customers and advocacy organizations. Our culture also includes service to the community through donations of personal and shareholder funds as discussed in the preceding question. When Delta decides to seek additional revenues through a rate increase, we do so only when necessary to continue providing safe and reliable gas service and excellent customer service, as we appreciate fully the impacts on customers resulting from our request.

Q. Does that conclude your testimony?

A. Yes, it does. Delta thanks the Commission for considering and reviewing its rate application.

VERIFICATION

COMMONWEALTH OF KENTUCKY	**)**	
	)	**SS:**
COUNTY OF CLARK	**)**	

The undersigned, **John B. Brown**, being duly sworn, deposes and says he is President and Chief Officer of Kentucky Operations of Delta Natural Gas Company, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John B Brown

JOHN B. BROWN

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of November, 2024.

Jennifer Page Bingham (SEAL)

Notary Public

My Commission Expires:

June 19, 2027

JENNIFER PAGE BINGHAM
NOTARY PUBLIC
STATE AT LARGE KENTUCKY
COMM. # KYNP74158
MY COMMISSION EXPIRES JUNE 19, 2027

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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ADJUSTMENT OF GAS RATES	**)**	

DIRECT TESTIMONY OF
LARRY FELTNER
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: November 25, 2024

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Exhibits

Exhibit LF-1 – Cost of Service Study – Functional Assignment and Classification
Exhibit LF-2 – Cost of Service Study – Class Allocation
Exhibit LF-3 – Storage Allocation Model
Exhibit LF-4 – Zero Intercept Distribution Mains
Exhibit LF-5 – Cost Components for Residential Service

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Larry Feltner. My business address is 2604 Sunningdale Place East, La Grange, Kentucky 40031.

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

A. I am the managing partner for The Prime Group, LLC, a firm located in La Grange, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. On whose behalf are you testifying in these proceedings?

A. I am testifying on behalf of Delta Natural Gas Company ("Delta"), which provides natural gas transportation and sales service in central and southeastern Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the fully allocated class cost of service study based on Delta's fully-forecasted costs for the 12 months ended June 30, 2026; to support the reasonableness of the Delta's forecasted billing determinants for the test year; to describe the proposed distribution of the revenue increase to the rate classes; and to sponsor Delta's proposed rate schedules for natural gas sales and transportation service.

Q. Please summarize your testimony.

A. My direct testimony addresses the following:

- **Class Cost of Service Study.** A cost-of-service study was performed for Delta's operations based on costs for the 12 months ended June 30, 2026. The purpose of a class cost-of-service study is to determine the contribution that each customer class is making towards the utility's overall rate of return. Cost-of-service is a standard measure of reasonableness for utility rate design. Rates of return are calculated for each rate class. Delta's gas cost of service study used the same methodology as was filed in its 2021 and prior rate cases. The Commission has approved this methodology in numerous rate cases. The class cost-of-service study was used as a guide for allocating the revenue increase to the rate classes and for developing unit charges for Delta's service rates.

- **Development of Forecasted Billing Determinants**. Based on a thirteen-year analysis of Delta's sales and transportation volumes and the numbers of customers served by Delta, it was determined that Delta's billing determinants have been essentially constant over the thirteen-year period, after adjusting for normal temperatures. This analysis supports the use of actual billing data for the 12 months ended December 31, 2023, for developing forecasted test-year billing units.

- **Distribution of the Revenue Increase to the Rate Classes.** Delta relied on the results of the class cost-of-service study for allocating the revenue increase to the classes of service. The Interruptible Service and Farm Tap rates both had rates of return much higher than the target of 7.91%. However, since the overall increase is large, Delta decided that every class should receive a 5% increase on net revenue. The cost-of-service study supports a higher percentage increase for Residential Service than for Small Non-Residential Service and Large Non-Residential Service. Delta is proposing a lower percentage increase for Off-System Transportation Service since its return was slightly higher than the target rate or return. The cost-of-service study supported a relatively higher increase for the Special Contracts.

- **Proposed Rates.** For Residential, Farm Tap, and Small Non-Residential, Delta is proposing to increase the Customer Charge by a greater percentage than the increase to the Delivery Charge because the customer charges in those are deficient. For Large Non-Residential, Interruptible, and the Special Contracts, Delta is proposing that all of the increase be picked up in the Distribution Charges. In those classes with Customer Charges, the existing Customer Charges were adequate.

- **Pipe Replacement Program**. Delta is not proposing to roll its current PRP costs into base rates in this proceeding.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 16(7) and 16(8)?

A. Yes. I am sponsoring the following schedules or portions of schedules for the corresponding Filing Requirements:

• Proposed Tariff	Section 16(1)(b)(3)	Tab 4
• Proposed Tariff (Side by Side)	Section 16(1)(b)(4)	Tab 5
• Factors used in Preparing Financial Model	Section 16(7)(c)(B)	Tab 16
• Cost of Service Studies	Section 16(7)(v)	Tab 52
• Revenue Summary	Section 16(8)(m)	Tab 66
• Typical Bill Comparison	Section 16(8)(n)	Tab 67

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Class Cost of Service Study, (IV) Development of Forecasted Billing Determinants, (V) Distribution of the Revenue Increase, (VI) Proposed Rates, and (VII) Pipe Replacement Program.

II. QUALIFICATIONS

Q. Please describe your educational and professional background.

A. I received a Bachelor of Arts degree in Business Management from the Transylvania University 1985. I received a Masters of Business Administration ("MBA") from the University of Kentucky in 1986.

Concerning my professional background, from February 1987 until April

2000, I was employed by Louisville Gas and Electric Company ("LG&E"). During that time, I held various positions within the Rate Department of LG&E. I left LG&E in May 2000 to join The Prime Group, LLC. Since leaving LG&E, I have performed or supervised the preparation of over 200 cost-of-service and rate studies for investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. Therefore, including my time at LG&E, I have more than 37 years of experience in the utility industry.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified before the Kentucky Public Service Commission in LG&E's Fuel Clause and Environment Cost Recovery hearings during my time with LG&E.

Q. Please describe your work and testimony experience as they relate to topics addressed in your testimony.

A. I have performed or supervised the development of over 200 cost-of-service and rate studies for utilities throughout North America. While I have not testified recently before the Kentucky Public Service Commission, I have consulted with Delta and numerous other utilities around the country in various Commission proceeding, such as rate cases, cost-of-service matters, rate design, and surcharges.

III. CLASS COST OF SERVICE STUDY

Q. Did you prepare a cost-of-service study for Delta?

A. Yes. I supervised the preparation of a fully allocated, embedded cost-of-service study for natural gas service based on Delta's fully forecasted test-year costs for the 12 months ended June 30, 2026.

Q. What is the objective of a cost-of-service study?

A. The objective in performing the cost-of-service study is to determine the rate of return on rate base that Delta is earning from each customer class, which provides an indication as to whether Delta's rates for gas service reflect the cost of providing service to each customer class.

Q. Have you ever prepared an embedded cost of service study?

A. Yes, on many occasions. Over the course of my career, I have prepared or supervised the preparation of well over 200 embedded cost-of-service studies for gas, electric, and water utilities. In Kentucky, I supervised and participated in the preparation of gas cost of service studies for Delta (Case Nos. 99-176, 2004-00067, 2007-00089, and 2010-00116) and LG&E (Case Nos. 2000-080, 2003-00433, 2008-00252 and 2009-00549, 2016-00371, 2018-00295, and 2020-00350).

Q. Was the same methodology used in the cost-of-service study submitted in this proceeding used in the cost-of-service study filed by Delta in Case No. 2021-00185?

A. Yes. That case settled so the Commission did not explicitly accept the cost-of-service study. However, the same methodology was used in Delta's Case No. 2010-00116, which was a fully litigated case.

In that case, the Commission stated:

> Delta filed an embedded, fully allocated cost-of-service study in order to determine the contribution that each customer class was making toward its overall rate of return and as an indicator of whether its rates reflected the cost to serve each customer class. Within the cost-of-service study, distribution mains costs were

> classified as customer costs or demand costs using the zero-intercept method. The Commission has accepted Delta's cost-of-service study, consistent with its past acceptance of the zero-intercept method.[1]

The same methodology was also utilized in the cost-of-service studies filed in Case Nos. 99-176, 2004-00067, and 2007-00089.

Q. Did you develop the model used to perform Delta's cost of service study?

A. Yes. Steve Seelye and I developed the spreadsheet model used to perform the cost-of-service study being submitted in this proceeding.

Q. What customer classes were analyzed in the cost-of-service study?

A. All of the current rate classes were analyzed in the cost-of-service study.

Q. What procedure was used in performing the cost-of-service study?

A. The cost-of-service study was prepared using the following basic procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups, (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to Delta's rate classes. This is a standard approach utilized in the preparation of embedded cost-of-service studies for gas utilities.

Q. What is the purpose of functionally assigning costs?

A. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service

[1] Case No. 2010-00116, Order (Ky. P. S. C. Oct. 21, 2010), at 24.

functions; and (3) it provides a mechanism for separating assignable costs from joint costs, which must be allocated.

Q. What functional groups were used in the natural gas cost-of-service study?

A. The following standard functional groups were identified in the cost-of-service study: (1) Storage, (2) Transmission, (3) Distribution Commodity, (4) Distribution Structures and Equipment, (5) Distribution Mains, (6) Services, (7) Meters, (8) Customer Accounts, and (9) Customer Service Expense.

Q. How were costs classified as commodity-related, demand-related, or customer-related?

A. Classification provides a method of arranging costs so that the service characteristics which give rise to the costs can serve as a basis for allocation. Costs classified as commodity-related tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost-of-service study, it was not necessary to classify gas supply costs. Costs classified as demand-related are costs related to facilities installed to meet design-day usage requirements. Costs classified as customer-related include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand-related. Distribution Structures and Equipment costs were classified as demand-related. Costs related to Distribution Mains were classified as demand-related and customer-related using the zero-intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were all classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost-of-service study?

A. Yes. Exhibit LF-1 shows the results of the first two steps of the cost-of-service study: functional assignment and classification.

Q. In your cost-of-service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost-of-service model used in this study, Delta's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using scalar multiplication) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Exhibit LF-1, Delta's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28 of Exhibit LF-1. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are shown on pages 29 and 30 of Exhibit LF-1. The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors." The results of the class allocation step of the cost-of-service study are included in Exhibit LF-2. The costs shown in the column labeled "Total System" in Exhibit LF-2 were carried forward from the functionally assigned and classified costs shown in Exhibit LF-1. The column labeled "Ref" in Exhibit LF-2 provides a reference to the results included in Exhibit LF-1.

Q. Please describe the allocation factors used in the gas cost-of-service study.

A. The following allocation factors were used in the gas cost of service study herein:

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on expected winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the expected winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Exhibit LF-3.
- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the basis of design-day demands determined

at Delta’s -8 degree F design-day mean temperature.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at Delta’s -8 degree F design day mean temperature. These demands were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment will be discussed later in my testimony.
- **DEM05** is used to allocate the demand-related portion of the cost of distribution mains and represents maximum class demands determined at the design day mean temperature.
- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of December through March.)
- **COM03** is used to allocate Transmission commodity-related costs and represents annual throughput volumes (including both sales and transportation).
- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including

both sales and transportation) of customers served on the distribution system.

- **CUST01** is used to allocate the customer-related portion of Delta's distribution mains and represents the year-end number of customers.
- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the average number of customers in each class.
- **CUST03** is used to allocate Meters and is based on the estimated cost of meters and meter installation costs per customer in each customer class weighted by the average number of customers in each class.
- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and is determined on the basis of the average number of customers. It uses a multiplier of 4 for the Large Non-Residential, Interruptible, Special Contract, and Off-System Transportation Classes to reflect the additional cost associated with reading the meter, etc.

- **CUST05** is used to allocate customer service expenses using the same allocation factor used to allocate Accounts 901, 902, 903, and 905 in CUST04.

Q. How are mains typically classified between demand and customer costs?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, a "minimum" standard pipe size is selected and the minimum system is obtained by pricing all of the distribution mains at the unit cost of this minimum size pipe. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system. Because even the minimum size pipe has the ability to deliver gas to the customer on the peak day, this methodology inherently captures demand-related costs in the customer component.

In preparing this study, the zero-intercept methodology, rather than the minimum system methodology, was used to determine the customer component of mains. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero-intercept methodology, we are not forced to choose a minimum size main to determine the customer component. In the zero-intercept methodology, a zero-diameter pipe is the absolute minimum system.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost ($/ft) of mains and the gas flow capability of the pipe, which is proportionate to its diameter. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the pipe,

x is the size of the pipe, and

a, ***b*** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a pipe with zero diameter (or pipe with zero gas flow capability) is ***a***, the zero intercept. The zero intercept is essentially the cost component of mains that is invariant to the size (and gas flow capability) of the pipe.

Like most gas distribution systems, the number of feet of mains on Delta's system is not uniformly distributed over all sizes of pipe. For example, Delta has over 5.4 million feet of 2-inch plastic mains, but only 57 thousand feet of 3-inch plastic mains. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Using a weighted regression analysis, the cost and diameter of each size pipe is, in effect, weighted by the number of feet of installed pipe. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where $\boldsymbol{w}$ is the weighting factor (in this case the feet of pipe) for each size of pipe, and $\boldsymbol{y}$ is the observed value and $\boldsymbol{\hat{y}}$ is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Exhibit LF-4 is the zero-intercept analysis used in this study. The zero-intercept unit cost of \$2.81 per foot pipe is applied to the total feet of mains in the analysis to determine the customer cost component. The listing on page 1 of the analysis indicates that the coefficient of determination R-squared for mains is 0.9714. The coefficient of determination is a relative measure of the closeness of fit, where a coefficient of 0.0 indicates no linear correlation between the independent variable and dependent variable and a coefficient of 1.0 indicates perfect linear correlation.

Q. Has the Commission accepted the use of the zero-intercept methodology in previous cases?

A. Yes, on many occasions. The Commission accepted the methodology utilized by Delta in both Case No. 2010-00116 and Case No. 2004-00067, which were fully litigated cases. The Commission has also accepted the zero-intercept methodology for other gas utilities, including LG&E and Duke-Kentucky. In my experience, the zero-intercept methodology is the predominant method used in Kentucky and is used widely in other jurisdictions.

Q. Please summarize the results of the gas cost of service study.

A. The following table (TABLE 1) summarizes the rates of return on net cost rate base for each customer class at the current rates. The Rate of Return at Current Rates was calculated by dividing the net operating income by the net cost rate base for each customer class.

TABLE 1 Class Rates of Return	
Customer Class	**Rate of Return at Current Rates**
Residential Service	-1.47%
Farm Tap Service	17.36%
Small Non-Residential Service	3.53%
Large Non-Residential Service	5.86%
Interruptible Service	70.01%
Special Contracts	-4.56%
Off-System Transportation Service	8.36%
Total System	2.81%

Q. What can be gleaned from the class rates of return shown in TABLE 1?

A. Several things. The rates of return for Residential Service and the Special Contracts are significantly below the overall rate of return. The rates of return for Small Non-Residential Service, Large Non-Residential Service, and Off-System Transportation Service are somewhat above the overall rate of return, and the rate of return for Farm Tap Service and Interruptible Service are significantly above the overall rate of return. These class rates of return are given consideration in Delta's proposed distribution of the revenue increase to the rate classes, as will be discussed later in my testimony.

IV. DEVELOPMENT OF FORECASTED BILLING DETERMINANTS

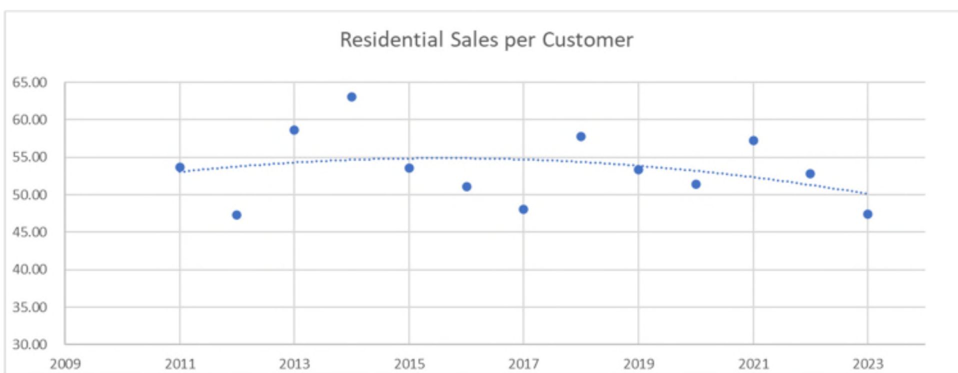
Q. Please summarize the development of the forecasted billing determinants for the test year.

A. In developing billing determinants for the forecasted test year, an analysis was performed for the period 2011 through 2023 identifying trends in the numbers of customers served and sales and transportation volumes. During the analysis period the numbers of residential and non-residential customers served by Delta have remained essentially constant. On-system sales and transportation volumes have also remained essentially constant.

Q. Please describe your analysis of residential sales for the ten-year period.

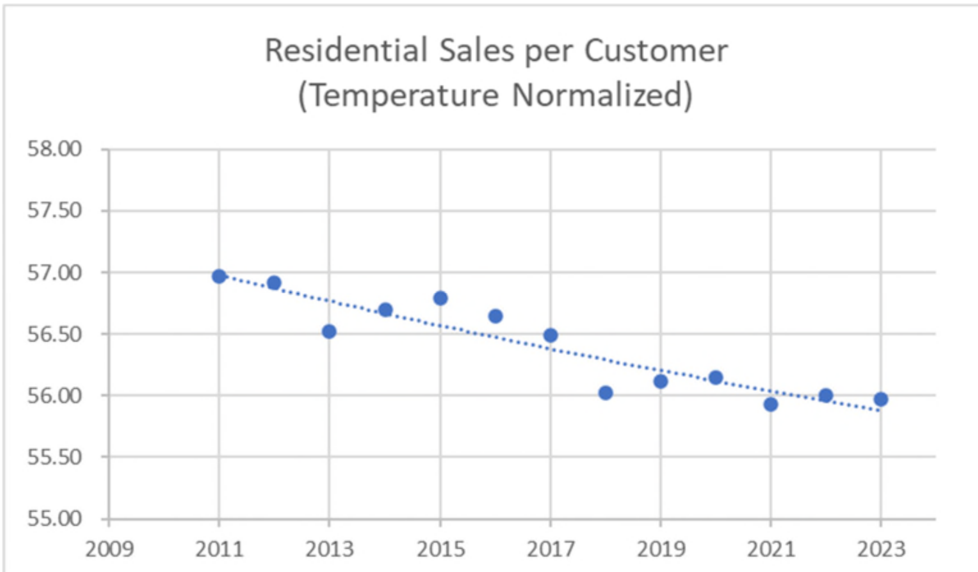
A. In 2011, Delta served approximately 33,500 residential customers, and in 2023, Delta served approximately 34,300 residential customers. Thus, there has been very little growth in the number of residential customers over the thirteen-year period. Over the last three years, customer growth has been essentially flat with 2021 having 34,200 residential customers. Over this period, residential sales per customer have also remained relatively flat, as seen in the following graph:

GRAPH 1



Over this period, temperature normalized residential sales per customer have shown a downward trend until recent years when it appears to have leveled off, as shown by the following graph (GRAPH 2):

GRAPH 2



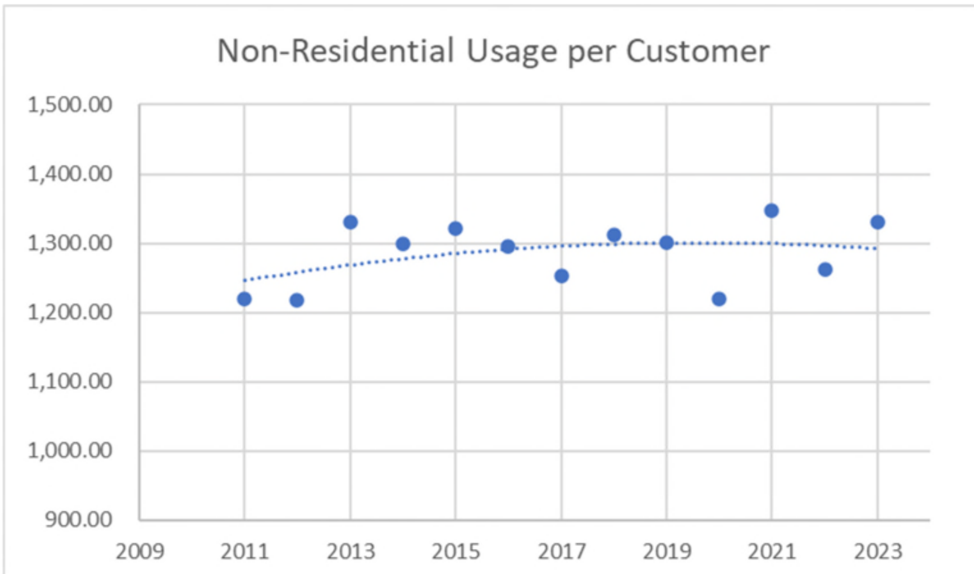
As can be seen in this graph, even though there is downward trend in the data, the decrease in temperature normalized usage per customer appears to have leveled off.

Q. Please describe your analysis of non-residential transportation and sales for the ten-year period.

A. In 2011, Delta served approximately 4,982 non-residential customers, and in 2023, Delta served approximately 5,164 non-residential customers. While there has been a small amount of growth over the thirteen-year period, customer growth over the last three years has been flat, with 5,154 customers served in 2021. The usage per customer has been essentially flat since 2013. The average non-residential usage per customer was 1,331.17 Mcf per customer in 2013 and was 1,331.21 Mcf per customer in 2023.

Non-residential customers are less temperature sensitive than residential customers. The following graph (GRAPH 3) shows non-residential usage per customer over the thirteen-year analysis period:

GRAPH 3



Q. Delta also provides off-system transportation service. What observations do you have on those transportation volumes?

A. Delta provides transportation service through its system primarily to allow gas producers in eastern Kentucky to deliver their gas to the market. As will be discussed below, Delta is proposing to increase the off-system transportation rate from $0.3142/Mcf to $0.3481/Mcf.

Q. After performing your analysis, how were forecasted billing determinants

developed for the test year?

A. After analyzing Delta's sales and transportation data for the past thirteen years, it was my recommendation to use temperature normalized billing determinants for the 12 months ended December 31, 2023, as the basis for Delta's forecasted sales and transportation volumes for the test year. Considering that the number of residential and customers and the average usage per customer have remained essentially flat over the thirteen-year period, and the number of non-residential customers have been essentially flat over the last 3 three years and the average usage per customer have been essentially flat over the last of 11 years, I concluded that it was reasonable to use billing determinants for the 12 months ended December 31, 2023, as the basis for Delta's forecast. The only adjustment necessary to the billing determinants was to perform a temperature normalization adjustment for the Residential Service and Small Non-Residential classes during the heating months in which Delta's Weather Normalization Adjustment Clause ("WNA") does not apply.[2]

V. DISTRIBUTION OF THE REVENUE INCREASE

Q. Please summarize your recommendations for allocating the gas revenue increase to the classes of service.

A. Delta is proposing an overall revenue increase of $10,909,513. Delta is proposing to increase charges on its Collection Charge and Reconnect Charge which will result in

[2] Delta's WNA applies during the winter months of December though April; therefore, it was not necessary to make a temperature normalization adjustment for those months. However, a small temperature normalization adjustment was made during the months of September, October, November, May and June for Residential and Small Non-Residential.

additional operating revenue of $28,862. Delta is proposing to increase the Collection Charge from $5 to $20 per trip to premises for the purpose of terminating service. Delta is proposing to increase its Reconnection Charge from $9 to $60 per reconnection. The base rate increase proposed by Delta is $10,880,651, which equates to an increase of 19%. In this proceeding, Delta is not proposing to roll the cost currently recovered through its Pipe Replacement Program ("PRP") into base rates in this proceeding.

I relied on the results of the cost-of-service study, along with balancing the considerations of the bill impacts for each class, to develop my recommendations for allocating the revenue increase to the classes of service. As can be seen in Table 1, the rates of return for Residential Service and the Special Contracts are significantly below the overall rate of return. As mentioned earlier, the rates of return for Small Non-Residential Service and Large Non-Residential Service are somewhat above the overall forecasted rate of return, and somewhat below the proposed rate of return of 7.91%. The rate of return for Farm Tap Service and interruptible Service are significantly above both the forecasted overall rate of return and the proposed rate of return. The rate of return of Off-System Transportation Service is moderately above the forecasted rate of return and slightly above the proposed rate of return of 7.91%.

I grouped classes with similar rates of return together and gave them the same increase, excluding gas cost. I grouped the high rate of return classes of Farm Tap Service (17.36%) and Interruptible Service (70.01%) together. Although the cost-of-service study indicates that no increase is necessary for these classes, due to the overall size of the increase, Delta is proposing that these classes receive an increase of 5% on base rate net revenue. Including gas cost, the proposed increase for Farm Tap Service is 3.0% and the increase for Interruptible Service is 4.7%. The increase appears larger for Interruptible Service when considering gas cost because most of the volume is from transportation.

I also grouped together the classes with the lowest rates of return, Residential (-1.47%) and Special Contracts (-4.56%). The proposed increase for both of those classes was 32.9%, not including gas costs. The increase for Residential Service, including gas cost, is 22.8%, or a proposed rate of return of 4.86%. The proposed increase for Special Contracts, including gas cost, is 32.9%, or a proposed rate of return of -0.07%. Since all of the customers in the Special Contract class are transportation customers, the increase is the same including and excluding gas cost. Although the study would have justified a larger increase for both classes, we mitigated the increase by spreading more of the overall increase to other rate classes. This was an attempt to balance the need to improve the rates of return for each class with the bill impacts from making those additional increases.

Small Non-Residential Service (3.53%) and Large Non-Residential Service (5.86%) both have rates of return that are slightly above the forecasted overall rate of return but below the proposed overall rate of return of 7.91%. I proposed an increase for these two classes of 27.8%, excluding gas cost, which is less than the group with low rates of return. The proposed increase to Small Non-Residential, including gas cost, is 18.0% which yields a proposed rate of return of 9.01%. The proposed increase for Large Non-Residential Service, including gas cost, is 19.9% which yields a proposed rate of return of 10.93%. Since Large Non-Residential Service has significantly more transportation that Small Non-Residential, the increase looks larger when considering gas costs.

The rate of return for Off-System Transportation on a forecasted basis is 8.36%, which is above the overall rate of return and slightly above the proposed rate of return of 7.91%. Delta is proposing to increase the rates for off-system transportation by 10.8% which is between the proposed increases of the high rate of return group and increase given to medium rate of return group of Small Non-Residential Service and Large Non-Residential Service. The proposed rate of return from this increase is 8.87%.

Q. Have you prepared a schedule showing the proposed revenue increase for each rate schedule?

A. Yes. The revenue increase for each rate class is shown on Schedule M-2.1 of Section 16(8)(m) of the Filing Requirements. The detailed billing calculations and proposed unit charges for each rate schedule are shown on Schedule M-2.3.

Q. What are the class rates of return based on the proposed charges shown in Schedule M-2.3?

A. The following table (TABLE 2) shows the class rates of return at the current and proposed rates:

TABLE 2 Class Rates of Return		
Customer Class	**Current Rate of Return**	**Proposed Rate of Return**
Residential	-1.47%	4.86%
Farm Tap Service	17.39%	14.63%
Small Non-Residential	3.54%	9.01%
Large Non-Residential	5.86%	10.93%
Interruptible	70.16%	60.02%
Special Contracts	-4.56%	-0.07%
Off-System Transportation	8.37%	8.87%
Total System	2.81%	7.91%

VI. PROPOSED RATES

A. RESIDENTIAL SERVICE

Q. Please provide a brief description of Residential Service.

A. Residential Service is the standard gas rate schedule available to residential customers. Residential Service consists of a Customer Charge and a Delivery Charge for all Mcf.

Q. What are the charges that Delta is proposing for Residential Service?

A. Delta's current *base* customer charge is $24.00 per month.[3] Delta is proposing to increase the Customer Charge to $33.60 per month. This increase in the Customer Charge corresponds to a 40% increase. Delta is also proposing to increase the Distribution Charge from $5.2539 per Mcf to $6.604 per Mcf, which also corresponds to an approximately 26% increase in the charge.

Q. Did you prepare an analysis calculating the customer-related costs for

[3] $0.30 is added to charge for an amount collected under Delta's Energy Assistance Program Tariff.

Residential Service from the cost-of-service study?

A. Yes. This calculation is shown in Exhibit LF-5. This exhibit shows the calculation of each cost component for Residential Service.

Q. What does this analysis indicate?

A. Exhibit LF-5 shows that the customer-related costs for Residential Service derived from the cost-of-service study are $45.35 per customer per month. As mentioned earlier in the discussion of the cost-of-service study, customer-related costs are calculated using the methodology that has been accepted by the Commission. Delta's proposed customer charge of $33.60 is significantly below the customer-related cost of $45.35 that can be supported by the cost-of-service study.

Q. Why is the customer charge being increased by a larger percentage than the delivery charge per Mcf?

A. The Residential Service customer cost from the cost-of-service study is $45.35. Having a customer charge below cost creates two issues with respect to rate design. First, it causes equity issues between customers in the class. When customer cost is in the distribution delivery charge, customers who use more than the average Mcf of gas overpay those customer costs and customers who use less than the average Mcf of gas underpay those costs. Second, recovering customer costs in the distribution delivery charge exposes a utility's recovery of fixed costs to weather variability. In order to correct the disparity in the customer charge over time, it must increase by a greater percentage than the distribution delivery charge.

B. FARM TAP SERVICE

Q. Please describe Delta's Farm Tap Service.

A. Farm Tap Service is applicable to farm tap customers that are served directly from a transmission system or gathering system. Farm Tap Service has the same customer charge as Residential Service but a lower distribution delivery charge.

Q. What are the proposed rates for Farm Tap Service?

A. Farm Tap Service has the second highest rate of return of any class in the study and was given a 3% increase, including gas costs. Delta is proposing the same $33.60 Customer Charge for Farm Tap Service as Residential, and a Delivery Charge of $2.1599 per Mcf. The proposed reduction in the Delivery Charge from $3.2110 per Mcf to $2.1599 per Mcf for Farm Tap Service represents a 32.7% reduction in the charge.

C. SMALL NON-RESIDENTIAL SERVICE

Q. What are the proposed charges for Small Non-Residential Service?

A. Delta is proposing a Customer Charge of $57.70 per customer per month and a Delivery Charge of $6.284 per Mcf. As with Residential Service, Delta is proposing to increase the Customer Charge by a higher percentage than the Delivery Charge.

D. LARGE NON-RESIDENTIAL SERVICE

Q. What are the proposed unit charges for the Large Non-Residential rate class?

A. Large Non-Residential Service has a blocked rate structure. Delta is proposing to keep the existing Customer Charge of $195.04 per customer per month. Delta is proposing Delivery Charges of $7.3549 for the first 200 Mcf, $4.4195 for the next 800 Mcf, $3.0024 for the next 4,000 Mcf, $2.2905 for the next 5,000 Mcf, and $1.9345 for all usage over 10,000 Mcf.

E. INTERRUPTIBLE SERVICE

Q. What are the proposed unit charges for the Interruptible Service rate class?

A. Because of the high rate of return for the Interruptible Service class, Delta is proposing a 4.7% increase for this class. Delta is proposing to keep the existing Customer Charge of $267.85 per customer per month. Delta is proposing Delivery Charges of $1.8052 for the first 1,000 Mcf, $1.3538 for the next 4,000 Mcf, $0.9025 for the next 5,000 Mcf, and $0.6768 for all usage over 10,000 Mcf.

F. ON-SYSTEM TRANSPORTATION SERVICE

Q. Please describe Delta's On-System Transportation Service.

A. Delta's On-System Transportation Service ("Transportation of Gas for Others on System Utilization") is currently available to customers served under Small Non-Residential Service, Large Non-Residential Service, and Interruptible Service. Under this rate schedule, the Customer Charge and the Delivery Charge reflect the same charges as set for in the underlying rate schedules. Consequently, the proposed rate changes for Small Non-Residential Service, Large Non-Residential Service, and Interruptible Service will apply to service under On-System Transportation.

G. OFF-SYSTEM TRANSPORTATION SERVICE

Q. Please describe Delta's Off-System Transportation Service.

A. Off-System Transportation Service is a transportation service generally available to customers to transport gas to a place of utilization not connected to Delta's facilities.

Q. What are the rates proposed by Delta for Off-System Transportation Service?

A. Delta is proposing to increase the Delivery Charge for Off-System Transportation Service from \$0.3142 to \$0.3481 per Mcf. The rate of return for this class is at 8.37% is slightly above the proposed rate of return of 7.91%. We are proposing an increase of 10.8% for the class and a proposed rate of return of 8.87%. Gas producers have other options in which to move their gas, so this is a competitive class. While it was important to spread some of the increase to every class, we tried to strike a balance with this increase based on the competitive nature of the class.

H. SPECIAL CONTRACTS

Q. Please describe the proposed rate changes for the Special Contracts.

A. Delta has three Special Contracts that have been filed with and approved by the Commission. One of the Special Contracts ("SC 1") currently has a flat Delivery Charge of \$0.1331 per Mcf. Delta is proposing to increase this Delivery Charge to \$0.1767 per Mcf, which corresponds to an increase of 32.8%. The other two Special Contracts ("SC 2 & SC 3") have a blocked rate structure, with a rate of \$0.621400/Mcf for the first usage block, \$0.3047/Mcf for the second block, and \$0.0933/Mcf for all excess Mcf. Delta is proposing to increase these charges by 32.9%, so that they would be \$0.8260/Mcf for the first block, \$0.4050 for the second block, and \$0.1240 for all excess Mcf. It should be noted that these Special Contracts are located near an interstate pipeline and are therefore at risk of bypassing Delta by connecting directly to the pipeline. If a bypass were to occur then the fixed costs recovered from these Special Contracts would be spread to other customers, thus placing upward pressure on Delta's other rates.

VII. PIPE REPLACEMENT PROGRAM

Q. Is Delta proposing to roll the existing Pipe Replacement Program costs into base rates in this proceeding?

A. Delta is not proposing to roll its Pipe Replacement Program costs into base rates in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF Kentucky)
) **SS:**
COUNTY OF Oldham)

The undersigned, **Larry Feltner**, being duly sworn, deposes and says he is Managing Partner for The Prime Group, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

L Feltner

LARRY FELTNER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of November, 2024.

Jennifer Page Bingham (SEAL)
Notary Public

My Commission Expires:

June 19, 2027

JENNIFER PAGE BINGHAM
NOTARY PUBLIC
STATE AT LARGE KENTUCKY
COMM. # KYNP74158
MY COMMISSION EXPIRES JUNE 19, 2027

Exhibit LF-1

Cost of Service Study
Functional Assignment and Classification

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Gas Plant at Original Cost												
Underground Storage Plant												
350-358	Underground Storage Plant	PT350	F003	$	35,873,415	-	-	35,873,415	-	-	-	-
Total Storage Plant		PTST		$	35,873,415	$ -	$ -	$ 35,873,415	$ -	$ -	$ -	$ -
Transmission Plant												
325-371	Transmission	PT365	F005	$	89,721,015	-	-	-	-	89,721,015	-	-
Distribution Plant												
374 & 304	Land and Land Rights	PT374	F008	$	372,993	-	-	-	-	-	-	-
375	Structures & Improvements	PT375	F008		128,102	-	-	-	-	-	-	-
376	Mains	PT376	F009		135,453,751	-	-	-	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008		3,379,688	-	-	-	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008		1,009,722	-	-	-	-	-	-	-
380	Services	PT380	F010		31,041,091	-	-	-	-	-	-	-
381	Meters	PT381	F011		14,754,877	-	-	-	-	-	-	-
382	Meter Installations	PT382	F011		5,793,064	-	-	-	-	-	-	-
383	House Regulators	PT383	F011		4,891,300	-	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011		-	-	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011		1,849,384	-	-	-	-	-	-	-
387	Other Equipment	PT387	F011		27,914	-	-	-	-	-	-	-
	Mt. Olivet	MTOVT				-	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$	198,701,884	-	-	-	-	-	-	-
Transmission & Distribution Subtotal		TDSUB		$	288,422,899	$ -	$ -	$ -	$ -	$ 89,721,015	$ -	$ -
U-T-D Subtotal		PTSUB		$	324,296,314	-	-	35,873,415	-	89,721,015	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	$	4,208,069	-	-	4,208,069	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB		10,153,196	-	-	1,123,139	-	2,809,021	-	-
389-399	General Plant	PT389	PTSUB		36,873,844	-	-	4,078,957	-	10,201,654	-	-
	Common Utility Plant	PTCP	PTSUB		-	-	-	-	-	-	-	-
Total Plant in Service		PTIS		$	375,531,423	-	-	45,283,580	-	102,731,690	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost										
Underground Storage Plant										
350-358	Underground Storage Plant	PT350	F003	-	-	-	-	-	-	-
Total Storage Plant		PTST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
325-371	Transmission	PT365	F005	-	-	-	-	-	-	-
Distribution Plant										
374 & 304	Land and Land Rights	PT374	F008	372,993	-	-	-	-	-	-
375	Structures & Improvements	PT375	F008	128,102	-	-	-	-	-	-
376	Mains	PT376	F009	-	70,788,130	64,665,620	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	3,379,688	-	-	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	1,009,722	-	-	-	-	-	-
380	Services	PT380	F010	-	-	-	31,041,091	-	-	-
381	Meters	PT381	F011	-	-	-	-	14,754,877	-	-
382	Meter Installations	PT382	F011	-	-	-	-	5,793,064	-	-
383	House Regulators	PT383	F011	-	-	-	-	4,891,300	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	-	-	-	1,849,384	-	-
387	Other Equipment	PT387	F011	-	-	-	-	27,914	-	-
	Mt. Olivet	MTOVT		-	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		4,890,504	70,788,130	64,665,620	31,041,091	27,316,539	-	-
Transmission & Distribution Subtotal		TDSUB		$ 4,890,504	$ 70,788,130	$ 64,665,620	$ 31,041,091	$ 27,316,539	$ -	$ -
U-T-D Subtotal		PTSUB		4,890,504	70,788,130	64,665,620	31,041,091	27,316,539	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	153,114	2,216,262	2,024,577	971,847	855,237	-	-
389-399	General Plant	PT389	PTSUB	556,071	8,048,906	7,352,751	3,529,502	3,106,004	-	-
	Common Utility Plant	PTCP	PTSUB	-	-	-	-	-	-	-
Total Plant in Service		PTIS		5,599,689	81,053,298	74,042,948	35,542,439	31,277,780	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Gas Plant at Original Cost (Continued)											
Construction Work In Progress											
Underground Storage	CWIPUS	F003	$	-	-	-	-	-	-	-	-
Transmission	CWIPTR	F005	$	-	-	-	-	-	-	-	-
Distribution Mains	CWIPDM	F009	$	-	-	-	-	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	$	-	-	-	-	-	-	-	-
General	CWIPCO	PT389	$	-	-	-	-	-	-	-	-
Total CWIP	CWIP		$	-	-	-	-	-	-	-	-
Total Gas Plant at Original Cost	PTT		$	375,531,423	-	-	45,283,580	-	102,731,690	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost (Continued)									
Construction Work In Progress									
Underground Storage	CWIPUS	F003	-	-	-	-	-	-	-
Transmission	CWIPTR	F005	-	-	-	-	-	-	-
Distribution Mains	CWIPDM	F009	-	-	-	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	-	-	-	-	-	-	-
General	CWIPCO	PT389	-	-	-	-	-	-	-
Total CWIP	CWIP		-	-	-	-	-	-	-
Total Gas Plant at Original Cost	PTT		5,599,689	81,053,298	74,042,948	35,542,439	31,277,780	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Net Cost Rate Base										
Total Gas Utility Plant at Original Cost			$ 375,531,423	$ -	$ -	$ 45,283,580	$ -	$ 102,731,690	$ -	$ -
Less:										
Reserve for Depreciation										
Underground Storage	DEPRUS	PTST	$ 14,866,664	-	-	14,866,664	-	-	-	-
Transmission	DEPTR	F005	46,213,782	-	-	-	-	46,213,782	-	-
Distribution	DEPRDI	PTDSUB	83,648,861	-	-	-	-	-	-	-
General	DEPRGE	PT389	12,145,659	-	-	1,343,544	-	3,360,263	-	-
Common	DEPRCO	PTSUB	4,235,828	-	-	468,564	-	1,171,900	-	-
Total Depreciation Reserve	DEPR		$ 161,110,794	$ -	$ -	$ 16,678,772	$ -	$ 50,745,945	$ -	$ -
Depreciation Adjustment		DEPR	$ -	-	-	-	-	-	-	-
Customer Advances For Construction	CAD	CADAL	$ 1,152,733	-	-	-	-	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	$ 39,415,057	-	-	4,360,064	-	10,904,715	-	-
Investment Tax Credit	ITC	PTSUB	$ -	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	$ -	-	-	-	-	-	-	-
PLUS:										
Materials and Supplies	MSP	PTSUB	$ 1,284,044	-	-	142,040	-	355,248	-	-
Prepayments	PPY	PTSUB	(121,268)	-	-	(13,415)	-	(33,550)	-	-
Gas Stored Underground	GSU	F003	2,266,771	-	-	2,266,771	-	-	-	-
Cash Working Capital	CWC	OMT	1,399,833	47	47	37,857	56,056	177,293	23,272	50,912
Adjustments:										
Unamortized Debt		PTSUB	$ 1,827,182	-	-	202,122	-	505,515	-	-
Utility ARO Assets										
Transmission		F003	$ 47,858	-	-	47,858	-	-	-	-
Storage		F005	$ 13,116	-	-	-	-	13,116	-	-
Plant Acquisition Adjustment		PTT	$ -	-	-	-	-	-	-	-
A/D on ARO Assets		DEPR	$ -	-	-	-	-	-	-	-
Net Cost Rate Base	NCRB		$ 180,570,375	$ 47	$ 47	$ 26,927,976	$ 56,056	$ 42,098,652	$ 23,272	$ 50,912

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Net Cost Rate Base									
Total Gas Utility Plant at Original Cost			$ 5,599,689	$ 81,053,298	$ 74,042,948	$ 35,542,439	$ 31,277,780	$ -	$ -
Less:									
Reserve for Depreciation									
Underground Storage	DEPRUS	PTST	-	-	-	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-	-	-	-
Distribution	DEPRDI	PTDSUB	2,058,788	29,800,152	27,222,719	13,067,576	11,499,626	-	-
General	DEPRGE	PT389	183,161	2,651,182	2,421,879	1,162,562	1,023,069	-	-
Common	DEPRCO	PTSUB	63,878	924,606	844,636	405,446	356,798	-	-
Total Depreciation Reserve	DEPR		$ 2,305,827	$ 33,375,940	$ 30,489,234	$ 14,635,584	$ 12,879,492	$ -	$ -
Depreciation Adjustment		DEPR	-	-	-	-	-	-	-
Customer Advances For Construction	CAD	CADAL	-	490,104	447,715	214,914	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	594,393	8,603,607	7,859,476	3,772,742	3,320,059	-	-
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-	-	-
PLUS:									
Materials and Supplies	MSP	PTSUB	19,364	280,284	256,042	122,907	108,159	-	-
Prepayments	PPY	PTSUB	(1,829)	(26,471)	(24,181)	(11,608)	(10,215)	-	-
Gas Stored Underground	GSU	F003	-	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	8,640	319,499	291,865	136,521	149,827	147,474	524
Adjustments:									
Unamortized Debt		PTSUB	27,555	398,841	364,345	174,895	153,910	-	-
Utility ARO Assets									
Transmission		F003	-	-	-	-	-	-	-
Storage		F005	-	-	-	-	-	-	-
Plant Acquisition Adjustment		PTT	-	-	-	-	-	-	-
A/D on ARO Assets		DEPR	-	-	-	-	-	-	-
Net Cost Rate Base	NCRB		$ 2,753,198	$ 39,555,800	$ 36,134,594	$ 17,341,913	$ 15,479,909	$ 147,474	$ 524

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Labor Expenses											
Production Expenses											
Operation & Maintenance											
753	Wells and Gathering	LB 753	F006	10,654	-	-	-	-	-	10,654	-
754	Compressor Station	LB754	F006	95,230	-	-	-	-	-	95,230	-
764	Maintenance of Wells and Gathering	LB764	F006	265	-	-	-	-	-	265	-
765	Maintenance of Compressor Station	LB765	F006	47,148	-	-	-	-	-	47,148	-
Total Production Operation & Maintenance Expenses				153,297	-	-	-	-	-	153,297	-
807-813	Procurement Expenses	LB807	DMCM	$ 681	341	341	-	-	-	-	-
Storage Expenses											
Operation											
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-	-	-
816	Well Expenses	LB816	F003	52,706	-	-	52,706	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	168,236	-	-	-	168,236	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-	-	-
824	Other Expenses	LB824	F004	22,680	-	-	-	22,680	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ 243,623	$ -	$ -	$ 52,706	$ 190,916	$ -	$ -	$ -
Storage Expense											
Maintenance											
830	Maintenance Super and Eng.	LB830	MSE	$ -	-	-	-	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	35,173	-	-	35,173	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	12,131	-	-	-	12,131	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-	-	-
Total Maintenance Labor		LBSM		$ 47,304	$ -	$ -	$ 35,173	$ 12,131	$ -	$ -	$ -
Total Storage Labor		LBS		$ 290,926	-	-	87,879	203,047	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses										
Production Expenses										
Operation & Maintenance										
753	Wells and Gathering	LB 753	F006	-	-	-	-	-	-	-
754	Compressor Station	LB754	F006	-	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	LB764	F006	-	-	-	-	-	-	-
765	Maintenance of Compressor Station	LB765	F006	-	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-	-	-	-
807-813	Procurement Expenses	LB807	DMCM	-	-	-	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-	-
816	Well Expenses	LB816	F003	-	-	-	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	-	-	-	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-	-
Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Labor		LBS		-	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Labor Expenses (Continued)												
Transmission												
850-867	Transmission Expenses	LB850	F005	$	728,052	-	-	-	-	728,052	-	-
Distribution Expenses												
Operation												
870	Operation Supr and Engr	LB870	DOES	$	288	-	-	-	-	-	-	21
871	Dist Load Dispatching	LB871	F007		-	-	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007		370,382	-	-	-	-	-	-	370,382
873	Compr. Station Fuel and Power	LB873	F007		-	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL		4,068,851	-	-	-	-	-	-	-
874.02	Leak Survey-Mains	LB874.02	F009		-	-	-	-	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010		-	-	-	-	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL		-	-	-	-	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010		-	-	-	-	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009		-	-	-	-	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009		-	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007		-	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009		-	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009		-	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008		1,678	-	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011		-	-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008		-	-	-	-	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011		323,088	-	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011		20,274	-	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB		232,028	-	-	-	-	-	-	-
881	Rents	LB881	PTDSUB		-	-	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$	5,016,589	$ -	$ -	$ -	$ -	$ -	$ -	$ 370,403
Total Operations Transmission and Distribution Labor		LBTDO		$	5,850,524	$ -	$ -	$ -	$ -	$ 728,052	$ 105,884	$ 370,403

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Distribution Structures & Equipment Demand		Distribution Mains Demand		Distribution Mains Customer		Services Customer		Meters Customer		Customer Accounts Customer		Customer Service Expense Customer
Labor Expenses (Continued)																	
Transmission																	
850-867	Transmission Expenses	LB850	F005		-		-		-		-		-		-		-
Distribution Expenses																	
Operation																	
870	Operation Supr and Engr	LB870	DOES		0		104		95		46		22		-		-
871	Dist Load Dispatching	LB871	F007		-		-		-		-		-		-		-
872	Compr. Station Labor and Exp.	LB872	F007		-		-		-		-		-		-		-
873	Compr. Station Fuel and Power	LB873	F007		-		-		-		-		-		-		-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL		-		1,729,942		1,580,318		758,592		-		-		-
874.02	Leak Survey-Mains	LB874.02	F009		-		-		-		-		-		-		-
874.03	Leak Survey - Service	LB874.03	F010		-		-		-		-		-		-		-
874.04	Locate Main per Request	LB874.04	CADAL		-		-		-		-		-		-		-
874.05	Check Stop Box Access	LB874.05	F010		-		-		-		-		-		-		-
874.06	Patrolling Mains	LB874.06	F009		-		-		-		-		-		-		-
874.07	Check/Grease Valves	LB874.07	F009		-		-		-		-		-		-		-
874.08	Opr. Odor Equipment	LB874.08	F007		-		-		-		-		-		-		-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009		-		-		-		-		-		-		-
874.1	Cut Grass - Right of Way	LB874.10	F009		-		-		-		-		-		-		-
875	Meas and Reg Station Exp.- General	LB875	F008		1,678		-		-		-		-		-		-
876	Meas and Reg Station Exp.- Industrial	LB876	F011		-		-		-		-		-		-		-
877	Meas and Reg Station Exp. - City Gate	LB877	F008		-		-		-		-		-		-		-
878	Meter and House Reg. Expense	LB878	F011		-		-		-		-		323,088		-		-
879	Customer Installation Expense	LB879	F011		-		-		-		-		20,274		-		-
880	Other Expenses	LB880	PTDSUB		5,711		82,661		75,511		36,247		31,898		-		-
881	Rents	LB881	PTDSUB		-		-		-		-		-		-		-
Total Operations Distribution Labor		LBDO		$	7,389	$	1,812,706	$	1,655,924	$	794,884	$	375,282	$	-	$	-
Total Operations Transmission and Distribution Labor		LBTDO		$	7,389	$	1,812,706	$	1,655,924	$	794,884	$	375,282	$	-	$	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Labor Expenses (Continued)												
Maintenance Expense -- Transmission and Distribution												
885	Maintenance Supr and Engr	LB885	DMES	$	110,060	-	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008		10,852	-	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009		140,141	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007		-	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008		1,670	-	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011		-	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008		-	-	-	-	-	-	-	-
892	Maintenance Services	LB892	F010		22,204	-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011		228,116	-	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB		68,230	-	-	-	-	-	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB		-	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB		-	-	-	-	-	-	-	-
Total Maintenance Labor		LBDM		$	581,272	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$	6,479,210	$ -	$ -	$ -	$ -	$ 728,052	$ 153,297	$ 370,403
Customer Accounts Expense												
901	Supervision	LB901	F012	$	-	-	-	-	-	-	-	-
902	Meter Reading	LB902	F012		39,426	-	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	$	573,009	-	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012		-	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012		-	-	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$	612,436	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses												
907-910	Customer Service	LB907	F013	$	-	-	-	-	-	-	-	-
Sales Expenses												
911-916	Sales Expenses	LB911	F013	$	2,146	-	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)										
Maintenance Expense -- Transmission and Distribution										
885	Maintenance Supr and Engr	LB885	DMES	3,317	22,783	20,813	7,676	55,471	-	-
886	Maintenance Structures	LB886	F008	10,852	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	-	73,238	66,903	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	1,670	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	22,204	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-	228,116	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	1,679	24,307	22,205	10,659	9,380	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB	-	-	-	-	-	-	-
Total Maintenance Labor		LBDM		$ 17,518	$ 120,328	$ 109,921	$ 40,538	$ 292,967	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 24,907	$ 1,933,034	$ 1,765,845	$ 835,422	$ 668,248	$ -	$ -
Customer Accounts Expense										
901	Supervision	LB901	F012	-	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	39,426	-
903	Customer Records and Collections	LB903	F012	-	-	-	-	-	573,009	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ -	$ -	$ -	$ 612,436	$ -
Customer Service Expenses										
907-910	Customer Service	LB907	F013	-	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	LB911	F013	-	-	-	-	-	-	2,146

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Labor Expenses (Continued)												
Administrative & General												
920	Admin and General Salaries	LB920	LBSUB	$	2,431,025	112	112	28,927	66,836	239,650	50,460	121,924
921	Office Supplies and Expense	LB921	LBSUB		-	-	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB		(1,598,731)	(74)	(74)	(19,023)	(43,954)	(157,603)	(33,185)	(80,182)
923	Outside Services Employed	LB923	OMSUB		-	-	-	-	-	-	-	-
924	Property Insurance	LB924	PTT		-	-	-	-	-	-	-	-
925	Injuries and Damages	LB925	PTT		425,087	-	-	51,259	-	116,288	-	-
926	Employee Pensions and Benefits	LB926	LBSUB		8,557	0	0	102	235	844	178	429
927	Franchise Requirement	LB927	PTT			-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT			-	-	-	-	-	-	-
929	Duplicate Charges -Dredit	LB929	PTT			-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT			-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB			-	-	-	-	-	-	-
931	Rents	LB931	PTT			-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389			-	-	-	-	-	-	-
Total Administrative and General Labor		LBAG		$	1,265,939	$ 39	$ 39	$ 61,265	$ 23,118	$ 199,179	$ 17,453	$ 42,172
Total Labor Expense		LBTOT		$	8,651,338	$ 380	$ 380	$ 149,144	$ 226,165	$ 927,231	$ 170,751	$ 412,575

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	LB920	LBSUB	8,199	636,290	581,257	274,993	219,965	201,593	706
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(5,392)	(418,447)	(382,256)	(180,845)	(144,657)	(132,575)	(465)
923	Outside Services Employed	LB923	OMSUB	-	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-	-
925	Injuries and Damages	LB925	PTT	6,339	91,749	83,814	40,233	35,405	-	-
926	Employee Pensions and Benefits	LB926	LBSUB	29	2,240	2,046	968	774	710	2
927	Franchise Requirement	LB927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-	-
929	Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB	-	-	-	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	-	-	-	-	-	-	-
Total Administrative and General Labor		LBAG		$ 9,174	$ 311,831	$ 284,861	$ 135,348	$ 111,487	$ 69,728	$ 244
Total Labor Expense		LBTOT		$ 34,082	$ 2,244,866	$ 2,050,706	$ 970,771	$ 779,736	$ 682,163	$ 2,390

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Operation & Maintenance Expenses											
Production Expenses											
Operation & Maintenance											
753	Wells and Gathering	OM 753	F006	10,654	-	-	-	-	-	10,654	-
754	Compressor Station	OM754	F006	95,230	-	-	-	-	-	95,230	-
764	Maintenance of Wells and Gathering	OM764	F006	265	-	-	-	-	-	265	-
765	Maintenance of Compressor Station	OM765	F006	72,032	-	-	-	-	-	72,032	-
Total Production Operation & Maintenance Expenses				178,182	-	-	-	-	-	178,182	-
807-813	Procurement Expenses	OM807	DMCM	$ 681	341	341	-	-	-	-	-
Storage Expenses											
Operation											
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-	-	-
816	Well Expenses	OM816	F003	52,707	-	-	52,707	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	400,650	-	-	-	400,650	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004	77,819	-	-	-	77,819	-	-	-
823	Gas losses	OM823	F004	-	-	-	-	-	-	-	-
824	Other Expenses	OM824	F004	22,681	-	-	-	22,681	-	-	-
825	Storage Well Royalities	OM825	F003	29,524	-	-	29,524	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ 583,380	$ -	$ -	$ 82,231	$ 501,150	$ -	$ -	$ -
Storage Expense											
Maintenance											
830	Maintenance Super and Eng.	OM830	MSE	$ -	-	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	3,392	-	-	3,392	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	81,980	-	-	81,980	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	19,844	-	-	-	19,844	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	464	-	-	464	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	249	-	-	249	-	-	-	-
Total Maintenance Expense		OMME		$ 105,929	$ -	$ -	$ 86,085	$ 19,844	$ -	$ -	$ -
Total Storage Expense		OMS		$ 689,309	-	-	168,315	520,994	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses										
Production Expenses										
Operation & Maintenance										
753	Wells and Gathering	OM 753	F006	-	-	-	-	-	-	-
754	Compressor Station	OM754	F006	-	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	OM764	F006	-	-	-	-	-	-	-
765	Maintenance of Compressor Station	OM765	F006	-	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-	-	-	-
807-813	Procurement Expenses	OM807	DMCM	-	-	-	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-	-
816	Well Expenses	OM816	F003	-	-	-	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004	-	-	-	-	-	-	-
823	Gas losses	OM823	F004	-	-	-	-	-	-	-
824	Other Expenses	OM824	F004	-	-	-	-	-	-	-
825	Storage Well Royalities	OM825	F003	-	-	-	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	-	-	-	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	-	-	-	-	-	-	-
Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		-	-	-	-	-	-	-

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Operation & Maintenance Expenses (Continued)											
Transmission											
850-867	Transmission Expenses	OM850	F005	$ 1,121,210	-	-	-	-	1,121,210	-	-
Distribution Expenses											
Operation											
870	Operation Supr and Engr	OM870	DOES	$ 781	-	-	-	-	-	-	58
871	Dist Load Dispatching	OM871	F007	-	-	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	370,382	-	-	-	-	-	-	370,382
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	4,068,851	-	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	2,279	-	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	470,871	-	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	20,274	-	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	622,920	-	-	-	-	-	-	-
881	Rents	OM881	PTDSUB	-	-	-	-	-	-	-	-
Total Operations Distribution Expense		OMDO		$ 5,556,357	-	-	-	-	-	-	370,440
Total Transmission and Distribution Oper Exp		OMTDO		$ 6,783,452	$ -	$ -	$ -	$ -	$ 1,121,210	$ 105,884	$ 370,440
				$ 5,555,577							

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)										
Transmission										
850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-	-
Distribution Expenses										
Operation										
870	Operation Supr and Engr	OM870	DOES	1	282	258	124	58	-	-
871	Dist Load Dispatching	OM871	F007	-	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	1,729,941	1,580,318	758,591	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	2,279	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	470,871	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	20,274	-	-
880	Other Expenses	OM880	PTDSUB	15,331	221,917	202,723	97,312	85,636	-	-
881	Rents	OM881	PTDSUB	-	-	-	-	-	-	-
Total Operations Distribution Expense		OMDO		17,611	1,952,141	1,783,299	856,027	576,839	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 17,611	$ 1,952,141	$ 1,783,299	$ 856,027	$ 576,839	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Operation & Maintenance Expenses (Continued)												
Maintenance Expense -- Transmission and Distribution												
885	Maintenance Supr and Engr	OM885	DMES	$	298,617	-	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008		26,369	-	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009		216,551	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007		-	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008		2,258	-	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011		-	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-	-	-	-	-	-	-	-
892	Maintenance Services	OM892	F010		22,204	-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011		436,125	-	-	-	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB		100,399	-	-	-	-	-	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB		-	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	OM900	TDSUB		-	-	-	-	-	-	-	-
Total Maintenance Expenses		OMME		$	1,102,523	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$	7,958,271	$ -	$ -	$ -	$ -	$ 1,121,210	$ 178,182	$ 370,440
Customer Accounts Expense												
901	Supervision	OM901	F012	$	-	-	-	-	-	-	-	-
902	Meter Reading	OM902	F012		39,427	-	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	$	907,132	-	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	F012		380,857	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	OM905	F012		-	-	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$	1,327,415	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses												
907-910	Customer Service	OM907	F013	$	-	-	-	-	-	-	-	-
Sales Expenses												
911-916	Sales Expenses	OM911	F013	$	4,730	-	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)										
Maintenance Expense -- Transmission and Distribution										
885	Maintenance Supr and Engr	OM885	DMES	9,000	61,816	56,470	20,826	150,506	-	-
886	Maintenance Structures	OM886	F008	26,369	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009	-	113,169	103,381	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	2,258	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-	-	-	-
892	Maintenance Services	OM892	F010	-	-	-	22,204	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	-	436,125	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	2,471	35,767	32,674	15,684	13,802	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	OM900	TDSUB	-	-	-	-	-	-	-
Total Maintenance Expenses		OMME		$ 40,097	$ 210,753	$ 192,525	$ 58,714	$ 600,433	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 57,708	$ 2,162,894	$ 1,975,824	$ 914,741	$ 1,177,272	$ -	$ -
Customer Accounts Expense										
901	Supervision	OM901	F012	-	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	39,427	-
903	Customer Records and Collections	OM903	F012	-	-	-	-	-	907,132	-
904	Uncollectible Accounts	OM904	F012	-	-	-	-	-	380,857	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ -	$ 1,327,415	$ -
Customer Service Expenses										
907-910	Customer Service	OM907	F013	-	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	OM911	F013	-	-	-	-	-	-	4,730

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Operation & Maintenance Expenses (Continued)												
Administrative & General												
920	Admin and General Salaries	OM920	LBSUB	$	2,431,025	112	112	28,927	66,836	239,650	50,460	121,924
921	Office Supplies and Expense	OM921	LBSUB		1,448,696	67	67	17,238	39,829	142,812	30,070	72,657
922	Admin. Expenses Transferred	OM922	LBSUB		(2,220,787)	(102)	(102)	(26,425)	(61,056)	(218,925)	(46,096)	(111,380)
923	Outside Services Employed	OM923	OMSUB		2,641,044	90	90	44,540	137,867	296,698	47,151	98,027
924	Property Insurance	OM924	PTT		662,947	-	-	79,942	-	181,358	-	-
925	Injuries and Damages	OM925	PTT		942,769	-	-	113,684	-	257,907	-	-
926	Employee Pensions and Benefits	OM926	LBSUB		3,522,781	163	163	41,918	96,852	347,275	73,122	176,680
927	Franchise Requirement	OM927	PTT		-	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT		565,317	-	-	68,169	-	154,650	-	-
929	Duplicate Charges -Dredit	OM929	PTT		-	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT		-	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB		54,851	2	2	925	2,863	6,162	979	2,036
931	Rents	OM931	PTT			-	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389		52,977	-	-	5,860	-	14,657	-	-
Total Administrative and General Expense		OMAGT		$	10,101,620	$ 331	$ 331	$ 374,777	$ 283,191	$ 1,422,245	$ 155,686	$ 359,944
Total Operation & Maintenance Expense		OMT		$	20,082,027	$ 672	$ 672	$ 543,092	$ 804,185	$ 2,543,455	$ 333,868	$ 730,383
				$	54,300							

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	OM920	LBSUB	8,199	636,290	581,257	274,993	219,965	201,593	706
921	Office Supplies and Expense	OM921	LBSUB	4,886	379,178	346,383	163,874	131,081	120,133	421
922	Admin. Expenses Transferred	OM922	LBSUB	(7,490)	(581,263)	(530,989)	(251,211)	(200,942)	(184,159)	(645)
923	Outside Services Employed	OM923	OMSUB	15,271	572,351	522,848	242,062	311,533	351,264	1,252
924	Property Insurance	OM924	PTT	9,885	143,088	130,712	62,745	55,216	-	-
925	Injuries and Damages	OM925	PTT	14,058	203,484	185,884	89,229	78,523	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	11,881	922,043	842,295	398,490	318,749	292,127	1,024
927	Franchise Requirement	OM927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	8,430	122,016	111,463	53,505	47,085	-	-
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	317	11,887	10,859	5,027	6,470	7,295	26
931	Rents	OM931	PTT	-	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	799	11,564	10,564	5,071	4,462	-	-
Total Administrative and General Expense		OMAGT		$ 66,236	$ 2,420,638	$ 2,211,276	$ 1,043,785	$ 972,144	$ 788,254	$ 2,783
Total Operation & Maintenance Expense		OMT		$ 123,944	$ 4,583,532	$ 4,187,100	$ 1,958,526	$ 2,149,416	$ 2,115,669	$ 7,513

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Depreciation Expenses											
Underground Storage											
350-357	Underground Storage Plant	DP350	F003	$ 909,888	-	-	909,888	-	-	-	-
Transmission											
365-371	Transmission Plant	DP365	F005	$ 2,929,640	-	-	-	-	2,929,640	-	-
Distribution											
374	Land & Land Rights	DP374	F008	$ -	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	2,998	-	-	-	-	-	-	-
376	Mains	DP376	F009	4,036,522	-	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	133,498	-	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	21,911	-	-	-	-	-	-	-
380	Services	DP380	F010	1,036,772	-	-	-	-	-	-	-
381	Meters	DP381	F011	469,205	-	-	-	-	-	-	-
382	Meter Installations	DP382	F011	223,612	-	-	-	-	-	-	-
383	House Regulators	DP383	F011	210,326	-	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	52,892	-	-	-	-	-	-	-
387	Other Equipment	DP387	F011	611	-	-	-	-	-	-	-
	Other		PTSUB		-	-	-	-	-	-	-
Total Distribution				$ 6,188,347	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	Gas Stored Underground	DP117	F003	$ -	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	1,010,005	-	-	111,726	-	279,432	-	-
389-399	General Plant	DP389	PTSUB	2,017,852	-	-	223,213	-	558,266	-	-
325-334	Production	DPCP	PTSUB	116,053	-	-	12,838	-	32,108	-	-
Amortization of Gas Plant		AMORT	PTSUB	-	-	-	-	-	-	-	-
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 13,171,785	$ -	$ -	$ 1,257,665	$ -	$ 3,799,446	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description		Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Depreciation Expenses										
Underground Storage										
350-357	Underground Storage Plant	DP350	F003	-	-	-	-	-	-	-
Transmission										
365-371	Transmission Plant	DP365	F005	-	-	-	-	-	-	-
Distribution										
374	Land & Land Rights	DP374	F008	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	2,998	-	-	-	-	-	-
376	Mains	DP376	F009	-	2,109,486	1,927,036	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	133,498	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	21,911	-	-	-	-	-	-
380	Services	DP380	F010	-	-	-	1,036,772	-	-	-
381	Meters	DP381	F011	-	-	-	-	469,205	-	-
382	Meter Installations	DP382	F011	-	-	-	-	223,612	-	-
383	House Regulators	DP383	F011	-	-	-	-	210,326	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	-	52,892	-	-
387	Other Equipment	DP387	F011	-	-	-	-	611	-	-
	Other		PTSUB	-	-	-	-	-	-	-
Total Distribution				$ 158,407	$ 2,109,486	$ 1,927,036	$ 1,036,772	$ 956,646	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	15,231	220,466	201,398	96,676	85,076	-	-
389-399	General Plant	DP389	PTSUB	30,430	440,461	402,366	193,145	169,970	-	-
325-334	Production	DPCP	PTSUB	1,750	25,332	23,141	11,108	9,776	-	-
Amortization of Gas Plant		AMORT	PTSUB	-	-	-	-	-	-	-
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 205,818	$ 2,795,746	$ 2,553,940	$ 1,337,702	$ 1,221,468	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Taxes Other Than Income Taxes											
Liscense & Privilege Fee	OTRE	PTT	$	-	-	-	-	-	-	-	-
Property Taxes	OTPP	PTT		853,479	-	-	102,917	-	233,481	-	-
Payroll Taxes	OTUN	LBTOT		2,491,300	109	109	42,948	65,128	267,012	49,171	118,808
Total Taxes Other Than Income Taxes	OTT		$	3,344,780	$ 109	$ 109	$ 145,866	$ 65,128	$ 500,493	$ 49,171	$ 118,808
Interest on Long Term Debt	INT	PTT	$	3,845,087	-	-	463,661	-	1,051,875	-	-

Functional Assignment and Classification

Description	Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Taxes Other Than Income Taxes									
Liscense & Privilege Fee	OTRE	PTT	-	-	-	-	-	-	-
Property Taxes	OTPP	PTT	12,727	184,212	168,279	80,778	71,086	-	-
Payroll Taxes	OTUN	LBTOT	9,814	646,447	590,536	279,550	224,538	196,441	688
Total Taxes Other Than Income Taxes	OTT		$ 22,541	$ 830,659	$ 758,815	$ 360,328	$ 295,624	$ 196,441	$ 688
Interest on Long Term Debt	INT	PTT	57,336	829,909	758,130	363,921	320,255	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Functional Assignment Vectors										
Gas Supply Demand	F001		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Transmission Commodity	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Accounts	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F013		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB		$ 225,174,766	$ -	$ -	$ -	$ -	$ 89,721,015	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Functional Assignment Vectors									
Gas Supply Demand	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.000000	0.522600	0.477400	0.000000	0.000000	0.000000	0.000000
Services	F010		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Transmission & Distribution Mains	TDMSUB		$ -	$ 70,788,130	$ 64,665,620	$ -	$ -	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity
Internally Generated Functional Vectors										
Sub-Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	1.000000	-	-	0.110619	-	0.276664	-	-
Total Storage Plant		PTST	1.000000	-	-	1.000000	-	-	-	-
Transmission Plant		PT365	1.000000	-	-	-	-	1.000000	-	-
General Plant		PT389	1.000000	-	-	0.110619	-	0.276664	-	-
Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	-	-
Sub-Total CWIP		CWIP	1.000000	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Depreciation Reserve		DEPR	1.000000	-	-	0.103524	-	0.314975	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1.000000	-	-	0.110619	-	0.276664	-	-
Transmission and Distribution Payroll		LBTD	1.000000	-	-	-	-	0.112367	0.023660	0.057168
Transmission and Distribution Mains		TDMSUB	1.000000	-	-	-	-	0.398451	-	-
Storage Operation Expenses Subtotal	OSE		243,623	-	-	52,706	190,916	-	-	-
Storage Maintenance Expenses Subtotal	MSE		47,304	-	-	35,173	12,131	-	-	-
Mains & Services	CADAL		166,494,841	-	-	-	-	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1.00000	0.5	0.5					
Distribution Operation Expenses Subtotal	DOES		5,016,301	-	-	-	-	-	-	370,382
Distribution Maintenance Expenses Subtotal	DMES		471,213	-	-	-	-	-	-	-
Subtotal Labor Expenses	LBSUB		$ 7,385,399	$ 341	$ 341	$ 87,879	$ 203,047	$ 728,052	$ 153,297	$ 370,403
Subtotal O&M Expenses	OMSUB		$ 9,980,406	$ 341	$ 341	$ 168,315	$ 520,994	$ 1,121,210	$ 178,182	$ 370,440

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Functional Assignment and Classification

Description	Name	Vector	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Internally Generated Functional Vectors									
Sub-Total Distribution Plant		PTDSUB	0.024612	0.356253	0.325440	0.156219	0.137475	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0.015080	0.218282	0.199403	0.095718	0.084233	-	-
Total Storage Plant		PTST	-	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-	-
General Plant		PT389	0.015080	0.218282	0.199403	0.095718	0.084233	-	-
Total Distribution Plant		PTDSUB	0.024612	0.356253	0.325440	0.156219	0.137475	-	-
Sub-Total CWIP		CWIP	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Depreciation Reserve		DEPR	0.014312	0.207161	0.189244	0.090842	0.079942	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.015080	0.218282	0.199403	0.095718	0.084233	-	-
Transmission and Distribution Payroll		LBTD	0.003844	0.298344	0.272540	0.128939	0.103137	-	-
Transmission and Distribution Mains		TDMSUB	-	0.314370	0.287180	-	-	-	-
Storage Operation Expenses Subtotal	OSE		-	-	-	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		-	-	-	-	-	-	-
Mains & Services	CADAL		-	70,788,130	64,665,620	31,041,091	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM								
Distribution Operation Expenses Subtotal	DOES		7,389	1,812,602	1,655,829	794,839	375,260	-	-
Distribution Maintenance Expenses Subtotal	DMES		14,201	97,545	89,108	32,863	237,495	-	-
Subtotal Labor Expenses	LBSUB		$ 24,907	$ 1,933,034	$ 1,765,845	$ 835,422	$ 668,248	$ 612,436	$ 2,146
Subtotal O&M Expenses	OMSUB		$ 57,708	$ 2,162,894	$ 1,975,824	$ 914,741	$ 1,177,272	$ 1,327,415	$ 4,730

Exhibit LF-2

Cost of Service Study
Class Allocation

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Plant in Service											
Gas Supply Costs											
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	PTIS	PTISSD	DEM02	$ 45,283,580	$ 19,669,442	$ -	$ 7,350,093	$ 18,264,044	$ -	$ -	$ -
Commodity	PTIS	PTISSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage				$ 45,283,580	$ 19,669,442	$ -	$ 7,350,093	$ 18,264,044	$ -	$ -	$ -
Transmission											
Demand	PTIS	PTISTD	TDEM	$ 102,731,690	$ 29,848,445	$ -	$ 11,077,970	$ 25,701,369	$ 2,012,884	$ 7,565,967	$ 26,525,054
Commodity	PTIS	PTISTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission				$ 102,731,690	$ 29,848,445	$ -	$ 11,077,970	$ 25,701,369	$ 2,012,884	$ 7,565,967	$ 26,525,054
Distribution Expenses											
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	PTIS	PTISDSD	DEM04	$ 5,599,689	$ 2,422,283	$ -	$ 899,008	$ 2,085,736	$ 163,351	$ 29,311	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Plant in Service (Continued)											
Distribution Mains											
Demand	PTIS	PTISDMD	DEM05	$ 81,053,298	$ 35,061,596	$ -	$ 13,012,782	$ 30,190,216	$ 2,364,442	$ 424,262	$ -
Customer	PTIS	PTISDMC	CUST01	74,042,948	$ 58,706,526	$ 5,326,511	$ 8,073,167	$ 1,866,317	$ 64,867	$ 5,560	$ -
Total Distribution Mains				155,096,246	$ 93,768,122	$ 5,326,511	$ 21,085,949	$ 32,056,534	$ 2,429,309	$ 429,822	$ -
Services											
Customer	PTIS	PTISSC	CUST02	$ 35,542,439	$ 26,392,400	$ 2,394,613	$ 4,746,140	$ 1,936,222	$ 67,297	$ 5,768	$ -
Meters											
Customer	PTIS	PTISMC	CUST03	$ 31,277,780	$ 18,435,137	$ 1,924,061	$ 6,128,344	$ 4,616,047	$ 160,439	$ 13,752	$ -
Customer Accounts											
Customer	PTIS	PTISCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service											
Customer	PTIS	PTISCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 375,531,423	$ 190,535,829	$ 9,645,185	$ 51,287,504	$ 84,659,952	$ 4,833,279	$ 8,044,620	$ 26,525,054

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base											
Gas Supply Costs											
Demand	NCRB	RBGSD	DEM01	$ 47	$ 13	$ 2	$ 5	$ 11	$ 1	$ 3	$ 12
Commodity	NCRB	RBGSC	COM01	47	$ 5	$ 1	$ 2	$ 6	$ 5	$ 6	$ 22
Total Procurement Expenses				$ 94	$ 18	$ 2	$ 7	$ 18	$ 5	$ 10	$ 34
Storage											
Demand	NCRB	RBSD	DEM02	$ 26,927,976	$ 11,696,476	$ -	$ 4,370,748	$ 10,860,753	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	56,056	$ 23,812	$ -	$ 8,310	$ 23,934	$ -	$ -	$ -
Total Storage				$ 26,984,033	$ 11,720,288	$ -	$ 4,379,058	$ 10,884,687	$ -	$ -	$ -
Transmission											
Demand	NCRB	RBTD	TDEM	$ 42,098,652	$ 12,231,662	$ -	$ 4,539,667	$ 10,532,222	$ 824,864	$ 3,100,475	$ 10,869,762
Commodity	NCRB	RBTC	COM03	23,272	$ 2,392	$ -	$ 938	$ 3,261	$ 2,284	$ 3,195	$ 11,203
Total Transmission				$ 42,121,925	$ 12,234,054	$ -	$ 4,540,605	$ 10,535,483	$ 827,148	$ 3,103,670	$ 10,880,965
Distribution Expenses											
Commodity	NCRB	RBDEC	COM04	$ 50,912	$ 13,721	$ -	$ 5,381	$ 18,706	$ 13,104	$ -	$ -
Distribution Structures & Equipment											
Demand	NCRB	RBDSD	DEM04	$ 2,753,198	$ 1,190,963	$ -	$ 442,015	$ 1,025,494	$ 80,315	$ 14,411	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Residential Farm Tap		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Rate Base (Continued)																			
Distribution Mains																			
Demand	NCRB	RBDMD	DEM05	$	39,555,800	$	17,110,833	$	-	$	6,350,525	$	14,733,492	$	1,153,900	$	207,049	$	-
Customer	NCRB	RBDMC	CUST01		36,134,594	$	28,650,081	$	2,599,455	$	3,939,884	$	910,804	$	31,657	$	2,713	$	-
Total Distribution Mains					75,690,394	$	45,760,915	$	2,599,455	$	10,290,409	$	15,644,296	$	1,185,557	$	209,762	$	-
Services																			
Customer	NCRB	RBSC	CUST02	$	17,341,913	$	12,877,414	$	1,168,383	$	2,315,743	$	944,724	$	32,835	$	2,814	$	-
Meters																			
Customer	NCRB	RBMC	CUST03	$	15,479,909	$	9,123,865	$	952,251	$	3,033,023	$	2,284,561	$	79,404	$	6,806	$	-
Customer Accounts																			
Customer	NCRB	RBCAC	CUST04	$	147,474	$	108,330	$	9,829	$	14,897	$	13,775	$	479	$	41	$	123
Customer Service																			
Customer	NCRB	RBCSC	CUST05	$	524	$	415	$	38	$	57	$	13	$	0	$	0	$	-
Total		RBT		$	180,570,375	$	93,029,982	$	4,729,957	$	25,021,195	$	41,351,756	$	2,218,848	$	3,337,515	$	10,881,122

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Residential Farm Tap		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Operation and Maintenance Expenses																			
Gas Supply Costs																			
Demand	OMT	OMGSD	DEM01	$	672	$	188	$	26	$	70	$	161	$	13	$	48	$	167
Commodity	OMT	OMGSC	COM01		672	$	68	$	9	$	27	$	93	$	65	$	91	$	319
Total Procurement Expenses		OMGST		$	1,343	$	256	$	36	$	96	$	254	$	78	$	138	$	485
Storage																			
Demand	OMT	OMSD	DEM02	$	543,092	$	235,898	$	-	$	88,151	$	219,043	$	-	$	-	$	-
Commodity	OMT	OMSC	COM02		804,185	$	341,607	$	-	$	119,220	$	343,358	$	-	$	-	$	-
Total Storage		OMST		$	1,347,278	$	577,505	$	-	$	207,371	$	562,402	$	-	$	-	$	-
Transmission																			
Demand	OMT	OMTD	TDEMOM	$	2,543,455	$	738,995	$	-	$	274,271	$	636,320	$	49,835	$	187,320	$	656,713
Commodity	OMT	OMTC	COM03		333,868	$	34,310	$	-	$	13,457	$	46,776	$	32,769	$	45,843	$	160,713
Total Transmission		OMTRT		$	2,877,322	$	773,305	$	-	$	287,728	$	683,096	$	82,604	$	233,163	$	817,426
Distribution Expenses																			
Commodity	OMT	OMDEC	COM04	$	730,383	$	196,837	$	-	$	77,203	$	268,350	$	187,993	$	-	$	-
Distribution Structures & Equipment																			
Demand	OMT	OMDSD	DEM04OM	$	123,944	$	53,615	$	-	$	19,899	$	46,166	$	3,616	$	649	$	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Residential Farm Tap		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Operation and Maintenance Expenses (Continued)																			
Distribution Mains																			
Demand	OMT	OMDMD	DEM05OM	$	4,583,532	$	1,982,719	$	-	$	735,868	$	1,707,245	$	133,708	$	23,992	$	-
Customer	OMT	OMDMC	CUST01OM		4,187,100	$	3,577,166	$	-	$	491,922	$	113,720	$	3,953	$	339	$	-
Total Distribution Mains					8,770,632	$	5,559,885	$	-	$	1,227,790	$	1,820,965	$	137,661	$	24,331	$	-
Services																			
Customer	OMT	OMSC	CUST02OM	$	1,958,526	$	1,454,323	$	131,952	$	261,531	$	106,693	$	3,708	$	318	$	-
Meters																			
Customer	OMT	OMMC	CUST03OM	$	2,149,416	$	1,266,867	$	132,222	$	421,141	$	317,216	$	11,025	$	945	$	-
Customer Accounts																			
Customer	OMT	OMCAC	CUST04OM	$	2,115,669	$	1,554,101	$	141,005	$	213,716	$	197,623	$	6,869	$	589	$	1,766
Customer Service																			
Customer	OMT	OMCSC	CUST05	$	7,513	$	5,957	$	540	$	819	$	189	$	7	$	1	$	-
Total		OMTT		$	20,082,027	$	11,442,651	$	405,756	$	2,717,294	$	4,002,955	$	433,561	$	260,133	$	819,678

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref		Name	Allocation Vector		Total System		Residential		Residential Farm Tap		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Payroll Expenses																				
Gas Supply Costs																				
Demand	LBTOT	LBGSD	DEM01		$	380	$	106	$	15	$	39	$	91	$	7	$	27	$	94
Commodity	LBTOT	LBGSC	COM01			380	$	38	$	5	$	15	$	52	$	37	$	51	$	180
Total Procurement Expenses		LBGST			$	759	$	144	$	20	$	54	$	144	$	44	$	78	$	274
Storage																				
Demand	LBTOT	LBSD	DEM02		$	149,144	$	64,782	$	-	$	24,208	$	60,154	$	-	$	-	$	-
Commodity	LBTOT	LBSC	COM02			226,165	$	96,072	$	-	$	33,529	$	96,564	$	-	$	-	$	-
Total Storage		LBST			$	375,308	$	160,854	$	-	$	57,737	$	156,718	$	-	$	-	$	-
Transmission																				
Demand	LBTOT	LBTD	TDEM		$	927,231	$	269,405	$	-	$	99,987	$	231,974	$	18,168	$	68,289	$	239,409
Commodity	LBTOT	LBTC	COM03			170,751	$	17,547	$	-	$	6,882	$	23,923	$	16,759	$	23,445	$	82,194
Total Transmission		LBTRT			$	1,097,982	$	286,952	$	-	$	106,869	$	255,897	$	34,927	$	91,734	$	321,602
Distribution Expenses																				
Commodity	LBTOT	LBDEC	COM04		$	412,575	$	111,188	$	-	$	43,610	$	151,584	$	106,193	$	-	$	-
Distribution Structures & Equipment																				
Demand	LBTOT	LBDSD	DEM04		$	34,082	$	14,743	$	-	$	5,472	$	12,695	$	994	$	178	$	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Payroll Expenses</u>											
Distribution Mains											
Demand	LBTOT	LBDMD	DEM05	$ 2,244,866	$ 971,072	$ -	$ 360,404	$ 836,153	$ 65,486	$ 11,750	$ -
Customer	LBTOT	LBDMC	CUST01	2,050,706	$ 1,625,946	$ 147,524	$ 223,596	$ 51,690	$ 1,797	$ 154	$ -
Total Distribution Mains				4,295,572	$ 2,597,018	$ 147,524	$ 584,000	$ 887,843	$ 67,283	$ 11,904	$ -
Services											
Customer	LBTOT	LBSC	CUST02	$ 970,771	$ 720,856	$ 65,404	$ 129,631	$ 52,884	$ 1,838	$ 158	$ -
Meters											
Customer	LBTOT	LBMC	CUST03	$ 779,736	$ 459,577	$ 47,966	$ 152,776	$ 115,075	$ 4,000	$ 343	$ -
Customer Accounts											
Customer	LBTOT	LBCAC	CUST04	$ 682,163	$ 501,095	$ 45,465	$ 68,909	$ 63,720	$ 2,215	$ 190	$ 569
Customer Service											
Customer	LBTOT	LBCSC	CUST05	$ 2,390	$ 1,895	$ 172	$ 261	$ 60	$ 2	$ 0	$ -
Total		LBTT		$ 8,651,338	$ 4,854,322	$ 306,551	$ 1,149,319	$ 1,696,620	$ 217,495	$ 104,585	$ 322,446

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Depreciation Expenses											
Gas Supply Costs											
Demand	DEPREX	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	DEPREX	DEGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	DEPREX	DESD	DEM02	$ 1,257,665	$ 546,281	$ -	$ 204,135	$ 507,249	$ -	$ -	$ -
Commodity	DEPREX	DESC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		DEST		$ 1,257,665	$ 546,281	$ -	$ 204,135	$ 507,249	$ -	$ -	$ -
Transmission											
Demand	DEPREX	DETD	TDEM	$ 3,799,446	$ 1,103,920	$ -	$ 409,709	$ 950,544	$ 74,445	$ 279,821	$ 981,007
Commodity	DEPREX	DETC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		DETT		$ 3,799,446	$ 1,103,920	$ -	$ 409,709	$ 950,544	$ 74,445	$ 279,821	$ 981,007
Distribution Expenses											
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	DEPREX	DEDSD	DEM04	$ 205,818	$ 89,032	$ -	$ 33,043	$ 76,662	$ 6,004	$ 1,077	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Depreciation Expenses (Continued)											
Distribution Mains											
Demand	DEPREX	DEDMD	DEM05	$ 2,795,746	$ 1,209,369	$ -	$ 448,846	$ 1,041,342	$ 81,556	$ 14,634	$ -
Customer	DEPREX	DEDMC	CUST01	2,553,940	$ 2,024,946	$ 183,726	$ 278,465	$ 64,374	$ 2,237	$ 192	$ -
Total Distribution Mains				5,349,686	$ 3,234,315	$ 183,726	$ 727,311	$ 1,105,716	$ 83,793	$ 14,826	$ -
Services											
Customer	DEPREX	DESC	CUST02	$ 1,337,702	$ 993,324	$ 90,125	$ 178,629	$ 72,873	$ 2,533	$ 217	$ -
Meters											
Customer	DEPREX	DEMC	CUST03	$ 1,221,468	$ 719,934	$ 75,139	$ 239,326	$ 180,267	$ 6,265	$ 537	$ -
Customer Accounts											
Customer	DEPREX	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service											
Customer	DEPREX	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 13,171,785	$ 6,686,805	$ 348,990	$ 1,792,154	$ 2,893,311	$ 173,041	$ 296,478	$ 981,007

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Other Taxes											
Gas Supply Costs											
Demand	OTT	OTTGSD	DEM01	$ 109	$ 31	$ 4	$ 11	$ 26	$ 2	$ 8	$ 27
Commodity	OTT	OTTGSC	COM01	109	$ 11	$ 2	$ 4	$ 15	$ 11	$ 15	$ 52
Total Procurement Expenses		OTTGST		$ 219	$ 42	$ 6	$ 16	$ 41	$ 13	$ 23	$ 79
Storage											
Demand	OTT	OTTSD	DEM02	$ 145,866	$ 63,358	$ -	$ 23,676	$ 58,831	$ -	$ -	$ -
Commodity	OTT	OTTSC	COM02	65,128	$ 27,665	$ -	$ 9,655	$ 27,807	$ -	$ -	$ -
Total Storage		OTTST		$ 210,994	$ 91,024	$ -	$ 33,331	$ 86,639	$ -	$ -	$ -
Transmission											
Demand	OTT	OTTTD	TDEM	$ 500,493	$ 145,417	$ -	$ 53,970	$ 125,213	$ 9,806	$ 36,860	$ 129,226
Commodity	OTT	OTTTC	COM03	49,171	$ 5,053	$ -	$ 1,982	$ 6,889	$ 4,826	$ 6,752	$ 23,669
Total Transmission		OTTTT		$ 549,663	$ 150,470	$ -	$ 55,952	$ 132,102	$ 14,633	$ 43,612	$ 152,895
Distribution Expenses											
Commodity	OTT	OTTDEC	COM04	$ 118,808	$ 32,019	$ -	$ 12,558	$ 43,651	$ 30,580	$ -	$ -
Distribution Structures & Equipment											
Demand	OTT	OTTDSD	DEM04	$ 22,541	$ 9,751	$ -	$ 3,619	$ 8,396	$ 658	$ 118	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Other Taxes (Continued)											
Distribution Mains											
Demand	OTT	OTTDMD	DEM05	$ 830,659	$ 359,322	$ -	$ 133,359	$ 309,399	$ 24,232	$ 4,348	$ -
Customer	OTT	OTTDMC	CUST01	758,815	$ 601,643	$ 54,588	$ 82,736	$ 19,127	$ 665	$ 57	$ -
Total Distribution Mains				1,589,474	$ 960,965	$ 54,588	$ 216,095	$ 328,525	$ 24,896	$ 4,405	$ -
Services											
Customer	OTT	OTTSC	CUST02	$ 360,328	$ 267,565	$ 24,277	$ 48,116	$ 19,629	$ 682	$ 58	$ -
Meters											
Customer	OTT	OTTMC	CUST03	$ 295,624	$ 174,241	$ 18,185	$ 57,922	$ 43,629	$ 1,516	$ 130	$ -
Customer Accounts											
Customer	OTT	OTTCAC	CUST04	$ 196,441	$ 144,299	$ 13,092	$ 19,844	$ 18,349	$ 638	$ 55	$ 164
Customer Service											
Customer	OTT	OTTCSC	CUST05	$ 688	$ 546	$ 50	$ 75	$ 17	$ 1	$ 0	$ -
Total		OTTT		$ 3,344,780	$ 1,830,920	$ 110,197	$ 447,528	$ 680,979	$ 73,616	$ 48,400	$ 153,138

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense											
Gas Supply Costs											
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	INT	INTSD	DEM02	$ 463,661	$ 201,397	$ -	$ 75,258	$ 187,007	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		INTST		$ 463,661	$ 201,397	$ -	$ 75,258	$ 187,007	$ -	$ -	$ -
Transmission											
Demand	INT	INTTD	TDEM	$ 1,051,875	$ 305,620	$ -	$ 113,428	$ 263,158	$ 20,610	$ 77,468	$ 271,591
Commodity	INT	INTTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		INTTT		$ 1,051,875	$ 305,620	$ -	$ 113,428	$ 263,158	$ 20,610	$ 77,468	$ 271,591
Distribution Expenses											
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	INT	INTDSD	DEM04	$ 57,336	$ 24,802	$ -	$ 9,205	$ 21,356	$ 1,673	$ 300	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense (Continued)											
Distribution Mains											
Demand	INT	INTDMD	DEM05	$ 829,909	$ 358,998	$ -	$ 133,239	$ 309,119	$ 24,210	$ 4,344	$ -
Customer	INT	INTDMC	CUST01	758,130	$ 601,099	$ 54,538	$ 82,662	$ 19,109	$ 664	$ 57	$ -
Total Distribution Mains				1,588,039	$ 960,097	$ 54,538	$ 215,900	$ 328,229	$ 24,874	$ 4,401	$ -
Services											
Customer	INT	INTSC	CUST02	$ 363,921	$ 270,233	$ 24,519	$ 48,596	$ 19,825	$ 689	$ 59	$ -
Meters											
Customer	INT	INTMC	CUST03	$ 320,255	$ 188,758	$ 19,701	$ 62,748	$ 47,264	$ 1,643	$ 141	$ -
Customer Accounts											
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service											
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 3,845,087	$ 1,950,907	$ 98,758	$ 525,136	$ 866,838	$ 49,488	$ 82,369	$ 271,591

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period											
Operating Revenues											
Sales and Transportation		REVUC	R01	40,172,022	18,051,310	1,571,898	5,655,901	9,636,983	2,020,388	452,988	2,782,555
PRP Revenue				$ 671,026	383,533		97,234	165,740	24,519		
Miscellaneous Service Revenues		RCTREV	REVUC	35,149	$ 15,794	$ 1,375	$ 4,949	$ 8,432	$ 1,768	$ 396	$ 2,435
Forfeited Discounts		BDCH	REVUC	19,774	$ 8,885	$ 774	$ 2,784	$ 4,744	$ 995	$ 223	$ 1,370
Total Operating Revenues -- Per Books		TOR		$ 40,897,971	$ 18,459,523	$ 1,574,047	$ 5,760,867	$ 9,815,899	$ 2,047,669	$ 453,607	$ 2,786,359
Pro-Forma Adjustments to Revenues											
Temperature normalization		REVADJ1		$ 234,725	$ 168,281	$ 23,451	$ 42,993	$ -	$ -	$ -	$ -
Total Revenue Adjustments				$ 234,725	$ 168,281	$ 23,451	$ 42,993	$ -	$ -	$ -	$ -
Total Adjusted Revenue				$ 41,132,696	$ 18,627,804	$ 1,597,497	$ 5,803,861	$ 9,815,899	$ 2,047,669	$ 453,607	$ 2,786,359
Expenses											
Operation and Maintenance Expenses				$ 20,082,027	$ 11,442,651	$ 405,756	$ 2,717,294	$ 4,002,955	$ 433,561	$ 260,133	$ 819,678
Depreciation and Amortization Expenses				$ 13,171,785	6,686,805	348,990	1,792,154	2,893,311	173,041	296,478	981,007
Other Taxes				$ 3,344,780	1,830,920	110,197	447,528	680,979	73,616	48,400	153,138
Total Operating Expenses		TOE		$ 36,598,592	$ 19,960,376	$ 864,943	$ 4,956,976	$ 7,577,245	$ 680,217	$ 605,011	$ 1,953,823

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period (Cont.)											
Pro-Forma Adjustments to Expenses											
Rate Case Expenses		EXADJ6	OMTT	54,300	$ 30,940	$ 1,097	$ 7,347	$ 10,824	$ 1,172	$ 703	$ 2,216
		EXADJ10	INTT	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expense Adjustments		ADJTOT		$ 54,300	$ 30,940	$ 1,097	$ 7,347	$ 10,824	$ 1,172	$ 703	$ 2,216
Net Income Before Income Taxes				$ 4,479,805	$ (1,363,512)	$ 731,457	$ 839,537	$ 2,227,830	$ 1,366,279	$ (152,108)	$ 830,320
Income Taxes			TAXINC	$ (594,290)	$ -	$ (89,876)	$ (44,661)	$ (193,331)	$ (187,053)	$ -	$ (79,368)
Net Operating Income (Adjusted)		TOM		$ 5,074,095	$ (1,363,512)	$ 821,333	$ 884,199	$ 2,421,162	$ 1,553,332	$ (152,108)	$ 909,689
			20,136,327								
Net Cost Rate Base				$ 180,570,375	$ 93,029,982	$ 4,729,957	$ 25,021,195	$ 41,351,756	$ 2,218,848	$ 3,337,515	$ 10,881,122
Rate of Return -- Actual				2.81%	-1.47%	17.36%	3.53%	5.86%	70.01%	-4.56%	8.36%

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
<u>Net Operating Income -- Adjusted For Increase</u>											
Revenue Per Books Before Increase				$ 41,132,696	$ 18,627,804	$ 1,597,497	$ 5,803,861	$ 9,815,899	$ 2,047,669	$ 453,607	$ 2,786,359
Proposed Increase				$ 10,880,811	5,987,407	79,767	1,584,673	2,679,081	101,019	148,863	300,000
Expected Increase to PRP Revenue				$ 1,370,892	$ 665,877		219,113	391,562	94,340		
Increase To Misc Revenue			REVUC	$ 28,862	$ 12,969	$ 1,129	$ 4,064	$ 6,924	$ 1,452	$ 325	$ 1,999
Total Increase				$ 12,280,565	$ 6,666,253	$ 80,897	$ 1,807,850	$ 3,077,567	$ 196,811	$ 149,188	$ 301,999
Total Revenue After Increase				$ 53,413,261	$ 25,294,057	$ 1,678,394	$ 7,611,710	$ 12,893,466	$ 2,244,480	$ 602,795	$ 3,088,359
O & M Expenses				$ 36,652,892	$ 19,991,316	$ 866,040	$ 4,964,323	$ 7,588,069	$ 681,390	$ 605,715	$ 1,956,039
Net Income Before Income Taxes		CLSINC		$ 16,760,370	$ 5,302,742	$ 812,354	$ 2,647,387	$ 5,305,397	$ 1,563,090	$ (2,919)	$ 1,132,319
Income Taxes			CLSINC	2,481,059	$ 784,972	$ 120,254	$ 391,896	$ 785,365	$ 231,386	$ (432)	$ 167,619
Net Operating Income Adjusted for Increase				14,279,311	4,517,770	692,100	2,255,491	4,520,033	1,331,704	(2,487)	964,701
Net Cost Rate Base				$ 180,570,375	$ 93,029,982	$ 4,729,957	$ 25,021,195	$ 41,351,756	$ 2,218,848	$ 3,337,515	$ 10,881,122
Rate of Return -- Proposed				7.91%	4.86%	14.63%	9.01%	10.93%	60.02%	-0.07%	8.87%

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors											
Commodity											
Procurement Expenses		COM01		17,087,725	1,731,475	239,077	679,114	2,360,539	1,653,683	2,313,453	8,110,384
					0.101329	0.013991	0.039743	0.138142			
Storage (Dec thru March)		COM02		2,901,000	1,232,304	-	430,072	1,238,624	-	-	-
Transmission		COM03		16,848,648	1,731,475	-	679,114	2,360,539	1,653,683	2,313,453	8,110,384
Distribution		COM04		6,424,811	1,731,475	-	679,114	2,360,539	1,653,683	-	-
				-	-	-	-	-	-	-	-
Demand									4,530.64		
Procurement Expenses		DEM01		89,560	25,004	3,502	9,280	21,530	1,686	6,338	22,220
Storage		DEM02		1.0000	0.4344	-	0.1623	0.4033	-	-	-
					0.4344	-	0.1623	0.4033			
Transmission		DEM03		86,058	25,004	-	9,280	21,530	1,686	6,338	22,220
Distribution Structures (Plant)		DEM04		57,803	25,004	-	9,280	21,530	1,686	303	-
Distribution Structures (O&M)											
Dist Structures Demand Allocator		DEMSTOM		57,803	25,004	-	9,280	21,530	1,686	303	-
Dist Structures O&M				123,944							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Dist Structures O&M			DEMSTOM	123,944	$ 53,615	$ -	$ 19,899	$ 46,166	$ 3,616	$ 649	$ -
Total Allocation of Dist Structures O&M				123,944	53,615	-	19,899	46,166	3,616	649	-
Dist Structures Allocator		DEM04OM		1.0000	0.43257	-	0.16055	0.37247	0.02917	0.00523	-
Distribution Mains		DEM05		57,803	25,004	-	9,280	21,530	1,686	303	-
Distribution Mains (O&M)											
Dist Mains Demand Allocator		DEMMNOM		57,803	25,004	-	9,280	21,530	1,686	303	-
Dist Mains O&M				4,583,532							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Dist Mains O&M			DEMMNOM	4,583,532	$ 1,982,719	$ -	$ 735,868	$ 1,707,245	$ 133,708	$ 23,992	$ -
Total Allocation of Dist Mains O&M				4,583,532	1,982,719	-	735,868	1,707,245	133,708	23,992	-
Dist Mains Allocator		DEM05OM		1.0000	0.43257	-	0.16055	0.37247	0.02917	0.00523	-
Customer											
Distribution Mains (Average Customers)		CUST01		39,951	31,676	2,874	4,356	1,007	35	3	-
Distribution Mains (O&M)											
Dist Mains Customer Allocator		CUSTMNOM		37,077	31,676	-	4,356	1,007	35	3	-
Dist Mains O&M				4,187,100							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Dist Mains O&M			CUSTMNOM	4,187,099.57	$ 3,577,166	$ -	$ 491,922	$ 113,720	$ 3,953	$ 339	$ -
Total Allocation of Dist Mains O&M				4,187,099.57	3,577,166	-	491,922	113,720	3,953	339	-
Dist Mains Allocator		CUST01OM		1.0000	0.85433	-	0.11749	0.02716	0.00094	0.00008	-
Services		CUST02		45,132,829	33,513,842	3,040,749	6,026,787	2,458,671	85,455	7,325	-
Services (O&M)											
Dist Services Allocator		CUSTSEROM		45,132,829	33,513,842	3,040,749	6,026,787	2,458,671	85,455	7,325	-
Dist Services O&M				1,958,526							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Dist Services O&M			CUSTSEROM	1,958,526	$ 1,454,323	$ 131,952	$ 261,531	$ 106,693	$ 3,708	$ 318	$ -
Total Allocation of Dist Services O&M				1,958,526	1,454,323	131,952	261,531	106,693	3,708	318	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Dist Services Allocator		CUST02OM		1.0000	0.74256	0.06737	0.13353	0.05448	0.00189	0.00016	-
Meters Plant Allocator		CUST03		37,576,930	22,147,859	2,311,555	7,362,555	5,545,690	192,750	16,521	-
Meters (O&M)											
Dist Meter Allocator		CUSTMTROM		37,576,930	22,147,859	2,311,555	7,362,555	5,545,690	192,750	16,521	-
Dist Meter O&M				2,149,416							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Dist Meter O&M			CUSTMTROM	2,149,416	$ 1,266,867	$ 132,222	$ 421,141	$ 317,216	$ 11,025	$ 945	$ -
Total Allocation of Dist Meter O&M				2,149,416	1,266,867	132,222	421,141	317,216	11,025	945	-
Dist Meter Allocator		CUST03OM		1.0000	0.58940	0.06152	0.19593	0.14758	0.00513	0.00044	-
Customer Count (Average)				39,951	31,676	2,874	4,356	1,007	35	3	-
Customer Accounts		CUST04		43,122	31,676	2,874	4,356	4,028	140	12	36
Customer Accounts (O&M)											
Cust Acc Allocator		CUSTACOM		43,122	31,676	2,874	4,356	4,028	140	12	36
Cust Acc O&M				2,115,669							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Cust Acc O&M			CUSTACOM	2,115,669	$ 1,554,101	$ 141,005	$ 213,716	$ 197,623	$ 6,869	$ 589	$ 1,766
Total Allocation of Cust Acc				2,115,669	1,554,101	141,005	213,716	197,623	6,869	589	1,766
Cust Accounts Allocator		CUST04OM		1.0000	0.73457	0.06665	0.10102	0.09341	0.00325	0.00028	0.00083
Customer Count (Average)				39,951	31,676	2,874	4,356	1,007	35	3	-
Customer Accounts		CUST04		43,122	31,676	2,874	4,356	4,028	140	12	36
Customer Service		CUST05		39,951	31,676	2,874	4,356	1,007	35	3	-
Customer Service (O&M)											
Cust Serv Allocator		CUSTSER		39,951	31,676	2,874	4,356	1,007	35	3	-
Cust Serv O&M				7,513							
Specific Assignment				-	-	-	-	-	-	-	-
Residual Cust Serv O&M			CUSTSER	7,513	$ 5,957	$ 540	$ 819	$ 189	$ 7	$ 1	$ -
Total Allocation of Cust Serv				7,513	5,957	540	819	189	7	1	-
Cust Service Allocator		CUST05OM		1.0000	0.79287	0.07194	0.10903	0.02521	0.00088	0.00008	-
					5,957	540	819	189	7	1	
Forfeited Discounts		REVFD		1	1	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended June 30, 2026

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Residential Farm Tap	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors Continued											
Taxable Income Actual											
Net Income Before Income Tax		NIBIT		$ 4,479,805	$ (1,363,512)	$ 731,457	$ 839,537	$ 2,227,830	$ 1,366,279	$ (152,108)	$ 830,320
Interest Expense		INT	PLT	$ 3,845,087	$ 1,950,907	$ 98,758	$ 525,136	$ 866,838	$ 49,488	$ 82,369	$ 271,591
Interest Adjustment			PLT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable Income		TXINC		$ 634,718	$ (3,314,418)	$ 632,700	$ 314,402	$ 1,360,992	$ 1,316,791	$ (234,477)	$ 558,729
		TAXINC		$ 4,183,613	-	632,700	314,402	1,360,992	1,316,791	-	558,729
Meter Allocation											
Number of Customers				39,951	31,676	3,306	4,356	1,007	35	3	-
Average Cost Per Service					699.20	699.20	1,690.21	5,507.14	5,507.14	5,507.14	
Meter Cost				37,576,930	22,147,859	2,311,555	7,362,555	5,545,690	192,750	16,521	-
Service Line Allocation											
Number of Customers				39,951	31,676	2,874	4,356	1,007	35	3	-
Average Cost Per Service					1,058.02	1,058.02	1,383.56	2,441.58	2,441.58	2,441.58	0
Service Cost				45,132,829	33,513,842	3,040,749	6,026,787	2,458,671	85,455	7,325	-
Collection Fees		COLL		1.00000	1.00000	-	-	-			
Reconnect Revenue		RCNCT		0.00000	0	0	0	0			
Bad Check Fees		BDCK		-	0.00000	-	-	-			
Customer Deposits		CSTDEP		-	0.00000	0.00000	0.00000	0.00000	0.00000		
Transmission Allocator											
Transmission Demand Allocator				86,058	25,004	-	9,280	21,530	1,686	6,338	22,220
Transmission Plant				$ 102,731,690							
Specific Assignment				$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Residual Transmission Plant			DEM03	102,731,690	$ 29,848,445	$ -	$ 11,077,970	$ 25,701,369	$ 2,012,884	$ 7,565,967	$ 26,525,054
Total Allocation of Transmission Plant				$ 102,731,690	$ 29,848,445.16	$ -	$ 11,077,970.37	$ 25,701,368.75	$ 2,012,883.93	$ 7,565,967.26	$ 26,525,054.05
Transmission Allocator		TDEM		1.000000	0.290547593	0	0.107834013	0.250179559	0.019593603	0.073647842	0.258197389
Transmission Demand Allocator				86,058	25,004	-	9,280	21,530	1,686	6,338	22,220
Transmission Plant				$ 2,543,455							
Specific Assignment				$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Residual Transmission Plant			DEM03	2,543,455	$ 738,995	$ -	$ 274,271	$ 636,320	$ 49,835	$ 187,320	$ 656,713
Total Allocation of Transmission Plant				$ 2,543,455	$ 738,994.68	$ -	$ 274,270.94	$ 636,320.41	$ 49,835.44	$ 187,319.96	$ 656,713.40
Transmission Allocator		TDEMOM		1.000000	0.290547593	0	0.107834013	0.250179559	0.019593603	0.073647842	0.258197389

Exhibit LF-3

Storage Allocation Model

DELTA NATURAL GAS COMPANY
Summary of Allocation of Underground Storage Investment

Calculation of Maximum Class Demands
On February 10th Design Day Assuming 73 Degree Days
For Determination of Demand Allocation Factors

	Total	Residential	Small Non Residential GS	Large Non Residential GS
Non-Temp Sensitive Load (per Day)	5,590	841	447	4,302
Temp Sensitive Load (per Degree Day)	688	331	121	236
Calculated Daily Requirements at -8 Degrees	55,814	25,004	9,280	21,530
Percentage of Total		44.80%	16.63%	38.57%

Allocation of Underground Storage

	Storage Withdrawals	Residential	Small Non Residential GS	Large Non Residential GS
Total Allocated Withdrawals Thru February 9th				
December	459,862	186,026	70,662	203,174
January	497,654	205,589	77,706	214,359
Feb. 1-9	154,733	63,368	24,000	67,365
Total	1,112,249	454,983	172,368	484,898
Balance of Working Gas Allocated on the Basis of -8 Degree Feb. 10 Design Day	2,064,738	924,978	343,297	796,463
Total Working Gas	3,176,987	1,379,961	515,665	1,281,361
Total Allocation Factor For Underground Storage	1.000000	0.434361	0.162313	0.403326

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(November)

	Residential	Small Non Residential GS	Large Non Residential GS		Total
Non-Temperature Sensitive Load (per Day)	841	447	4,302	0	5,590
Temperature Sensitive Load (per Degree Day)	331	121	236	0	688

		Requirements						Storage Allocation		
Date	**Heating Degree Days**	**Residential**	**Small Non Residential GS**	**Large Non Residential GS**		**Total**	**Storage Withdrawals (Injections)**	**Residential**	**Small Non Residential GS**	**Large Non Residential GS**
1	14	5,475	2,141	7,606	0	15,222	0	0	0	0
2	14	5,475	2,141	7,606	0	15,222	0	0	0	0
3	14	5,475	2,141	7,606	0	15,222	0	0	0	0
4	15	5,806	2,262	7,842	0	15,910	0	0	0	0
5	15	5,806	2,262	7,842	0	15,910	0	0	0	0
6	16	6,137	2,383	8,078	0	16,598	0	0	0	0
7	16	6,137	2,383	8,078	0	16,598	0	0	0	0
8	16	6,137	2,383	8,078	0	16,598	0	0	0	0
9	16	6,137	2,383	8,078	0	16,598	0	0	0	0
10	17	6,468	2,504	8,314	0	17,286	0	0	0	0
11	17	6,468	2,504	8,314	0	17,286	0	0	0	0
12	18	6,799	2,625	8,550	0	17,974	0	0	0	0
13	18	6,799	2,625	8,550	0	17,974	0	0	0	0
14	18	6,799	2,625	8,550	0	17,974	0	0	0	0
15	19	7,130	2,746	8,786	0	18,662	0	0	0	0
16	19	7,130	2,746	8,786	0	18,662	0	0	0	0
17	20	7,461	2,867	9,022	0	19,350	0	0	0	0
18	20	7,461	2,867	9,022	0	19,350	0	0	0	0
19	21	7,792	2,988	9,258	0	20,038	0	0	0	0
20	21	7,792	2,988	9,258	0	20,038	0	0	0	0
21	21	7,792	2,988	9,258	0	20,038	0	0	0	0
22	21	7,792	2,988	9,258	0	20,038	0	0	0	0
23	22	8,123	3,109	9,494	0	20,726	0	0	0	0
24	22	8,123	3,109	9,494	0	20,726	0	0	0	0
25	23	8,454	3,230	9,730	0	21,414	0	0	0	0
26	23	8,454	3,230	9,730	0	21,414	0	0	0	0
27	23	8,454	3,230	9,730	0	21,414	0	0	0	0
28	23	8,454	3,230	9,730	0	21,414	0	0	0	0
29	24	8,785	3,351	9,966	0	22,102	0	0	0	0
30	24	8,785	3,351	9,966	0	22,102	0	0	0	0
Total	570	213,900	82,380	263,580	0	559,860	0	0	0	0

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(December)

	Residential	Small Non Residential GS	Large Non Residential GS		Total
Non-Temperature Sensitive Load (per Day)	841	447	4,302	0	5,590
Temperature Sensitive Load (per Degree Day)	331	121	236	0	688

		Requirements						Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Residential GS	Large Non Residential GS		Total	Storage Withdrawals (Injections)	Residential	Small Non Residential GS	Large Non Residential GS
1	24	8,785	3,351	9,966	0	22,102	13,649	5,425	2,069	6,154
2	24	8,785	3,351	9,966	0	22,102	12,537	4,983	1,901	5,653
3	24	8,785	3,351	9,966	0	22,102	12,556	4,991	1,904	5,662
4	24	8,785	3,351	9,966	0	22,102	13,466	5,352	2,042	6,072
5	24	8,785	3,351	9,966	0	22,102	13,859	5,509	2,101	6,249
6	24	8,785	3,351	9,966	0	22,102	13,994	5,562	2,122	6,310
7	24	8,785	3,351	9,966	0	22,102	14,387	5,719	2,181	6,487
8	24	8,785	3,351	9,966	0	22,102	14,388	5,719	2,181	6,488
9	24	8,785	3,351	9,966	0	22,102	14,390	5,720	2,182	6,489
10	24	8,785	3,351	9,966	0	22,102	14,391	5,720	2,182	6,489
11	24	8,785	3,351	9,966	0	22,102	13,950	5,545	2,115	6,290
12	25	9,116	3,472	10,202	0	22,790	14,342	5,737	2,185	6,420
13	25	9,116	3,472	10,202	0	22,790	14,343	5,737	2,185	6,421
14	26	9,447	3,593	10,438	0	23,478	14,735	5,929	2,255	6,551
15	26	9,447	3,593	10,438	0	23,478	14,735	5,929	2,255	6,551
16	26	9,447	3,593	10,438	0	23,478	14,753	5,936	2,258	6,559
17	27	9,778	3,714	10,674	0	24,166	14,753	5,969	2,267	6,516
18	27	9,778	3,714	10,674	0	24,166	15,144	6,127	2,327	6,689
19	27	9,778	3,714	10,674	0	24,166	15,144	6,127	2,327	6,689
20	27	9,778	3,714	10,674	0	24,166	15,535	6,286	2,388	6,862
21	28	10,109	3,835	10,910	0	24,854	15,483	6,297	2,389	6,796
22	29	10,440	3,956	11,146	0	25,542	15,483	6,328	2,398	6,756
23	29	10,440	3,956	11,146	0	25,542	15,874	6,488	2,459	6,927
24	30	10,771	4,077	11,382	0	26,230	15,874	6,519	2,467	6,888
25	31	11,102	4,198	11,618	0	26,918	15,874	6,547	2,476	6,851
26	31	11,102	4,198	11,618	0	26,918	16,007	6,602	2,496	6,909
27	32	11,433	4,319	11,854	0	27,606	16,007	6,629	2,504	6,873
28	32	11,433	4,319	11,854	0	27,606	16,007	6,629	2,504	6,873
29	32	11,433	4,319	11,854	0	27,606	16,069	6,655	2,514	6,900
30	32	11,433	4,319	11,854	0	27,606	16,069	6,655	2,514	6,900
31	32	11,433	4,319	11,854	0	27,606	16,069	6,655	2,514	6,900
Total	838	303,449	115,255	331,130	0	749,834	459,867	186,026	70,662	203,174

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(January)

	Residential	Small Non Residential GS	Large Non Residential GS		Total
Non-Temperature Sensitive Load (per Day)	841	447	4,302	0	5,590
Temperature Sensitive Load (per Degree Day)	331	121	236	0	688

		Requirements						Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Residential GS	Large Non Residential GS		Total	Storage Withdrawals (Injections)	Residential	Small Non Residential GS	Large Non Residential GS
1	33	11,764	4,440	12,090	0	28,294	15,613	6,492	2,450	6,672
2	33	11,764	4,440	12,090	0	28,294	15,586	6,480	2,446	6,660
3	33	11,764	4,440	12,090	0	28,294	15,602	6,487	2,448	6,667
4	33	11,764	4,440	12,090	0	28,294	15,596	6,485	2,447	6,664
5	33	11,764	4,440	12,090	0	28,294	15,602	6,487	2,448	6,667
6	33	11,764	4,440	12,090	0	28,294	15,728	6,539	2,468	6,721
7	33	11,764	4,440	12,090	0	28,294	15,727	6,539	2,468	6,720
8	33	11,764	4,440	12,090	0	28,294	15,734	6,542	2,469	6,723
9	32	11,433	4,319	11,854	0	27,606	15,731	6,515	2,461	6,755
10	32	11,433	4,319	11,854	0	27,606	15,722	6,511	2,460	6,751
11	32	11,433	4,319	11,854	0	27,606	15,745	6,521	2,463	6,761
12	32	11,433	4,319	11,854	0	27,606	15,720	6,511	2,459	6,750
13	32	11,433	4,319	11,854	0	27,606	15,712	6,507	2,458	6,747
14	32	11,433	4,319	11,854	0	27,606	15,681	6,494	2,453	6,734
15	32	11,433	4,319	11,854	0	27,606	15,720	6,511	2,459	6,750
16	31	11,102	4,198	11,618	0	26,918	16,115	6,647	2,513	6,956
17	31	11,102	4,198	11,618	0	26,918	16,107	6,643	2,512	6,952
18	31	11,102	4,198	11,618	0	26,918	16,109	6,644	2,512	6,953
19	31	11,102	4,198	11,618	0	26,918	16,133	6,654	2,516	6,963
20	31	11,102	4,198	11,618	0	26,918	16,112	6,645	2,513	6,954
21	31	11,102	4,198	11,618	0	26,918	15,992	6,596	2,494	6,902
22	31	11,102	4,198	11,618	0	26,918	15,999	6,599	2,495	6,905
23	30	10,771	4,077	11,382	0	26,230	16,000	6,570	2,487	6,943
24	30	10,771	4,077	11,382	0	26,230	16,390	6,730	2,547	7,112
25	30	10,771	4,077	11,382	0	26,230	16,390	6,730	2,547	7,112
26	30	10,771	4,077	11,382	0	26,230	16,523	6,785	2,568	7,170
27	30	10,771	4,077	11,382	0	26,230	16,912	6,945	2,629	7,339
28	30	10,771	4,077	11,382	0	26,230	16,912	6,945	2,629	7,339
29	30	10,771	4,077	11,382	0	26,230	16,912	6,945	2,629	7,339
30	30	10,771	4,077	11,382	0	26,230	16,912	6,945	2,629	7,339
31	30	10,771	4,077	11,382	0	26,230	16,912	6,945	2,629	7,339
Total	975	348,796	131,832	363,462	0	844,090	497,654	205,589	77,706	214,359

DELTA NATURAL GAS COMPANY
Allocation of Underground Storage Investment

(February)

	Residential	Small Non Residential GS	Large Non Residential GS		Total
Non-Temperature Sensitive Load (per Day)	841	447	4,302	0	5,590
Temperature Sensitive Load (per Degree Day)	331	121	236	0	688

		Requirements						Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Residential GS	Large Non Residential GS		Total	Storage Withdrawals (Injections)	Residential	Small Non Residential GS	Large Non Residential GS
1	30	10,771	4,077	11,382	0	26,230	16,348	6,713	2,541	7,094
2	30	10,771	4,077	11,382	0	26,230	16,321	6,702	2,537	7,082
3	30	10,771	4,077	11,382	0	26,230	15,952	6,550	2,479	6,922
4	30	10,771	4,077	11,382	0	26,230	15,560	6,389	2,418	6,752
5	29	10,440	3,956	11,146	0	25,542	15,180	6,205	2,351	6,624
6	29	10,440	3,956	11,146	0	25,542	15,306	6,256	2,371	6,679
7	29	10,440	3,956	11,146	0	25,542	15,305	6,256	2,370	6,679
8	29	10,440	3,956	11,146	0	25,542	14,926	6,101	2,312	6,513
9	29	10,440	3,956	11,146	0	25,542	14,923	6,100	2,311	6,512
10	29	10,440	3,956	11,146	0	25,542	14,914	6,096	2,310	6,508
Total	294	105,724	40,044	112,404	0	258,172	154,734	63,368	24,000	67,365

Exhibit LF-4

Zero Intercept Analysis
Distribution Mains

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2023

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per Foot)	2.8137880	0.8321061
Zero Intercept ($ per Foot)	6.3239973	2.1883383
R-Square	0.9713700	

Plant Classification

Total Number of Units	8,134,740
Zero Intercept	6.3239973
Zero Intercept Cost	$ 51,444,076
Total Cost of Sample	$ 107,763,020
Percentage of Total	0.477381537
Percentage Classified as Customer-Related	47.74%
Percentage Classified as Demand-Related	52.26%

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2023

Description	Pipe Size		Cost of Plant	Quantity (Feet)	Unit Cost ($ per Foot)
Distribution Main Pipe, Under 2" Plastic	1.500	$	7,400,249	464,473	15.93257
Distribution Main Pipe, 2" Plastic	2.000	$	64,673,238	5,424,121	11.92327
Distribution Main Pipe, 3" Plastic	3.000	$	253,540	57,549	4.40564
Distribution Main Pipe, 4" Plastic	4.000	$	32,143,425	1,779,790	18.06023
Distribution Main Pipe, 6" Plastic	6.000	$	2,125,592	87,055	24.41666
Distribution Main Pipe, Under 2" Steel	1.500	$	233,227	54,814	4.25488
Distribution Main Pipe, 2" Steel	2.000	$	799,469	226,777	3.52535
Distribution Main Pipe, 3" Steel	3.000	$	134,279	40,161	3.34353
Total		$	107,763,019.62	8,134,740	

Exhibit LF-5

Cost Component for Residential Service

Delta Natural Gas Company

Unit Cost of Service Based on the Cost of Service Study
12 Months Ended June 2026

Residential Rate

	Description	Reference	Customer Costs: Customer-Related Mains Costs	Customer Costs: Customer-Related Direct Costs	Customer Costs: Total Customer-Related Costs	Demand- and Commodity-Related Costs	Total Costs
(1)	Rate Base	Exhibit 2 Pages 5 & 7	$ 28,650,081	$ 22,110,025	$ 50,760,106	$ 42,269,876	$93,029,982
(2)	Rate of Return	Proposed Overall ROR	7.91%	7.91%	7.91%	7.91%	7.91%
(3)	Return	(1) x (2)	$ 2,265,618	$ 1,748,437	$ 4,014,054	$ 3,342,656	$ 7,356,711
(4)	Interest Expenses	Exhibit 2 Pages 25 & 27	$ 601,099	$ 458,992	$ 1,060,091	$ 890,816	$ 1,950,907
(5)	Net Income	(3) - (4)	$ 1,664,518	$ 1,289,445	$ 2,953,963	$ 2,451,840	$ 5,405,804
(6)	Income Taxes		$ 241,703	$ 187,239	$ 428,942	$ 356,029	$ 784,972
(7)	Operation and Maintenance Expenses	Exhibit 2 Pages 9 & 11	$ 3,577,166	$ 4,281,248	$ 7,858,413	$ 3,584,237	$11,442,651
(8)	Depreciation Expenses	Exhibit 2 Pages 17 & 19	2,024,946	1,713,258	3,738,204	2,948,601	6,686,805
(9)	Other Taxes	Exhibit 2 Pages 21 & 23	601,643	586,651	1,188,293	642,627	1,830,920
(10)	Expense Adjustments	Exhibit 2 Page 29	9,672	11,576	21,248	9,691	30,940
(11)	Total Cost of Service	(3)+(6)+(7)+(8)+(9)+(10)	$ 8,720,747	$ 8,528,409	$ 17,249,156	$ 10,883,842	$28,132,998
(12)	Less: Misc Revenue	Exhibit 2 Page 29	4,896	4,788	9,684	6,110	15,794
(13)	Net Cost of Service	(11) - (12)	$ 8,715,851	$ 8,523,621	$ 17,239,472	$ 10,877,732	$28,117,204
(14)	Billing Units	Exhibit 2 Page 35	31,676	31,676	31,676	1,731,475	
(15)	Unit Costs	(13) / (14)	$22.93/Cust/Mo	$22.42/Cust/Mo	$45.35/Cust/Mo	$6.2824/Mcf	

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF GAS RATES	**)))**	**CASE NO. 2024-00346**

TESTIMONY OF
JONATHAN MORPHEW
DIRECTOR OF OPERATIONS
DELTA NATURAL GAS COMPANY, INC.

Filed: November 25, 2024

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Background

Q. Please state your name and business address.

A. My name is Jonathan Morphew. My business address is 3617 Lexington Road, Winchester, Kentucky 40391.

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

A. I am employed by Delta Natural Gas Company, Inc. ("Delta") as its Director of Operations.

Q. Please briefly describe your professional history with Delta.

A. My career with Delta dates back to 1987, when I began as an Engineering Technician. I was promoted to Lead Engineer in 1989 and Director – Engineering in 1995. In 2003, I was promoted to Manager – Engineering with oversight over the Corrosion and Measurement & Regulation departments. In 2016, I was promoted to SR Manager – Distribution and managed the Engineering, Construction, Corrosion, Measurement & Regulation, and Distribution departments. I was promoted to Delta's Vice President – Operations in 2018 with oversight over Delta's Engineering, Construction, Corrosion, Measurement & Regulation, Distribution, Transmission, and Safety Operations. Effective May 1, 2021, my title changed to Director of Operations. My current responsibilities as Director of Operations include oversight over Delta's Engineering, Construction, Distribution, and Safety Operations.

Q. Please briefly describe your educational background.

A. I attended Morehead State University and received a Bachelor of Science degree in Industrial Technology in 1985. I was employed by Nucor Steel in Grapeland, Texas and Palmer Engineering in Winchester, Kentucky before beginning my career at Delta in 1987.

Q. What is the purpose of your testimony?

A. My testimony provides an overview of Delta's system, operations, and significant capital projects. I am also sponsoring filing requirements that are part of Delta's application.

Gas System and Operations

Q. Please briefly describe Delta's gas system and operations.

A. Delta purchases, sells, stores, and transports natural gas in Bath, Estill, Montgomery, Menifee, Madison, Powell, Garrard, Jackson, Lee, Bourbon, Jessamine, Rowan, Bell, Knox, Whitley, Laurel, Clay, Leslie, Fayette, Fleming, Clark, Robertson, Mason, Pike, Johnson, Floyd, Perry, Letcher, Knott, Martin, Lawrence, and Magoffin Counties, Kentucky. Delta currently serves approximately 40,000 customers in primarily rural areas of Kentucky where there is no large concentration of customers.

Delta owns and operates six district offices, two warehouses, an underground natural gas storage facility with approximately 5 Bcf of capacity and 2 Bcf of working capacity, a natural gas liquids processing plant, and approximately 2,700 miles of transmission, distribution, service and gathering pipeline in 33 counties in central and southeastern Kentucky.

Q. Please describe Delta's commitment to safety.

A. The safety of Delta's employees, customers, and the communities we serve is Delta's highest priority. Delta operates and maintains approximately 151 miles of transmission pipeline as defined by the Department of Transportation, and approximately 1,934 miles of distribution piping. Delta strives for excellent safety performance in all aspects of its operations and pipeline safety is a key component of our efforts.

Q. Please describe how Delta monitors its transmission system.

A. Delta's transmission system is patrolled annually for leaks, at which time Delta simultaneously performs both a leak survey and a general line patrol. The leak survey is performed to ensure that if any leaks exist, they are identified by exact location and classified by severity. The classification process allows Delta to prioritize the most severe leaks, but timely action is taken on all the identified anomalies regardless of classification. The line patrol is performed to identify any other hazards or concerns regarding the pipeline or associated right of way. Examples of these concerns include erosion over the pipeline or an unacceptable public use of the right of way, such as the construction of permanent structures, change of grade, or excavation. If any unacceptable situations exist, location coordinates are provided to the appropriate personnel to visit the site as soon as possible to determine a mitigation process.

Q. Has Delta complied with the Transmission Pipeline Integrity Rule?

A. Yes. In 2003, the Department of Transportation enacted the Transmission Pipeline Integrity Rule in order to establish a higher standard of transmission pipeline safety operations. The Rule resulted in regulations that specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas. High Consequences Areas are areas where an inadvertent release could have the most significant adverse consequences. Delta immediately addressed this requirement and implemented a Transmission Integrity Management Program ("TIMP"). Delta has received outstanding reviews on all Kentucky Public Service Commission inspections of the TIMP program and associated actions. Delta continues to provide the highest level of attention on all safety aspects of its transmission line operations.

Q. Is Delta's process for ensuring the safety of its distribution system similar to the process you described for the transmission system?

A. Yes. Delta performs a leak survey on 33 percent of its entire distribution system annually. Delta also performs a leak survey annually on the portions of the distribution system located within a business district. Thus, over a three-year period, this schedule results in the entire distribution system being leak surveyed in its entirety, as well as all business districts being leak surveyed three times. As with the transmission system, any leaks found during this process are classified immediately and addressed based on the severity of the issue.

Q. Has Delta complied with the Distribution Integrity Rule?

A. Yes. In 2010, the Department of Transportation enacted the Distribution Integrity Rule in order to establish a higher standard of distribution system safety operations. The Rule requires operators like Delta to develop, write, and implement an integrity management program with certain elements. Delta immediately addressed this requirement and implemented a Distribution Integrity Management Program ("DIMP") that complied with the Rule's requirements. Delta has received outstanding reviews on all Kentucky Public Service Commission inspections of the DIMP program and associated actions. Delta continues to provide the highest level of attention on all safety aspects of its distribution systems operations.

Q. Does Delta also comply with all OSHA and operator training requirements?

A. Yes. Delta complies with all OSHA requirements and Operator Qualification ("OQ") training. As evidence of the paramount importance of safety to Delta, I recall only one OSHA violation since I began working at Delta in 1987.

Q. Could you provide examples of safety policies Delta has implemented since its last rate case to further improve safety?

A. Yes. Since 2021, Delta has implemented new safety policies and programs in several areas. For example, during 2022, Delta adopted a near miss program created by our ultimate parent company, Essential. This program utilizes a fully integrated environmental health and safety software program known as “Cority,” which collects and stores all data pertaining to near miss reporting. The near miss reporting allows employees to report safety concerns which in turn notifies the Safety & Training Department to conduct an investigation. When warranted, the Company commences a consultation in order to provide a safe resolution and prevent reoccurrence.

Next, Delta recognizes the “Stop Work” policy, which allows any employee, regardless of title or position, to stop work any time the employee observes any unsafe act or condition.

Delta also investigates all reports of unsafe acts and conditions. Delta follows a Post Incident Analysis (“PIA”) investigation format created by our immediate parent company PNG Companies LLC (“PNG”), which Delta adopted in 2023. This format examines the root cause of all applicable accidents, incidents, and injuries, including motor vehicle accidents. This analysis seeks to prevent future incidents while encouraging creativity of new ideas that can be adopted company-wide among all employees.

In a further effort to prevent future incidents, Delta’s Safety & Training Department has increased its field presence and documentation of all observations. Any on-site safety concerns or issues are addressed immediately and Delta initiates retraining when necessary. During 2023, Delta added an Administrative Coordinator to the Safety & Training Department. This has allowed greater coverage of Delta’s safety and training footprint throughout Delta’s operations. Furthermore, the addition of this position has expedited personal protective and other safety equipment deliveries, increased field presence, created more efficient training programs, and ensured requalification training deadline compliance.

Q. Please describe Delta's compliance with Kentucky's 811 laws.

A. Delta is in full compliance with all aspects of Kentucky's 811 "Call Before You Dig" law, KRS 367.4901. As a member of Kentucky 811, Delta receives notifications from the Kentucky 811 Call Center via our locate ticket management software, Utilisphere. Upon receipt of a location request, a Delta Operator-Qualified Locator will review the ticket to determine if Delta has natural gas facilities in that area and if so, report to the site and perform the location of the underground natural gas facilities. Delta then submits a positive response informing the excavator whether or not there are natural gas facilities within the site, and what action Delta took to locate said natural gas facilities. Delta strives to ensure that all requests for line locations are addressed within the 48-hour window established by the Kentucky Dig Law. Additionally, Delta provides periodic updates of our mapping information to the Kentucky 811 Call Center to ensure they have the most recent information for Delta's system. This information enables the Kentucky 811 Call Center to accurately notify Delta of a locate request by an excavator. Delta continues to abide by the Kentucky 811 law when performing excavation activities on maintenance or installation of new natural gas facilities.

Q. Are the costs of compliance with Kentucky's 811 laws increasing?

A. Delta has observed an increase in the monthly fee that is paid to Kentucky 811 for the number of locate requests it receives. This increase is a result of more locates being called in, which is a positive reflection of more excavators and homeowners being aware of and abiding by the Kentucky 811 law.

Q. Is Delta implementing any additional measures that will improve the safety of Delta's system?

A. Yes. Delta's Safety & Training department strives to provide compliant, informative, and quality training to all Delta employees in order to ensure a knowledgeable workforce. Delta recently implemented "Damage Prevention Refresher Training," which is a program that monitors all pipeline damage Delta incurs. If an at-fault damage occurs (e.g. employee mismark, inadequate marking practices, etc.), then the employee involved will be scheduled for in-person retraining. The training session consists of an in-person comprehensive review of all pertinent damage prevention regulations and company standards. This includes a hands-on demonstration by the employee(s) while being observed by the Safety & Training Specialist. The Safety & Training Specialist then addresses any inadequate locating techniques observed and any other relevant misunderstandings, should there be any.

With damage prevention being a vital priority, Delta's Safety & Training department in conjunction with Delta's Engineering Department, worked extensively during 2023 with Paradigm Alliance, Inc. to reach and inform all residents within close proximity to any Delta pipeline. Delta's Engineering Department provided GIS mapping to ensure accurate coverage of the mailings. This resulted in a total of 83,012 booklets being distributed containing a reply card.

Delta also strives to ensure that all emergency responders and public officials are informed regarding any emergency response. Delta partners with the Paradigm Alliance, Inc. annually to participate in the Kentucky Liaison/Public Awareness meetings. In addition to the annual meetings, Delta continues to distribute an additional Public Liaison booklet to all applicable emergency responders and public officials every two years. A total of 336 booklets were mailed during 2022 and a total of 348 booklets were mailed during 2023. Delta used the Standard Industrial Classification code data to capture addresses of all relevant agencies and individuals.

<u>Unionization</u>

Q. Have there been changes to Delta's workforce since the last rate?

A. Yes. The most significant change to Delta's workforce since the last rate case is that a majority of Delta's workers voted to join the Utility Workers Union of America ("UWUA"), AFL-CIO in August 2022. Prior to August 2022, no Delta employees were members of a collective bargaining organization.

Q. Please describe the impact to Delta resulting from the unionization.

A. After joining the UWUA in August 2022, Delta and UWUA representatives began negotiating a bargaining agreement in February 2023. After six months of negotiations, the parties executed a contract in October 2023 that contains a 3.5-year term. As a result of the contract, revised salary rates went into effect on November 1, 2023. The amount of the increases varied by position. Following the initial salary changes, the contract establishes wage increases of 2.75%, 3% and 3% to become effective each year on May 1 in 2025 through 2027.

Q. Are there other changes related to the unionization?

A. No, not at this time.

Q. Please briefly describe Delta's Pipeline Replacement Program ("PRP").

A. The Commission approved Delta's PRP in Case No. 2010-00116 to accelerate the recovery of the cost of replacing Delta's bare steel and unprotected coated steel pipe, including service lines, curb valves, meter loops, and mandated pipe relocations. With Commission approval, Delta expanded the program several years ago to include certain plastic pipes. Through the PRP, Delta is replacing approximately 16 miles of pipe each year. The PRP has helped reduce the number of leaks in Delta's system. Delta is not proposing operational changes to the PRP in this proceeding.

Q. Are there any other changes to Delta's system that you would like to mention?

A. Not at this time.

<u>Construction Projects</u>

Q. Are you sponsoring filing requirements in this case related to construction budgets?

A. Yes, I am sponsoring the following filing requirements:

807 KAR 5:001 Section 16(7)(b)	Most recent capital construction budget containing at minimum a 3 year forecast of construction expenditures.
807 KAR 5:001 Section 16(7)(f)	Certain information for each major construction project constituting 5% or more of annual construction budget within 3 year forecast.
807 KAR 5:001 Section 16(7)(g)	Certain information for all construction projects constituting less than 5% of annual construction budget within 3 year forecast.

Q. In Case No. 2022-00085, the Commission issued a Certificate of Public Convenience and Necessity (CPCN) for construction of a pipeline to provide a second source of natural gas to Nicholasville and Wilmore in Jessamine County, Kentucky. Please provide an update regarding this project.

A. On July 18, 2024, Delta entered into a contract with Swartz Pipeline, Inc., to construct the first 9.3 miles of the 16.6 mile high pressure distribution pipeline project. This pipeline will provide additional natural gas supply to the Nicholasville natural gas system and will offer enough supply to provide the entire system with natural gas in the event of an emergency. The construction of Phase I of the pipeline continues to progress from the north extremity near the intersection of US 27 and Industry Parkway, in a southerly direction until ultimately reaching an interstate pipeline where it will be connected for an additional supply of natural gas. The contract requires the completion of 3.0 miles of pipeline to be completed by December 31, 2024. Currently there are approximately 2.5 miles completed of Phase I. In early 2025, Delta will contract Phase II of this project consisting of the remaining 7.3 miles. All right of way for Phase I of the project has been acquired. Delta is in the process of acquiring right of way for Phase II of the project and is still in need of six parcels, which are currently being procured through the eminent domain process. Delta plans to complete Phase II of the project by year end 2025.

Q. In Case No. 2022-00295, the Commission issued a CPCN to permit the construction of a natural gas transmission pipeline extension to service unserved portions of Lincoln and Rockcastle counties. Please provide an update regarding this project.

A. On April 14, 2023, Delta entered into a contract with Martin Contracting, Inc., to construct the first Phase of a 19.8 mile high pressure distribution pipeline. This pipeline is being constructed to provide natural gas to the communities of Crab Orchard, Broadhead, Mt Vernon, and Renfro Valley. The pipeline is designed to be constructed in two phases. Phase I is approximately 10.1 miles in length and originates near the Lincoln County Industrial Park, where the pipeline is connected to an interstate pipeline supply. The interstate pipeline will provide natural gas into Delta's line which extends in an easterly direction to the Crab Orchard Community. Delta will be installing distribution main piping in the community of Crab Orchard as the demand for service requires. Phase II of the pipeline is designed to continue from Crab Orchard, in an easterly direction to the Broadhead community, and continuing until reaching the city of Mt Vernon. All right of way acquisition for this project is complete. The construction of this pipeline is progressing well and currently approximately 12.3 miles of the project is completed. Phase I of the project was completed in November of 2024. Phase II of the pipeline is approximately 9.7 miles in length and is planned to be complete by year end 2025. There will be approximately 3.5 miles of distribution line piping to be extended into the Renfro Valley area as the demand for natural gas is needed.

Q. Can you please describe Delta's recent change in meter technology?

A. Yes. To measure gas usage, Delta utilizes a diaphragm meter. From 1996 to 2003, Delta installed Itron 40 encoder receiver transmitter ("ERT") modules on each of its meters to allow radio frequency readings of the meters rather than manually reading the meters. The Itron 40 ERT modules have a useful life of about 20 years. As the modules reached the end of their service life, Delta began replacing modules in 2016 with the Itron 100 ERT modules. Delta has replaced approximately 32,000 of its 40,000 Itron 40 ERT modules with the Itron 100 ERT modules.

As Delta explained in Case No. 2024-00135, the Company has encountered manufacturing challenges in obtaining Itron 100 ERT modules that have prohibited Delta from timely receiving replacement modules. Delta is transitioning from its current Honeywell American meter base with Itron 100 ERT modules to the Intelis 250 meter with an integrated ERT module. The integrated ERT modules are compatible with Delta's current radio meter-reading equipment. Furthermore, the Intelis 250 meter with integrated ERT module has an automatic shutoff feature and a remote disconnection feature that Delta's current meter and module do not possess. These features will enhance our customers' safety.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF CLARK)

The undersigned, **Jonathan Morphew**, being duly sworn, deposes and says he is Director of Operations of Delta Natural Gas Company, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

JONATHAN MORPHEW

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of November, 2024.

Jennifer Page Bingham (SEAL)
Notary Public

My Commission Expires:

June 19, 2027

JENNIFER PAGE BINGHAM
NOTARY PUBLIC
STATE AT LARGE KENTUCKY
COMM. # KYNP74158
MY COMMISSION EXPIRES JUNE 19, 2027

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

APPLICATION OF DELTA NATURAL GAS	**)**	
COMPANY, INC. FOR AN ADJUSTMENT	**)**	**CASE NO. 2024-00346**
OF RATES	**)**	

DIRECT TESTIMONY OF

PAUL R. MOUL

Filed: November 25, 2024

Delta Natural Gas Company, Inc.
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
FPFTY	Fully Projected Future Test Year
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Companies
Lev	Leverage modification
LT	Long Term
M&M	Modigliani & Miller
P-E	Price-earnings
KPSC	Kentucky Public Service Commission
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a Firm
SBBI	Stocks, Bonds, Bills and Inflation
s x v	Represents external growth
PRP	Pipe Replacement Program
S&P	Standard & Poor's

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
WNA	Weather Normalization Adjustment Mechanism

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Kentucky Public Service Commission ("KPSC" or the "Commission") should recognize in the determination of the revenues that Delta Natural Gas Company, Inc. ("Delta" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Attachments PRM-1 through PRM-15.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 10.95%. As shown on page 1 of Attachment PRM-1, I have presented the weighted average cost of capital for the Company, which is 7.91%. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and provides the Company with the ability to attract capital on reasonable terms.

Q. Are there specific factors that you included in your analysis of the cost of equity for the Company?

A. Yes. My cost of equity analysis reflects the recent reduction in the Fed Funds rate implemented by the Federal Open Market Committee ("FOMC"). Until recently, the rate of inflation spiked upward after the Pandemic, but has now fallen to a level that approaches the policy goal of 2% by the FOMC. The FOMC uses its open market operations to control the Fed Funds rate as a means of implementing its dual mandate of healthy employment and price stability. During its fight against high inflation, the FOMC increased the Fed Funds rate by 525 basis points through 11 increases in 17 months. As noted above, the FOMC reduced the Fed Funds rate by fifty basis points on September 5, 2024. Another rate reduction of twenty-five basis points occurred on November 7, 2024. Further, reductions in the Fed Funds rate are expected in 2025. In spite of these reductions, the Fed Funds rate continues to be above Pandemic levels. Furthermore, long-term interest rates measured by Treasury bond yields and the yields on A-rated public utility bonds remain at elevated levels. Relatively high interest rates have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt - and the need for more cautious financial practices, such as a prudent level of borrowing.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is wholly-owned subsidiary of PNG Companies, LLC, which is a wholly-owned subsidiary of Essential Utilities, Inc.

The Company provides natural gas distribution service to approximately 40,000 customers located in the central portion of Kentucky. Throughput to its customers in 2023 was represented by approximately 54% to residential customers, approximately 23% to commercial customers, and approximately 23% to industrial customers. Overall, throughput on the Delta system consists of approximately 13% to sales customers and 87% to transportation customers. Delta's customers obtain their gas supplies from producers and marketers and the Company has transportation arrangements with two pipelines. The Company has underground storage to supplement flowing gas.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as Delta. In this regard, I have considered four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What market evidence have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a proxy gas group of eight gas utility companies. I began with all of the gas utilities contained in the basic service of The Value Line Investment Survey, which consists of nine companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international liquefied petroleum gas ("LPG") segments, natural gas utility, energy services, and gas generation. The companies in the Gas Group are identified on page 2 of Attachment PRM-3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches:

	Gas Group[2]
DCF	11.07%
Risk Premium	11.25%
CAPM	13.55%
Comparable Earnings	13.35%

Focusing upon the DCF and Risk Premium approaches of the cost of equity, the average equity return is 11.16% (11.07% + 11.25% = 22.32% ÷ 2). After removing the leverage adjustment from the DCF model, the average results are 10.68% (10.10% + 11.25% = 21.35% ÷ 2). The 10.95% equity return that I propose in this case rests

[2] Excluding flotation costs, which are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.

between these measures, i.e., 10.68% and 11.16%, and is near its midpoint, i.e., 10.92%. My recommended cost of equity of 10.95% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, customer usage patterns, and potential initiatives directed toward decarbonization as a national energy policy. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of Company witness Mr. Brown discusses the investments that the Company has made and will make to address these issues.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with throughput of uncertain volumes to large volume customers, especially those with interruptible service, risk will continue to rise as end-users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Q. How does the Company's throughput to large volume users affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial customers. Indeed, the Company's largest customers represent approximately 8.7 million Mcf of throughput. Throughput to these customers is especially vulnerable in this economic environment. Large volume users, which have traditionally used transportation service, also have the ability to bypass the Company's system. Indeed, the Company has lost customers to bypass in the past.

Success in this segment of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory. As these firms search for cheaper labor, or go out of business, load can be lost for large customers, as well as the out-migration of high paying jobs associated with these customers. This puts fixed cost recovery at risk. Some of that loss can be offset by economic growth, but the Company faces potential for lackluster growth.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure, including replacement of vintage plastic pipe, represents a non-revenue producing use of capital. The Company projects its construction expenditures will be $98,399,257 in the period 2025-2029. Over this five-year period, these capital expenditures will represent approximately 52% ($98,399,257

÷ $189,406,134) of its net utility plant at August 31, 2024. Given its large construction expenditures forecast for the future, the Commission should be supportive of the Company's cash flow needs for its infrastructure rehabilitation. A fair rate of return represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its capital needs on reasonable terms.

Q. Are you aware that there is a Pipe Replacement Program ("PRP") available to natural gas utilities in Kentucky, and does the PRP affect the Company's cost of capital?

A. I am aware that the Company had utilized the PRP. However there is no need to focus on this item separately in this case. I say this because all of the proxy group companies whose data has been used to develop the cost of equity for Delta in this proceeding, have at least, some form of a PRP or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a PRP, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To deal with this issue, the Company's tariff contains a weather normalization adjustment ("WNA") clause for residential and small non-residential customers.

Q. Does your cost of equity analysis and recommendation take into account the WNA that the Company has?

A. Yes. All of my Gas Group companies have some form of WNA mechanism, and in some cases, other forms of revenue decoupling. Therefore, the market prices of all companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a normalization mechanism. Therefore, my analysis reflects the impacts of normalization adjustment mechanisms on investor expectations through the use of market-determined models.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular Delta?

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared Delta to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Attachment PRM-3.

Q. What criteria did you employ to assemble the Gas Group?

A. I previously enumerated the criteria that I employed to assemble the Gas Group. The Gas Group members are: Atmos Energy, Chesapeake Utilities, New Jersey Resources, NiSource, Inc., Northwest Natural, ONE Gas, Southwest Gas, and Spire Inc.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for Delta, the Gas Group, and the S&P Public Utilities?

A. Delta has no bond rating because its debt is held by an affiliate. The average credit quality of the Gas Group is an A3 from Moody's and A- from S&P. For the S&P Public Utilities, the average composite rating is A3 by Moody's and BBB+ by S&P. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for Delta, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Attachments PRM-2, PRM-3, and PRM-4. The data cover the five-year period 2019-2023. The important categories of relative risk may be summarized as follows:

<u>Size</u>. In terms of capitalization, Delta is less than two percent the average size of the Gas Group. Delta is also very much smaller than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm.

<u>Market Ratios</u>. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[3]

There are no market ratios available for Delta because Essential Utilities ultimately owns its stock. The five-year average price-earnings multiple for the Gas Group was slightly higher than that of the S&P Public Utilities. The five-year average

[3] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The average market-to-book ratios was lower for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on total capital including short-term debt, were 53.5% for Delta, 43.4% for the Gas Group, and 38.3% for the S&P Public Utilities. Year-end capital structures including short-term debt are somewhat misleading due to the seasonal nature of those borrowings, which typically peak for the gas utilities around year-end. By excluding short-term debt, the common equity ratios were 58.2% for Delta, 47.4% for the Gas Group, and 39.7% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.235 (2.3% ÷ 9.8%) for Delta, 0.087 (0.8% ÷ 9.2%) for the Gas Group, and 0.050 (0.5% ÷ 10.1%) for the S&P Public Utilities. Delta has much greater risk due to its significantly higher earnings variability as compared to the Gas Group and S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[4] The five-year average operating ratios were 81.2% for Delta, 82.1% for the Gas Group, and 80.9 for the S&P Public Utilities. Delta's operating risk is similar to the Gas Group and the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 4.48 times for Delta, 4.24 times for the Gas Group, and 2.90 times for the S&P Public Utilities. Delta's credit risk is fairly similar to that of the Gas Group and better than the S&P Public Utilities.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for Delta, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of

[4] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 76.7% for Delta, 57.0% for the Gas Group, and 59.0% for the S&P Public Utilities. In recent years, the Company's cash flow to construction has benefited from the absence of common dividend payments. Moreover, the IGF percentage for Delta has been very volatile.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[5] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .88 as the average for the Gas Group (see page 2 of Attachment PRM-3), and .94 as the average for the S&P Public Utilities (see page 3 of Attachment PRM-4). The systematic risk for the Gas Group as measured by the Value Line beta has been lower compared to the S&P Public Utilities.

Q. Please summarize your risk evaluation.

A. The risk of Delta exceeds that of the Gas Group. It is very much smaller than the Gas Group and it has much more variable earned returns, which indicates high risk. The Company's quality of earnings, credit risk, and operating risk have been fairly similar to the Gas Group. The financial risk and cash flow risk (albeit highly variable) have

[5] The procedure used to calculate the beta coefficient published by Value Line is described on page 3 of Attachment PRM-15. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

been lower for Delta. On balance, the Gas Group will provide a very conservative basis for measuring the Company's cost of equity for this case.

CAPITAL STRUCTURE RATIOS

Q. Does Attachment PRM-5 provide Delta's capitalization and capital structure ratios?

A. Yes. Attachment PRM-5 presents Delta's capitalization and related capital structure ratios. The thirteen-month average for August 31, 2024 corresponds with the base period for the Company. Before the end of the fully forecasted test period, the Company plans to issue $34,000 million of long-term debt. The resulting capital structure ratios are 47.24% long-term debt, 0.00% short-term debt, and 52.76% common equity, based upon the thirteen month average balance for the June 30, 2026 test year.

Q. Are these capital structure ratios reasonable?

A. Yes. I have verified the reasonableness of the Company's common equity ratio by considering the capital structure ratios for the Gas Group and with analysts' forecasts, which influence investor expectations. Historically, the Gas Group has employed common equity, excluding short-term debt, within the range of 35.0% to 57.7% for the 5-year average and 36.8% to 60.9% for fiscal year 2023. I have also compared the Company's proposed common equity ratio to that of the Gas Group based upon forecast data widely available to investors from <u>Value Line</u>. In the case of the <u>Value Line</u> forecasts, the common equity ratios are computed without regard to short-term debt. Those ratios are:

Gas Group Common Equity Ratios

		Value Line forecasts		
	FY	2024	2025	2027-29
ATMOS ENERGY CORP	09/30	61.0%	60.0%	60.0%
CHESAPEAKE UTILITIES CORP	12/31	52.0%	52.0%	52.0%
NEW JERSEY RESOURCES CORP	09/30	42.5%	43.0%	45.0%
NISOURCE INC	12/31	44.0%	45.0%	45.0%
NORTHWEST NATURAL HLDNG CO	12/31	47.5%	45.0%	45.0%
ONE GAS INC	12/31	55.0%	55.0%	49.0%
SOUTHWEST GAS HOLDINGS INC	12/31	42.0%	42.0%	44.0%
SPIRE INC	09/30	45.0%	45.0%	45.0%
	High	61.0%	60.0%	60.0%
	Low	42.0%	42.0%	44.0%
	Midpoint	51.5%	51.0%	52.0%

And, of course, due to the very small size of Delta, its common equity ratio should be higher due to the Company's higher business risk. These forecasts show that the 52.76% common equity ratio for Delta is reasonable by reference to the forecast ratios for the Gas Group.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since rate setting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the fully forecasted test period. As a result, I will adopt the Company's fully forecasted test period capital structure ratios of 47.24% long-term debt, 0.00% short-term debt and 52.76% common equity. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of Delta's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Attachment PRM-6, I have computed the actual embedded cost rate of debt for August 31, 2024 using thirteen month average balances. On page 2 of Attachment PRM-6, the embedded cost of debt is shown for June 30, 2026 using the thirteen-month average balances. For the new issue of long-term debt, I have used an actual cost of 4.011% for the issue in December 2024 and the 5.40% estimated cost for the issue in June 2025. The reason that the December 2024 issue has a lower interest rate is because it represents a blended rate derived from an old issue of PNG debt of 2.40% issued on April 18, 2021 when interest rates were much lower during the Pandemic. That rate was blended with a more recent issue of debt on May 20, 2022 with an interest rate of 5.30% for the remaining amount. The 2.40% rate received 44.44% weight and the 5.30% rate received 55.56% weight, thus producing a 4.01% blended rate. The June 2025 issue reflects an expected rate determined from a debt issue on January 8, 2024.

I will adopt the 4.51% embedded cost of long-term debt, as shown on page 2 of Attachment PRM-6. This rate is related to the amount of long-term debt shown on Attachment PRM-5 which provides the basis for the 47.24% long-term debt ratio**.**

<u>COST OF EQUITY – GENERAL APPROACH</u>

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among Delta, the Gas Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage and bond ratings, must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 10.95% for Delta.

<u>DISCOUNTED CASH FLOW</u>

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k = D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on page 2 of Attachment PRM-1 for the Gas Group. The DCF return is 11.07% with the leverage adjustment and 10.10% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance. And, indeed, the FERC has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the 12 months ended August 2024, the monthly dividend yields are shown in Attachment

[6] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950s, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

PRM-7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the 12 months ended August 2024, the average dividend yield was 3.86% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.73% and 3.67%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.73% for the Gas Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different but generally accepted manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Attachment PRM-7.[7] This adjustment adds 12 basis points to the six-month average historical yield, thus producing the 3.85% adjusted dividend yield for the Gas Group.

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[7] These adjustments are the 1/2 growth approach, the discrete approach and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)* results in this third DCF formulation. This DCF equation provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus on prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares that the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage during which a firm enjoys rapidly expanding markets, high profit margins and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, investment opportunities begin to mature, capital requirements decline and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps up and ramps down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle but rather to rely upon analysts' growth forecasts used by investors when pricing common stocks.

Q. What factor should be considered in the determination of an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Attachments PRM-8 and PRM-9, which reflect historical (Attachment PRM-8) and projected (Attachment PRM-

9) rates of growth in earnings per share, dividends per share, book value per share and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the P-E multiple. As such, my company-specific growth analysis, which focuses principally on five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Attachment PRM-9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and <u>Value Line</u>. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The <u>Value Line</u> forecasts are also widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Attachment PRM-9.

Q. What are the projected growth rates published by the sources you discussed?

A. Attachment PRM-9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.83%), Zacks (6.00%) and Value Line (6.56%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While various factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[8] Consistent with Professor Gordon's findings,

[8] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

projections of earnings per share growth, such as those published by IBES/First Call, Zacks and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Attachment PRM-9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.83% to 6.56%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.25% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 41.52% long-term debt, 0.73% preferred stock, and 57.75% common equity, as shown on Attachment PRM-10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate-setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Attachment PRM-10, under the heading "M&M,"[9] provide a return of 8.47% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed, the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in

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[9] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such “excesses” if they actually exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a “leverage adjustment” is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Attachment PRM-10, the equity return applicable to the book value common equity ratio is equal to 8.47%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.55% to compensate investors for the risk of 52.71% debt ratio and 0.05% for a 0.77% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 11.07% (8.47% + 2.55% + 0.05%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.85% dividend yield, the 6.25% growth rate, and 0.97% for the leverage adjustment to arrive at the same 11.07% return computed directly with the "M&M" formula. I know of no means to mathematically solve for the 0.97% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.97% adjustment is merely a convenient way to compare the 11.07% return computed using the Modigliani & Miller formulas to the 10.10% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Attachment PRM-7) based on a market-value capital structure. A 10.10% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs (flot.), as shown on Attachment PRM-11. In developing the flotation cost adjustment factor, I reduced the 3.6% issuance and selling expenses shown on Attachment PRM-11 to 1.5% (i.e., 1.000 + 0.015). I did this because I applied the adjustment factor to the entire DCF return rather than to just the dividend yield component. The resulting DCF cost rate is 11.24%, computed as follows:

	D_1/P_0	+	*g*	+	*lev.*	=	*k*	x	*flot.*	=	*K*
Gas Group	3.85%	+	6.25%	+	0.97%	=	11.07%	x	1.015	=	11.24%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.17% (11.24% - 11.07%) to the rate of return on common equity for the Gas Group. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Attachment PRM-1. That result is 11.25%, excluding flotation cost.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 4.75% yield represents a very conservative estimate of the prospective yield on long-term, public utility bonds.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Attachment PRM-12, page 1. For the 12 months ended August 2024 the average monthly yield on Moody's index public utility bonds was 5.69%. For the six- and three-month periods ended August 2024, the yields were 5.62% and 5.54%, respectively. During the 12 months ended August 2024, the range of the yields on A-rated public utility bonds was 5.38% to 6.34%. Page 2 of Attachment PRM-12 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Attachment PRM-12, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.23% on a 12-month average basis, 1.17% on a six-month average basis, and 1.19% on a three-month average basis. With these data, 1.00% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of various interest rates compiled from a panel of banking, brokerage and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on August 30, 2024, and a yield spread of 1.00%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I have also shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2024	Third	4.9%	5.7%	4.2%	1.00%	5.20%
2024	Fourth	4.9%	5.7%	4.2%	1.00%	5.20%
2025	First	4.8%	5.7%	4.1%	1.00%	5.10%
2025	Second	4.8%	5.7%	4.1%	1.00%	5.10%
2025	Third	4.8%	5.7%	4.1%	1.00%	5.10%
2025	Fourth	4.8%	5.7%	4.1%	1.00%	5.10%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its May 31, 2024 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2026-2030	5.2%	6.1%	4.3%
2031-2035	5.2%	6.2%	4.4%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 4.75% yield on A-rated public utility bonds represents a reasonably conservative benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Attachment PRM-13.

Common Equity Risk Premiums

Low Interest Rates	7.13%
Average Across All Interest Rates	5.96%
High Interest Rates	4.76%

Based on my analysis of the historical data, the equity risk premium was 7.13% when the marginal cost of long-term government bonds was low (i.e., 2.83%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 4.76%. Over the entire spectrum of interest rates, the equity risk premium was 5.96% when the average government bond yield was 4.93%. From this data, I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% is between the premiums associated with low interest rates (i.e., 7.13%) and average for the entire historical period interest rates (i.e., 5.96%).

Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), the equity risk premium (i.e., "RP"), and the adjustment for flotation costs (i.e., flot.). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*	+	*flot.*	=	*K*
Gas Group	4.75%	+	6.50%	=	11.25%	+	0.17%	=	11.42%

<u>CAPITAL ASSET PRICING MODEL</u>

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Attachment PRM-1, the result of the CAPM is 13.55% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 11.99% (13.55% - (0.19 x 8.21%)) through use of the <u>Value Line</u> beta excluding the leverage adjustment (i.e., 1.07 - 0.88 = 0.19). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β") and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the <u>Value Line</u> betas. As shown on page 2 of Attachment PRM-3, the average beta is 0.88 for the Gas Group.

Q. Did you use the <u>Value Line</u> betas in the CAPM determined cost of equity?

A. I used the <u>Value Line</u> betas as a foundation for the leverage-adjusted betas that I used in the CAPM. The <u>Value Line</u> betas are measured over a five-year period. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[10] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.56 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Attachment PRM-10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.07 for the book value capital structure of the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Attachment PRM-14 I provided the historical yields on Treasury notes and bonds. For the 12 months ended August 2024, the average yield on 30-year Treasury bonds was 4.46%. For the six- and three-months ended August 2024, the

[10] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks;" The Journal of Finance, Vol. 27, No. 2; Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, Dec. 27-29, 1971. (May 1972), pp. 435-52.

yields on 30-year Treasury bonds were 4.45% and 4.35%, respectively. During the 12 months ended August 2024, the range of the yields on 30-year Treasury bonds was 4.14% to 4.95%.

The low yields that existed prior to 2022 can be traced to extraordinary events associated with the Pandemic that jolted the capital markets. Since then, higher rates took place. Higher inflation during the period was a contributing factor that prompted the FOMC to raise the Fed Funds rate from the low levels that existed during the Pandemic.

Due to high inflation rates above the policy goal of the FOMC, the accommodative policy was ended by the FOMC in the first quarter of 2022. A tighter monetary policy began at that time, which caused higher interest rates. After the FOMC ended its bond-buying program (i.e., quantitative easing) in March 2022, it is in the process of running off its $9 trillion asset portfolio, which will keep interest rates at elevated levels after the Pandemic. As noted previously, the FOMC changed course and recently reduced the Fed Funds rate to support the job market as is the second part of its dual mandate.

High interest rates clearly point to high capital costs prospectively. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, for the first time since late 2018. By August 2024, the yield on 30-year Treasury bonds moved to 4.15%, or an increase of 2.48% (or 148%) since December 2020.

As shown on page 2 of Attachment PRM-14, forecasts published by Blue Chip on August 30, 2024, indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.1% to 4.2% during the next six quarters. This means that elevated interest rates will continue near current levels into 2025. The longer-term forecasts show that the yields on 30-year Treasury bonds will average 4.3% from 2026 through 2030 and 4.4% from 2031 to 2035. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a conservative 3.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Attachment PRM-14, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Attachment PRM-13. On that schedule, the market return was 12.21% (12.40% + 12.02% = 24.42% ÷ 2) as the midpoint of the “low” and “average” interest rate environments. During those periods, the yield on long-term government bonds was 3.87% (2.83% + 4.91% = 7.74% ÷ 2). The resulting market premium is 8.34% (12.21% - 3.87%) based on historical data, as shown on page 2 of Attachment PRM-14. As also shown on page 2 of Attachment PRM-14, I calculated the forecast returns, which show a 11.83% total market return based on the Value Line forecasts. With these data, I calculated a market premium of 8.08% (11.83% - 3.75%) using the forecast data by Value Line. The resulting market premium applicable to the CAPM derived from these sources equals 8.21% (8.08% + 8.34% = 16.42% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Eugene F. Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could significantly understate the cost of equity according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Attachment PRM-14, for the CAPM calculation. The adjustment here is related to the size of the Gas Group.

Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 1.07 for the Gas Group, the 8.21% market premium, and the 1.02% size adjustment, and the flotation cost adjustment, the following result is indicated:

	Rf	+	*ß*	*x (*	*Rm-Rf*	*) +*	*size*	=	*k*	+	*flot.*	=	*K*
Gas Group	3.75%	+	1.07	x (	8.21%	) +	1.02%	=	13.55%	+	0.17%	=	13.72%

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the

> public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works v. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Attachment PRM-15. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Attachment PRM-15.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Attachment PRM-13, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach to cover conditions over an entire business cycle. A 10-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.7% using only the returns that were less than 20%, as shown on page 2 of Attachment PRM-15. The average forecasted rate of return, as published by Value Line, is 14.0% also using values less than 20%, as provided on page 2 of Attachment PRM-15. Using the average of these data, my Comparable Earnings result is 13.35%, as shown on page 2 of Attachment PRM-1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of various methods and models described previously, it is my opinion that the reasonable cost of common equity is 10.95% for the Company. My proposed cost of equity will accommodate the Company's small size and its business risk characteristics. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

VERIFICATION

STATE OF NEW JERSEY)
) **SS:**
COUNTY OF CAMDEN)

The undersigned, **Paul R. Moul**, being duly sworn, deposes and says he is Managing Consultant at P. Moul & Associates, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Paul R. Moul
PAUL R. MOUL

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of November, 2024.

Swapna Ghosh (SEAL)
Notary Public

My Commission Expires:
3/6/28

SWAPNA GHOSH
Notary Public, State of New Jersey
My Commission Expires Mar 6, 2028

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia.

My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

APPLICATION OF DELTA NATURAL GAS	)	
COMPANY, INC. FOR AN ADJUSTMENT	)	CASE NO. 2024-00346
OF RATES	)	

ATTACHMENTS TO ACCOMPANY THE

DIRECT TESTIMONY OF

PAUL R. MOUL

November 25, 2024

Delta Natural Gas Company, Inc.
Index of Attachments

Delta Natural Gas Company, Inc.
Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.24%	4.51%	2.13%
Short-Term Debt	0.00%		0.00%
Total Debt	47.24%		2.13%
Common Equity	52.76%	10.95%	5.78%
Total	100.00%		7.91%

Indicated levels of fixed charge coverage assuming that
the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense	4.35 x
Post-tax coverage of interest expense	3.71 x

Delta Natural Gas Company, Inc.
Cost of Equity
as of August 30, 2024

Discounted Cash Flow (DCF)					D_1/P_0 [1]	+	g [2]		+	lev. [3]	=	k	x	flot. [4]	=	K
Gas Group					3.85%	+	6.25%		+	0.97%	=	11.07%	x	1.015	=	11.24%
Risk Premium (RP)							I [5]		+	RP [6]	=	k	+	flot. [4]	=	K
Gas Group							4.75%		+	6.50%	=	11.25%	+	0.17%	=	11.42%
Capital Asset Pricing Model (CAPM)	Rf [7]	+	ß [8]	x (			Rm-Rf [9]		) +	size [10]	=	k	+	flot. [4]	=	K
Gas Group	3.75%	+	1.07	x (			8.21%		) +	1.02%	=	13.55%	+	0.17%	=	13.72%
Comparable Earnings (CE) [11]												Historical		Forecast		Average
Comparable Earnings Group												12.7%		14.0%		13.35%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) Schedule 11
(5) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return (Schedule 13 page 2) and a yield spread of 1.00% (Schedule 11 page 3)
(6) Schedule 12 page 1
(7) Schedule 13 page 2
(8) Schedule 10
(9) Schedule 13 page 2
(10) Schedule 13 page 3
(11) Schedule 14 page 2

Delta Natural Gas Company, Inc.
Capitalization and Financial Statistics
2019-2023, Inclusive

	2023	2022	2021	2020	2019	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 137.9	$ 132.9	$ 124.8	$ 99.8	$ 111.8	
Short-Term Debt	$ 7.3	$ 15.4	$ 12.1	$ 15.8	$ 4.3	
Total Capital	$ 145.1	$ 148.3	$ 136.9	$ 115.6	$ 116.1	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	38.9%	41.5%	45.5%	43.1%	39.8%	41.8%
Common Equity [1]	61.1%	58.5%	54.5%	56.9%	60.2%	58.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	42.0%	47.5%	50.3%	50.8%	42.1%	46.5%
Common Equity [1]	58.0%	52.5%	49.7%	49.2%	57.9%	53.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	8.0%	13.4%	8.5%	8.5%	10.8%	9.8%
Operating Ratio [2]	83.6%	77.5%	84.2%	82.2%	78.4%	81.2%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	4.61 x	5.70 x	3.48 x	3.75 x	4.86 x	4.48 x
Post-tax: All Interest Charges	4.05 x	4.82 x	3.32 x	3.45 x	4.31 x	3.99 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	4.61 x	5.70 x	3.48 x	3.75 x	4.86 x	4.48 x
Post-tax: All Interest Charges	4.05 x	4.82 x	3.32 x	3.45 x	4.31 x	3.99 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Effective Income Tax Rate	15.5%	18.8%	6.4%	11.2%	14.3%	13.2%
Internal Cash Generation/Construction [4]	132.9%	98.7%	59.0%	17.3%	75.7%	76.7%
Gross Cash Flow/ Avg. Total Debt [5]	25.9%	27.2%	20.5%	28.3%	30.8%	26.5%
Gross Cash Flow Interest Coverage [6]	8.02 x	7.42 x	5.71 x	7.10 x	7.12 x	7.07 x
Common Dividend Coverage [7]	x	x	x	1.17 x	3.07 x	2.12 x

See Page 2 for Notes.

Delta Natural Gas Company, Inc.
Capitalization and Financial Statistics
2019-2023, Inclusive

Notes:

(1) Excluding the Transitional Funding Obligations that were issue for stranded generating assets, and whose debt service is covered through dedicated revenue collections.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(6) Gross Cash Flow plus interest charges divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to the PSC

Gas Group
Capitalization and Financial Statistics [1]
2019-2023, Inclusive

	2023	2022	2021	2020	2019	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 8,611.7	$ 7,730.2	$ 7,293.8	$ 6,052.7	$ 5,316.3	
Short-Term Debt	$ 685.6	$ 745.4	$ 577.9	$ 285.2	$ 516.3	
Total Capital	$ 9,297.3	$ 8,475.6	$ 7,871.7	$ 6,337.9	$ 5,832.6	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	19 x	19 x	21 x	24 x	25 x	22 x
Market/Book Ratio	164.3%	193.5%	185.7%	188.6%	225.0%	191.4%
Dividend Yield	3.6%	3.1%	3.2%	3.1%	2.5%	3.1%
Dividend Payout Ratio	68.9%	57.1%	65.6%	74.7%	63.9%	66.0%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	52.5%	52.1%	53.5%	48.6%	46.4%	50.6%
Preferred Stock	2.0%	2.1%	2.3%	1.8%	1.7%	2.0%
Common Equity [2]	45.5%	45.7%	44.2%	49.6%	52.0%	47.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	55.3%	57.0%	58.2%	52.3%	51.4%	54.8%
Preferred Stock	1.8%	1.9%	2.1%	1.7%	1.5%	1.8%
Common Equity [2]	42.9%	41.2%	39.7%	46.1%	47.2%	43.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	8.7%	10.6%	9.0%	8.7%	9.0%	9.2%
Operating Ratio [3]	81.7%	81.9%	81.3%	82.7%	83.1%	82.1%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.59 x	5.01 x	4.88 x	4.18 x	4.02 x	4.34 x
Post-tax: All Interest Charges	3.17 x	4.28 x	4.09 x	3.61 x	3.57 x	3.74 x
Overall Coverage: All Int. & Pfd. Div.	3.12 x	4.18 x	3.99 x	3.57 x	3.52 x	3.68 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.49 x	4.90 x	4.76 x	4.07 x	3.96 x	4.24 x
Post-tax: All Interest Charges	3.07 x	4.16 x	3.97 x	3.50 x	3.50 x	3.64 x
Overall Coverage: All Int. & Pfd. Div.	3.02 x	4.06 x	3.87 x	3.46 x	3.45 x	3.57 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.3%	2.4%	4.3%	3.1%	2.5%	3.1%
Effective Income Tax Rate	18.2%	20.7%	20.3%	16.5%	14.3%	18.0%
Internal Cash Generation/Construction [5]	54.5%	61.0%	62.8%	54.8%	52.1%	57.0%
Gross Cash Flow/ Avg. Total Debt [6]	14.9%	15.2%	17.4%	19.1%	19.8%	17.3%
Gross Cash Flow Interest Coverage [7]	5.49 x	7.02 x	8.34 x	7.35 x	6.67 x	6.97 x
Common Dividend Coverage [8]	3.67 x	3.85 x	4.22 x	3.96 x	4.10 x	3.96 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2019-2023, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group “Natural Gas Utility,” they are not currently the target of a publicly-announced merger or acquisition (i.e., South Jersey Industries), and after eliminating UGI Corp. due to its highly diversified businesses.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
ATO	Atmos Energy Corp.	A1	A-	NYSE	0.85
CPK	Chesapeake Utilities Corp.	NAIC "2b"		NYSE	0.80
NJR	New Jersey Resources Corp.	A1	-	NYSE	1.00
NI	NiSource Inc.	Baa2	BBB+	NYSE	0.95
NWN	Northwest Natural Holding Comp	Baa1	A+	NYSE	0.85
OGS	ONE Gas, Inc.	A3	A-	NYSE	0.85
SWX	Southwest Gas Holdings, Inc.	Baa1	BBB	NYSE	0.90
SR	Spire, Inc.	A1	A-	NYSE	0.85
	Average	A3	A-		0.88

Note: Ratings are those of utility subsidiaries

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT
Moody’s Investors Service
Standard & Poor’s Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2019-2023, Inclusive

	2023	2022	2021	2020	2019	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 45,149.6	$ 42,136.6	$ 40,154.3	$ 38,732.9	$ 36,461.6	
Short-Term Debt	$ 1,657.1	$ 1,713.7	$ 1,397.4	$ 1,154.1	$ 1,221.9	
Total Capital	$ 46,806.7	$ 43,850.3	$ 41,551.7	$ 39,887.0	$ 37,683.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	23 x	22 x	23 x	20 x	21 x
Market/Book Ratio	192.4%	220.6%	220.7%	218.2%	220.9%	214.6%
Dividend Yield	3.8%	3.3%	3.5%	3.6%	3.2%	3.5%
Dividend Payout Ratio	67.6%	72.5%	72.9%	78.0%	62.7%	70.7%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	59.4%	58.3%	57.4%	58.1%	56.7%	58.0%
Preferred Stock	2.3%	2.2%	2.3%	2.6%	2.4%	2.3%
Common Equity [2]	38.3%	39.6%	40.4%	39.4%	41.0%	39.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	60.9%	60.0%	58.9%	59.4%	58.1%	59.5%
Preferred Stock	2.2%	2.1%	2.2%	2.5%	2.3%	2.2%
Common Equity [2]	37.0%	37.9%	38.9%	38.1%	39.6%	38.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.8%	9.9%	9.4%	10.2%	10.3%	10.1%
Operating Ratio [3]	79.1%	83.1%	83.1%	79.8%	79.3%	80.9%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.72 x	3.28 x	3.16 x	2.80 x	3.05 x	3.00 x
Post-tax: All Interest Charges	2.52 x	2.94 x	2.87 x	2.60 x	3.10 x	2.81 x
Overall Coverage: All Int. & Pfd. Div.	2.49 x	2.89 x	2.81 x	2.55 x	3.04 x	2.76 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.61 x	3.17 x	3.06 x	2.70 x	2.95 x	2.90 x
Post-tax: All Interest Charges	2.41 x	2.84 x	2.78 x	2.50 x	3.00 x	2.71 x
Overall Coverage: All Int. & Pfd. Div.	2.38 x	2.79 x	2.72 x	2.46 x	2.94 x	2.66 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.1%	7.0%	7.3%	6.8%	6.0%	6.8%
Effective Income Tax Rate	9.6%	12.9%	10.6%	9.9%	12.2%	11.0%
Internal Cash Generation/Construction [5]	52.7%	58.9%	58.9%	58.6%	65.9%	59.0%
Gross Cash Flow/ Avg. Total Debt [6]	14.2%	15.1%	15.0%	15.9%	17.5%	15.5%
Gross Cash Flow Interest Coverage [7]	4.35 x	5.70 x	5.17 x	4.90 x	4.97 x	5.02 x
Common Dividend Coverage [8]	3.36 x	3.49 x	3.47 x	3.52 x	5.56 x	3.88 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2019-2023, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating [1] Moody's	Credit Rating [1] S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.90
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.90
American Electric Power	AEP	Baa1	A-	NYSE	0.80
American Water Works	AWK	Baa1	A	NYSE	0.95
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.15
CMS Energy	CMS	Baa1	A-	NYSE	0.85
Consolidated Edison	ED	Baa1	A-	NYSE	0.80
Dominion Energy	D	A2	BBB+	NYSE	0.90
DTE Energy Co.	DTE	A2	A-	NYSE	1.00
Duke Energy	DUK	A2	BBB+	NYSE	0.90
Edison Int'l	EIX	Baa1	BBB	NYSE	1.00
Entergy Corp.	ETR	Baa1	BBB+	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	0.95
Eversource	ES	A3	A	NYSE	0.95
Exelon Corp.	EXC	A2	BBB+	NDQ	NMF
FirstEnergy Corp.	FE	A3	BBB	NYSE	0.90
NextEra Energy Inc.	NEE	A1	A	NYSE	0.95
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.90
NRG Energy Inc.	NRG	Ba1	BB	NYSE	1.10
Pinnacle West Capital	PNW	A3	BBB+	NYSE	0.95
PPL Corp.	PPL	A3	A	NYSE	1.10
Public Serv. Enterprise Inc.	PEG	A3	A-	NYSE	0.95
Sempra Energy	SRE	A3	BBB+	NYSE	1.00
Southern Co.	SO	Baa1	BBB+	NYSE	0.95
WEC Energy Corp.	WEC	A2	A-	NYSE	0.85
Xcel Energy Inc	XEL	A2	A-	NYSE	0.85
Average for S&P Utilities		A3	BBB+		0.94

Note: [1] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service, Inc.
S&P Global Inc.
The Value Line Investment Survey

Delta Natural Gas Company, Inc.
Investor-provided Capitalization
For the Base Period ending August 31, 2024 and the Test Period ending June 30, 2026

	Base Period ending August 31, 2024		Test Period ending June 30, 2026	
	Amount Outstanding	Ratios	Amount Outstanding	Ratios
Long Term Debt	$ 53,637,600	37.18%	$ 85,255,815	47.24%
Common Equity	87,094,442	60.37%	95,224,983	52.76%
Total Permanent Capital	140,732,042	97.55%	180,480,798	100.00%
Short Term Debt	3,537,732	2.45%	-	0.00%
Total Capital Employed	$ 144,269,774	100.00%	$ 180,480,798	100.00%

Source of information: Company provided data

Delta Natural Gas Company, Inc.
Total Debt Outstanding
For the Base Period ending August 31, 2024

Issue	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
PNG Notes (Delta 2017)	December 20, 2031	4.26%	$ 38,500,000	$ 1,640,100	
PNG Notes (Peoples KY 2014)	April 15, 2030	2.704%	6,818,182	184,364	
PNG Notes (Delta 2022)	April 15, 2050	3.351%	8,181,818	274,173	
PNG Notes (Delta 2022)	December 19, 2025	2.43%	137,600	3,344	
Amortization of Issuance Expenses				217,092	
Long-Term Debt			53,637,600	2,319,072	4.32%
Short-Term Debt		6.344%	3,537,732	224,434	
Total Debt			$ 57,175,332	$ 2,543,506	4.45%

Source of information: Company provided data

Delta Natural Gas Company, Inc.
Total Debt Outstanding
For the Test Period ending June 30, 2026

Issue	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
PNG Notes (Delta 2017)	December 20, 2031	4.26%	$ 36,192,308	$ 1,541,792	
PNG Notes (Peoples KY 2014)	April 15, 2030	2.704%	6,818,182	184,364	
PNG Notes (Delta 2022)	April 15, 2050	3.351%	8,181,818	274,173	
PNG Notes (Delta 2022)	December 19, 2025	2.43%	63,508	1,543	
PNG Notes (Delta 2024)	May 1, 2031	4.011%	15,111,111	606,107	
PNG Notes (Delta 2025)	May 1, 2052	5.40%	18,888,889	1,020,000	
Amortization of Issuance Expenses				217,092	
Long-Term Debt			85,255,815	3,845,071	4.51%
Short-Term Debt			-	-	
Total Debt			$ 85,255,815	$ 3,845,071	4.51%

Source of information: Company provided data

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending August 2024

Company	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	2.80%	3.01%	2.83%	2.79%	2.84%	2.85%	2.72%	2.74%	2.78%	2.77%	2.53%	2.46%			
Chesapeake Utilities Corp (CPK)	2.42%	2.67%	2.48%	2.24%	2.34%	2.32%	2.20%	2.24%	2.30%	2.41%	2.18%	2.17%			
New Jersey Resources Corporation (NJR)	3.84%	4.16%	4.01%	3.78%	4.14%	4.07%	3.92%	3.87%	3.90%	3.94%	3.87%	3.92%			
NiSource Inc (NI)	4.08%	3.98%	3.91%	3.79%	4.12%	4.08%	3.86%	3.81%	3.66%	3.70%	3.39%	3.22%			
Northwest Natural Holding Company (NWN)	5.13%	5.31%	5.35%	5.05%	5.29%	5.33%	5.29%	5.11%	5.24%	5.45%	4.88%	4.87%			
ONE Gas Inc (OGS)	3.83%	4.34%	4.52%	4.10%	4.34%	4.43%	4.11%	4.12%	4.29%	4.16%	3.82%	3.84%			
Southwest Gas Holdings Inc (SWX)	4.13%	4.27%	4.20%	3.93%	4.26%	3.64%	3.27%	3.35%	3.20%	3.54%	3.37%	3.42%			
Spire Inc. (SR)	5.11%	5.47%	5.01%	4.86%	5.36%	5.15%	4.94%	4.92%	4.98%	4.99%	4.56%	4.62%			
Average	**3.92%**	**4.15%**	**4.04%**	**3.82%**	**4.09%**	**3.98%**	**3.79%**	**3.77%**	**3.79%**	**3.87%**	**3.58%**	**3.57%**	**3.86%**	**3.73%**	**3.67%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: https://finance.yahoo.com/quote
https://www.nasdaq.com/market-activity/stocks

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$
	3.73%	1.031250	3.85%	
Discrete	D_0/P_0	Adj.	D_1/P_0	$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$
	3.73%	1.038767	3.87%	
Quarterly	D_0/P_0	Adj.	D_1/P_0	$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$
	0.9325%	1.015272	3.84%	
Average			3.85%	
Growth rate			6.25%	
K			10.10%	

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	Earnings per Share Value Line 5 Year	Earnings per Share Value Line 10 Year	Dividends per Share Value Line 5 Year	Dividends per Share Value Line 10 Year	Book Value per Share Value Line 5 Year	Book Value per Share Value Line 10 Year	Cash Flow per Share Value Line 5 Year	Cash Flow per Share Value Line 10 Year
Atmos Energy Corp (ATO)	9.00%	9.50%	8.50%	7.00%	12.00%	9.50%	7.00%	6.50%
Chesapeake Utilities Corp (CPK)	10.00%	9.00%	10.00%	8.00%	10.50%	10.50%	7.00%	7.00%
New Jersey Resources Corporation (NJR)	2.50%	5.00%	6.50%	6.50%	7.00%	7.50%	4.50%	7.00%
NiSource Inc (NI)	15.00%	1.50%	3.50%	-0.50%	0.50%	-3.00%	6.50%	0.50%
Northwest Natural Holding Company (NWN)	2.50%	-1.00%	0.50%	1.50%	0.50%	1.00%	2.50%	1.00%
ONE Gas Inc (OGS)	6.00%	-	8.50%	-	4.50%	-	7.00%	-
Southwest Gas Holdings Inc (SWX)	4.50%	5.50%	7.00%	8.50%	7.00%	6.50%	1.50%	4.00%
Spire Inc. (SR)	3.00%	5.00%	5.50%	5.00%	3.50%	5.50%	5.00%	8.00%
Average	6.56%	4.93%	6.25%	5.14%	5.69%	5.36%	5.13%	4.86%

Source of Information: Value Line Investment Survey, August 23, 2024

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	I/B/E/S First Call	Zacks	Value Line Earnings Per Share	Value Line Dividends Per Share	Value Line Book Value Per Share	Value Line Cash Flow Per Share	Value Line Percent Retained to Common Equity
Atmos Energy Corp (ATO)	7.40%	7.00%	7.00%	7.50%	5.00%	6.50%	4.50%
Chesapeake Utilities Corp (CPK)	7.60%	NA	6.50%	8.00%	6.50%	5.00%	5.50%
New Jersey Resources Corporation	6.00%	NA	5.00%	5.00%	4.50%	5.00%	5.50%
NiSource Inc (NI)	7.50%	6.00%	9.50%	4.50%	5.00%	5.50%	3.50%
Northwest Natural Holding Compan	2.80%	NA	6.50%	0.50%	4.00%	5.00%	2.50%
ONE Gas Inc (OGS)	5.00%	5.00%	3.50%	2.50%	4.50%	9.00%	3.50%
Southwest Gas Holdings Inc (SWX)	4.00%	6.00%	10.00%	5.50%	7.50%	8.50%	2.50%
Spire Inc. (SR)	6.36%	NA	4.50%	4.50%	5.50%	4.00%	2.50%
Average	5.83%	6.00%	6.56%	4.75%	5.31%	6.06%	3.75%

Source of Information : Yahoo Finance, August 29, 2024
Zacks, August 29, 2024
Value Line Investment Survey, August 23, 2024

Gas Group
Financial Risk Adjustment

	ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year	09/30/23	12/31/23	09/30/23	12/31/23	12/31/23	12/31/23	12/31/23	09/30/23	
Capitalization at Fair Values									
Debt(D)	5,402,591	1,200,000	2,106,536	10,370,900	1,447,941	2,800,000	4,328,205	3,270,200	3,865,797
Preferred(P)	0	0	0	486,100	0	0	0	242,000	91,013
Equity(E)	15,729,841	2,348,719	3,964,327	11,877,983	1,465,359	3,603,106	4,533,563	3,008,371	5,816,409
Total	21,132,432	3,548,719	6,070,863	22,734,983	2,913,300	6,403,106	8,861,768	6,520,571	9,773,218
Capital Structure Ratios									
Debt(D)	25.57%	33.82%	34.70%	45.62%	49.70%	43.73%	48.84%	50.15%	41.52%
Preferred(P)	0.00%	0.00%	0.00%	2.14%	0.00%	0.00%	0.00%	3.71%	0.73%
Equity(E)	74.43%	66.18%	65.30%	52.25%	50.30%	56.27%	51.16%	46.14%	57.75%
Total	100.00%	100.00%	100.00%	100.01%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock									
Issued	148,492.783	22,235.337	97,584.455		37,631.212	56,545.924	71,563.750	53,170.224	
Treasury	0.000	0.000	13.041		0.000	0.000	0.000	0.000	
Outstanding	148,492.783	22,235.337	97,571.414	447,381.671	37,631.212	56,545.924	71,563.750	53,170.224	
Market Price	$ 105.93	$ 105.63	$ 40.63	$ 26.55	$ 38.94	$ 63.72	$ 63.35	$ 56.58	
Capitalization at Carrying Amounts									
Debt(D)	6,560,000	1,200,000	2,587,845	11,079,300	1,576,300	2,960,815	4,652,390	3,710,600	4,290,906
Preferred(P)	0	0	0	486,100	0	0	0	242,000	91,013
Equity(E)	10,870,064	1,246,104	1,990,735	7,783,500	1,283,838	2,765,877	3,310,036	2,675,300	3,990,682
Total	17,430,064	2,446,104	4,578,580	19,348,900	2,860,138	5,726,692	7,962,426	6,627,900	8,372,601
Capital Structure Ratios									
Debt(D)	37.64%	49.06%	56.52%	57.26%	55.11%	51.70%	58.43%	55.98%	52.71%
Preferred(P)	0.00%	0.00%	0.00%	2.51%	0.00%	0.00%	0.00%	3.65%	0.77%
Equity(E)	62.36%	50.94%	43.48%	40.23%	44.89%	48.30%	41.57%	40.36%	46.52%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%
Betas Value Line	0.85	0.80	1.00	0.95	0.85	0.85	0.90	0.85	0.88

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.88	=	Bu	[1+	(1-0.21)	0.7190	+	0.0126	]
	0.88	=	Bu	[1+	0.79	0.7190	+	0.0126	]
	0.88	=	Bu	1.5806					
	0.56	=	Bu						

Hamada	Bl	=	0.56	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.56	[1+	0.79	1.1332	+	0.0166	]
	Bl	=	0.56	1.9118					
	Bl	=	1.07						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	-	d	)	P	/	E
	8.47%	=	10.10%	-	(((	8.47%	-	5.62%	)	0.79	)	41.52%	/	57.75%	-	8.47%	-	5.68%	)	0.73%	/	57.75%
	8.47%	=	10.10%	-	(((	2.85%			)	0.79	)	0.7190			-	2.79%			)	0.0126		
	8.47%	=	10.10%	-	((	2.25%					)	0.719			-	2.79%			)	0.0126		
	8.47%	=	10.10%	-		1.62%									-	0.04%						

M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	-	d	)	P	/	E
	11.07%	=	8.47%	+	(((	8.47%	-	5.62%	)	0.79	)	52.71%	/	46.52%	+	8.47%	-	5.68%	)	0.77%	/	46.52%
	11.07%	=	8.47%	+	(((	2.85%			)	0.79	)	1.1332			+	2.79%			)	0.0166		
	11.07%	=	8.47%	+	((	2.25%					)	1.1332			+	2.79%			)	0.0166		
	11.07%	=	8.47%	+		2.55%									+	0.05%						

Analysis of Public Offerings of Gas Distribution Company Common Stock

									Percent of offering price		
Company	Date of Offering	No. of shares offered	Dollar amount of offering	Price to public	Underwriters' discount and commission	Gross Proceeds per share	Estimated company issuance expenses	Net proceeds per share	Underwriters' discount and commission	Estimated company issuance expenses	Total Issuance and selling expense
New Jersey Resources Corp.	12/04/19	5,700,000	$ 235,125,000	$41.00	$1.2375	$39.763	$0.088	$39.675	3.0%	0.2%	3.2%
Northwest Natural Gas Company	06/04/19	1,250,000	$ 83,750,000	$67.00	$2.1775	$64.823	$0.320	$64.503	3.3%	0.5%	3.8%
Atmos Energy Corporation	12/3/018	7,008,000	$ 650,000,000	$92.75	$0.9769	$91.773	$0.143	$91.630	1.1%	0.2%	1.3%
Southwest Gas Holkings	11/30/18	3,100,000	$ 234,050,000	$75.50	$2.5481	$72.952	$0.194	$72.758	3.4%	0.3%	3.7%
South Jersey Industries, Inc.	04/18/18	11,018,000	$ 325,029,000	$29.50	$1.0325	$28.468	$0.064	$28.404	3.5%	0.2%	3.7%
Spire, Inc.	04/07/18	2,000,000	$ 137,500,000	$68.75	$2.1094	$66.641	$0.500	$66.141	3.1%	0.7%	3.8%
Atmos Energy Corporation	11/28/17	7,008,087	$ 650,000,069	$92.75	$0.9769	$91.773	$0.143	$91.630	1.1%	0.2%	1.3%
Chesapeake Utilities Corp.	09/22/16	835,000	$ 51,987,000	$62.26	$2.3300	$59.930	$0.188 M-2	$59.742	3.7%	0.3%	4.0%
Spire, Inc.	05/12/16	1,900,000	$ 1,891,500,000	$63.05	$2.0491	$61.001	$0.158 of 2	$60.843	3.2%	0.3%	3.5%
South Jersey Industries, Inc.	05/12/16	7,000,000	$ 49,875,000	$26.50	$0.9188	$25.581	$0.047	$25.534	3.5%	0.2%	3.7%
The Laclede Group, Inc.	06/05/14	9,000,000	$ 585,000,000	$47.19	$1.7110	$45.479	$0.111	$45.368	3.6%	0.2%	3.8%
Atmos Energy Corporation	02/11/14	8,000,000	$ 542,000,000	$44.00	$1.5400	$42.460	$0.044	$42.416	3.5%	0.1%	3.6%
Piedmont Natural Gas Company, Inc.	01/29/13	4,000,000	$ 128,000,000	$32.00	$1.1200	$30.880	$0.088	$30.792	3.5%	0.3%	3.8%
Atmos Energy Corporation	12/07/06	5,500,000	$ 173,250,000	$31.50	$1.1025	$30.398	$0.073	$30.325	3.5%	0.2%	3.7%
AGL Resources Inc.	11/19/04	9,600,000	$ 297,696,000	$31.01	$0.9300	$30.080	$0.042	$30.038	3.0%	0.1%	3.1%
Atmos Energy Corporation	10/21/04	14,000,000	$ 346,500,000	$24.75	$0.9900	$23.760	$0.029	$23.731	4.0%	0.1%	4.1%
Atmos Energy Corporation	07/19/04	8,650,000	$ 214,087,500	$24.75	$0.9900	$23.760	$0.046	$23.714	4.0%	0.2%	4.2%
The Laclede Group, Inc.	05/25/04	1,500,000	$ 40,200,000	$26.80	$0.8710	$25.929	$0.067	$25.862	3.3%	0.3%	3.6%
Northwest Natural Gas Company	03/30/04	1,200,000	$ 37,200,000	$31.00	$1.0100	$29.990	$0.146	$29.844	3.3%	0.5%	3.8%
Piedmont Natural Gas Company, Inc.	01/23/04	4,250,000	$ 180,625,000	$42.50	$1.4900	$41.010	$0.082	$40.928	3.5%	0.2%	3.7%
Atmos Energy Corporation	06/18/03	4,000,000	$ 101,240,000	$25.31	$1.0124	$24.298	$0.095	$24.203	4.0%	0.4%	4.4%
AGL Resources Inc.	02/11/03	5,600,000	$ 123,200,000	$22.00	$0.7700	$21.230	$0.045	$21.185	3.5%	0.2%	3.7%
WGL Holdings, Inc	06/26/01	1,790,000	$ 47,846,700	$26.73	$0.8950	$25.835	$0.031	$25.804	3.3%	0.1%	3.4%
Atmos Energy Corporation	11/07/00	6,000,000	$ 133,500,000	$22.25	$1.1100	$21.140	$0.058	$21.082	5.0%	0.3%	5.3%
Average									3.3%	0.3%	3.6%

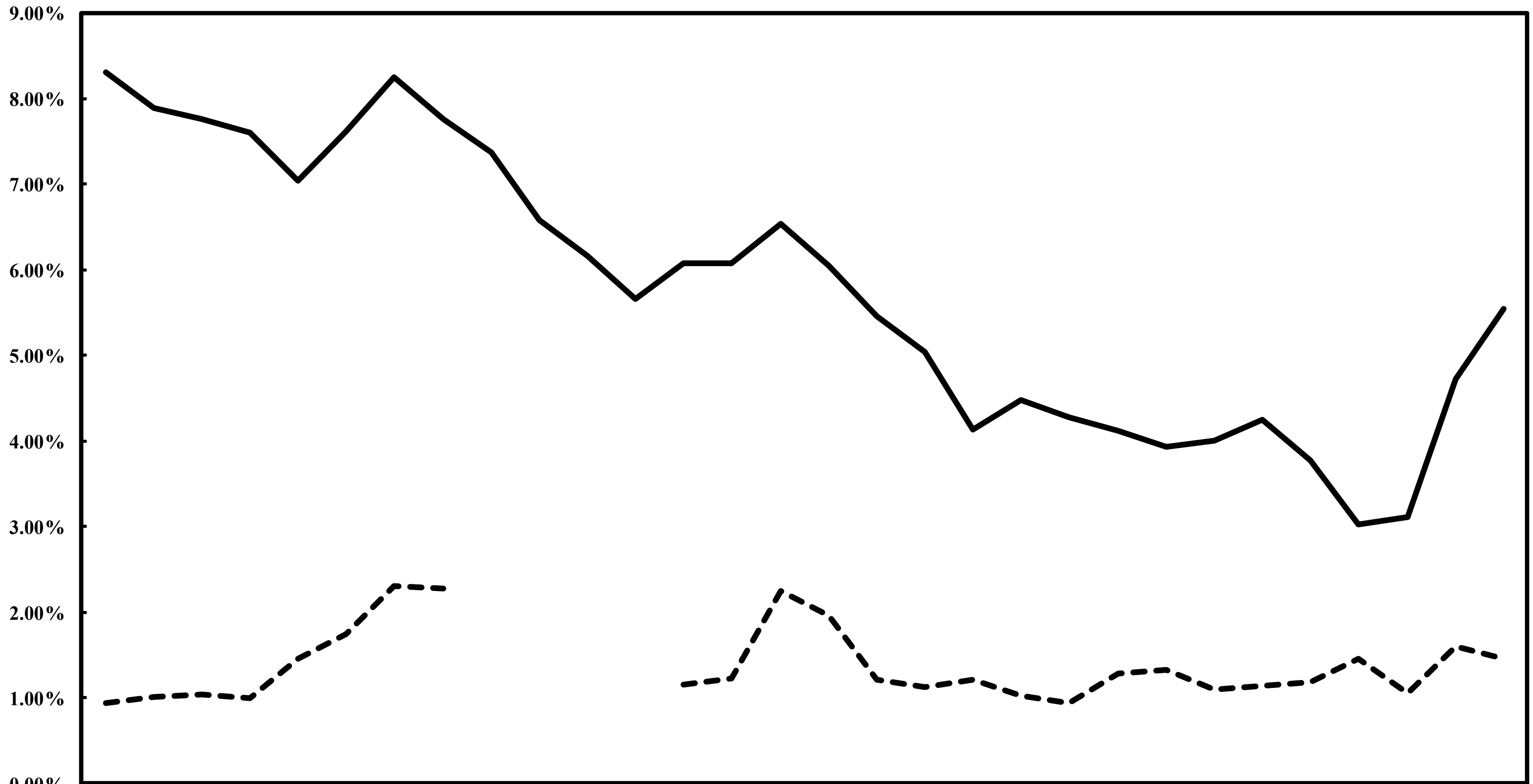
Source of Information: SNL Financial and SEC filings

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2019-2023
and the Twelve Months Ended August 2024

Years	Aa Rated	A Rated	Baa Rated	Average
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
2021	2.97%	3.11%	3.36%	3.15%
2022	4.53%	4.72%	5.03%	4.77%
2023	5.39%	5.54%	5.84%	5.59%
Five-Year Average	3.86%	4.03%	4.36%	4.09%
Months				
Sep-23	5.72%	5.86%	6.15%	5.91%
Oct-23	6.19%	6.34%	6.61%	6.38%
Nov-23	5.82%	5.96%	6.20%	5.99%
Dec-23	5.27%	5.42%	5.68%	5.46%
Jan-24	5.34%	5.48%	5.73%	5.51%
Feb-24	5.42%	5.56%	5.79%	5.59%
Mar-24	5.43%	5.55%	5.79%	5.59%
Apr-24	5.67%	5.79%	6.01%	5.83%
May-24	5.62%	5.74%	5.97%	5.78%
Jun-24	5.50%	5.61%	5.84%	5.65%
Jul-24	5.54%	5.64%	5.85%	5.68%
Aug-24	5.27%	5.38%	5.61%	5.42%
Twelve-Month Average	5.57%	5.69%	5.94%	5.73%
Six-Month Average	5.51%	5.62%	5.85%	5.66%
Three-Month Average	5.44%	5.54%	5.77%	5.58%

Source: Mergent Bond Record

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A-rated Public Utility	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.77	3.02	3.11	4.72	5.54
Spread vs. 30-year	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.33	1.10	1.14	1.19	1.46	1.06	1.60	1.45

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Jan-21	2.91%	1.82%	1.09%
Feb-21	3.09%	2.04%	1.05%
Mar-21	3.44%	2.34%	1.10%
Apr-21	3.30%	2.30%	1.00%
May-21	3.33%	2.32%	1.01%
Jun-21	3.16%	2.16%	1.00%
Jul-21	2.95%	1.94%	1.01%
Aug-21	2.95%	1.92%	1.03%
Sep-21	2.96%	1.94%	1.02%
Oct-21	3.09%	2.06%	1.03%
Nov-21	3.02%	1.94%	1.08%
Dec-21	3.13%	1.85%	1.28%
Jan-22	3.33%	2.10%	1.23%
Feb-22	3.68%	2.25%	1.43%
Mar-22	3.98%	2.41%	1.57%
Apr-22	4.32%	2.81%	1.51%
May-22	4.75%	3.07%	1.68%
Jun-22	4.86%	3.25%	1.61%
Jul-22	4.78%	3.10%	1.68%
Aug-22	4.76%	3.13%	1.63%
Sep-22	5.28%	3.56%	1.72%
Oct-22	5.88%	4.04%	1.84%
Nov-22	5.75%	4.00%	1.75%
Dec-22	5.28%	3.66%	1.62%
Jan-23	5.20%	3.66%	1.54%
Feb-23	5.29%	3.80%	1.49%
Mar-23	5.39%	3.77%	1.62%
Apr-23	5.13%	3.68%	1.45%
May-23	5.36%	3.86%	1.50%
Jun-23	5.38%	3.87%	1.51%
Jul-23	5.41%	3.96%	1.45%
Aug-23	5.71%	4.28%	1.43%
Sep-23	5.86%	4.47%	1.39%
Oct-23	6.34%	4.95%	1.39%
Nov-23	5.96%	4.66%	1.30%
Dec-23	5.42%	4.14%	1.28%
Jan-24	5.48%	4.26%	1.22%
Feb-24	5.56%	4.38%	1.18%
Mar-24	5.55%	4.36%	1.19%
Apr-24	5.79%	4.66%	1.13%
May-24	5.74%	4.62%	1.12%
Jun-24	5.61%	4.44%	1.17%
Jul-24	5.64%	4.46%	1.18%
Aug-24	5.38%	4.15%	1.23%
	Recent Average:	12-month:	1.23%
		6-month:	1.17%
		3-month:	1.19%

<u>Common Equity Risk Premiums</u>
<u>Years 1926-2022</u>

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.40%	5.27%	7.13%	2.83%
Average Across All Interest Rates	12.02%	6.06%	5.96%	4.91%
High Interest Rates	11.63%	6.87%	4.76%	7.03%

Source of Information: <u>2023 SBBI Yearbook Stocks, Bonds, Bills, and Inflation</u>

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
2020	18.40%	15.40%	1.37%
2021	28.71%	-2.66%	1.88%
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
2022	-18.11%	-26.18%	4.24%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%
97	12.02%	6.06%	4.91%

Yields for Treasury Constant Maturities
Yearly for 2019-2023
and the Twelve Months Ended August 2024

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
2020	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
2021	0.10%	0.27%	0.46%	0.86%	1.19%	1.44%	1.98%	2.05%
2022	2.79%	2.98%	3.05%	3.00%	3.01%	2.95%	3.30%	3.12%
2023	5.08%	4.58%	4.30%	4.06%	4.02%	3.96%	4.25%	4.09%
Five-Year Average	2.08%	2.04%	2.04%	2.08%	2.20%	2.28%	2.66%	2.68%
Months								
Sep-23	5.44%	5.02%	4.74%	4.49%	4.46%	4.38%	4.65%	4.47%
Oct-23	5.42%	5.07%	4.89%	4.77%	4.82%	4.80%	5.13%	4.95%
Nov-23	5.28%	4.88%	4.64%	4.49%	4.53%	4.50%	4.84%	4.66%
Dec-23	4.96%	4.46%	4.19%	4.00%	4.04%	4.02%	4.32%	4.14%
Jan-24	4.79%	4.32%	4.11%	3.98%	4.03%	4.06%	4.39%	4.26%
Feb-24	4.92%	4.54%	4.33%	4.19%	4.21%	4.21%	4.49%	4.38%
Mar-24	4.99%	4.59%	4.38%	4.20%	4.21%	4.21%	4.46%	4.36%
Apr-24	5.14%	4.87%	4.71%	4.56%	4.56%	4.54%	4.77%	4.66%
Jan-24	5.16%	4.86%	4.66%	4.50%	4.49%	4.48%	4.71%	4.62%
Feb-24	5.11%	4.74%	4.50%	4.32%	4.30%	4.31%	4.54%	4.44%
Mar-24	4.90%	4.50%	4.29%	4.16%	4.19%	4.25%	4.56%	4.46%
Apr-24	4.43%	3.97%	3.79%	3.71%	3.77%	3.87%	4.25%	4.15%
Twelve-Month Average	5.05%	4.65%	4.44%	4.28%	4.30%	4.30%	4.59%	4.46%
Six-Month Average	4.96%	4.59%	4.39%	4.24%	4.25%	4.28%	4.55%	4.45%
Three-Month Average	4.81%	4.40%	4.19%	4.06%	4.09%	4.14%	4.45%	4.35%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated May 31, 2024 and August 30, 2024

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2024	Third	4.6%	4.1%	3.9%	4.0%	4.2%	4.9%	5.7%
2024	Fourth	4.3%	3.9%	3.7%	3.9%	4.2%	4.9%	5.7%
2025	First	3.9%	3.7%	3.6%	3.8%	4.1%	4.8%	5.7%
2025	Second	3.8%	3.5%	3.6%	3.8%	4.1%	4.8%	5.7%
2025	Third	3.6%	3.5%	3.6%	3.8%	4.1%	4.8%	5.7%
2025	Fourth	3.4%	3.4%	3.6%	3.8%	4.1%	4.8%	5.7%
Long-range CONSENSUS								
2025		4.0%	3.8%	3.9%	4.0%	4.2%	5.1%	6.0%
2026		3.6%	3.7%	3.8%	4.0%	4.2%	5.1%	6.0%
2027		3.5%	3.6%	3.8%	4.0%	4.2%	5.1%	6.1%
2028		3.5%	3.6%	3.9%	4.0%	4.3%	5.2%	6.1%
2029		3.5%	3.6%	3.9%	4.2%	4.4%	5.3%	6.2%
2030		3.5%	3.6%	3.9%	4.2%	4.4%	5.3%	6.2%
Averages:								
	2026-2030	3.5%	3.6%	3.9%	4.1%	4.3%	5.2%	6.1%
	2031-2035	3.4%	3.6%	3.9%	4.2%	4.4%	5.2%	6.2%

Measures of the Market Premium

Historical Market Premium

Avg. to Low Interest Rates	(Rm)	(Rf)	
1926-2022 Arith. mean	12.21%	3.87%	8.34%

Forecast Market Premium

Value Line	Dividend Yield		Median Appreciation Potential		Median Total Return
As of: 30-Aug-24	2.1%	+	9.73%	=	11.83%
Risk-free Rate of Return (Rf)					3.75%
					8.08%
Average - Historical/Forecast					8.21%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 3 & 4; Safety Rank of 1 & 2; Financial Strength of B++ & A;
Price Stability of 75 to 95; Betas of .80 to 1.00; and Technical Rank of 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AbbVie Inc	Drug	3	2	A	95	0.85	3
Analog Devices Inc	Insurance (Prop/Cas.)	3	2	A	85	1.00	3
Arthur J Gallagher and Company	Semiconductor	3	1	A	95	0.95	3
Booz Allen Hamilton Holding Corporatio	Financial Svcs. (Div.)	4	2	B++	85	0.85	3
Brown and Brown Inc	Industrial Services	3	1	A	95	0.95	3
Brown Forman Corp (Class B)	Financial Svcs. (Div.)	4	1	A	95	0.90	4
Caseys General Stores Inc	Beverage	3	2	B++	85	0.90	3
Cboe Global Markets	Retail (Hardlines)	3	2	A	95	0.80	4
Dolby Laboratories Inc	Brokers & Exchanges	4	2	A	90	0.95	3
FactSet Research Systems Inc	Brokers & Exchanges	3	2	A	90	1.00	4
Franklin Electric Co Inc	Entertainment Tech	3	2	A	95	0.90	3
GATX Corp	Industrial Services	4	2	A	85	0.95	3
Hanover Insurance Group Inc	Information Services	3	2	B++	95	0.95	4
Huntington Ingalls Industries Inc	Retail Building Supply	3	2	A	80	0.95	3
Intercontinental Exch.	Electrical Equipment	3	1	A	95	0.95	4
Keysight Technologies	Railroad	3	2	A	80	0.90	4
Lincoln Electric Holdings Inc	Insurance (Prop/Cas.)	3	2	A	90	1.00	3
McCormick and Co	Aerospace/Defense	3	2	B++	90	0.80	4
MSC Industrial Direct Co Inc	Brokers & Exchanges	4	2	B++	90	0.90	4
O Reilly Automotive Inc	Computer Software	3	2	B++	90	0.90	3
Pfizer Inc	Financial Svcs. (Div.)	4	2	A	90	0.80	4
Philip Morris International Inc	Precision Instrument	3	2	A	95	0.95	3
RLI Corp	Machinery	3	2	A	95	0.80	3
Selective Insurance Group Inc	Food Processing	3	2	B++	90	0.85	4
Sonoco Products	Machinery	3	2	A	95	1.00	4
Tradeweb Markets Inc	Retail Automotive	3	2	A	80	0.90	3
UniFirst Corp	Trucking	3	2	A	90	0.90	3
United Parcel Service	Computer Software	3	2	A	85	0.80	3
Verisk Analytics Inc	Drug	3	2	B++	95	0.90	3
Waters Corp	Tobacco	3	2	A	85	0.95	3
Watts Water Technologies Inc	Insurance (Prop/Cas.)	3	2	B++	80	1.00	3
Average		3	2	A	90	0.91	3
Gas Group	Average	3	2	A	87	0.88	4

Source of Information: Value Line Investment Survey for Windows, August 2024

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2019-2023 and
Projected 3-5 Year Returns

Company	2019	2020	2021	2022	2023	Average	Projected 2027-29
AbbVie Inc	-	NMF	NMF	NMF	NMF	-	NMF
Analog Devices Inc	16.3%	15.2%	6.8%	13.6%	14.2%	13.2%	15.5%
Arthur J Gallagher and Company	12.8%	13.2%	10.7%	12.2%	9.0%	11.6%	15.5%
Booz Allen Hamilton Holding Corporation	56.4%	50.8%	54.5%	61.3%	69.2%	58.4%	34.0%
Brown and Brown Inc	11.9%	12.8%	14.0%	14.6%	15.6%	13.8%	20.0%
Brown Forman Corp (Class B)	41.9%	29.1%	30.6%	24.0%	29.1%	30.9%	49.5%
Caseys General Stores Inc	16.1%	16.2%	15.2%	16.8%	16.6%	16.2%	16.0%
Cboe Global Markets	11.1%	13.9%	14.6%	6.8%	19.0%	13.1%	14.0%
Dolby Laboratories Inc	11.1%	9.5%	11.9%	8.2%	8.5%	9.8%	10.0%
FactSet Research Systems Inc	52.5%	41.6%	42.5%	39.1%	35.0%	42.1%	32.0%
Franklin Electric Co Inc	12.3%	12.1%	16.3%	17.5%	16.0%	14.8%	18.0%
GATX Corp	10.9%	6.5%	9.0%	10.7%	11.3%	9.7%	13.5%
Hanover Insurance Group Inc	11.4%	11.1%	10.1%	8.5%	2.3%	8.7%	26.5%
Huntington Ingalls Industries Inc	36.5%	36.6%	19.4%	16.6%	16.6%	25.1%	16.0%
Intercontinental Exch.	12.7%	12.8%	12.8%	13.1%	12.4%	12.8%	11.5%
Keysight Technologies	30.0%	27.8%	30.8%	33.4%	32.4%	30.9%	29.0%
Lincoln Electric Holdings Inc	35.8%	31.6%	43.2%	47.0%	41.9%	39.9%	22.0%
McCormick and Co	20.8%	19.4%	18.7%	14.6%	14.4%	17.6%	16.0%
MSC Industrial Direct Co Inc	20.0%	20.1%	23.4%	25.5%	24.0%	22.6%	16.5%
O Reilly Automotive Inc	NMF	NMF	-	-	-	-	NMF
Pfizer Inc	25.8%	11.0%	29.0%	32.8%	2.4%	20.2%	22.0%
Philip Morris International Inc	-	-	-	-	-	-	NMF
RLI Corp	11.8%	10.4%	14.5%	17.8%	15.9%	14.1%	13.5%
Selective Insurance Group Inc	12.0%	9.1%	13.5%	13.0%	12.1%	11.9%	31.0%
Sonoco Products	19.8%	18.2%	19.4%	22.6%	19.6%	19.9%	17.0%
Tradeweb Markets Inc	2.5%	3.9%	4.9%	6.2%	6.8%	4.9%	9.5%
UniFirst Corp	10.0%	7.8%	8.1%	5.4%	5.2%	7.3%	7.5%
United Parcel Service	NMF	NMF	NMF	57.2%	43.6%	50.4%	48.5%
Verisk Analytics Inc	19.9%	26.4%	23.7%	45.5%	NMF	28.9%	51.5%
Waters Corp	-	NMF	NMF	NMF	55.8%	55.8%	26.0%
Watts Water Technologies Inc	14.2%	12.3%	16.0%	18.4%	18.3%	15.8%	14.0%
Average						22.2%	22.0%
Median						16.0%	16.8%
Average (excluding companies with values >20%)						12.7%	14.0%

Comparable Earnings Approach

Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DELTA	**)**	
NATURAL GAS COMPANY, INC. FOR AN	**)**	**CASE NO. 2024-00346**
ADJUSTMENT OF GAS RATES	**)**	

TESTIMONY OF
ABDUL-AZEEZ ODUSANYA
CONTROLLER
DELTA NATURAL GAS COMPANY, INC.

Filed: November 25, 2024

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Background

Q. Please state your name and business address.

A. My name is Abdul-Azeez Odusanya. My business address is 3617 Lexington Road, Winchester, Kentucky 40391.

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

A. I am employed by Delta Natural Gas Company, Inc. ("Delta") as its Controller. I joined Delta in May 2023.

Q. Please briefly describe your educational background.

A. I have two Masters degrees from the University of Kentucky; I received a Master of Science in Economics in 2004 and a Master of Business Administration in 2022. I completed my Bachelor's Degree in Nigeria in 1999. I passed the Certified Public Accountant exams and became a CPA in 2008 and have maintained my licensure since I received it.

Q. Please briefly describe your professional history.

A. I have experience in multiple industries in financial and accounting roles. After I became a CPA, I worked at Toyota Tsusho as the Corporate Operations Accountant. Following that, I served as the Director of Financial Planning and Treasury at Rhino Energy, LLC. Prior to joining Delta, I worked at UK Healthcare as a Senior Finance Specialist in the Budget unit of the Finance group. I also have consulting experience with various companies.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present certain schedules required by 807 KAR 5:001 Section 16 filed with Delta's application.

Filing Requirements

Q. Please state which filing requirements you are sponsoring in this case.

A. I am sponsoring or co-sponsoring the following filing requirements:

807 KAR 5:001 Section 16(6)(a)	Statement regarding requirements for pro forma adjustments to base period.	Tab 8
807 KAR 5:001 Section 16(6)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Tab 9
807 KAR 5:001 Section 16(6)(c)	Capitalization and net investment rate base shall be based on a 13-month average for the forecasted period.	Tab 10
807 KAR 5:001 Section 16(6)(d)	No revisions to the forecast.	Tab 11
807 KAR 5:001 Section 16(6)(e)	Commission may require alternative forecast.	Tab 12
807 KAR 5:001 Section 16(6)(f)	Reconciliation of rate base and capital.	Tab 13
807 KAR 5:001 Section 16(7)(d)	Annual and monthly budgets.	Tab 17
807 KAR 5:001 Section 16(7)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: subsections (1) through (4) and (12).	Tabs 22 to 25, 33
807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings	Tab 40
807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 2 (gas).	Tab 41
807 KAR 5:001 Section 16(7)(l)	Annual report to shareholders or members and statistical supplements covering the most recent 2 years from the application filing date.	Tab 42
807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts Chart.	Tab 43
807 KAR 5:001 Section 16(7)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast.	Tab 44
807 KAR 5:001 Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months immediately prior to base period, each month of base period, and subsequent months, as available.	Tab 45

807 KAR 5:001 Section 16(7)(p)	SEC's annual report (Form 10-K) for most recent 2 years, any Form 8-Ks issued during past 2 years, and any Form 10-Qs issued during past 6 quarters.	Tab 46
807 KAR 5:001 Section 16(7)(q)	Independent auditor's annual opinion report, with any written communication from auditor which indicates the existence of a material weakness in internal controls.	Tab 47
807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Tab 48
807 KAR 5:001 Section 16(7)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program.	Tab 50
807 KAR 5:001 Section 16(7)(u)	Amounts charged or allocated by an affiliate.	Tab 51
807 KAR 5:001 Section 16(8)(a)	Jurisdictional financial summary for both base and forecasted periods.	Tab 54
807 KAR 5:001 Section 16(8)(b)	Jurisdictional operating income summary for both base and forecasted periods.	Tab 55
807 KAR 5:001 Section 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods.	Tab 56
807 KAR 5:001 Section 16(8)(d)	Summary of jurisdictional adjustments to operating income.	Tab 57
807 KAR 5:001 Section 16(8)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases.	Tab 59
807 KAR 5:001 Section 16(8)(i)	Comparative income statements, revenue statistics, and sales statistics.	Tab 62
807 KAR 5:001 Section 16(8)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period.	Tab 64

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Q. Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(6)?

A. Yes, I am sponsoring all information required by 807 KAR 5:001 Section 16(6). The schedule required by 807 KAR 5:001 Section 16(6)(f) reconciles capitalization versus rate base. As shown in Tab 13, Delta's pro forma rate base is $180,570,376, which agrees to unadjusted pro forma capitalization of $180,570,376. The reconciling difference between pro forma rate base of $180,570,376 and adjusted pro forma capitalization of $180,480,799 is the 13-month average short-term debt of $89,578 removed for ratemaking purposes.

Q. Please describe Tab 17 of the Filing Requirements.

A. Tab 17 provides Delta's annual and monthly budgets for 2023, 2024, and 2025.

Q. Describe the information you are sponsoring required by 807 KAR 5:001 Section 16(7)(h).

A. For each of the three forecasted years included in the capital construction budget, I am sponsoring the operating income statement, balance sheet, statement of cash flows, revenue requirements necessary to support the forecasted rate of return, and rate base supporting the financial forecast.

Q. Is Delta providing a chart of accounts that is more detailed than the Uniform System of Accounts in Tab 43?

A. Yes. Delta uses the SAP data platform for accounting purposes and at the end of each month, the SAP accounts are translated into the FERC accounts. The primary difference between the two systems is that SAP categorizes operations and maintenance expenses by cost element while the FERC system of accounts organizes them around event/activity. There is no difference in total expenses or net income between the two systems.

Q. Please describe Tabs 44 and 45.

A. Tab 44 provides the latest 12 months of monthly managerial reports, which show monthly actuals compared to the forecast. Tab 45 describes with narrative explanations the variances between the actuals and budgeted amounts for October 2023 through August 2024.

Q. Please describe Tab 59.

A. Tab 59 provides a schedule showing rate case expense, outside services, professional service expenses, charitable contributions, certain civic and political activities, organization membership dues, country club expenditures, marketing, sales and advertising, director's fees and expenses, employee events, and employee gift expenses for the base period and forecasted period. The schedule also notes the amounts that are booked below the line and not proposed to be recovered in rates.

Q. How does Delta derive value from the industry associations and organizations of which it is a member?

A. Delta derives significant value from its membership in dues-paying organizations. Delta's employees participate in these groups to gain knowledge, training, timely information, and experience throughout the industry to allow Delta to provide service to its customers in the most economical, cost-effective, safe, and reliable manner. As an example, I attended an educational rate case course sponsored by the American Gas Association, which was very helpful in learning the rate case process.

Q. Do any of the dues-paying organizations participate in lobbying?

A. Yes. Many of the organizations in which Delta participates do not engage in any lobbying. But for those that do, I have appropriately excluded from Delta's revenue requirement the portions of association dues attributable to lobbying based on the lobbying percentages identified in the organization's invoice.

Q. Are you sponsoring other filing requirements that you do not describe in detail in your testimony?

A. Yes, I am sponsoring each of the filing requirements shown in the table in my testimony. I describe certain filing requirements further below. Additionally, a number of these filing requirements are not applicable to Delta, confirm that information is presented in the manner requested, or simply provide reports or lists that do not require explanation. I have not described these filing requirements in detail in my testimony.

<u>Budgeting Process</u>

Q. Can you please describe the budgeting process Delta has utilized?

A. Certainly. Delta's local management team directs the development of Delta's budget. It is a bottom-up process, in which our team analyzes the priorities, needs, and expectations for Delta and our customers. Delta has utilized this budget process to prepare the forecasted test year information in this case.

There are five major inputs in the financial budgeting process: (1) capital budget; (2) expense budget; (3) revenue budget; (4) financing and interest requirements; and (5) depreciation. I am primarily involved with the expense budget, financing and interest requirements, and depreciation. Mr. Brown discusses the development of the capital budget and revenue budget in his testimony.

The expense budget begins within Delta's departments, which includes estimating salary and benefit data. Once all approvals are complete, each department prepares detailed monthly cost center budgets that are loaded into SAP for monitoring and reporting. The remaining components of the financial budgeting process, which are depreciation expense and financing and interest requirements are based on approved depreciation rates and the debt costs in the issued securities.

Q. Did Delta use the budget to develop its projections for the forecasted test period in this case?

A. Yes, the proposed amounts in the forecasted test period align with Delta's budget.

Employee Level and Labor Forecast

Q. At Delta, are you responsible for the labor forecast?

A. Yes. I work with Peoples Natural Gas ("PNG") in the preparation of the labor forecast for Delta. I review the employee level for reasonableness.

Q. How is Delta's employee level projected to change?

A. Tab 30 shows the forecasted number of employees for the years 2024 through 2027. The 2024 forecast includes 153 full-time employees. We project 149 employees in 2025, which remains constant through 2027. The forecast assumes Delta is fully staffed and does not count any part-time employees.

Affiliate Allocations

Q. You are co-sponsoring Tab 51. Please describe your role in the affiliate allocation process.

A. Certainly. I am responsible for reviewing the affiliate allocations from PNG. I review each of the allocations on a monthly basis and have the opportunity to request more detail or contest any allocations. When I started at Delta, I discussed the process with PNG to gain a full understanding of the methodologies for allocation.

Q. Do you review each affiliate allocation?

A. Yes. I review the amount and calculation for each allocation to ensure it is correct. I contact PNG when I have questions regarding the rationale for the allocation, the calculation, or any other concerns.

<u>Deferral Accounting Request</u>

Q. Did Delta make a tax change associated with the natural gas safe harbor rules?

A. Yes. On April 14, 2023, the IRS issued Revenue Procedure 2023-15, which provides safe harbor methods of accounting for taxpayers that have a depreciable interest in natural gas transmission or distribution property and pay or incur certain costs to maintain, repair, replace, or improve such property. Delta's parent company, PNG, made tax classification changes based on Revenue Procedure 2023-15 that will result in tax savings.

Q. Did Delta incur any costs to make this method change?

A. Yes. PNG engaged Ernst & Young and Regulated Capital to perform a study to determine which property was eligible for more favorable tax rate changes. Delta's portion of these study expenses is $162,900.

Q. Is Delta requesting regulatory asset treatment for the savings associated with this method change?

A. Yes. Delta is requesting a regulatory asset be established for the costs associated with the study to determine which property was eligible for a favorable tax change. These costs were necessary to achieve tax savings, which will benefit customers.

Q. Why is a regulatory asset appropriate for study-related costs?

A. The Commission has authorized deferral accounting in four circumstances when a utility has incurred:

> (a) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (b) an expense resulting from a statutory or administrative directive; (c) an

> expense in relation to an industry-sponsored initiative: or (d) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[1]

Two of these circumstances apply here: (1) The study costs and reduction in taxes due to the natural gas safe harbor rules are extraordinary and nonrecurring, and (2) The study costs result from a federal administrative directive. The Commission has previously found deferral accounting treatment is appropriate for savings associated with tax changes.[2]

Q. Over what period of time does Delta propose to amortize the regulatory asset?

A. Delta proposes to amortize the regulatory asset over a three-year period.

Q. Does this conclude your testimony?

A. Yes.

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[1] *Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with Two 2015 Major Storm Events*, Case No. 2016-00180, Order (Ky. PSC Nov. 3, 2016).

[2] *Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, and Duke Energy Kentucky, Inc.*, Case No. 2017-00477, Order (Ky. PSC Dec. 27, 2017).

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF CLARK)

The undersigned, **Abdul-Azeez Odusanya**, being duly sworn, deposes and says he is Controller of Delta Natural Gas Company, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

aodusanya
ABDUL-AZEEZ ODUSANYA

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of November, 2024.

Jennifer Page Bingham (SEAL)
Notary Public

My Commission Expires:
June 19, 2027

JENNIFER PAGE BINGHAM
NOTARY PUBLIC
STATE AT LARGE KENTUCKY
COMM. # KYNP74158
MY COMMISSION EXPIRES JUNE 19, 2027

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF GAS RATES	**)))**	**CASE NO. 2024-00346**

TESTIMONY OF
WILLIAM C. PACKER
VICE PRESIDENT, REGULATORY ACCOUNTING AND REGIONAL CONTROLLER
ESSENTIAL UTILITIES, INC.

Filed: November 25, 2024

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Q. Please state your name and business address.

A. My name is William C. Packer. My business address is 762 W. Lancaster Avenue, Bryn Mawr, Pennsylvania 19010.

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

A. I am employed by Essential Utilities, Inc. ("Essential"), which is the ultimate parent company of Delta Natural Gas Company, Inc. ("Delta" or "Company"), as Vice President Regulatory Accounting and Regional Controller.

Q. Please describe your educational and professional experience.

A. I graduated from Richard Stockton College of New Jersey in 1998 with a Bachelor of Science degree in Business Studies with a concentration in Accounting. I began my more than 20-year career in the utility industry in September 1999, when I joined New Jersey American Water Company ("American") as a General Staff Accountant and from 2001 to 2005 held various positions in finance and accounting at American. At American, I had the opportunity to support the rate-making process by working closely with operating subsidiaries in 23 states, preparing schedules, and answering interrogatories.

I began my career at Essential in March 2005 where I joined Aqua New Jersey, Inc., as Assistant Controller. Since then, I have held a variety of positions in finance and accounting. In April 2017, I was promoted to the position of Vice President – Controller of Aqua PA. Since starting at Essential, I have been the chief accounting and revenue requirement witness in rates cases filed in Pennsylvania since 2008 and in New Jersey since 2005. I have also provided expert witness testimony for Aqua North Carolina, Inc., a subsidiary of Essential.

Q. What are your duties as Vice President, Regulatory Accounting and Regional Controller?

A. My overarching responsibility is to lead the execution of regulatory strategies – including transmission and distribution rate setting to recover investments and operating costs – to optimize revenues and return on investments. I am responsible for ensuring that the financial planning process achieves the strategic objectives from both a short and long-term perspective. I also oversee efforts to achieve all capital resources required to provide the most cost effective and efficient means of operation. In addition to this, I also serve as the Regional Controller for Essential's largest water subsidiary Aqua Pennsylvania, Inc. and Aqua New Jersey, Inc. In my capacity as Regional Controller, I directly oversee the financial operations of these two subsidiaries and assist local leadership in the discharge of our duty to provide safe, adequate, and reliable utility service to our customers.

Q. Have you testified before the Kentucky Public Service Commission?

A. Yes. I testified in Delta's last base rate case, Case No. 2021-00085.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the support that Essential is providing to Delta. As part of my position, I assist Delta with rates and accounting issues, especially with regard to topics that involve collaboration between Delta and Essential. My testimony describes: (1) the budgeting process; (2) Delta's capital structure; (3) cost of capital; (4) income taxes; (5) affiliate allocations; (6) Delta's compensation structure; and (7) benefits that are offered to employees.

Q. Are you sponsoring any of the filing requirements in this case?

A. Yes, I am sponsoring or co-sponsoring the following filing requirements:

807 KAR 5:001 Section 16(7)(u)	Information related to any amounts charged, allocated, or paid to utility by an affiliate or general or home office
807 KAR 5:001 Section 16(8)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes
807 KAR 5:001, Section 16(8)(g)	Analysis of payroll costs
807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period
807 KAR 5:001 Section 16(8)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure

Budgeting Process

Q. Can you provide an overview of the budgeting process at Essential?

A. Yes. As referenced by Mr. Brown, the leadership team at each of our subsidiaries is the owner and preparer of their respective budgets and strategic plans. Specifically, the state subsidiary President and the chief financial personnel, usually the state Controller, direct the preparation. Together, they are responsible to work with their own management teams to prepare budgets that are specific to their state and are representative of the operating conditions, regulatory guidelines, and other factors unique to the subsidiary. The Essential finance team also works closely with each subsidiary with regard to the timeline for developing the budgets and specific plans, and coordination of the budget review processes. In its totality, our process is a collaborative effort across the organization that ensures that both local and corporate management are in concurrence on the plans and futures of each subsidiary.

Q. What is your role in the process?

A. Aside from participating in a direct preparation role in my capacity as Regional Controller, I, among other executives, participate in the review of the budgets to ensure their completeness and accuracy.

Q. Do you agree with the use of a forecasted test year in this case?

A. Yes. Forecasted test years are more prevalent in the utility industry and I support their use when available. Doing so allows for timely recovery of investments and ordinarily allows for a greater amount of time between base rate filings, which lowers filing costs and provides a longer period of stable rates for customers.

Q. How did Delta determine the capital projects that are included in the forecasted test period in this case?

A. The capital projects included in the forecasted test period in this case were determined by Delta's construction schedules and budget, and only those projects that are used and useful were included in the forecasted test period. The capital projects are discussed more extensively in Mr. Morphew's testimony.

Q. Can you please describe how the sales forecast was developed?

A. The Company's sales forecast is based upon the actual results experienced in 2023, as Delta's revenues continue to be quite flat. The Company's analysis of historical billing determinants, volumes, and weather is supported by Mr. Wernert. The conclusions drawn from that analysis support utilizing the actual billing determinants from 2023 as a reasonable basis for setting rates in this proceeding.

Q. Please explain how operation and maintenance expenses are budgeted for inclusion in the forecasted test period in this case.

A. Delta's operation and maintenance expenses in the base year, which are the twelve months ending February 28, 2025, are constructed utilizing six months of actual results through August 2024 and six months of projections. The base year is adjusted for specific line items, as shown in the Company's accounting exhibits. The forecasted data aligns with Delta's budget.

Q. Did Delta include certain assumptions concerning the cost of capital when developing the forecasted test period for these cases?

A. Yes, Delta included assumptions concerning their capital structures, cost of equity, and cost of debt in developing the forecasted test period supporting the rate application in this case. Assumptions that are based on the forecasted cost of equity are set forth in Mr. Moul's direct testimony.

<u>GRCF</u>

Q. Has Delta prepared a computation of a gross revenue conversion factor ("GRCF") for the forecasted test period as required by 807 KAR 5:001 Section 16(8)(h)?

A. Yes. This information is located at Tab 61 to Delta's application.

Q. Please describe the GRCF Delta calculated.

A. The GRCF is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. The use of a GRCF is a long-standing practice in calculating the revenue requirement and is necessary to calculate the adjustment to income taxes, which vary in direct proportion to changes in revenues, in determining the overall revenue requirement. The federal and state income tax rates are calculated as shown at Tab 61. The GRCF is used to compute the respective calculated revenue deficiency based on the associated calculated net operating income deficiency and includes components for bad debt rate/uncollectible expense and the PSC/utility regulatory assessment fee.

Capital Structure

Q. Please describe Delta's capital structure.

A. A significant indicator of any company's financial strength is its level of debt as compared to its total capitalization. A lower percentage of debt signals that a company should have sufficient cash flow to meet its interest and other debt obligations. Maintaining a moderate level of debt affords a company greater flexibility to raise additional funds when needed. Cumulatively, this leads to lower interest costs. Delta and Essential are mindful of these principles in managing Delta's capital structure.

For the forecasted test period, Delta has projected a debt-to-capitalization ratio of 47.24 percent. This is consistent with the commitment made in Case No. 2018-00369 that Delta maintain a maximum debt-to-capitalization ratio, excluding working capital borrowing, of 55 percent.

Q. What is Delta's credit rating?

A. Delta does not have its own credit rating from either Moody's or Standard and Poor's. However, its affiliates at Peoples Natural Gas ("Peoples") and Essential do have ratings. Essential and Peoples have an A- issuer credit rate from S&P. Regarding Moody's, Essential has an Baa2 and Peoples has an Baa1.

Q. Can you please describe Essential's dividend policy?

A. Yes. As a utility, a stable dividend is an important component of our ability to attract capital in the markets. At Essential, our policy is to achieve a 50% to 60% payout ratio on an annual basis.

Q. Please explain how Essential's dividend policy has been implemented with regard to Delta?

A. As it pertains to Delta, the goal is to maintain the approximate range of 50% equity capital and 50% permanent long-term debt capital. In the course of running the business operations, it is necessary to infuse additional capital and/or dividend excess capitalization to the parent in order to maintain this approximate range. The number of times this is necessary is dependent on each utility subsidiary's financial operating needs considering its costs and investment activities.

Cost of Capital Summary

Q. Has Delta prepared a cost of capital summary for both the base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(j)?

A. Yes. This information is located at Tab 63 of the application. This schedule consists of two sub-schedules. Sheet 1 of 2 shows the cost of capital summary for the base period and contains embedded supporting schedules for each component of the capital structure. Sheet 2 of 2 sets forth the cost of capital summary for the forecasted period and likewise contains embedded schedules for each component of the capital structure. These schedules show that for the base year ending February 28, 2025, Delta's capitalization is 54.57% equity, 40.61% long term debt, and 4.82% short term debt. For the purposes of the forecasted test period, the Company has updated its 13-month average projection through June 30, 2026, which is the first full year rates would be in effect from this case and arrived at a proposed capital structure of 52.76% equity, 47.24% long term debt, and 0% short term debt.

Federal and State Income Tax Summary

Q. Has Delta prepared jurisdictional federal and state income tax summaries for both base and forecasted test periods as required by 807 KAR 20 5:001 Section 16(8)(e)?

A. Yes. This information is located in Tab 58 to the application.

Affiliate Costs and Services

Q. Are you sponsoring 807 KAR 5:001 Section 16(7)(u), which sets forth information regarding amounts charged or allocated to Delta by an affiliate?

A. Yes. This information is located in Tab 51 to the application.

Q. Please describe the range of affiliate services that are available to Delta through being a party of the Essential family of utilities.

A. Delta, as part of the PNG and Essential family of utilities, is the beneficiary of a multitude of resources and services including, but not necessarily limited, to the following:

- Accounting
- Accounts Payable
- Audit
- Communications
- Customer Relations
- Cybersecurity
- Finance/Planning/Budget
- Fleet Management/Supply Chain
- Human Relations
- Information Technology
- Labor Relations
- Legal
- Safety
- Tax
- Treasury

Q. Can you please explain how costs from Essential are allocated to Delta?

A. Yes. Delta has a utility services agreement with its immediate parent company, PNG Companies LLC ("PNG") that was approved by the Commission in Case No. 2018-00379. Costs from Essential are first allocated to PNG, and then to Delta, in accordance with the services agreement.

Q. Does Delta's management have the opportunity to challenge and question affiliate expenses?

A. Certainly, and PNG and Essential expects that Delta's management will do so. It is vitally important to our family of utilities that the services performed and allocated to Delta reflect accurate and responsible expenses that provide a good value to Delta's customers.

<u>Employee Compensation</u>

Q. Are you sponsoring the analysis of payroll costs required by 807 KAR 5:001, Section 16(8)(g)?

A. Yes. This information is at Tab 60 of Delta's application.

Q. Please provide an overview of Delta's employee structure.

A. Delta employs approximately 149 people to run the business. Delta has projected its labor assuming no additions to its employee complement.

Q. Can you describe Essential's approach to setting compensation and how that philosophy pertains to Delta?

A. Essential's philosophy and goal is to compensate proficient employees equal at or better than the 50^{th} percentile of the market. In this regard, we utilize a peer group comparative approach that starts with a complete job description and then market prices are assessed based on available compensation data in the market.

Q. Have a majority of Delta's workforce recently voted to unionize?

A. Yes. A majority of Delta's workers voted to join the Utility Workers Union of America, AFL-CIO in August 2022. Prior to August 2022, no Delta employees were members of a collective bargaining organization. Mr. Morphew discusses the union contract negotiations in more detail in his direct testimony.

Q. Does this rate case includes the results of union contract negotiations?

A. Yes. The payroll costs in the forecasted test year include the updated union contract rates.

Q. Does Delta's non-union employee compensation package include incentive pay?

A. Yes, non-union employees are still eligible for incentive pay. As a result of union contract negotiations, union employees are no longer eligible for incentive pay.

Q. Are you familiar with the Commission's prior orders on the recoverability of incentive compensation?

A. Yes. In summary, the Kentucky Public Service Commission has taken the position that employee compensation relative to incentive-based pay, both long-term and short-term, to the extent based on the delivery of financial metrics, is not permissible for recovery in base rates.

Q. Has Delta included incentive compensation expense in its forecast test period?

A. Yes, Delta has both short-term incentive and long-term incentive-based pay included in the forecasted test period. Delta has done so because, as explained below, Delta can demonstrate that the total compensation an employee can earn is reasonable based on the market. Having a component of an employee's total compensation at-risk is an important aspect of setting compensation.

Q. Why is having a portion of employee's compensation at-risk important?

A. We benchmark the reasonableness to market conditions on an all-in, total compensation basis. The primary component of an employee's pay is base pay. In addition to the base pay, certain employees may be eligible for both short-term and long-term incentive compensation. Short-term incentive compensation is designed to drive efficiency and performance that are consistent with our core values and mission. It gives the employees a true stake in the process, such that their ability to perform at the highest level could yield this component of their compensation. Specifically, the short-term incentive pay is measured by the following factors: individual goals (60%), safety (25%), customer satisfaction (10%), and environmental stewardship (5%). Similar to the short-term incentive plan, certain employees that are not eligible for the short-term plan may be eligible for Achievement Awards. These awards are discretionary in nature and are designed to reward specific performance that goes over and above the call of duty. Lastly, long-term incentive opportunities are meant to recruit and retain top-quality employees who best serve our customers through equity shares. These are typically performance and restricted shares of stock that are vested over three years. Based on the level of the employee, these components comprise the total compensation an employee can earn, which is a mix of base and at-risk compensation. This mix in pay structure is both competitive to the market and is designed to attract and retain the best talent as well as drive performance that ultimately benefits customers in the service they receive from the utility.

Q. Is there a review of compensation expense to ensure it is reasonable?

A. Yes. We employ the services of a Compensation Director. This role is charged with the evaluation of employee compensation relative to current market conditions. We evaluate approximately one-third of the jobs each year for updated trends and statistics.

Q. How does Delta's compensation structure benefit its customers?

A. Employee compensation that is reflective of current market expectations and trends enhances Delta's ability to attract and retain its talented workforce. The utility business is a long-term business, and as such, there are innumerable benefits to an experienced and mature workforce that is able to meet the demands of system operations, safety, and customer responsiveness.

Employee Benefits

Q. Please describe the benefits that are available to Delta employees.

A. As of 2024, all Delta employees are afforded the option to receive the Essential benefits packages including Health, Dental, Vision, Prescription, 401K, and Disability Insurance.

Q. How does this help Delta control the costs of its medical insurance offerings?

A. Essential's benefits plan afforded to all of its employees, including Delta, are procured at our parent company level, which maximizes the amount of employee participation and ultimately results in more affordable plans. Employees have multiple options for health benefit plans so that participants can better match their own personal circumstances, such as higher or lower deductible and health spending accounts. In addition to the plan packages, the Company also makes available certain resources to employees that both educate, bring awareness, and encourage our employees of the benefits of healthy lifestyles. In its entirety, the Company's plan for its approximate 3,200 employees is positioned well for it to control cost due to its economies of scale, diversified pool, and variety of plan options.

Q. Please summarize Delta's retirement benefits.

A. Delta's retirement benefits consist of a defined benefit pension plan and a defined contribution 401K plan. Effective in May 2021, the plan accrual of new benefits was frozen for employees who are still employed. In lieu of continuing to accrue for additional pension benefits, those employees have the option to participate in the 401K plan.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF PENNSYLVANIA)
) **SS:**
COUNTY OF MONTGOMERY)

The undersigned, **William Packer**, being duly sworn, deposes and says he is Vice President, Regulatory Accounting & Regional Controller for Essential Utilities, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

William C. Packer
WILLIAM PACKER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of November, 2024.

Jennifer Page Bingham (SEAL)
Notary Public

My Commission Expires:
June 19, 2027

JENNIFER PAGE BINGHAM
NOTARY PUBLIC
STATE AT LARGE KENTUCKY
COMM. # KYNP74158
MY COMMISSION EXPIRES JUNE 19, 2027

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DELTA	**)**	
NATURAL GAS COMPANY, INC. FOR AN	**)**	**CASE NO. 2024-00346**
ADJUSTMENT OF GAS RATES	**)**	

DIRECT TESTIMONY OF
JEFFREY W. WERNERT, JR
PRINCIPAL
THE PRIME GROUP, LLC

Filed: November 25, 2024

Table of Contents

Exhibits

Exhibit JWW-1 – Depreciation Study
Exhibit JWW-2 – Summary of Current and Proposed Depreciation Rates
Exhibit JWW-3 – Summary of Lead-Lag Study

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey W. Wernert, Jr. My business address is 2604 Sunningdale Place East, La Grange, Kentucky 40031.

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

A. I am a principal with The Prime Group, LLC, a firm located in La Grange, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. On whose behalf are you testifying in these proceedings?

A. I am testifying on behalf of Delta Natural Gas Company ("Delta"), which provides natural gas transportation and sales service in central and southeastern Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Delta's depreciation study supporting the proposed depreciation rates and to sponsor the lead-lag study which supports Delta's proposed cash working capital ("CWC") calculation.

Q. Please summarize your testimony.

A. My direct testimony addresses the following:

- **Depreciation Study.** I assisted with the preparation of a depreciation study for Delta using the Simulated Property Records ("SPR") model, which is the methodology used in Delta's previous depreciation studies approved by the Commission in Case Nos. 2004-00067, 2007-00089, 2010-00116 and 2021-00185.

- **Lead-Lag Study.** I assisted with the preparation of a lead-lag study using the same methodology utilized by Delta in Case No 2021-00185.

Q. Are you supporting certain information required by Commission Regulation 807 KAR 5:001, Section 16(7)?

A. Yes. I am sponsoring the following schedule for the corresponding Filing Requirements:

- Summary of Latest Depreciation Study Section 16(7)(s) Tab 49

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Depreciation Study, and (IV) Lead-Lag Study.

II. QUALIFICATIONS

Q. Please describe your educational and professional background.

A. I received a Bachelor of Engineering degree in Electrical Engineering from the University of Louisville in 2008 and a Master of Engineering degree in Electrical Engineering from the University of Louisville in 2009. Following completion of these degrees, I was hired as a Consultant by The Prime Group, LLC in July 2009. In October 2016, I was promoted to Principal and still hold this position today.

My responsibilities at the Prime Group include performing cost of service studies for electric and gas utilities, revenue requirement analyses, developing rates for electric utilities, performing depreciation and lead-lag studies, presenting on cost of service, rate design, and depreciation studies to electric industry groups, and assisting several electric utilities with stakeholder representation at the Midcontinent Independent System Operator ("MISO"). During my 15 years at the Prime Group, I have performed or assisted with the preparation of cost of service, rate studies, depreciation studies and/or lead-lag studies for over 100 investor-owned, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities.

III. DEPRECIATION STUDY

Q. Did you assist with the preparation of a depreciation study for Delta?

A. Yes. Under the supervision of my former colleague Steve Seelye, I assisted with the preparation of the depreciation study for Delta.

Q. Was a standard methodology used to determine the depreciation accrual rates?

A. Yes. Where suitable information was available, the Simulated Plant Record (SPR) methodology was used to determine the survivor curve that best fit the plant retirement data for Delta's plant accounts. The SPR methodology is described in *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners and in other publications. Where sufficient data were not available, or the resulting statistics were not satisfactory, I relied on professional experience and comparisons to the survivor curves and depreciation rates utilized by neighboring gas utilities. The methodology used to develop the depreciation accrual rates is described in more detail in the report included in Exhibit JWW-1.

Q. Was the same methodology used in this depreciation study as in studies filed by Delta in its last four rate cases (Case Nos. 2004-00067, 2007-00089, 2010-00116 and 2021-00185)?

A. Yes.

Q. Please describe the depreciation study report submitted in this proceeding.

A. The depreciation study submitted in this proceeding provides a detailed description of the methodologies used to determine Delta's proposed depreciation rates. The study is based on a comprehensive examination of Delta's service lives, net salvage percentages, and proposed depreciation rates. The report included in Exhibit JWW-1 consists of a narrative, an average service life (ASL) analysis, and a net salvage analysis. The results of the SPR analysis and the analysis of net salvage for the plant accounts are provided in the report.

Q. Have you prepared an exhibit summarizing the recommended depreciation rates for each distribution plant account?

A. Yes. Exhibit JWW-2 shows the current and proposed depreciation rates for each major plant account.

Q. What is your recommendation to the Commission?

A. It is my recommendation that Delta be allowed to implement the depreciation rates shown in Exhibit JWW-2.

IV. LEAD-LAG STUDY

Q. Did you prepare a lead-lag study for Delta for this proceeding?

A. Yes. Under the supervision of my former colleague Steve Seelye, I assisted with the preparation of a lead-lag study for Delta.

Q. Did Delta perform a lead-lag study in its Application in Case No. 2021-00185?

A. No. Prior to that proceeding, Delta used the 1/8th methodology to calculate CWC and proposed that same methodology in the Application in Case No. 2021-00185. This long-standing methodology resulted in a positive CWC value for Delta. During the course of that proceeding, Intervenors performed a lead-lag study which resulted in a negative CWC recommendation for Delta. Delta subsequently undertook its own lead-lag study which resulted in a slightly less negative CWC value. Ultimately, Delta proposed to set CWC to zero as a compromise position which was ultimately included in the Stipulation Agreement at the conclusion of the proceeding.

Q. In Kentucky, are utilities required to perform a lead-lag study?

A. No. However, many recent rate case proceedings in Kentucky have relied upon the results of a lead-lag study to set CWC requirements for gas and electric utilities.

Q. What period was used to perform the lead-lag study?

A. Although Delta utilizes a forecasted test year, the lead and lag days must be determined using actual historical data. A lead-lag study is essentially a statistical analysis that utilizes historical payment data to calculate lead days and lag days. The lead-lag studies were performed using revenue and expense data for the calendar year 2023.

Q. How were revenue lag days determined?

A. The revenue lag measures the number of days from the date service was rendered by Delta until the date payment was received from customers and the funds deposited and available to Delta. In the calculation, the revenue lag consists of four time spans: (1) meter reading lag, which is the time period from the midpoint of the service period to the meter read date; (2) billing lag, which is the period from when the meter is read to the date when the bill is invoiced; (3) collection lag, which is the period from when the bill is invoiced to when the customer payment is received; and (4) bank lag, which is the period from when the customer payment is received to when Delta has access to the funds. The collection lag was determined using the turnover approach, which calculates the collection lag days by dividing the average daily accounts receivable balance by the average daily revenues and pass-through items (*viz.*, sales taxes, gross receipt taxes, and franchise fees).

Q. Please summarize the components of the revenue lag for Delta's gas operations?

A. The revenue lag by component is summarized below (TABLE 1):

TABLE 1

Lag Component	
Meter Reading Lag	15.21
Billing Lag	7.00
Collection Lag	31.33
Bank Lag	1.00
Total Revenue Lag	54.54

Q. Have there been any significant changes in revenue lag since the last proceeding?

A. Yes. Upon completion of the lead-lag study, a more detailed review of the revenue lag components revealed a large change in the collection lag in 2023 compared to the study performed in Delta's last rate case. In the last case, Delta calculated a 10.72 day lag for collection lag based on calendar year 2020 data. Collection lag using 2023 data shows a 31.33 day lag, a substantial change from the previous filing. As discussed in more detail in Mr. John Brown's testimony, Delta carried an unusually high Accounts Receivable ("A/R") balance in 2023 due to several factors which are a focus of internal improvement efforts. Carrying higher A/R balances generally leads to longer collection lags which results in higher CWC requirements.

Q. Did you evaluate collection lag using a more recent historical period?

A. Yes. A more recent evaluation of collection lag using data from the twelve-months ending August 2024 resulted in a collection lag of 25.74 days, a roughly 18% reduction.

Q. Is Delta proposing a different collection lag than what was calculated in the lead-lag study?

A. Yes. Delta expects a continued reduction in A/R balances as internal improvements are made and as such, is proposing a collection lag of 15 days in this proceeding. We believe 15 days represents a more reasonable collection lag time which balances the impact of rate changes in this proceeding with the CWC requirements of the Company.

Q. Do you have a comparison showing the effect each of these collection lag times has on CWC?

A. The impact of the collection lag times discussed above on the overall CWC requirement are summarized below (TABLE 2):

TABLE 2

	Collection Lag	**Cash Working Capital Requirement**
Calendar Year 2023	31.33	$4,507,030
12 months ended August 2024	25.74	$3,443,391
Proposed	15.00	$ 1,399,833

Q. How were expense lead days determined?

A. Expense lead days were determined for the following expense categories, as applicable: (1) O&M expenses including purchased gas, payroll and related expenses, pension expenses, uncollectible expenses, charges from affiliates, and other; (2) income tax expenses, (3) taxes other than income, and (4) interest expenses. Expense lead days were determined by calculating the difference between the service date of the expense, or the mid-point of the service period of the expense, as applicable, and the date the expenditure was paid (i.e., cleared the bank) by the Company, and weighted by the contribution of each expense payment amount or category to the total. For example, with payroll expenses, the expense leads were determined by calculating the number of days from the mid-point of the payroll period (normally, bi-weekly) to the actual payment clearing date. For Delta's incentive pay contributions, the leads were calculated from the mid-point of the previous calendar year (service period) to the payment clearing date the following year. Affiliate charges are settled in the month following the month in which the charges are incurred; therefore, the leads are determined by calculating the days from the middle of the service month to the date when the expense is settled. For interest expenses, leads were determined by calculating the days from the mid-point of the interest accrual period to the date when the payment clears the Companies' bank accounts. For income taxes, leads were determined by calculating the days from the mid-point of the tax year to the statutory due date for the quarterly tax payments.

Q. Do you have an exhibit showing the lead-lag days for each category of revenue and expense for the calendar year 2023?

A. Yes. The summary of the lead-lag days based on calendar year 2023 are shown on Exhibit JWW-3.

Q. What is your recommendation to the Commission?

A. It is my recommendation that Delta's CWC be set to the level shown in Table 2 based on a 15-day collection lag.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF Kentucky)
) **SS:**
COUNTY OF Oldham)

The undersigned, **Jeff Wernert**, being duly sworn, deposes and says he is a Consultant for The Prime Group, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Jeff Wernert

JEFF WERNERT

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of November, 2024.

Jennifer Page Bingham (SEAL)
Notary Public

My Commission Expires:

June 19, 2027

JENNIFER PAGE BINGHAM
NOTARY PUBLIC
STATE AT LARGE KENTUCKY
COMM. # KYNP74158
MY COMMISSION EXPIRES JUNE 19, 2027

Exhibit JWW-1

Depreciation Study

The Prime Group LLC

2024 Depreciation Study

Delta Natural Gas Company

June 2024

William Steven Seelye – Managing Partner
Jeffrey Wernert – Principal
The Prime Group LLC©

Executive Summary

The Prime Group LLC ("The Prime Group") prepared a depreciation study for Delta Natural Gas Company ("Delta"). In developing its recommended depreciation rates, The Prime Group performed a Simulated Property Records ("SPR") analysis to identify the appropriate survivor curve and average service life ("ASL" or "service life") that most accurately matched Delta's historical retirement data. The Prime Group also performed an analysis of historical salvage values and removal costs to estimate net salvage percentages. In calculating the proposed depreciation rates the average service life depreciation procedure, the straight-line method, and the remaining life basis were utilized.

The depreciation study rates were determined using standard methodologies used in the industry and accepted by the Kentucky Public Service Commission ("KYPSC" or "Commission") for Delta in previous depreciation studies. Delta's filed depreciation studies in Case Nos. 2004-00067, 2007-00089, 2010-00116, and 2021-00185 used the same procedures and methodologies as used in the current study.

The primary purpose of performing a depreciation study is to ensure that there is an appropriate matching between the recovery of the original cost of plant and the useful economic life of the property. A service life that is too short places excessive burden on current customers to the benefit of future customers by charging current customers depreciation expenses that are overstated. A service life that is too long creates a risk that the utility may not be able to recover its costs, creates long-term exposure to risks of realizing stranded costs, and places an inappropriate burden on future customers.

Description of Delta

Delta is a gas distribution utility established in 1940 providing gas service to customers in central and eastern Kentucky. Delta serves approximately 40,000 residential, commercial industrial members and farm tap customers. Delta operates in 33 counties in the central and eastern part of Kentucky.

Description of Life Methodology

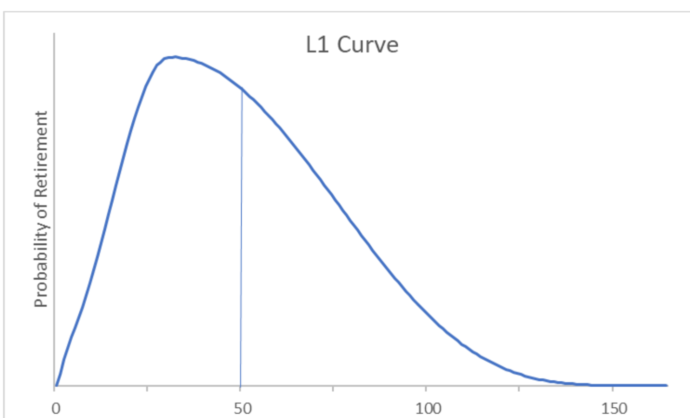
The purpose of performing a depreciation study is to ensure that the depreciation expenses recorded by the utility and included in cost of service represent a reasonably accurate and systematic measurement of the annual accrual levels necessary to distribute plant costs, less salvage and removal, over the estimated useful life of the assets.

In performing this study, data was compiled showing plant additions, retirements and transfers going back as far as 1940 shortly after when Delta was formed. Where sufficient data was available, the average service lives ("ASLs") were determined by identifying the survivor curve and associated ASL that best fit the pattern of retirements or plant balances from the historical data provided by Delta. A computer software model was used to perform a Simulated Property Records ("SPR") analysis using the plant additions and retirements for each major plant account. For each of 40 standard survivor curves, the SPR model calculated the (a) the sum of square differences (SSDs) between the actual retirements and simulated retirements, (b) the sum of absolute differences (SADs) between the actual retirements and simulated retirements, and (c) the SSDs between the actual plant balances and simulated plant balances for the years 2017, 2020, and 2023. The computer model also produces a graph of the simulated plant and simulated retirements compared to actual plant and retirements. These graphs are used in validating the survivor curve.

The survivor curves utilized in this study correspond to the "Iowa Curves" that were developed under the direction of Robley Winfrey at Iowa State University, as described in various bulletins and publications. These curves are still widely used within the gas and electric utility industries.

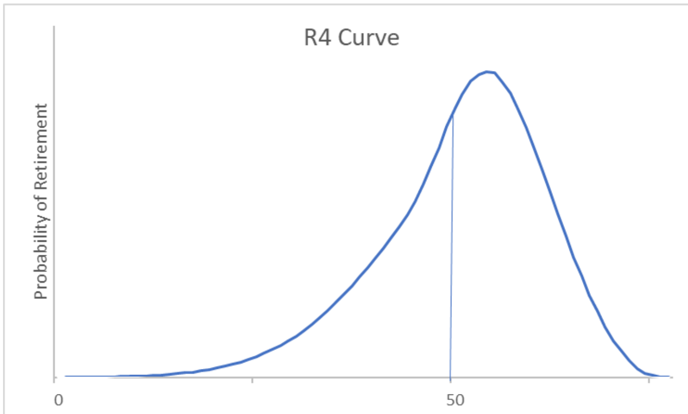
The original Iowa State publications identified four classes of survivor curves: (i) Left-Model Curves ("L" curves), (ii) Right-Model Curves ("R" curves), (iii) Symmetrical Curves ("S" curves), and (iv) Origin Model Curves ("O" curves).

With the "L" curve, most of the property is retired prior to the ASL; therefore, the probability density curve is skewed toward the left, as illustrated in the following graph showing an L1 curve with an ASL of 50 years:



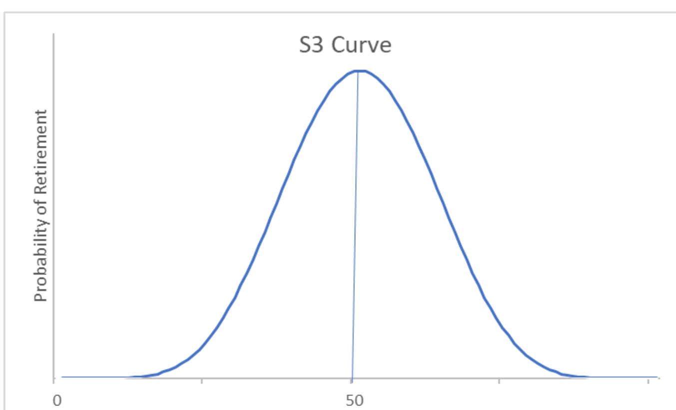
A characteristic of the "L" class of survivor curves is that while a high percentage of the property is retired prior to the average service life, the longer the property has been in service the less likely it is to fail, as illustrated by the long tail of the probability density curve on the right.

With an “R” curve, most of the property is retired after the ASL; therefore, the probability density curve is skewed to the right. This is illustrated in the following graph showing the R1 curve with an ASL of 50 years:

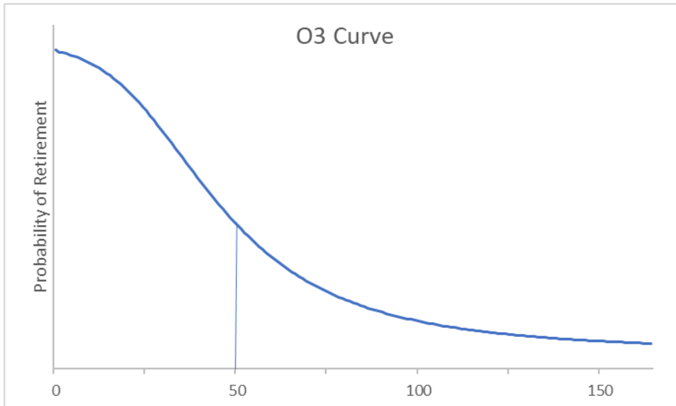


A characteristic of the “R” class of survivor curves is that most of the property is retired after the average service life.   However, the longer the property has been in service the more likely it is to fail, as illustrated by the short tail of the probability density curve on the right.

With the “S” curves, the retirements are distributed symmetrically about the ASL, in a manner similar to the bell-shaped Gaussian or Normal curve. This is illustrated in the following graph showing the S3 curve with an ASL of 50 years:



With the "O" class of curves, most of the plant is retired in the earliest years of the plant life, as illustrated in the following graph showing the O3 curve with an ASL of 50 years:

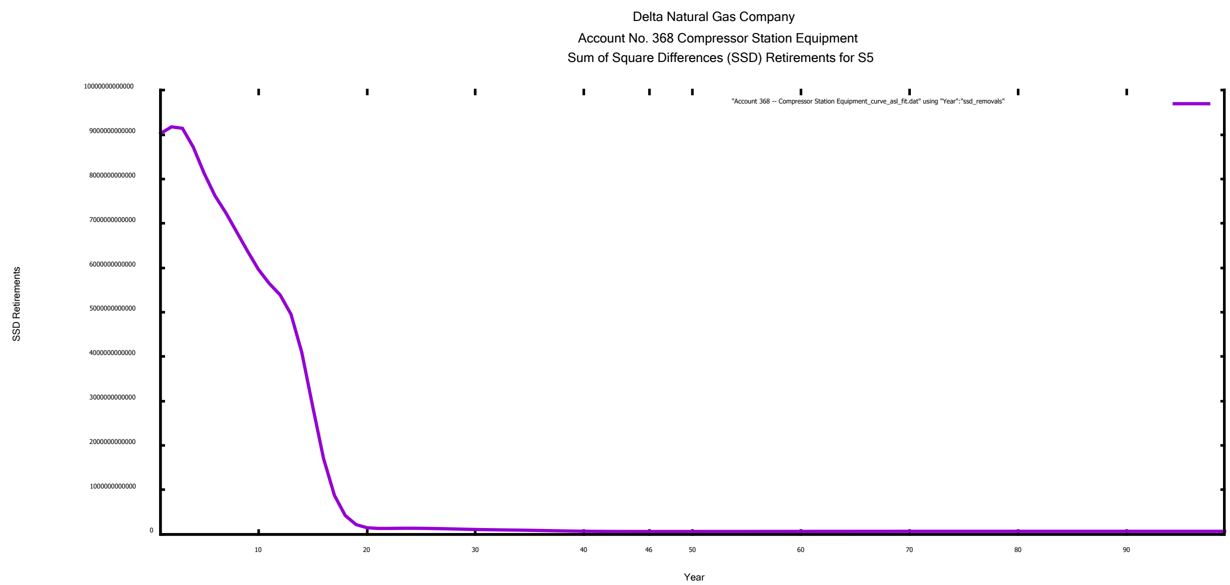


In addition to the curves identified in the Iowa State publications, so-called "half curves" were also utilized in the SPR analysis. Half curves are simple averages between two curves within the same class of Iowa Curves. For example, The S1.5 curve represents the simple average of an S1 and S2 curve.

The following is a list of the Iowa Curves used in the SPR analysis:

- **L Curves (11):** L0, L0.5, L1, L1.5, L2, L2.5, L3, L3.5, L4, L4.5, L5
- **R Curves (9):** R1, R1.5, R2, R2.5, R3, R3.5, R4, R4.5, R5
- **S Curves (13):** S0, S0.5, S1, S1.5, S2, S2.5, S3, S3.5, S4, S4.5, S5, S5.5, S6
- **O Curves (7):** O1, O1.5, O2, O2.5, O3, O3.5, O4

For each survivor curve, the SPR model identifies the ASL that "optimizes" the SSD between simulated and actual retirements by determining the ASL that generates the minimum SSD for each curve. The model also calculates the sum of absolute differences (SAD) for the optimal curve determined based on minimum SSD. This optimization process is illustrated in the graph showing the SSD between actual retirements and simulated retirements based on an S5 Iowa Curve for Delta's plant data for Transmission Compressor Station Equipment.



As can be seen from the above graph, the SSDs between simulated and actual retirements are minimized when the ASL is equal to approximately 46 years. This process is similar to the minimization of the sum of squares ("least squares") used in linear regression models.

The proposed Iowa Curves and associated ASLs for the major property groups were developed based on the information included in the SPR analysis while also considering qualitative information obtained from discussions with Delta's executive and engineering staff. The selection of the Iowa Curves and ASLs was guided by the minimum SSDs for retirements and plant balances.

Net Salvage Methodology

Net Salvage is the result of adding the gross salvage received for plant removed from service and the cost of removal. The trend in the industry is that removal costs are increasing more rapidly than salvage. Typically, net salvage is analyzed over the most recent five-year, ten-year or longer periods of time. Net Salvage is often adjusted if there is a discernable trend in the data.

In this study, 23 years of annual salvage amounts and removal accounts were analyzed for the transmission and distribution accounts. A net salvage percentage was calculated for each of the 23 years. The negative net salvage percentage is calculated as follows:

$$Negative\ Net\ Salvage\ Percentage = \frac{Gross\ Salvage - Removal\ Cost}{Plant\ Retirements}$$

Average net salvage percentages were also calculated for the 23-year period and the most recent five and ten years. Comparison of the 5-year average net salvage percentages to the 10- and 23-year average net salvage percentages generally indicated an increase in the negative net salvage percentages (i.e., becoming more negative).

Depreciation Rate Methodology

The depreciation accrual rates are calculated using the average service life depreciation procedure, the straight-line method, and the remaining life basis. Using this approach, the remaining life annual accrual for each category of plant is determined by dividing one less the net salvage percentage (stated as a ratio) by the ASL, as follows:

$$Depreciation\ Rate = \frac{1}{Remaining\ Life}$$

Where Remaining Life is determined based on the analysis of the calculated retirements and remaining life of each property year based on the selected ASL and Iowa Curve.

Analysis of Property Records

The service life analysis was based on accounting data for the years 1940 to 2023, which reflects the data utilized in Delta's 2009 Depreciation Study updated to include the 2010 to 2023 accounting data.

Account 376 – Distribution Mains is the account with the largest amount of assets. Delta's records included plant additions dating back to 1940. Account 376 was analyzed using the SPR model. Based on the SPR analysis, the R5 curve is recommended using an ASL of 55 years. The R5 curve with an ASL of 55 years results in a remaining life of 34.51 years. Using a negative net salvage of -3% for this account results in a depreciation rate of 2.98%, which is a slight reduction from the current depreciation rate of 3.05%.

For Account 378 – Measurement & Regulation Station - General, Delta's records included plant additions dating back to 1940. Account 378 was analyzed using the SPR model. Based on the SPR analysis, the L5 curve is recommended using an ASL of 50 years. The L5 curve with an ASL of 50 years results in a remaining life of 29.12 years. With a negative net salvage of -15%, the depreciation rate is 3.95%, which is an increase from the current depreciation rate of 3.18%.

For Account 380 – Services, Delta's records included plant additions dating back to 1990. Account 380 was analyzed using the SPR model. Based on the SPR analysis, the L0 curve is recommended using an ASL of 53 years. The L0 curve with an ASL of 53 years results in a remaining life of 44.88 years. Using a negative net salvage of -50% for this account results in a depreciation rate of 3.34%, which is a slight increase from the current depreciation rate of 3.10%.

For Account 381 – Meters, Delta's records included plant additions dating back to 1940. This account also includes additional meters formerly owned by People's Gas. Account 381 was analyzed using the SPR model. Based on the SPR analysis, the O2 curve is recommended using an ASL of 43 years. The O2 curve with an ASL of 46 years results in a remaining life of 31.4 years. Using a net salvage of zero for this account results in a depreciation rate of 3.18%, which is a slight increase from the current depreciation rate of 2.86%.

For Account 382 – Meter and Regulator Installations, Delta's records included plant additions dating back to 1940. Account 382 was analyzed using the SPR model. Based on the SPR analysis, the S0 curve is recommended using an ASL of 43 years. The S0 curve with an ASL of 43 years results in a remaining life of 29.81 years. Using a negative net salvage of -15% for this account results in a depreciation rate of 3.86%, which is a slight reduction from the current depreciation rate of 4.00%.

For Account 383 – House Regulators, Delta's records included plant additions dating back to 1940. This account also includes additional house regulators formerly owned by People's Gas. Account 383 was analyzed using the SPR model. Based on the SPR analysis, the S3 curve is recommended using an ASL of 43 years. The S3 curve with an ASL of 43 years results in a remaining life of 22.77 years. Using a net salvage of 2% for this account results in a depreciation rate of 4.30%, which is a slight increase from the current depreciation rate of 3.96%.

For Account 385 – Industrial Meter Sets, Delta's records included plant additions dating back to 1956. Account 385 was analyzed using the SPR model. Based on the SPR analysis, the L0 curve is recommended using an ASL of 49 years. The L0 curve with an ASL of 49 years results in a remaining life of 36.73 years. Using a negative net salvage of -5% for this account results in a depreciation rate of 2.86%, which is an increase from the current depreciation rate of 2.64%.

Account 367 – Transmission Mains is the account with the second largest amount of assets. Delta's records included plant additions dating back to 1951. Account 367 was analyzed using the SPR model. Based on the SPR analysis, the S3 curve is recommended using an ASL of 55 years. The S3 curve with an ASL of 55 years results in a remaining life of 30.63 years. Using a negative net salvage of -2.5% for this account results in a depreciation rate of 3.35%, which is an increase from the current depreciation rate of 2.88%.

For Account 368 – Transmission Compressor Station Equipment, Delta's records included plant additions dating back to 1951. Account 368 was analyzed using the SPR model. Based on the SPR analysis, the S5 curve is recommended using an ASL of 46 years. The S5 curve with an ASL of 46 years results in a remaining life of 26.3 years. Using a negative net salvage of -0.7% for this account results in a depreciation rate of 3.83%, which is an increase from the current depreciation rate of 3.20%.

For Account 369 – Transmission Measuring and Regulation Station Equipment, Delta's records included plant additions dating back to 1951. Account 369 was analyzed using the SPR model. Based on the SPR analysis, the L2 curve is recommended using an ASL of 34 years. The L2 curve with an ASL of 34 years results in a remaining life of 23.8 years. Using a negative net salvage of -7% for this account results in a depreciation rate of 4.50%, which is an increase from the current depreciation rate of 3.50%.

Other property accounts did not have sufficient data to perform an SPR analysis. It is therefore recommended that Delta's depreciation rates for these other accounts remain at their current levels.

The parameter results from the depreciation property record analysis, as discussed above, are shown in the following table (TABLE1):

TABLE 1

Delta Natural Gas Company
Analysis of Depreciation Rates

Account	Description	Survivor Curve		Average Srervice Life (ASL)		Remaining Life		Net Salvage		Depreciation Rates	
		Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	Current	Recommended
367	TRANSMISSION MAINS	S3	S3	53	55	35.5	30.63	-2.3	-2.5	2.88%	3.35%
368	COMPRESSOR STATION EQUIPMENT	S5	S5	48	46	31.6	26.3	-1	-0.7	3.20%	3.83%
369	MEASURING & REG STAT EQUIPMENT	L2	L2	44	34	30	23.8	-5	-7	3.50%	4.50%
376	DISTRIBUTION MAINS	R5	R5	53	55	32.82	34.51	0	-3	3.05%	2.98%
378	MEAS & REG STAT - GENERAL	L1	L5	49	50	34.9	29.12	-11	-15	3.18%	3.95%
380	SERVICES	L0	L0	53	53	45.1	44.88	-40	-50	3.10%	3.34%
381	METERS	O2	O2	46	43	35	31.4	0	0	2.86%	3.18%
382	METER & REGULATOR INSTALLATION	S0	S0	43	43	28	29.81	-12	-15	4.00%	3.86%
383	HOUSE REGULATORS	S3	S3	43	43	24.5	22.77	3	2	3.96%	4.30%
385	INDUSTRIAL METER SETS	L0	L0	49	49	37.9	36.73	0	-5	2.64%	2.86%

Recommended Depreciation Rates

In its previous depreciation studies, the remaining life method was used to determine Delta's depreciation rates. This was the methodology used in Delta's previous depreciation studies, which were approved by the Commission. As discussed above, the recommended service lives were developed based on an SPR analysis and the net salvage percentages were developed based on empirical data. The following table (TABLE 2) is a summary of the current depreciation rates and the recommended depreciation rates for the property accounts with sufficient historical to perform the SPR analysis. The Prime Group is recommending that the depreciation rates for other accounts remain at their current levels.

TABLE 2

Summary of Depreciation Rates

Account	Description	Depreciation Rates	
		Current	Recommended
367	TRANSMISSION MAINS	2.88%	3.35%
368	COMPRESSOR STATION EQUIPMENT	3.20%	3.83%
369	MEASURING & REG STAT EQUIPMENT	3.50%	4.50%
376	DISTRIBUTION MAINS	3.05%	2.98%
378	MEAS & REG STAT - GENERAL	3.18%	3.95%
380	SERVICES	3.10%	3.34%
381	METERS	2.86%	3.18%
382	METER & REGULATOR INSTALLATION	4.00%	3.86%
383	HOUSE REGULATORS	3.96%	4.30%
385	INDUSTRIAL METER SETS	2.64%	2.86%

It is recommended that Delta take measured steps in adjusting its service lives and net salvage percentages. Empirical data supports modifying the service lives and net salvage percentages for the above property accounts, resulting in relatively small changes in the depreciation rates.

Study Exhibits

On a Total Company Basis

Appendix A -- Analysis of Depreciation Rates

Appendix B – Analysis of Change in Depreciation Expenses

Appendix C – Depreciation Analysis by Account:

(a) Summary of SPR Analysis and Theoretical Reserve

(b) Graph of Survivor Curve

(c) Graph of Simulated Balances to Book Balances

(d) Account Investment Summary

(e) Net Salvage Table

Appendix A

Analysis of Depreciation Rates

Delta Natural Gas Company
Analysis of Depreciation Rates

Account	Description	Survivor Curve		Average Srervice Life (ASL)		Remaining Life		Net Salvage		Depreciation Rates	
		Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	Current	Recommended
367	TRANSMISSION MAINS	S3	S3	53	55	35.5	30.63	-2.3	-2.5	2.88%	3.35%
368	COMPRESSOR STATION EQUIPMENT	S5	S5	48	46	31.6	26.3	-1	-0.7	3.20%	3.83%
369	MEASURING & REG STAT EQUIPMENT	L2	L2	44	34	30	23.8	-5	-7	3.50%	4.50%
376	DISTRIBUTION MAINS	R5	R5	53	55	32.82	34.51	0	-3	3.05%	2.98%
378	MEAS & REG STAT - GENERAL	L1	L5	49	50	34.9	29.12	-11	-15	3.18%	3.95%
380	SERVICES	L0	L0	53	53	45.1	44.88	-40	-50	3.10%	3.34%
381	METERS	O2	O2	46	43	35	31.4	0	0	2.86%	3.18%
382	METER & REGULATOR INSTALLATION	S0	S0	43	43	28	29.81	-12	-15	4.00%	3.86%
383	HOUSE REGULATORS	S3	S3	43	43	24.5	22.77	3	2	3.96%	4.30%
385	INDUSTRIAL METER SETS	L0	L0	49	49	37.9	36.73	0	-5	2.64%	2.86%

Appendix B

Analysis of Change in

Depreciation Rates

Delta Natural Gas Company
Analysis of Depreciation Rates

Account	Description	Depreciation Rates		Change in
		Current	Recommended	Rate
367	TRANSMISSION MAINS	2.88%	3.35%	-0.46%
368	COMPRESSOR STATION EQUIPMENT	3.20%	3.83%	-0.63%
369	MEASURING & REG STAT EQUIPMENT	3.50%	4.50%	-1.00%
376	DISTRIBUTION MAINS	3.05%	2.98%	0.06%
378	MEAS & REG STAT - GENERAL	3.18%	3.95%	-0.77%
380	SERVICES	3.10%	3.34%	-0.24%
381	METERS	2.86%	3.18%	-0.33%
382	METER & REGULATOR INSTALLATION	4.00%	3.86%	0.14%
383	HOUSE REGULATORS	3.96%	4.30%	-0.34%
385	INDUSTRIAL METER SETS	2.64%	2.86%	-0.22%

Appendix C

Depreciation Analysis by Account

Account 367 – Transmission Mains

Delta Natural Gas Company
Account 367 -- Transmission Mains

Simulated Balance for Iowa Curve S3 with ASL = 55

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1951	61761	0	61761	0	61761	0	0
1952	0	0	61761	0	61761	0	0
1953	0	0	61761	0	61761	0	0
1954	8944	0	70705	0	70705	0	0
1955	95433	0	166138	0	166138	0	0
1956	153043	0	319181	0	319181	0	0
1957	2766	0	321947	0	321947	0	0
1958	40731	0	362678	0	362678	-0	0
1959	209986	0	572664	0	572664	-0	0
1960	443547	0	1016211	0	1016211	-0	0
1961	0	0	1016211	1	1016210	-1	1
1962	11049	0	1027260	1	1027257	-1	3
1963	5069	0	1032329	2	1032324	-2	5
1964	43691	0	1076020	4	1076011	-4	9
1965	401158	2041	1475137	8	1477162	2033	-2025
1966	185675	3161	1657651	12	1662825	3149	-5174
1967	42318	253	1699716	19	1705124	234	-5408
1968	570758	857	2269617	31	2275851	826	-6234
1969	10242	0	2279859	45	2286048	-45	-6189
1970	30291	0	2310150	69	2316269	-69	-6119
1971	390160	2034	2698276	100	2706330	1934	-8054
1972	220046	1507	2916815	143	2926233	1364	-9418
1973	20159	16495	2920479	206	2946186	16289	-25707
1974	155219	1027	3074671	280	3101124	747	-26453
1975	1038377	2117	4110931	380	4139122	1737	-28191
1976	667139	20496	4757574	517	4805743	19979	-48169
1977	32582	3803	4786353	678	4837647	3125	-51294
1978	351269	0	5137622	881	5188036	-881	-50414

Delta Natural Gas Company
Account 367 -- Transmission Mains

Simulated Balance for Iowa Curve S3 with ASL = 55

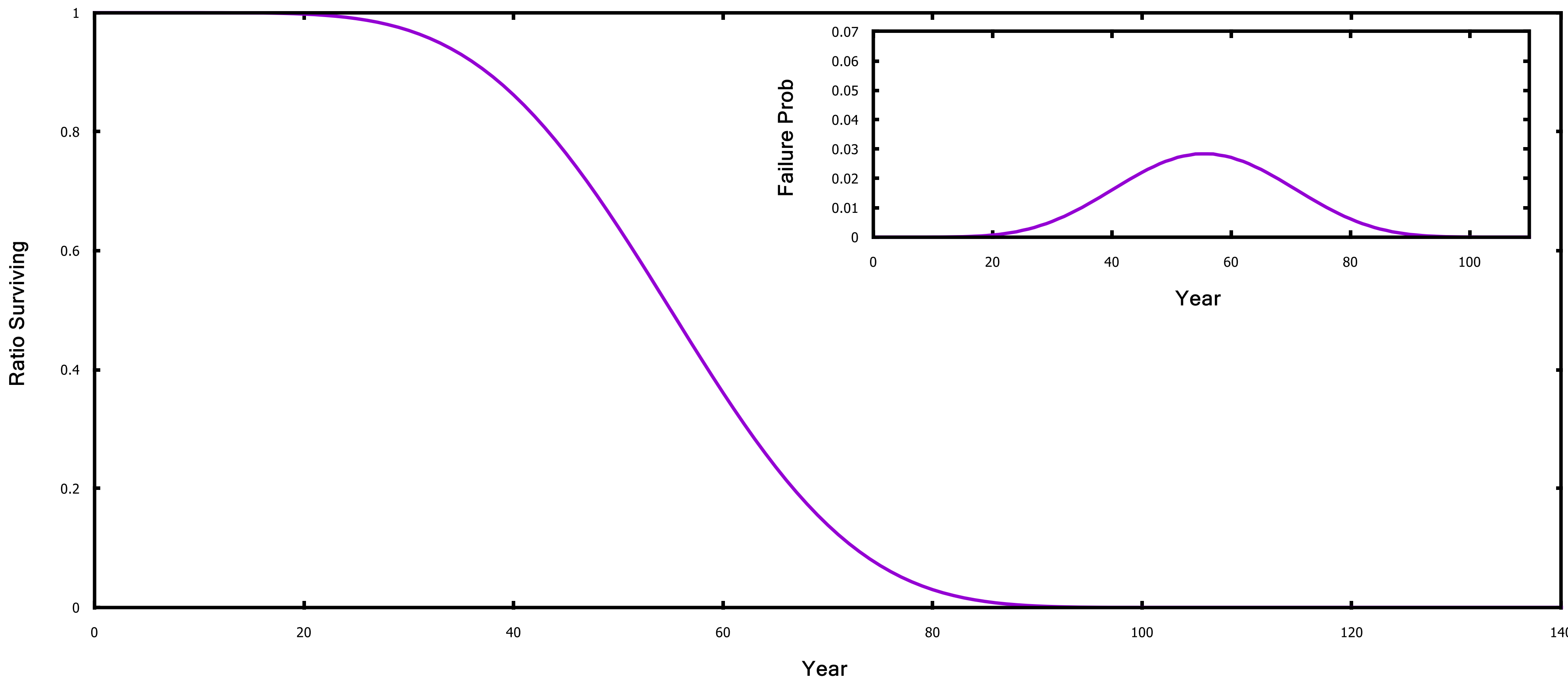
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1979	157163	49379	5245406	1148	5344051	48231	-98645
1980	637037	55435	5827008	1452	5979636	53983	-152628
1981	94865	6555	5915318	1827	6072674	4728	-157356
1982	67797	0	5983115	2305	6138166	-2305	-155051
1983	100369	1955	6081529	2819	6235717	-864	-154188
1984	124371	4268	6201632	3461	6356626	807	-154994
1985	920732	68009	7054355	4244	7273114	63765	-218759
1986	679514	6010	7727859	5060	7947568	950	-219709
1987	367787	37158	8058488	6089	8309266	31069	-250778
1988	407419	25639	8440268	7271	8709414	18368	-269146
1989	1575177	91099	9924346	8526	10276065	82573	-351719
1990	375466	55172	10244640	10064	10641467	45108	-396827
1991	590206	26277	10808569	11745	11219929	14532	-411360
1992	770645	69983	11509231	13593	11976981	56390	-467750
1993	1311531	10603	12810159	15762	13272749	-5159	-462590
1994	2015785	149281	14676663	18063	15270472	131218	-593809
1995	2576777	192503	17060937	20641	17826608	171862	-765671
1996	2231947	299672	18993212	23551	20035004	276121	-1041792
1997	983281	16271	19960222	26624	20991661	-10353	-1031439
1998	1073527	22418	21011331	30030	22035158	-7612	-1023827
1999	4791367	11535	25791163	33779	26792746	-22244	-1001583
2000	1951563	56873	27685853	37768	28706541	19105	-1020688
2001	710776	131121	28265508	42082	29375235	89039	-1109727
2002	3267445	0	31532953	46775	32595905	-46775	-1062952
2003	4131461	71705	35592709	51785	36675581	19920	-1082872
2004	1726918	197446	37122181	57085	38345414	140361	-1223233
2005	639279	281	37761179	62858	38921836	-62577	-1160657
2006	3695479	9636	41447022	68968	42548347	-59332	-1101325

Delta Natural Gas Company
Account 367 -- Transmission Mains

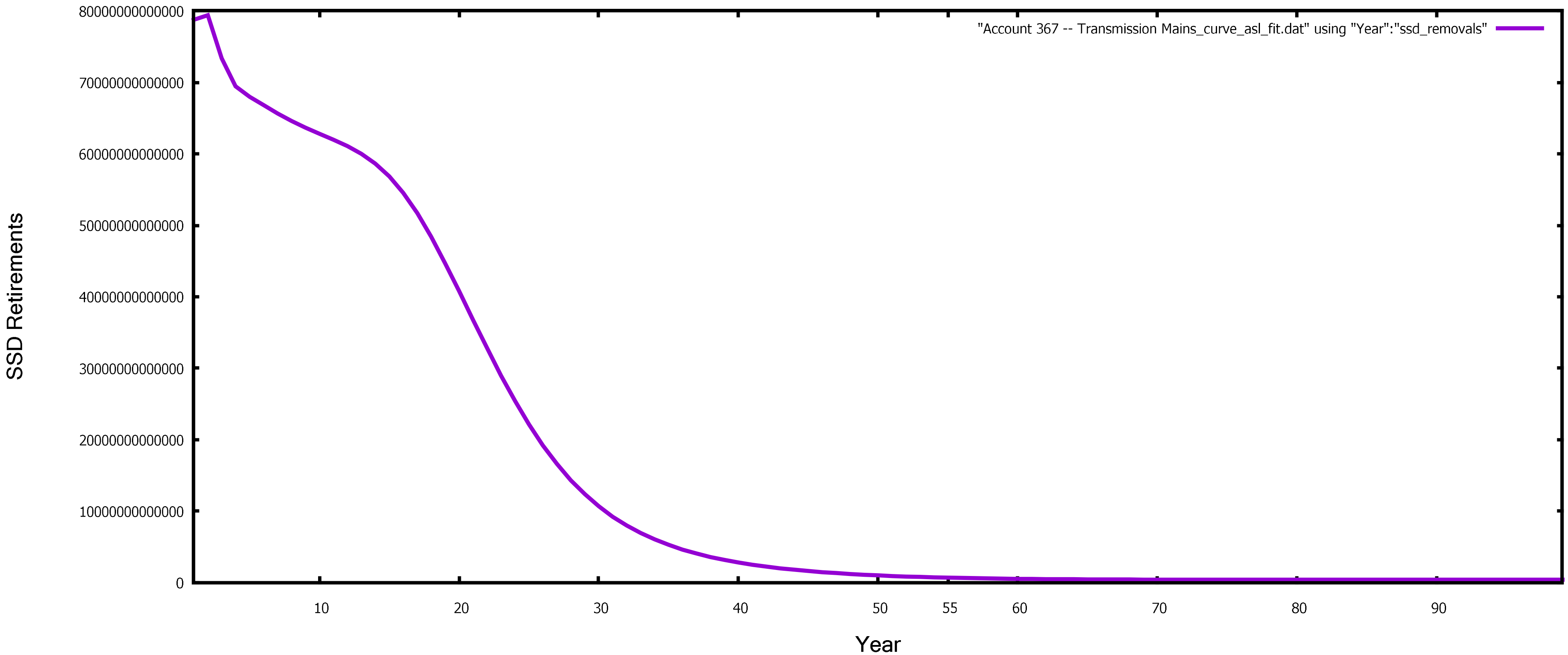
Simulated Balance for Iowa Curve S3 with ASL = 55

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2007	23029	413654	41056396	75394	42495982	338261	-1439586
2008	422077	30824	41447649	82421	42835639	-51596	-1387989
2009	584129	16882	42014896	89752	43330016	-72870	-1315120
2010	132196	10519	42136573	97546	43364665	-87027	-1228093
2011	171642	5091	42303123	106059	43430248	-100968	-1127125
2012	125059	31477	42396705	114861	43440446	-83384	-1043741
2013	82313	827	42478191	124454	43398305	-123627	-920114
2014	414762	10678	42882274	134746	43678320	-124068	-796046
2015	1738289	4801	44615762	145487	45271123	-140686	-655360
2016	252006	34975	44832793	157452	45365677	-122477	-532883
2017	218446	28149	45023090	170016	45414106	-141867	-391016
2018	951614	39298	45935407	183376	46182344	-144079	-246937
2019	659733	5126	46590014	198272	46643805	-193146	-53791
2020	243108	28574	46804548	213839	46673075	-185265	131474
2021	532392	720	47336219	230599	46974868	-229878	361352
2022	0	4357	47331862	248972	46725895	-244615	605967
2023	4403458	0	51735320	268275	50861078	-268275	874242

Account No. 367 -- Transmission Mains
Iowa Curve: S3 ASL: 55 Years



Delta Natural Gas Company
Account No. 367 Transmission Mains
Sum of Square Differences (SSD) Retirements for S3



Delta Natural Gas Company
Account Investment Summary

367 -- Transmission Mains

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	-	-	-
1941	-	-	-	-	-
1942	-	-	-	-	-
1943	-	-	-	-	-
1944	-	-	-	-	-
1945	-	-	-	-	-
1946	-	-	-	-	-
1947	-	-	-	-	-
1948	-	-	-	-	-
1949	-	-	-	-	-
1950	-	-	-	-	-
1951	-	-	61,761.00	-	61,761.00
1952	61,761.00	-	-	-	61,761.00
1953	61,761.00	-	-	-	61,761.00
1954	61,761.00	-	8,944.00	-	70,705.00
1955	70,705.00	-	95,433.00	-	166,138.00
1956	166,138.00	-	153,043.00	-	319,181.00
1957	319,181.00	-	2,766.00	-	321,947.00
1958	321,947.00	-	40,731.00	-	362,678.00
1959	362,678.00	-	209,986.00	-	572,664.00
1960	572,664.00	-	443,547.00	-	1,016,211.00
1961	1,016,211.00	-	-	-	1,016,211.00
1962	1,016,211.00	-	11,049.00	-	1,027,260.00
1963	1,027,260.00	-	5,069.00	-	1,032,329.00
1964	1,032,329.00	-	43,691.00	-	1,076,020.00
1965	1,076,020.00	-	401,158.00	2,041.00	1,475,137.00
1966	1,475,137.00	-	185,675.00	3,161.00	1,657,651.00
1967	1,657,651.00	-	42,318.00	253.00	1,699,716.00
1968	1,699,716.00	-	570,758.00	857.00	2,269,617.00
1969	2,269,617.00	-	10,242.00	-	2,279,859.00
1970	2,279,859.00	-	30,291.00	-	2,310,150.00
1971	2,310,150.00	-	390,160.00	2,034.00	2,698,276.00
1972	2,698,276.00	-	220,046.00	1,507.00	2,916,815.00
1973	2,916,815.00	-	20,159.00	16,495.00	2,920,479.00
1974	2,920,479.00	-	155,219.00	1,027.00	3,074,671.00
1975	3,074,671.00	-	1,038,377.00	2,117.00	4,110,931.00
1976	4,110,931.00	-	667,139.00	20,496.00	4,757,574.00
1977	4,757,574.00	-	32,582.00	3,803.00	4,786,353.00
1978	4,786,353.00	-	351,269.00	-	5,137,622.00
1979	5,137,622.00	-	157,163.00	49,379.00	5,245,406.00
1980	5,245,406.00	-	637,037.00	55,435.00	5,827,008.00
1981	5,827,008.00	-	94,865.00	6,555.00	5,915,318.00
1982	5,915,318.00	-	67,797.00	-	5,983,115.00
1983	5,983,115.00	-	100,369.00	1,955.00	6,081,529.00
1984	6,081,529.00	-	124,371.00	4,268.00	6,201,632.00
1985	6,201,632.00	-	920,732.00	68,009.00	7,054,355.00
1986	7,054,355.00	22,818.00	656,696.00	6,010.00	7,727,859.00
1987	7,727,859.00	(52,209.00)	419,996.00	37,158.00	8,058,488.00

Delta Natural Gas Company
Account Investment Summary

367 -- Transmission Mains

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1988	8,058,488.00	-	407,419.00	25,639.00	8,440,268.00
1989	8,440,268.00	171,586.00	1,403,591.00	91,099.00	9,924,346.00
1990	9,924,346.00	(34,163.00)	409,629.00	55,172.00	10,244,640.00
1991	10,244,640.00	114,998.00	475,208.00	26,277.00	10,808,569.00
1992	10,808,569.00	-	770,645.00	69,983.00	11,509,231.00
1993	11,509,231.00	-	1,311,531.00	10,603.00	12,810,159.00
1994	12,810,159.00	172,928.00	1,842,857.00	149,281.00	14,676,663.00
1995	14,676,663.00	-	2,576,777.00	192,503.00	17,060,937.00
1996	17,060,937.00	25,867.00	2,206,080.00	299,672.00	18,993,212.00
1997	18,993,212.00	-	983,281.00	16,271.00	19,960,222.00
1998	19,960,222.00	-	1,073,527.00	22,418.00	21,011,331.00
1999	21,011,331.00	4,126,412.00	664,955.00	11,535.00	25,791,163.00
2000	25,791,163.00	-	1,951,563.00	56,873.00	27,685,853.00
2001	27,685,853.00	-	710,776.00	131,121.00	28,265,508.00
2002	28,265,508.00	-	3,267,444.96	-	31,532,952.96
2003	31,532,952.96	-	4,131,461.00	71,705.00	35,592,708.96
2004	35,592,708.96	(51,036.00)	1,777,954.00	197,446.00	37,122,180.96
2005	37,122,180.96	(128,430.77)	767,710.11	281.19	37,761,179.11
2006	37,761,179.11	-	3,695,478.73	9,635.91	41,447,021.93
2007	41,447,021.93	-	23,028.84	413,654.37	41,056,396.40
2008	41,056,396.40	-	422,077.24	30,824.43	41,447,649.21
2009	41,447,649.21	-	584,129.18	16,882.01	42,014,896.38
2010	42,014,896.38	-	132,195.71	10,519.38	42,136,572.71
2011	42,136,572.71	-	171,641.54	5,090.87	42,303,123.38
2012	42,303,123.38	-	125,058.62	31,477.30	42,396,704.70
2013	42,396,704.70	-	82,312.73	826.70	42,478,190.73
2014	42,478,190.73	-	414,761.55	10,678.43	42,882,273.85
2015	42,882,273.85	1,031,954.00	706,335.07	4,800.74	44,615,762.18
2016	44,615,762.18	-	252,005.98	34,974.77	44,832,793.39
2017	44,832,793.39	-	218,445.77	28,148.74	45,023,090.42
2018	45,023,090.42	-	951,613.95	39,297.67	45,935,406.70
2019	45,935,406.70	-	659,732.92	5,125.79	46,590,013.83
2020	46,590,013.83	-	243,108.48	28,574.08	46,804,548.23
2021	46,804,548.23	-	532,391.61	720.50	47,336,219.34
2022	47,336,219.34	-	-	4,356.86	47,331,862.48
2023	47,331,862.48	-	4,403,457.76	-	51,735,320.24

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 367
Transmission Mains

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	28,265,508	131,121	0.5%	-	-	-	0.0%
2002	31,532,953	-	0.0%	-	-	-	0.0%
2003	35,592,709	71,705	0.2%	-	-	-	0.0%
2004	37,122,181	197,446	0.5%	-	-	-	0.0%
2005	37,761,179	281	0.0%	-	-	-	0.0%
2006	41,447,022	9,636	0.0%	-	-	-	0.0%
2007	41,056,396	413,654	1.0%	-	-	-	0.0%
2008	41,447,649	30,824	0.1%	-	-	-	0.0%
2009	42,014,896	16,882	0.0%	-	-	-	0.0%
2010	42,136,573	10,519	0.0%	-	-	-	0.0%
2011	42,303,123	5,091	0.0%	-	166	(166)	-3.3%
2012	42,396,705	31,477	0.1%	-	1,847	(1,847)	-5.9%
2013	42,478,191	827	0.0%	-	-	-	0.0%
2014	42,882,274	10,678	0.0%	-	-	-	0.0%
2015	44,615,762	4,801	0.0%	-	1,173	(1,173)	-24.4%
2016	44,832,793	34,975	0.1%	-	5,044	(5,044)	-14.4%
2017	45,023,090	28,149	0.1%	-	6,354	(6,354)	-22.6%
2018	45,935,407	39,298	0.1%	-	4,369	(4,369)	-11.1%
2019	46,590,014	5,126	0.0%	-	4,884	(4,884)	-95.3%
2020	46,804,548	28,574	0.1%	-	604	(604)	-2.1%
2021	47,336,219	721	0.0%	-	15,473	(15,473)	-2147.6%
2022	47,331,862	4,357	0.0%	-	-	-	0.0%
2023	51,735,320	-	0.0%	-	121	(121)	0.0%
Total	968,642,376	1,076,142	0.1%	-	40,035	(40,035)	-3.7%

Five Year Average Net Salvage	-15.6%
Ten Year Average Net Salvage	-12.9%
Current Net Salvage	-2.3%
Recommend Net Salvage	-2.5%

Account 368 – Compressor Station Equipment

Delta Natural Gas Company
Account 368 -- Compressor Station Equipment

Simulated Retirements for Iowa Curve S5   with ASL = 46

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1961	794	0	794	0	794	0	0
1962	11090	0	11884	0	11884	0	0
1963	89639	0	101523	0	101523	0	0
1964	2757	0	104280	0	104280	0	0
1965	76220	0	180500	0	180500	0	0
1966	1010	0	181510	0	181510	0	0
1967	1745	0	183255	0	183255	0	0
1968	0	0	183255	0	183255	0	0
1969	3869	0	187124	0	187124	0	0
1970	480	0	187604	0	187604	0	0
1971	23086	0	210690	0	210690	0	0
1972	309	0	210999	0	210999	0	0
1973	0	0	210999	0	210999	0	0
1974	958	0	211957	0	211957	0	0
1975	57007	0	268964	0	268964	0	0
1976	43971	0	312935	0	312935	0	0
1977	0	0	312935	0	312935	0	0
1978	600	0	313535	0	313535	0	0
1979	14111	0	327646	0	327646	0	0
1980	12740	0	340386	0	340386	0	0
1981	1020	0	341406	0	341406	0	0
1982	640	0	342046	0	342046	0	0
1983	0	0	342046	0	342046	0	0
1984	483934	23800	802180	0	825980	23800	-23800
1985	77490	53250	826420	0	903470	53250	-77050
1986	374408	0	1200828	0	1277878	-0	-77050
1987	-74580	24684	1101564	0	1203297	24684	-101733
1988	-9661	0	1091903	1	1193635	-1	-101732

Delta Natural Gas Company
Account 368 -- Compressor Station Equipment

Simulated Retirements for Iowa Curve S5 with ASL = 46

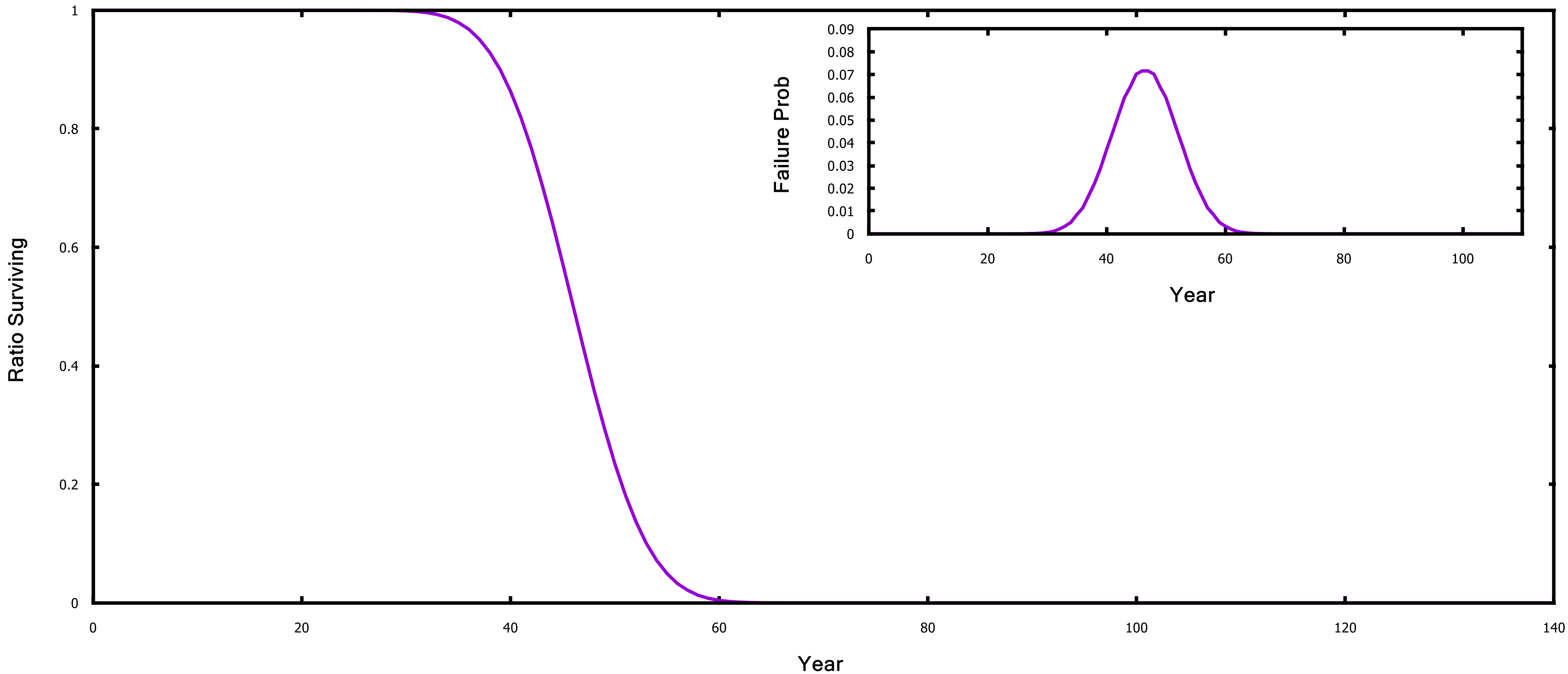
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1989	11796	6000	1097699	3	1205428	5997	-107729
1990	0	0	1097699	9	1205419	-9	-107720
1991	190334	0	1288033	18	1395735	-18	-107702
1992	12181	0	1300214	39	1407877	-39	-107663
1993	-2	0	1300212	78	1407797	-78	-107585
1994	-32363	0	1267849	138	1375296	-138	-107447
1995	0	0	1267849	270	1375025	-270	-107176
1996	0	0	1267849	443	1374582	-443	-106733
1997	0	0	1267849	719	1373863	-719	-106014
1998	8440	0	1276289	1167	1381136	-1167	-104847
1999	519600	0	1795889	1646	1899090	-1646	-103201
2000	26345	0	1822234	2472	1922963	-2472	-100729
2001	-415000	0	1407234	3307	1504656	-3307	-97422
2002	6074	0	1413308	4450	1506281	-4450	-92973
2003	443449	0	1856757	5741	1943988	-5741	-87231
2004	17735	221236	1653256	7099	1954624	214137	-301368
2005	1622	0	1654878	8608	1947639	-8608	-292761
2006	827361	22421	2459817	10103	2764897	12319	-305079
2007	2407136	0	4866954	11397	5160636	-11397	-293683
2008	155458	0	5022412	12814	5303281	-12814	-280869
2009	2475742	0	7498154	13673	7765350	-13673	-267196
2010	82891	459	7580586	14576	7833665	-14117	-253079
2011	0	0	7580586	15093	7818572	-15093	-237986
2012	0	0	7580586	15268	7803304	-15268	-222718
2013	1163388	0	8743973	15531	8951160	-15531	-207187
2014	69288	0	8813261	15400	9005048	-15400	-191787
2015	58683	4500	8867443	15459	9048272	-10959	-180829
2016	-130880	64061	8672502	15735	8901656	48326	-229154

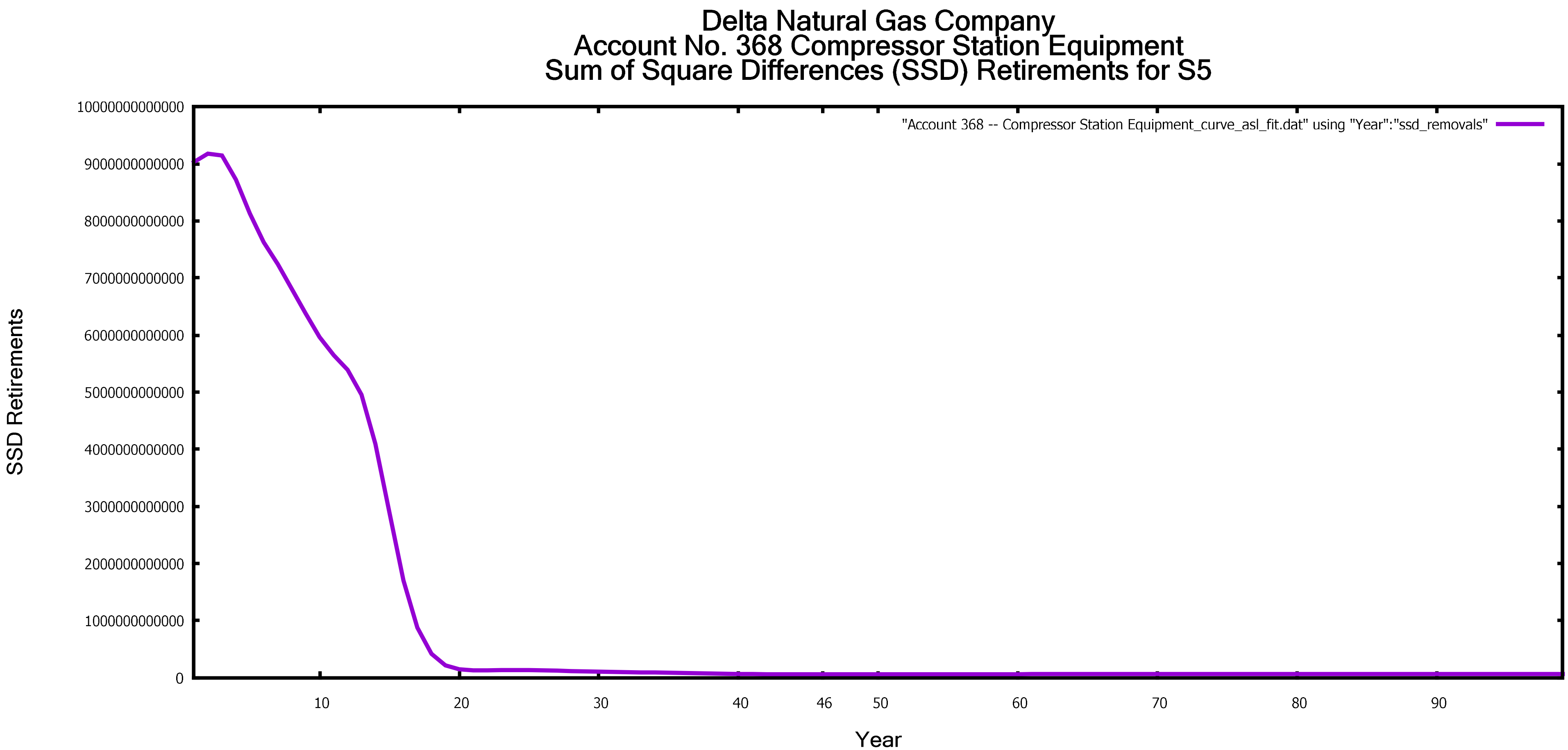
Delta Natural Gas Company
Account 368 -- Compressor Station Equipment

Simulated Retirements for Iowa Curve S5 with ASL = 46

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2017	34360	0	8706862	16112	8919904	-16112	-213042
2018	40170	32636	8714395	17073	8943000	15563	-228605
2019	176316	95759	8794952	18836	9100480	76923	-305528
2020	12021	11476	8795497	20640	9091862	-9164	-296365
2021	0	0	8795497	24321	9067541	-24321	-272044
2022	0	0	8795497	27658	9039883	-27658	-244386
2023	107751	0	8903248	32735	9114898	-32735	-211651

Account No. 368 -- Transmission Compressor Stations
Iowa Curve: S5 ASL: 46 Years





Delta Natural Gas Company
Account No. 368 Compressor Station Equipment
Sum of Square Differences (SSD) Retirements for S5
"Account 368 -- Compressor Station Equipment_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
Year
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9000000000000
8000000000000
7000000000000
6000000000000
5000000000000
4000000000000
3000000000000
2000000000000
1000000000000
0
10
20
30
40
46
50
60
70
80
90

Delta Natural Gas Company
Account Investment Summary

368 -- Compressor Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	-	-	-
1941	-	-	-	-	-
1942	-	-	-	-	-
1943	-	-	-	-	-
1944	-	-	-	-	-
1945	-	-	-	-	-
1946	-	-	-	-	-
1947	-	-	-	-	-
1948	-	-	-	-	-
1949	-	-	-	-	-
1950	-	-	-	-	-
1951	-	-	-	-	-
1952	-	-	-	-	-
1953	-	-	-	-	-
1954	-	-	-	-	-
1955	-	-	-	-	-
1956	-	-	-	-	-
1957	-	-	-	-	-
1958	-	-	-	-	-
1959	-	-	-	-	-
1960	-	-	-	-	-
1961	-	-	794.00	-	794.00
1962	794.00	-	11,090.00	-	11,884.00
1963	11,884.00	-	89,639.00	-	101,523.00
1964	101,523.00	-	2,757.00	-	104,280.00
1965	104,280.00	-	76,220.00	-	180,500.00
1966	180,500.00	-	1,010.00	-	181,510.00
1967	181,510.00	-	1,745.00	-	183,255.00
1968	183,255.00	-	-	-	183,255.00
1969	183,255.00	-	3,869.00	-	187,124.00
1970	187,124.00	-	480.00	-	187,604.00
1971	187,604.00	-	23,086.00	-	210,690.00
1972	210,690.00	-	309.00	-	210,999.00
1973	210,999.00	-	-	-	210,999.00
1974	210,999.00	-	958.00	-	211,957.00
1975	211,957.00	-	57,007.00	-	268,964.00
1976	268,964.00	-	43,971.00	-	312,935.00
1977	312,935.00	-	-	-	312,935.00
1978	312,935.00	-	600.00	-	313,535.00
1979	313,535.00	-	14,111.00	-	327,646.00
1980	327,646.00	-	12,740.00	-	340,386.00
1981	340,386.00	-	1,020.00	-	341,406.00
1982	341,406.00	-	640.00	-	342,046.00
1983	342,046.00	-	-	-	342,046.00
1984	342,046.00	-	483,934.00	23,800.00	802,180.00
1985	802,180.00	-	77,490.00	53,250.00	826,420.00
1986	826,420.00	(22,818.00)	397,226.00	-	1,200,828.00

Delta Natural Gas Company
Account Investment Summary

368 -- Compressor Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1987	1,200,828.00	(117,016.00)	42,436.00	24,684.00	1,101,564.00
1988	1,101,564.00	(9,661.00)	-	-	1,091,903.00
1989	1,091,903.00	-	11,796.00	6,000.00	1,097,699.00
1990	1,097,699.00	-	-	-	1,097,699.00
1991	1,097,699.00	-	190,334.00	-	1,288,033.00
1992	1,288,033.00	-	12,181.00	-	1,300,214.00
1993	1,300,214.00	-	(2.00)	-	1,300,212.00
1994	1,300,212.00	(40,367.00)	8,004.00	-	1,267,849.00
1995	1,267,849.00	-	-	-	1,267,849.00
1996	1,267,849.00	-	-	-	1,267,849.00
1997	1,267,849.00	-	-	-	1,267,849.00
1998	1,267,849.00	-	8,440.00	-	1,276,289.00
1999	1,276,289.00	519,600.00	-	-	1,795,889.00
2000	1,795,889.00	-	26,345.00	-	1,822,234.00
2001	1,822,234.00	(415,000.00)	-	-	1,407,234.00
2002	1,407,234.00	-	6,074.03	-	1,413,308.03
2003	1,413,308.03	-	443,449.00	-	1,856,757.03
2004	1,856,757.03	-	17,735.00	221,236.00	1,653,256.03
2005	1,653,256.03	1,622.00	-	-	1,654,878.03
2006	1,654,878.03	-	827,360.81	22,421.41	2,459,817.43
2007	2,459,817.43	-	2,407,136.28	-	4,866,953.71
2008	4,866,953.71	(87,474.06)	242,932.50	-	5,022,412.15
2009	5,022,412.15	-	2,475,741.96	-	7,498,154.11
2010	7,498,154.11	-	82,890.62	459.00	7,580,585.73
2011	7,580,585.73	-	-	-	7,580,585.73
2012	7,580,585.73	-	-	-	7,580,585.73
2013	7,580,585.73	-	1,163,387.64	-	8,743,973.37
2014	8,743,973.37	-	69,287.55	-	8,813,260.92
2015	8,813,260.92	(12,405.26)	71,087.77	4,500.00	8,867,443.43
2016	8,867,443.43	(160,867.12)	29,986.64	64,060.86	8,672,502.09
2017	8,672,502.09	-	34,359.76	-	8,706,861.85
2018	8,706,861.85	-	40,169.53	32,636.27	8,714,395.11
2019	8,714,395.11	-	176,315.59	95,759.00	8,794,951.70
2020	8,794,951.70	-	12,021.06	11,476.00	8,795,496.76
2021	8,795,496.76	-	-	-	8,795,496.76
2022	8,795,496.76	-	-	-	8,795,496.76
2023	8,795,496.76	-	107,751.10	-	8,903,247.86

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 368
Transmission Compressor Station

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	1,407,234	-	0.0%	-	-	-	0.0%
2002	1,413,308	-	0.0%	-	-	-	0.0%
2003	1,856,757	-	0.0%	-	-	-	0.0%
2004	1,653,256	221,236	13.4%	-	3,684	(3,684)	-1.7%
2005	1,654,878	-	0.0%	-	-	-	0.0%
2006	2,459,817	22,421	0.9%	-	-	-	0.0%
2007	4,866,954	-	0.0%	-	-	-	0.0%
2008	5,022,412	-	0.0%	-	-	-	0.0%
2009	7,498,154	-	0.0%	-	-	-	0.0%
2010	7,580,586	459	0.0%	-	-	-	0.0%
2011	7,580,586	-	0.0%	-	-	-	0.0%
2012	7,580,586	-	0.0%	-	-	-	0.0%
2013	8,743,973	-	0.0%	-	-	-	0.0%
2014	8,813,261	-	0.0%	-	-	-	0.0%
2015	8,867,443	4,500	0.1%	-	-	-	0.0%
2016	8,672,502	64,061	0.7%	-	-	-	0.0%
2017	8,706,862	-	0.0%	-	-	-	0.0%
2018	8,714,395	32,636	0.4%	-	-	-	0.0%
2019	8,794,952	95,759	1.1%	-	-	-	0.0%
2020	8,795,497	11,476	0.1%	-	751	(751)	-6.5%
2021	8,795,497	-	0.0%	-	-	-	0.0%
2022	8,795,497	-	0.0%	-	-	-	0.0%
2023	8,903,248	-	0.0%	-	-	-	0.0%
Total	147,177,654	452,549	0.3%	-	4,435	(4,435)	-1.0%

Five Year Average Net Salvage	-0.4%
Ten Year Average Net Salvage	-0.4%
Current Net Salvage	-1.0%
Recommend Net Salvage	-0.7%

Account 369 – Measuring & Reg Station Equipment

Delta Natural Gas Company
Account 369 -- Meas & Reg Station Equipment

Simulated Retirements for Iowa Curve L2 with ASL = 34

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1951	604	0	604	0	604	0	0
1952	0	0	604	0	604	-0	0
1953	0	0	604	0	604	-0	0
1954	0	0	604	0	604	-0	0
1955	2821	0	3425	1	3424	-1	1
1956	3317	0	6742	1	6740	-1	2
1957	1730	0	8472	2	8468	-2	4
1958	4222	0	12694	4	12686	-4	8
1959	11640	0	24334	7	24318	-7	16
1960	36436	0	60770	13	60741	-13	29
1961	2350	0	63120	23	63068	-23	52
1962	143	360	62903	39	63173	321	-270
1963	1590	321	64172	67	64695	254	-523
1964	2469	486	66155	102	67062	384	-907
1965	11196	4853	72498	143	78115	4710	-5617
1966	12600	43	85055	191	90524	-148	-5469
1967	6054	450	90659	245	96333	205	-5674
1968	5943	84	96518	308	101968	-224	-5450
1969	18946	1420	114044	382	120532	1038	-6488
1970	4457	0	118501	465	124525	-465	-6024
1971	22690	0	141191	559	146656	-559	-5465
1972	1848	0	143039	675	147829	-675	-4790
1973	11003	0	154042	810	158022	-810	-3980
1974	21450	339	175153	977	178496	-638	-3343
1975	68977	2071	242059	1164	246309	907	-4250
1976	25972	620	267411	1376	270904	-756	-3493
1977	5860	662	272609	1608	275157	-946	-2548
1978	2125	1040	273694	1871	275411	-831	-1717

Delta Natural Gas Company
Account 369 -- Meas & Reg Station Equipment

Simulated Retirements for Iowa Curve L2   with ASL = 34

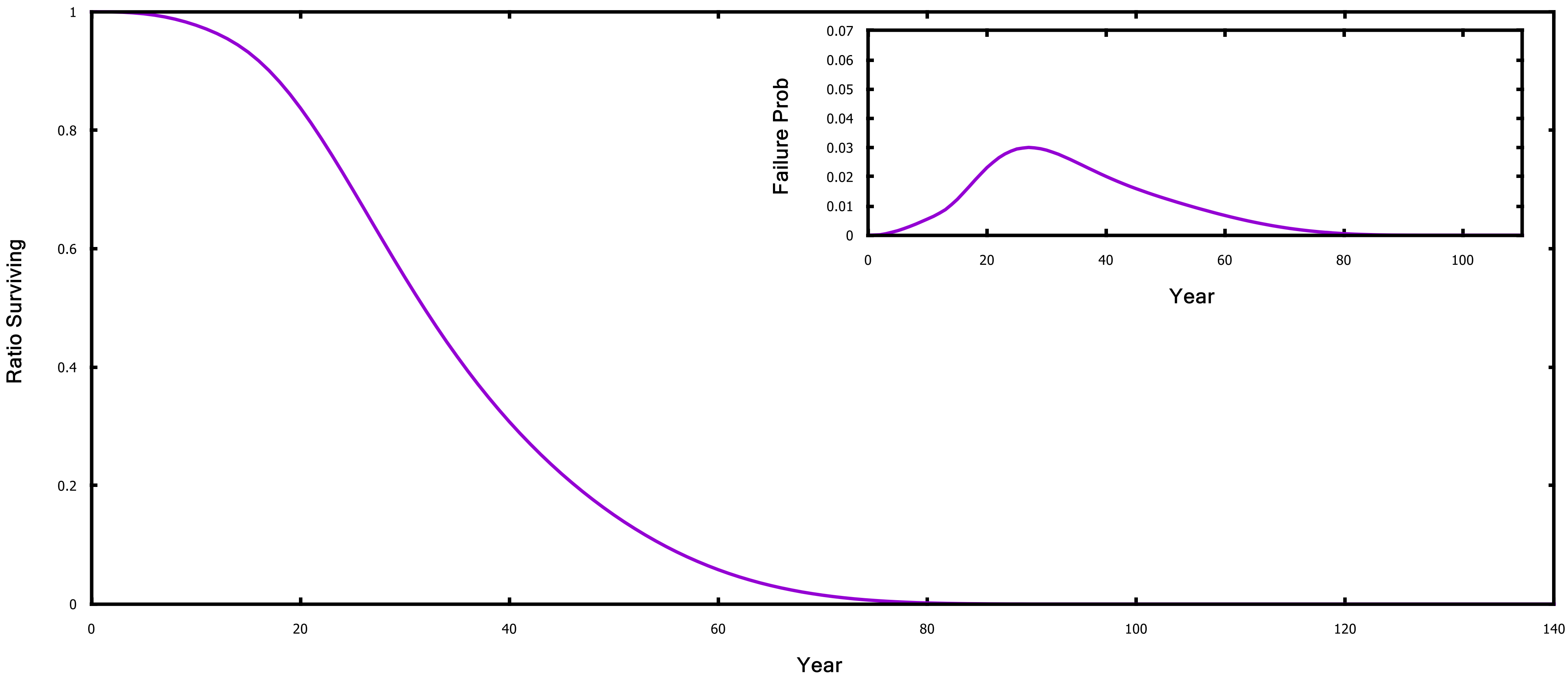
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1979	11949	0	285643	2154	285206	-2154	437
1980	4539	0	290182	2452	287293	-2452	2889
1981	2096	0	292278	2762	286627	-2762	5651
1982	2119	0	294397	3084	285662	-3084	8735
1983	11231	0	305628	3415	293478	-3415	12150
1984	93670	2350	396948	3747	383402	-1397	13546
1985	40669	1654	435963	4093	419977	-2439	15986
1986	4156	0	440119	4437	419696	-4437	20423
1987	1551	0	441670	4823	416425	-4823	25245
1988	14728	1210	455188	5231	425922	-4021	29266
1989	88465	5909	537744	5676	508711	233	29033
1990	36020	0	573764	6146	538585	-6146	35179
1991	39795	0	613559	6646	571734	-6646	41825
1992	43190	0	656749	7170	607754	-7170	48995
1993	44138	3756	697131	7713	644179	-3957	52952
1994	37008	0	734139	8254	672933	-8254	61206
1995	11055	23312	721882	8800	675188	14512	46694
1996	19636	0	741518	9350	685474	-9350	56044
1997	138952	0	880470	9909	814517	-9909	65953
1998	198341	0	1078811	10504	1002355	-10504	76456
1999	526196	3327	1601680	11121	1517429	-7794	84251
2000	185729	15619	1771790	11832	1691326	3787	80464
2001	84508	20741	1835557	12633	1763201	8108	72356
2002	184938	3080	2017415	13626	1934513	-10546	82902
2003	78872	0	2096287	14784	1998601	-14784	97686
2004	146005	0	2242292	16063	2128543	-16063	113749
2005	261710	25999	2478004	17530	2372724	8469	105280
2006	211113	26574	2662543	19143	2564693	7431	97849

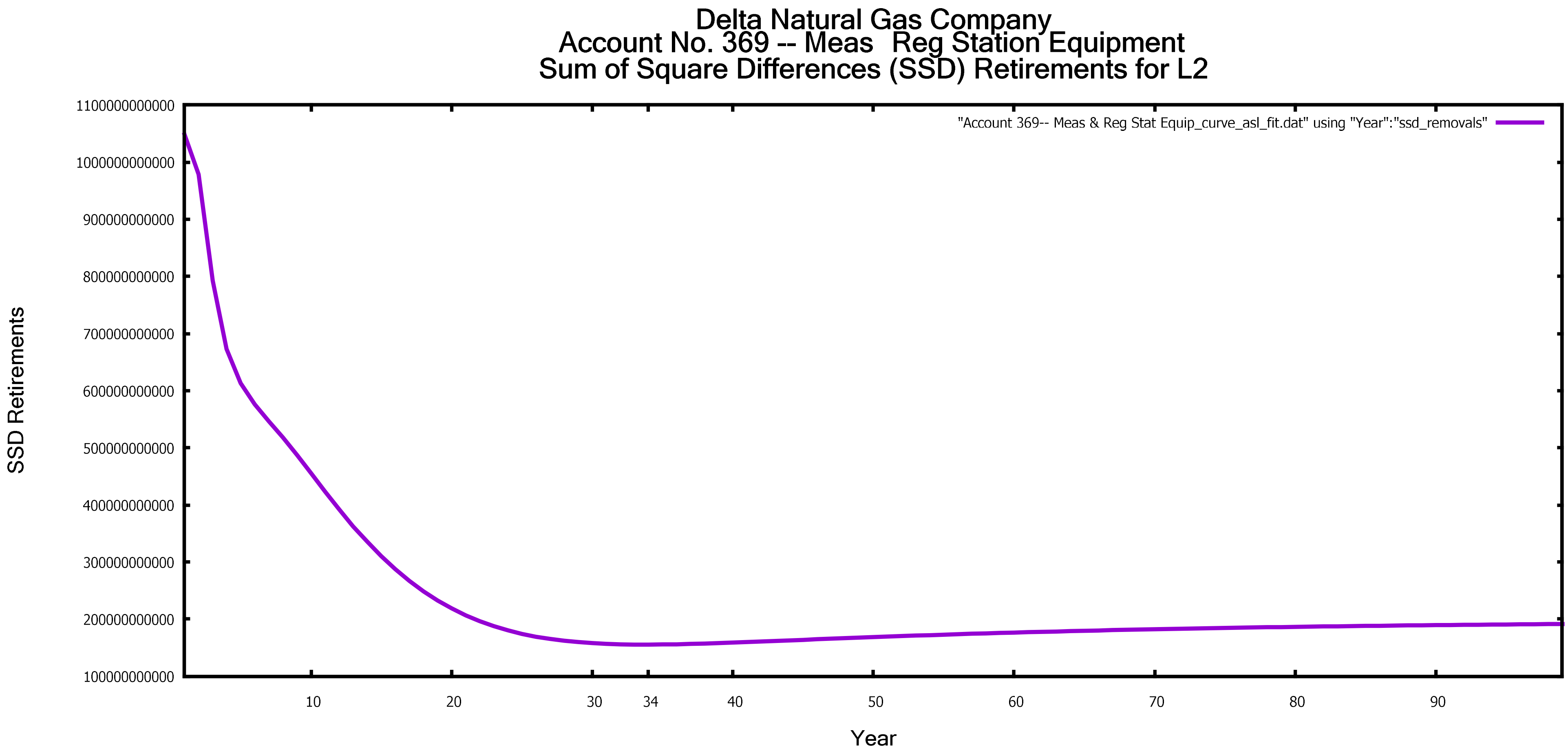
Delta Natural Gas Company
Account 369 -- Meas & Reg Station Equipment

Simulated Retirements for Iowa Curve L2   with ASL = 34

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2007	409207	0	3071750	20899	2953001	-20899	118748
2008	103098	0	3174847	22839	3033260	-22839	141587
2009	207408	1934	3380321	24941	3215727	-23007	164594
2010	-115981	3000	3261340	27251	3072495	-24251	188845
2011	109283	0	3370623	29833	3151945	-29833	218678
2012	138950	16522	3493051	32697	3258198	-16175	234853
2013	97467	16000	3574518	35942	3319724	-19942	254795
2014	394151	6095	3962575	39483	3674392	-33388	288183
2015	55084	33007	3984652	43372	3686104	-10365	298548
2016	135806	0	4120458	47473	3774437	-47473	346021
2017	43935	0	4164393	51822	3766550	-51822	397843
2018	12824	390249	3786969	56300	3723074	333949	63895
2019	49414	0	3836383	60933	3711556	-60933	124828
2020	809562	46923	4599023	65614	4455504	-18691	143518
2021	21954	198808	4422169	70455	4407002	128352	15166
2022	4357	0	4426525	75193	4336166	-75193	90360
2023	186154	0	4612679	80060	4442260	-80060	170419

Account No. 369 -- Transmission Measurement Reg Station Equipment
Iowa Curve: L2 ASL: 34 Years





Delta Natural Gas Company
Account No. 369 -- Meas Reg Station Equipment
Sum of Square Differences (SSD) Retirements for L2
"Account 369-- Meas & Reg Stat Equip_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
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900000000000
800000000000
700000000000
600000000000
500000000000
400000000000
300000000000
200000000000
100000000000
10
20
30
34
40
50
60
70
80
90
Year

Delta Natural Gas Company
Account Investment Summary

369 -- Measuring Regulating Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	-	-	-
1941	-	-	-	-	-
1942	-	-	-	-	-
1943	-	-	-	-	-
1944	-	-	-	-	-
1945	-	-	-	-	-
1946	-	-	-	-	-
1947	-	-	-	-	-
1948	-	-	-	-	-
1949	-	-	-	-	-
1950	-	-	-	-	-
1951	-	-	604.00	-	604.00
1952	604.00	-	-	-	604.00
1953	604.00	-	-	-	604.00
1954	604.00	-	-	-	604.00
1955	604.00	-	2,821.00	-	3,425.00
1956	3,425.00	-	3,317.00	-	6,742.00
1957	6,742.00	-	1,730.00	-	8,472.00
1958	8,472.00	-	4,222.00	-	12,694.00
1959	12,694.00	-	11,640.00	-	24,334.00
1960	24,334.00	-	36,436.00	-	60,770.00
1961	60,770.00	-	2,350.00	-	63,120.00
1962	63,120.00	-	143.00	360.00	62,903.00
1963	62,903.00	-	1,590.00	321.00	64,172.00
1964	64,172.00	-	2,469.00	486.00	66,155.00
1965	66,155.00	-	11,196.00	4,853.00	72,498.00
1966	72,498.00	-	12,600.00	43.00	85,055.00
1967	85,055.00	-	6,054.00	450.00	90,659.00
1968	90,659.00	-	5,943.00	84.00	96,518.00
1969	96,518.00	-	18,946.00	1,420.00	114,044.00
1970	114,044.00	-	4,457.00	-	118,501.00
1971	118,501.00	-	22,690.00	-	141,191.00
1972	141,191.00	-	1,848.00	-	143,039.00
1973	143,039.00	-	11,003.00	-	154,042.00
1974	154,042.00	-	21,450.00	339.00	175,153.00
1975	175,153.00	-	68,977.00	2,071.00	242,059.00
1976	242,059.00	-	25,972.00	620.00	267,411.00
1977	267,411.00	-	5,860.00	662.00	272,609.00
1978	272,609.00	-	2,125.00	1,040.00	273,694.00
1979	273,694.00	-	11,949.00	-	285,643.00
1980	285,643.00	-	4,539.00	-	290,182.00
1981	290,182.00	-	2,096.00	-	292,278.00
1982	292,278.00	-	2,119.00	-	294,397.00
1983	294,397.00	-	11,231.00	-	305,628.00
1984	305,628.00	-	93,670.00	2,350.00	396,948.00
1985	396,948.00	-	40,669.00	1,654.00	435,963.00

Delta Natural Gas Company
Account Investment Summary

369 -- Measuring Regulating Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1986	435,963.00	-	4,156.00	-	440,119.00
1987	440,119.00	-	1,551.00	-	441,670.00
1988	441,670.00	-	14,728.00	1,210.00	455,188.00
1989	455,188.00	23,055.00	65,410.00	5,909.00	537,744.00
1990	537,744.00	(4,697.00)	40,717.00	-	573,764.00
1991	573,764.00	-	39,795.00	-	613,559.00
1992	613,559.00	-	43,190.00	-	656,749.00
1993	656,749.00	-	44,138.00	3,756.00	697,131.00
1994	697,131.00	-	37,008.00	-	734,139.00
1995	734,139.00	-	11,055.00	23,312.00	721,882.00
1996	721,882.00	-	19,636.00	-	741,518.00
1997	741,518.00	-	138,952.00	-	880,470.00
1998	880,470.00	-	198,341.00	-	1,078,811.00
1999	1,078,811.00	163,168.00	363,028.00	3,327.00	1,601,680.00
2000	1,601,680.00	-	185,729.00	15,619.00	1,771,790.00
2001	1,771,790.00	-	84,508.00	20,741.00	1,835,557.00
2002	1,835,557.00	-	184,938.00	3,080.00	2,017,415.00
2003	2,017,415.00	-	78,872.33	-	2,096,287.33
2004	2,096,287.33	-	146,005.00	-	2,242,292.33
2005	2,242,292.33	12,021.00	249,689.42	25,999.20	2,478,003.55
2006	2,478,003.55	(8,873.45)	219,986.57	26,574.14	2,662,542.53
2007	2,662,542.53	-	409,207.14	-	3,071,749.67
2008	3,071,749.67	-	103,097.77	-	3,174,847.44
2009	3,174,847.44	-	207,407.55	1,933.76	3,380,321.23
2010	3,380,321.23	(346,800.46)	230,819.19	3,000.00	3,261,339.96
2011	3,261,339.96	-	109,282.95	-	3,370,622.91
2012	3,370,622.91	4,803.37	134,146.78	16,522.42	3,493,050.64
2013	3,493,050.64	-	97,467.39	16,000.00	3,574,518.03
2014	3,574,518.03	-	394,151.18	6,094.52	3,962,574.69
2015	3,962,574.69	(5,754.67)	60,838.93	33,006.85	3,984,652.10
2016	3,984,652.10	(17,434.47)	153,240.08	-	4,120,457.71
2017	4,120,457.71	(29,211.73)	73,147.21	-	4,164,393.19
2018	4,164,393.19	(4,500.00)	17,324.39	390,248.62	3,786,968.96
2019	3,786,968.96	-	49,414.40	-	3,836,383.36
2020	3,836,383.36	15,241.33	794,321.05	46,923.10	4,599,022.64
2021	4,599,022.64	-	21,953.58	198,807.59	4,422,168.63
2022	4,422,168.63	-	4,356.86	-	4,426,525.49
2023	4,426,525.49	-	186,153.91	-	4,612,679.40

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 369
Transmission Meas & Reg Station Equipment

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	1,835,557	20,741	1.1%	-	21,388	(21,388)	-103.1%
2002	2,017,415	3,080	0.2%	-	-	-	0.0%
2003	2,096,287	-	0.0%	-	-	-	0.0%
2004	2,242,292	-	0.0%	-	-	-	0.0%
2005	2,478,004	25,999	1.0%	-	-	-	0.0%
2006	2,662,543	26,574	1.0%	-	-	-	0.0%
2007	3,071,750	-	0.0%	-	-	-	0.0%
2008	3,174,847	-	0.0%	-	-	-	0.0%
2009	3,380,321	1,934	0.1%	-	-	-	0.0%
2010	3,261,340	3,000	0.1%	-	-	-	0.0%
2011	3,370,623	-	0.0%	-	-	-	0.0%
2012	3,493,051	16,522	0.5%	-	147	(147)	-0.9%
2013	3,574,518	16,000	0.4%	-	-	-	0.0%
2014	3,962,575	6,095	0.2%	-	-	-	0.0%
2015	3,984,652	33,007	0.8%	-	8,376	(8,376)	-25.4%
2016	4,120,458	-	0.0%	-	-	-	0.0%
2017	4,164,393	-	0.0%	-	-	-	0.0%
2018	3,786,969	390,249	10.3%	5,848	5,253	596	0.2%
2019	3,836,383	-	0.0%	-	5,314	(5,314)	0.0%
2020	4,599,023	46,923	1.0%	-	49,075	(49,075)	-104.6%
2021	4,422,169	198,808	4.5%	-	(10,083)	10,083	5.1%
2022	4,426,525	-	0.0%	-	-	-	0.0%
2023	4,612,679	-	0.0%	-	-	-	0.0%
Total	78,574,374	788,931	1.0%	5,848	79,470	(73,621)	-9.3%

Five Year Average Net Salvage	-12.3%
Ten Year Average Net Salvage	-12.2%
Current Net Salvage	-5%
Recommend Net Salvage	-7%

Account 376 – Distribution Mains

Delta Natural Gas Company
Account 376 -- Distribution Mains

Simulated Retirements for Iowa Curve R5 with ASL = 55

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1940	58962	0	58962	0	58962	0	0
1941	0	0	58962	0	58962	0	0
1942	0	0	58962	0	58962	0	0
1943	0	0	58962	0	58962	0	0
1944	0	0	58962	0	58962	0	0
1945	0	0	58962	0	58962	0	0
1946	0	0	58962	0	58962	0	0
1947	75766	0	134728	0	134728	0	0
1948	67865	0	202593	0	202593	0	0
1949	62008	0	264601	0	264601	0	0
1950	29854	0	294455	0	294455	0	0
1951	36626	0	331081	0	331081	0	0
1952	18609	0	349690	0	349690	0	0
1953	12981	0	362671	0	362671	0	0
1954	47353	0	410024	0	410024	0	0
1955	148499	0	558523	0	558523	0	0
1956	143937	0	702460	0	702460	0	0
1957	39727	0	742187	0	742187	0	0
1958	34326	0	776513	0	776513	0	0
1959	106509	0	883022	0	883022	0	0
1960	69660	0	952682	0	952682	-0	0
1961	110606	0	1063288	0	1063288	-0	0
1962	71538	0	1134826	0	1134826	-0	0
1963	86884	9832	1211878	1	1221709	9831	-9831
1964	89514	5084	1296308	2	1311221	5082	-14913
1965	123728	7814	1412222	3	1434946	7811	-22724
1966	135264	5133	1542353	5	1570205	5128	-27852
1967	317430	7612	1852171	10	1887625	7602	-35454

Delta Natural Gas Company
Account 376 -- Distribution Mains

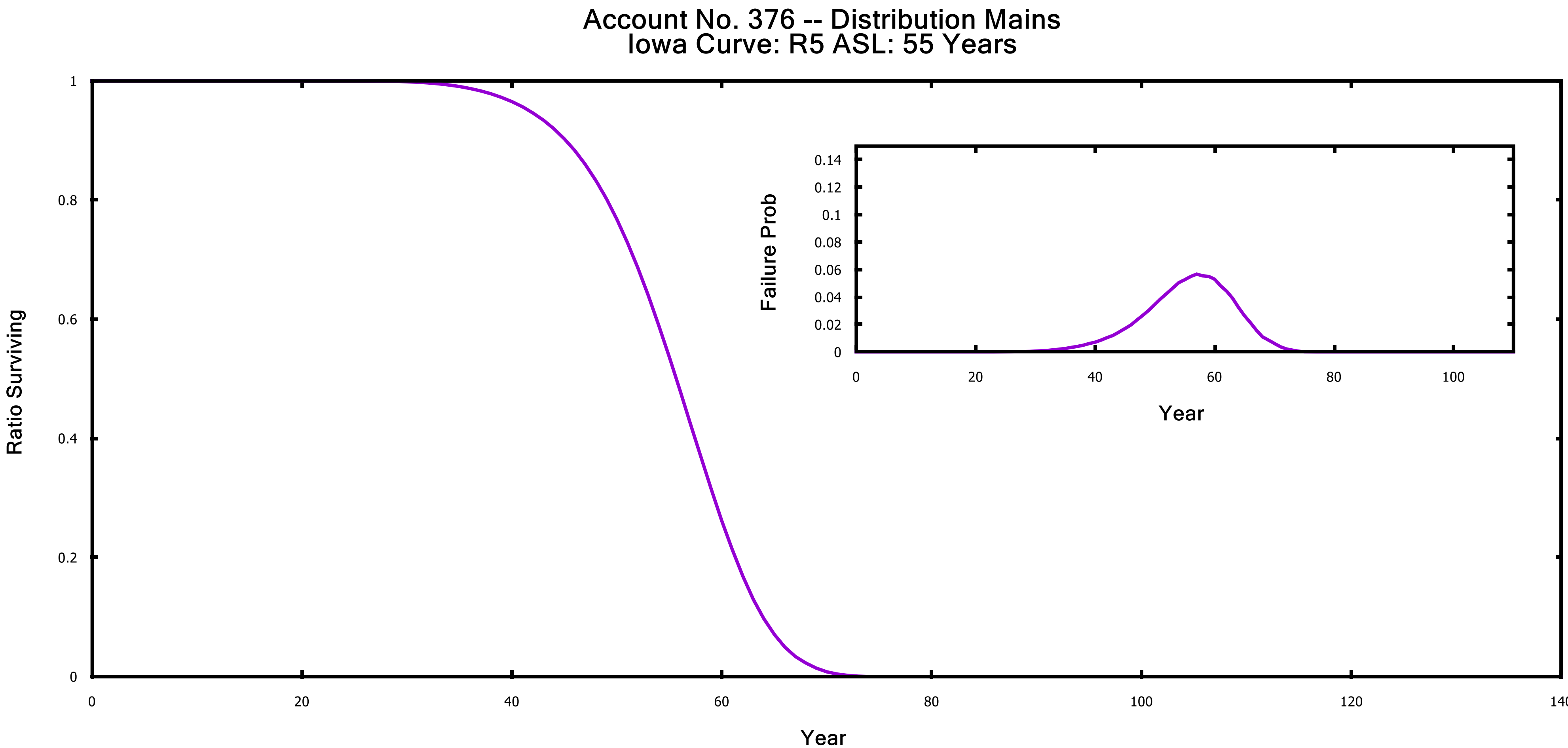
Simulated Retirements for Iowa Curve R5   with ASL = 55

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	182038	13540	2020669	17	2069646	13523	-48977
1969	582335	11971	2591033	22	2651959	11949	-60926
1970	1455571	8116	4038488	36	4107494	8080	-69006
1971	1074050	109721	5002817	54	5181490	109667	-178673
1972	324850	26975	5300692	71	5506268	26904	-205576
1973	448840	12035	5737497	104	5955005	11931	-217508
1974	294232	42315	5989414	141	6249095	42174	-259681
1975	409344	47820	6350938	189	6658251	47631	-307313
1976	201118	19238	6532818	258	6859111	18980	-326293
1977	215318	19383	6728753	333	7074096	19050	-345343
1978	316671	46128	6999296	436	7390331	45692	-391035
1979	723822	90065	7633053	570	8113583	89495	-480530
1980	646465	46371	8233147	718	8759329	45653	-526182
1981	1960024	104484	10088687	921	10718432	103563	-629745
1982	1666448	145027	11610108	1170	12383710	143857	-773602
1983	1579871	121613	13068366	1456	13962126	120157	-893760
1984	1436971	129563	14375774	1827	15397270	127736	-1021496
1985	1581605	169907	15787472	2257	16976618	167650	-1189146
1986	1813432	202979	17397925	2770	18787281	200209	-1389356
1987	1928903	131752	19195076	3393	20712790	128359	-1517714
1988	2394747	75173	21514650	4105	23103432	71068	-1588782
1989	823954	67192	22271412	4948	23922438	62244	-1651026
1990	2593632	212392	24652652	5924	26510146	206468	-1857494
1991	3006462	91401	27567713	7065	29509543	84336	-1941830
1992	2091957	89533	29570137	8351	31593148	81182	-2023011
1993	2514631	63196	32021572	9819	34097960	53377	-2076388
1994	2265544	73474	34213642	11561	36351944	61913	-2138302
1995	3168792	105369	37277065	13444	39507292	91925	-2230227

Delta Natural Gas Company
Account 376 -- Distribution Mains

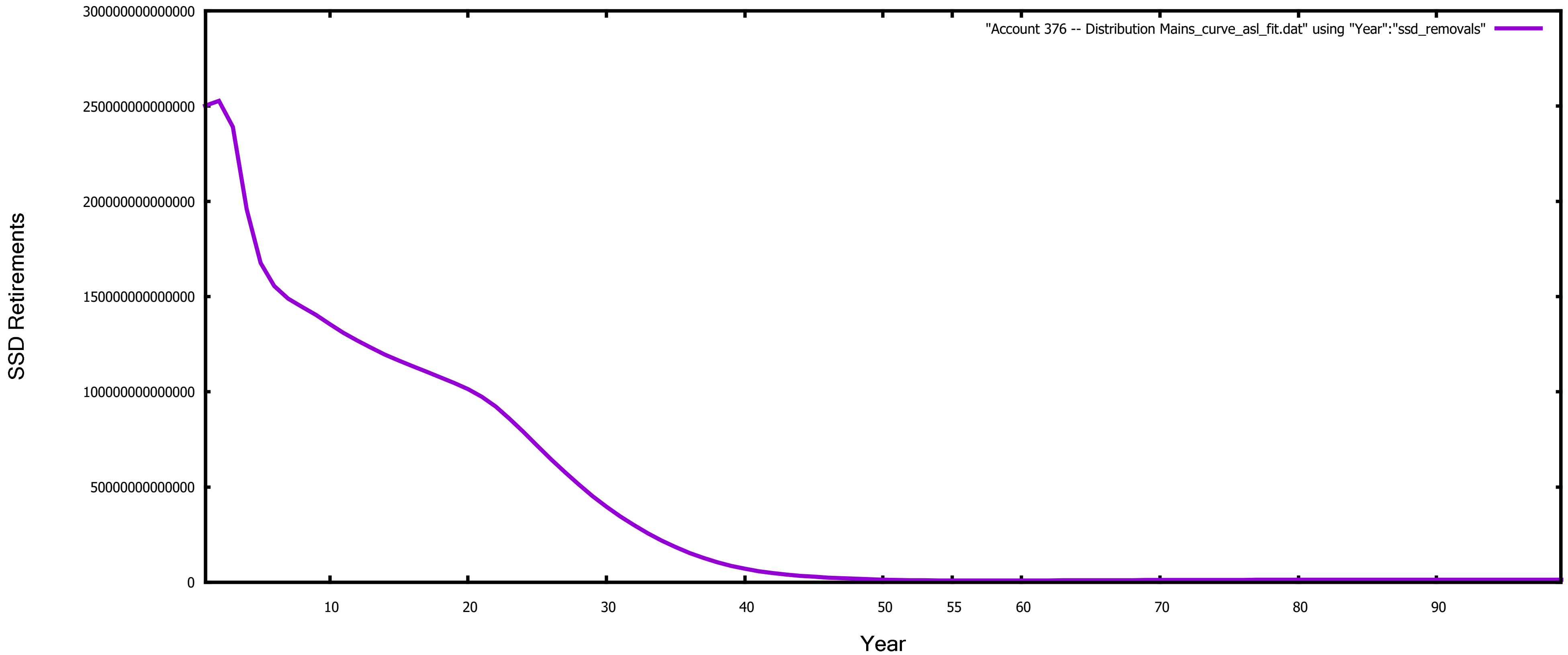
Simulated Retirements for Iowa Curve R5 with ASL = 55

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	2615832	143644	39749253	15615	42107509	128029	-2358256
1997	2773515	145370	42377398	18160	44862864	127210	-2485466
1998	4460035	338435	46498998	20900	49301999	317535	-2803001
1999	3293998	67788	49725208	24035	52571962	43753	-2846754
2000	3187950	248859	52664299	27627	55732285	221232	-3067986
2001	1640935	59039	54246195	31529	57341691	27510	-3095496
2002	1118712	111651	55253256	35888	58424515	75763	-3171258
2003	1493803	52274	56694785	40856	59877462	11418	-3182677
2004	1920768	156346	58459207	46201	61752029	110145	-3292822
2005	1752060	80120	60131148	52069	63452021	28052	-3320873
2006	1344632	52646	61423134	58814	64737839	-6168	-3314705
2007	1100003	220944	62302193	65912	65771930	155032	-3469737
2008	2211046	270986	64242253	73757	67909219	197229	-3666966
2009	1821352	88858	65974747	82752	69647819	6106	-3673072
2010	1943240	92785	67825201	92220	71498839	566	-3673637
2011	1390833	227609	68988425	102947	72786724	124661	-3798299
2012	2501565	175151	71314839	115135	75173154	60017	-3858315
2013	2340376	118585	73536630	128356	77385174	-9771	-3848544
2014	1979981	153030	75363581	143801	79221354	9230	-3857773
2015	1653150	146963	76869767	161295	80713209	-14332	-3843442
2016	1942210	113560	78698417	180526	82474892	-66966	-3776475
2017	2619977	201584	81116811	202896	84891973	-1313	-3775163
2018	3893676	241302	84769184	227839	88557810	13463	-3788626
2019	7341094	221885	91888393	254800	95644104	-32915	-3755711
2020	6084618	318513	97654497	285205	101443517	33309	-3789020
2021	1713446	497543	98870400	318598	102838364	178944	-3967964
2022	10001	0	98880401	354003	102494362	-354003	-3613961
2023	12398931	0	111279332	392825	114500467	-392825	-3221135



Account No. 376 -- Distribution Mains
Iowa Curve: R5 ASL: 55 Years
Ratio Surviving
Year
Failure Prob
Year

Delta Natural Gas
Account No. 376 Distribution Mains
Sum of Square Differences (SSD) Retirements for R5



Delta Natural Gas Company
Account Investment Summary

376 -- Distribution Mains

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	58,962.00	-	58,962.00
1941	58,962.00	-	-	-	58,962.00
1942	58,962.00	-	-	-	58,962.00
1943	58,962.00	-	-	-	58,962.00
1944	58,962.00	-	-	-	58,962.00
1945	58,962.00	-	-	-	58,962.00
1946	58,962.00	-	-	-	58,962.00
1947	58,962.00	-	75,766.00	-	134,728.00
1948	134,728.00	-	67,865.00	-	202,593.00
1949	202,593.00	-	62,008.00	-	264,601.00
1950	264,601.00	-	29,854.00	-	294,455.00
1951	294,455.00	-	36,626.00	-	331,081.00
1952	331,081.00	-	18,609.00	-	349,690.00
1953	349,690.00	-	12,981.00	-	362,671.00
1954	362,671.00	-	47,353.00	-	410,024.00
1955	410,024.00	-	148,499.00	-	558,523.00
1956	558,523.00	-	143,937.00	-	702,460.00
1957	702,460.00	-	39,727.00	-	742,187.00
1958	742,187.00	-	34,326.00	-	776,513.00
1959	776,513.00	-	106,509.00	-	883,022.00
1960	883,022.00	-	69,660.00	-	952,682.00
1961	952,682.00	-	110,606.00	-	1,063,288.00
1962	1,063,288.00	-	71,538.00	-	1,134,826.00
1963	1,134,826.00	-	86,884.00	9,832.00	1,211,878.00
1964	1,211,878.00	-	89,514.00	5,084.00	1,296,308.00
1965	1,296,308.00	-	123,728.00	7,814.00	1,412,222.00
1966	1,412,222.00	-	135,264.00	5,133.00	1,542,353.00
1967	1,542,353.00	-	317,430.00	7,612.00	1,852,171.00
1968	1,852,171.00	-	182,038.00	13,540.00	2,020,669.00
1969	2,020,669.00	-	582,335.00	11,971.00	2,591,033.00
1970	2,591,033.00	-	1,455,571.00	8,116.00	4,038,488.00
1971	4,038,488.00	-	1,074,050.00	109,721.00	5,002,817.00
1972	5,002,817.00	-	324,850.00	26,975.00	5,300,692.00
1973	5,300,692.00	-	448,840.00	12,035.00	5,737,497.00
1974	5,737,497.00	-	294,232.00	42,315.00	5,989,414.00
1975	5,989,414.00	-	409,344.00	47,820.00	6,350,938.00
1976	6,350,938.00	-	201,118.00	19,238.00	6,532,818.00
1977	6,532,818.00	-	215,318.00	19,383.00	6,728,753.00
1978	6,728,753.00	-	316,671.00	46,128.00	6,999,296.00
1979	6,999,296.00	-	723,822.00	90,065.00	7,633,053.00
1980	7,633,053.00	-	646,465.00	46,371.00	8,233,147.00
1981	8,233,147.00	-	1,960,024.00	104,484.00	10,088,687.00
1982	10,088,687.00	-	1,666,448.00	145,027.00	11,610,108.00
1983	11,610,108.00	-	1,579,871.00	121,613.00	13,068,366.00
1984	13,068,366.00	-	1,436,971.00	129,563.00	14,375,774.00
1985	14,375,774.00	-	1,581,605.00	169,907.00	15,787,472.00

Delta Natural Gas Company
Account Investment Summary

376 -- Distribution Mains

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1986	15,787,472.00	(27,191.00)	1,840,623.00	202,979.00	17,397,925.00
1987	17,397,925.00	(9,731.00)	1,938,634.00	131,752.00	19,195,076.00
1988	19,195,076.00	2,500.00	2,392,247.00	75,173.00	21,514,650.00
1989	21,514,650.00	(1,695,594.00)	2,519,548.00	67,192.00	22,271,412.00
1990	22,271,412.00	129,136.00	2,464,496.00	212,392.00	24,652,652.00
1991	24,652,652.00	(117,893.00)	3,124,355.00	91,401.00	27,567,713.00
1992	27,567,713.00	(61,677.00)	2,153,634.00	89,533.00	29,570,137.00
1993	29,570,137.00	(4,340.00)	2,518,971.00	63,196.00	32,021,572.00
1994	32,021,572.00	(132,561.00)	2,398,105.00	73,474.00	34,213,642.00
1995	34,213,642.00	(22,307.00)	3,191,099.00	105,369.00	37,277,065.00
1996	37,277,065.00	(11,262.00)	2,627,094.00	143,644.00	39,749,253.00
1997	39,749,253.00	1,000.00	2,772,515.00	145,370.00	42,377,398.00
1998	42,377,398.00	-	4,460,035.00	338,435.00	46,498,998.00
1999	46,498,998.00	(1,417.00)	3,295,415.00	67,788.00	49,725,208.00
2000	49,725,208.00	(3,948.00)	3,191,898.00	248,859.00	52,664,299.00
2001	52,664,299.00	6,556.00	1,634,379.00	59,039.00	54,246,195.00
2002	54,246,195.00	-	1,118,712.41	111,651.00	55,253,256.41
2003	55,253,256.41	-	1,493,803.00	52,274.00	56,694,785.41
2004	56,694,785.41	54,324.00	1,866,444.00	156,346.00	58,459,207.41
2005	58,459,207.41	117,601.23	1,634,459.18	80,120.16	60,131,147.66
2006	60,131,147.66	-	1,344,631.97	52,645.78	61,423,133.85
2007	61,423,133.85	102.28	1,099,900.67	220,944.24	62,302,192.56
2008	62,302,192.56	1,034.47	2,210,011.83	270,986.21	64,242,252.65
2009	64,242,252.65	-	1,821,352.28	88,857.89	65,974,747.04
2010	65,974,747.04	(3,000.00)	1,946,239.65	92,785.42	67,825,201.27
2011	67,825,201.27	5,896.47	1,384,936.13	227,608.60	68,988,425.27
2012	68,988,425.27	-	2,501,564.77	175,151.26	71,314,838.78
2013	71,314,838.78	-	2,340,376.20	118,584.75	73,536,630.23
2014	73,536,630.23	591.00	1,979,389.65	153,030.32	75,363,580.56
2015	75,363,580.56	(1,031,954.00)	2,685,103.72	146,963.33	76,869,766.95
2016	76,869,766.95	-	1,942,210.31	113,560.30	78,698,416.96
2017	78,698,416.96	-	2,619,977.09	201,583.52	81,116,810.53
2018	81,116,810.53	-	3,893,676.33	241,302.36	84,769,184.50
2019	84,769,184.50	-	7,341,093.70	221,884.91	91,888,393.29
2020	91,888,393.29	(4,910.34)	6,089,527.88	318,513.47	97,654,497.36
2021	97,654,497.36	-	1,713,445.57	497,542.80	98,870,400.13
2022	98,870,400.13	-	10,001.33	-	98,880,401.46
2023	98,880,401.46	-	12,398,930.56	-	111,279,332.02

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 376
Distribution Mains

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	54,246,195	59,039	0.1%	-	-	-	0.0%
2002	55,253,256	111,651	0.2%	-	-	-	0.0%
2003	56,694,785	52,274	0.1%	-	-	-	0.0%
2004	58,459,207	156,346	0.3%	-	-	-	0.0%
2005	60,131,148	80,120	0.1%	-	-	-	0.0%
2006	61,423,134	52,646	0.1%	-	-	-	0.0%
2007	62,302,193	220,944	0.4%	-	-	-	0.0%
2008	64,242,253	270,986	0.4%	-	-	-	0.0%
2009	65,974,747	88,858	0.1%	-	-	-	0.0%
2010	67,825,201	92,785	0.1%	-	-	-	0.0%
2011	68,988,425	227,609	0.3%	-	18,839	(18,839)	-8.3%
2012	71,314,839	175,151	0.2%	-	49,323	(49,323)	-28.2%
2013	73,536,630	118,585	0.2%	-	20,642	(20,642)	-17.4%
2014	75,363,581	153,030	0.2%	-	22,979	(22,979)	-15.0%
2015	76,869,767	146,963	0.2%	-	14,811	(14,811)	-10.1%
2016	78,698,417	113,560	0.1%	-	41,854	(41,854)	-36.9%
2017	81,116,811	201,584	0.2%	-	15,397	(15,397)	-7.6%
2018	84,769,185	241,302	0.3%	-	50,003	(50,003)	-20.7%
2019	91,888,393	221,885	0.2%	-	48,247	(48,247)	-21.7%
2020	97,654,497	318,513	0.3%	-	50,407	(50,407)	-15.8%
2021	98,870,400	497,543	0.5%	-	108,031	(108,031)	-21.7%
2022	98,880,401	-	0.0%	-	199,906	(199,906)	#DIV/0!
2023	111,279,332	-	0.0%	-	124,217	(124,217)	#DIV/0!
Total	1,715,782,797	3,601,375	0.2%	-	764,655	(764,655)	-21.2%

Five Year Average Net Salvage	-18.8%
Ten Year Average Net Salvage	-17.3%
Previous	0%
Recommend Net Salvage	-3%

Account 378 – Measurement & Reg Station

Delta Natural Gas Company
Account 378 --Measurement & Regulator Stations

Simulated Retirements for Iowa Curve L5   with ASL = 50

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1940	110	0	110	0	110	0	0
1941	0	0	110	0	110	0	0
1942	0	0	110	0	110	0	0
1943	0	0	110	0	110	0	0
1944	0	0	110	0	110	0	0
1945	0	0	110	0	110	0	0
1946	0	0	110	0	110	0	0
1947	0	0	110	0	110	0	0
1948	260	0	370	0	370	0	0
1949	97	0	467	0	467	0	0
1950	202	0	669	0	669	0	0
1951	535	0	1204	0	1204	0	0
1952	904	0	2108	0	2108	0	0
1953	789	0	2897	0	2897	0	0
1954	38	0	2935	0	2935	0	0
1955	5199	0	8134	0	8134	0	0
1956	3855	0	11989	0	11989	0	0
1957	1094	0	13083	0	13083	0	0
1958	0	0	13083	0	13083	0	0
1959	12372	0	25455	0	25455	0	0
1960	0	0	25455	0	25455	0	0
1961	0	0	25455	0	25455	0	0
1962	321	198	25578	0	25776	198	-198
1963	0	0	25578	0	25776	-0	-198
1964	608	0	26186	0	26384	-0	-198
1965	881	131	26936	0	27265	131	-329
1966	5272	156	32052	0	32537	156	-485
1967	0	0	32052	0	32537	-0	-485

Delta Natural Gas Company
Account 378 --Measurement & Regulator Stations

Simulated Retirements for Iowa Curve L5   with ASL = 50

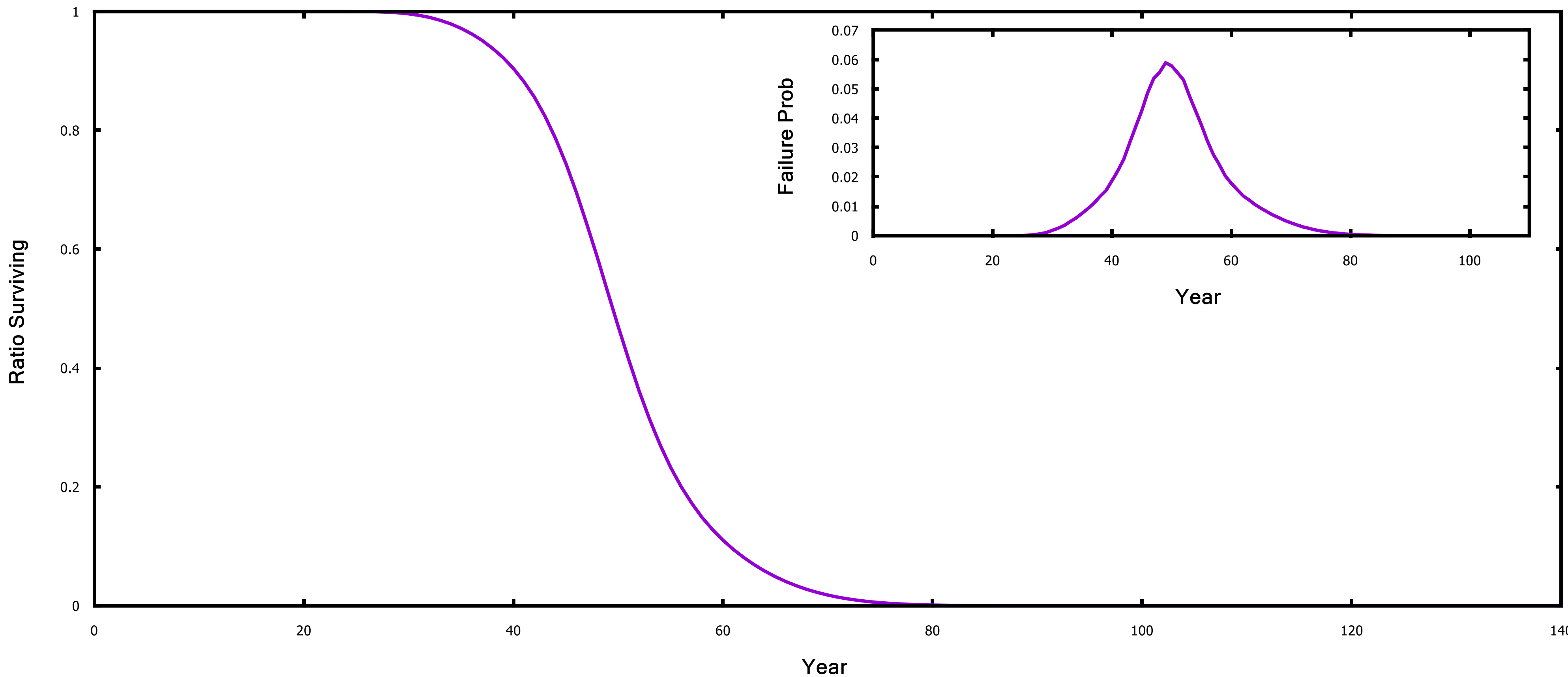
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	317	845	31524	0	32854	845	-1330
1969	281	0	31805	0	33135	-0	-1330
1970	23330	0	55135	0	56465	-0	-1330
1971	24948	0	80083	0	81412	-0	-1329
1972	13981	136	93928	0	95393	136	-1465
1973	3975	632	97271	1	99367	631	-2096
1974	5207	594	101884	1	104574	593	-2690
1975	6244	929	107199	1	110817	928	-3618
1976	3610	2518	108291	1	114425	2517	-6134
1977	8552	171	116672	2	122976	169	-6304
1978	7190	797	123065	3	130163	794	-7098
1979	9000	0	132065	4	139159	-4	-7094
1980	41132	575	172622	5	180286	570	-7664
1981	51901	1879	222644	8	232179	1871	-9535
1982	13595	819	235420	12	245762	807	-10342
1983	20919	447	255892	18	266664	429	-10772
1984	16759	0	272651	25	283398	-25	-10747
1985	12417	0	285068	36	295778	-36	-10710
1986	37728	3248	319548	51	333455	3197	-13907
1987	54661	700	373509	68	388049	632	-14540
1988	57764	6061	425212	90	445723	5971	-20511
1989	84602	4564	505250	118	530208	4446	-24958
1990	52015	9780	547485	148	582074	9632	-34589
1991	44062	2750	588797	184	625952	2566	-37155
1992	36700	15670	609827	228	662424	15442	-52597
1993	49956	13127	646656	276	712104	12851	-65448
1994	44296	9493	681459	333	756068	9160	-74609
1995	101062	32084	750437	399	856731	31685	-106294

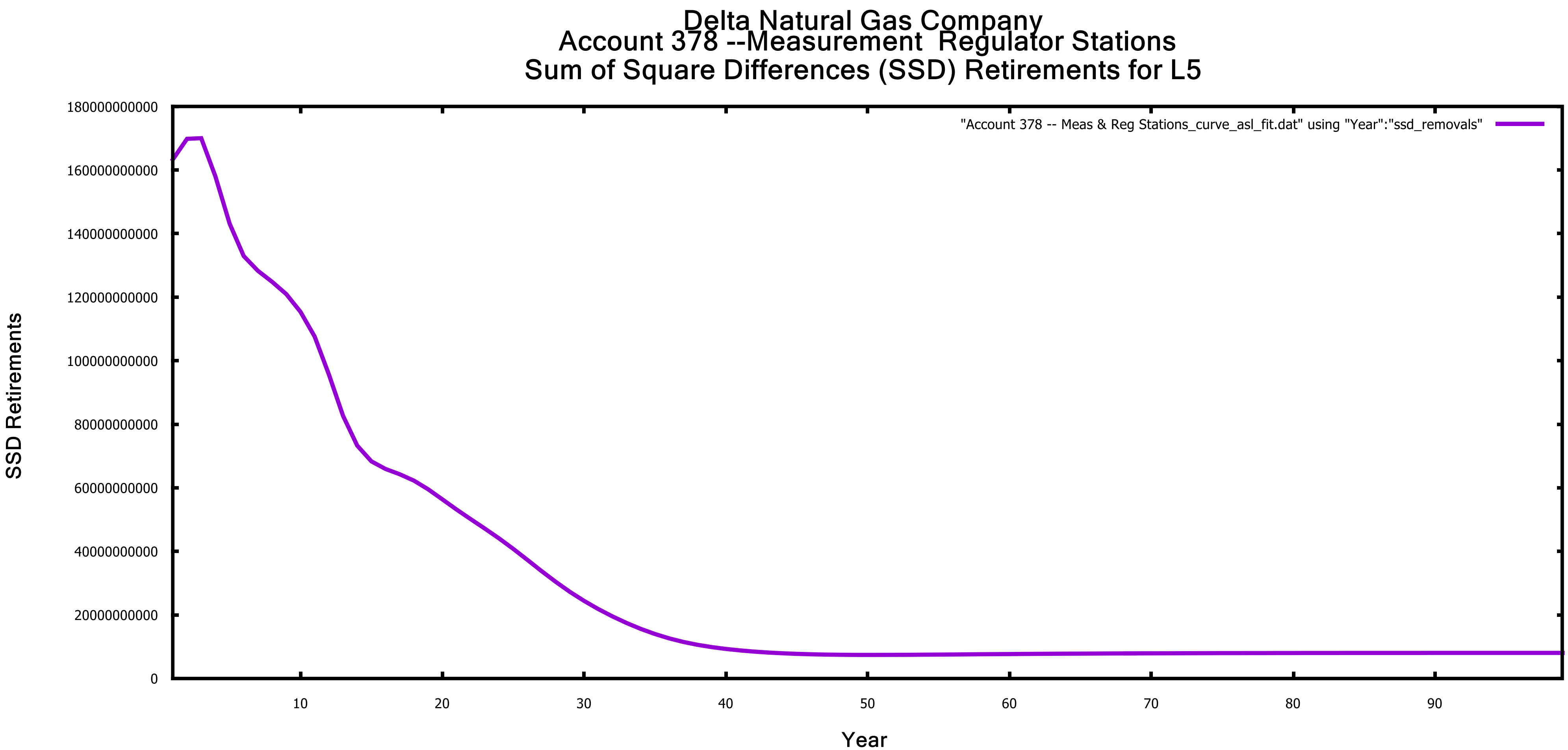
Delta Natural Gas Company
Account 378 --Measurement & Regulator Stations

Simulated Retirements for Iowa Curve L5   with ASL = 50

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	58206	6552	802091	477	914459	6075	-112368
1997	116218	11878	906431	571	1030106	11307	-123675
1998	62585	3424	965592	678	1092013	2746	-126421
1999	133573	5574	1093591	814	1224772	4760	-131181
2000	8746	5017	1097320	961	1232557	4056	-135237
2001	27018	1727	1122611	1128	1258447	599	-135836
2002	14796	0	1137407	1320	1271923	-1320	-134516
2003	132610	17455	1252562	1505	1403028	15950	-150466
2004	59940	27748	1284754	1698	1461270	26050	-176516
2005	117525	63211	1339068	1898	1576898	61314	-237830
2006	21873	4571	1356370	2082	1596689	2489	-240319
2007	0	11456	1344914	2252	1594437	9204	-249524
2008	48697	10839	1382772	2456	1640678	8383	-257906
2009	14183	200	1396755	2636	1652225	-2436	-255470
2010	209969	5886	1600838	2864	1859329	3021	-258491
2011	184982	18834	1766985	3156	2041155	15678	-274170
2012	98827	4837	1860975	3477	2136505	1360	-275530
2013	9495	1247	1869223	3914	2142086	-2667	-272863
2014	128519	2009	1995734	4439	2266166	-2431	-270432
2015	74727	4825	2065636	5042	2335851	-217	-270216
2016	16268	1925	2079978	5739	2346380	-3813	-266402
2017	2773	6043	2076709	6520	2342634	-477	-265925
2018	44965	12768	2108906	7321	2380278	5447	-271372
2019	68280	6217	2170969	8182	2440377	-1965	-269408
2020	28512	5147	2194334	9080	2459808	-3933	-265474
2021	13413	1693	2206054	10027	2463194	-8334	-257140
2022	0	905	2205149	11034	2452160	-10129	-247011
2023	236117	205	2441061	12150	2676127	-11945	-235066

Account No. 378 -- Measurement Reg Station Equipment
Iowa Curve: L5 ASL: 50 Years




Delta Natural Gas Company
Account 378 --Measurement Regulator Stations
Sum of Square Differences (SSD) Retirements for L5
"Account 378 -- Meas & Reg Stations_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
180000000000
160000000000
140000000000
120000000000
100000000000
80000000000
60000000000
40000000000
20000000000
0
10
20
30
40
50
60
70
80
90
Year

Delta Natural Gas Company
Account Investment Summary

378 -- Measuring Regulating Equipment - General

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	110.00	-	110.00
1941	110.00	-	-	-	110.00
1942	110.00	-	-	-	110.00
1943	110.00	-	-	-	110.00
1944	110.00	-	-	-	110.00
1945	110.00	-	-	-	110.00
1946	110.00	-	-	-	110.00
1947	110.00	-	-	-	110.00
1948	110.00	-	260.00	-	370.00
1949	370.00	-	97.00	-	467.00
1950	467.00	-	202.00	-	669.00
1951	669.00	-	535.00	-	1,204.00
1952	1,204.00	-	904.00	-	2,108.00
1953	2,108.00	-	789.00	-	2,897.00
1954	2,897.00	-	38.00	-	2,935.00
1955	2,935.00	-	5,199.00	-	8,134.00
1956	8,134.00	-	3,855.00	-	11,989.00
1957	11,989.00	-	1,094.00	-	13,083.00
1958	13,083.00	-	-	-	13,083.00
1959	13,083.00	-	12,372.00	-	25,455.00
1960	25,455.00	-	-	-	25,455.00
1961	25,455.00	-	-	-	25,455.00
1962	25,455.00	-	321.00	198.00	25,578.00
1963	25,578.00	-	-	-	25,578.00
1964	25,578.00	-	608.00	-	26,186.00
1965	26,186.00	-	881.00	131.00	26,936.00
1966	26,936.00	-	5,272.00	156.00	32,052.00
1967	32,052.00	-	-	-	32,052.00
1968	32,052.00	-	317.00	845.00	31,524.00
1969	31,524.00	-	281.00	-	31,805.00
1970	31,805.00	-	23,330.00	-	55,135.00
1971	55,135.00	-	24,948.00	-	80,083.00
1972	80,083.00	-	13,981.00	136.00	93,928.00
1973	93,928.00	-	3,975.00	632.00	97,271.00
1974	97,271.00	-	5,207.00	594.00	101,884.00
1975	101,884.00	-	6,244.00	929.00	107,199.00
1976	107,199.00	-	3,610.00	2,518.00	108,291.00
1977	108,291.00	-	8,552.00	171.00	116,672.00
1978	116,672.00	-	7,190.00	797.00	123,065.00
1979	123,065.00	-	9,000.00	-	132,065.00
1980	132,065.00	-	41,132.00	575.00	172,622.00
1981	172,622.00	-	51,901.00	1,879.00	222,644.00
1982	222,644.00	-	13,595.00	819.00	235,420.00
1983	235,420.00	-	20,919.00	447.00	255,892.00
1984	255,892.00	-	16,759.00	-	272,651.00
1985	272,651.00	-	12,417.00	-	285,068.00

Delta Natural Gas Company
Account Investment Summary

378 -- Measuring Regulating Equipment - General

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1986	285,068.00	-	37,728.00	3,248.00	319,548.00
1987	319,548.00	-	54,661.00	700.00	373,509.00
1988	373,509.00	-	57,764.00	6,061.00	425,212.00
1989	425,212.00	(2,500.00)	87,102.00	4,564.00	505,250.00
1990	505,250.00	947.00	51,068.00	9,780.00	547,485.00
1991	547,485.00	-	44,062.00	2,750.00	588,797.00
1992	588,797.00	(15,925.00)	52,625.00	15,670.00	609,827.00
1993	609,827.00	-	49,956.00	13,127.00	646,656.00
1994	646,656.00	-	44,296.00	9,493.00	681,459.00
1995	681,459.00	-	101,062.00	32,084.00	750,437.00
1996	750,437.00	-	58,206.00	6,552.00	802,091.00
1997	802,091.00	-	116,218.00	11,878.00	906,431.00
1998	906,431.00	-	62,585.00	3,424.00	965,592.00
1999	965,592.00	-	133,573.00	5,574.00	1,093,591.00
2000	1,093,591.00	-	8,746.00	5,017.00	1,097,320.00
2001	1,097,320.00	-	27,018.00	1,727.00	1,122,611.00
2002	1,122,611.00	-	14,796.17	-	1,137,407.17
2003	1,137,407.17	-	132,610.00	17,455.00	1,252,562.17
2004	1,252,562.17	-	59,940.00	27,748.00	1,284,754.17
2005	1,284,754.17	-	117,525.11	63,211.36	1,339,067.92
2006	1,339,067.92	-	21,872.83	4,570.91	1,356,369.84
2007	1,356,369.84	-	-	11,456.21	1,344,913.63
2008	1,344,913.63	-	48,697.43	10,839.09	1,382,771.97
2009	1,382,771.97	-	14,182.93	200.00	1,396,754.90
2010	1,396,754.90	38,409.78	171,558.83	5,885.74	1,600,837.77
2011	1,600,837.77	1,000.00	183,981.50	18,834.15	1,766,985.12
2012	1,766,985.12	-	98,827.23	4,837.33	1,860,975.02
2013	1,860,975.02	-	9,495.35	1,247.16	1,869,223.21
2014	1,869,223.21	-	128,519.47	2,008.81	1,995,733.87
2015	1,995,733.87	-	74,727.09	4,825.41	2,065,635.55
2016	2,065,635.55	-	16,268.16	1,925.44	2,079,978.27
2017	2,079,978.27	-	2,773.09	6,042.80	2,076,708.56
2018	2,076,708.56	-	44,965.13	12,767.76	2,108,905.93
2019	2,108,905.93	-	68,280.22	6,217.13	2,170,969.02
2020	2,170,969.02	-	28,511.83	5,146.95	2,194,333.90
2021	2,194,333.90	-	13,412.85	1,692.71	2,206,054.04
2022	2,206,054.04	-	-	905.22	2,205,148.82
2023	2,205,148.82	-	236,117.26	204.79	2,441,061.29

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 378
Distribution General Reg Station

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	1,122,611	1,727	0.2%	-	2,180	(2,180)	-126.2%
2002	1,137,407	-	0.0%	-	-	-	0.0%
2003	1,252,562	17,455	1.4%	-	-	-	0.0%
2004	1,284,754	27,748	2.2%	-	-	-	0.0%
2005	1,339,068	63,211	4.7%	-	42,523	(42,523)	-67.3%
2006	1,356,370	4,571	0.3%	-	-	-	0.0%
2007	1,344,914	11,456	0.9%	-	1,036	(1,036)	-9.0%
2008	1,382,772	10,839	0.8%	-	-	-	0.0%
2009	1,396,755	200	0.0%	-	-	-	0.0%
2010	1,600,838	5,886	0.4%	-	969	(969)	-16.5%
2011	1,766,985	18,834	1.1%	-	11,337	(11,337)	-60.2%
2012	1,860,975	4,837	0.3%	-	-	-	0.0%
2013	1,869,223	1,247	0.1%	-	-	-	0.0%
2014	1,995,734	2,009	0.1%	-	-	-	0.0%
2015	2,065,636	4,825	0.2%	-	-	-	0.0%
2016	2,079,978	1,925	0.1%	-	-	-	0.0%
2017	2,076,709	6,043	0.3%	-	145	(145)	-2.4%
2018	2,108,906	12,768	0.6%	-	1,146	(1,146)	-9.0%
2019	2,170,969	6,217	0.3%	-	2,964	(2,964)	-47.7%
2020	2,194,334	5,147	0.2%	-	2,116	(2,116)	-41.1%
2021	2,206,054	1,693	0.1%	-	19,550	(19,550)	-1155.0%
2022	2,205,149	905	0.0%	-	4,608	(4,608)	-509.0%
2023	2,441,061	205	0.0%	-	11,478	(11,478)	-5605.0%
Total	40,259,763	209,749	0.5%	-	100,052	(100,052)	-47.7%

Five Year Average Net Salvage	-19.8%
Ten Year Average Net Salvage	-25.4%
Current Net Salvage	-11%
Recommend Net Salvage	-15%

Account 380 – Services

Delta Natural Gas Company
Account 380 -- Services

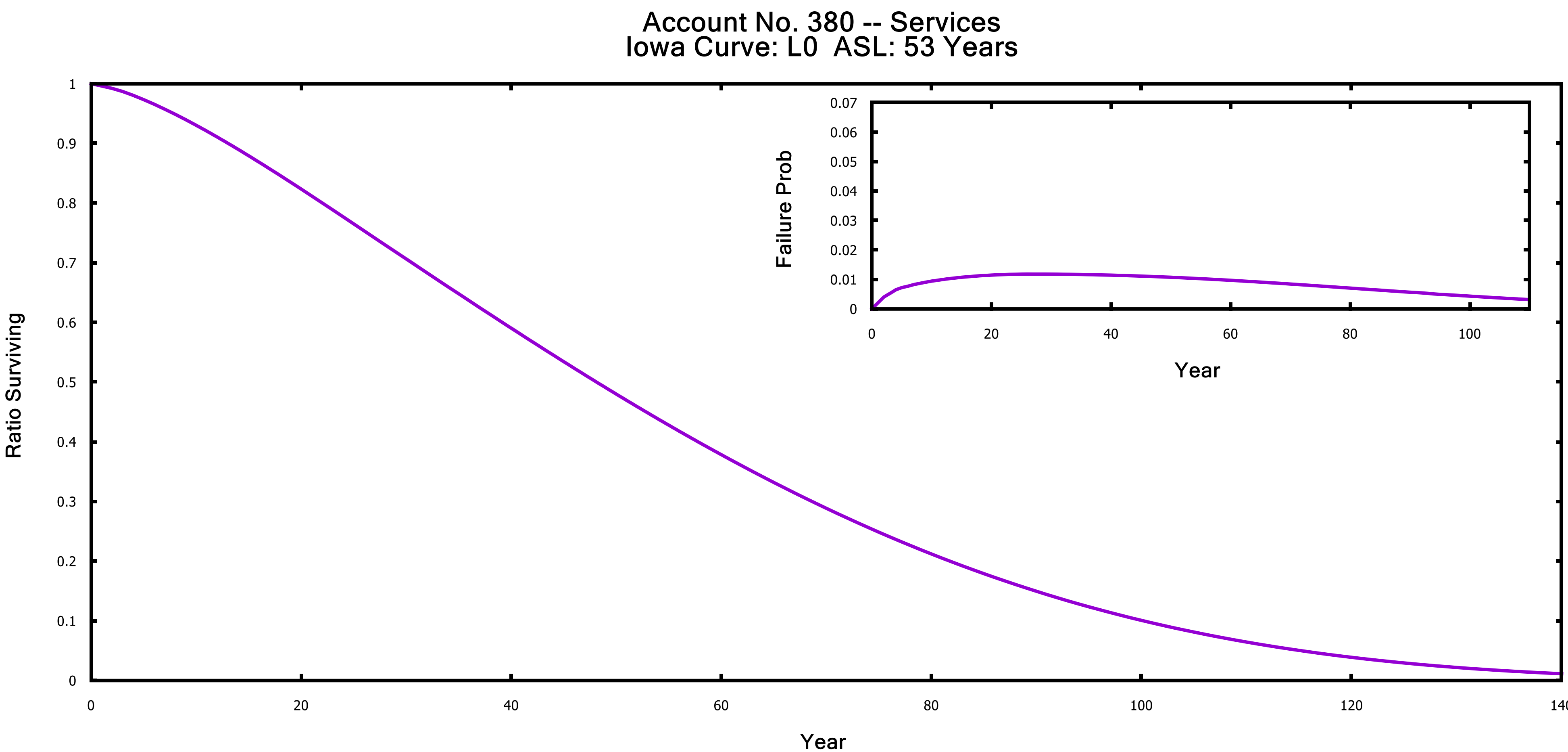
Simulated Retirements for Iowa Curve L0 with ASL = 53

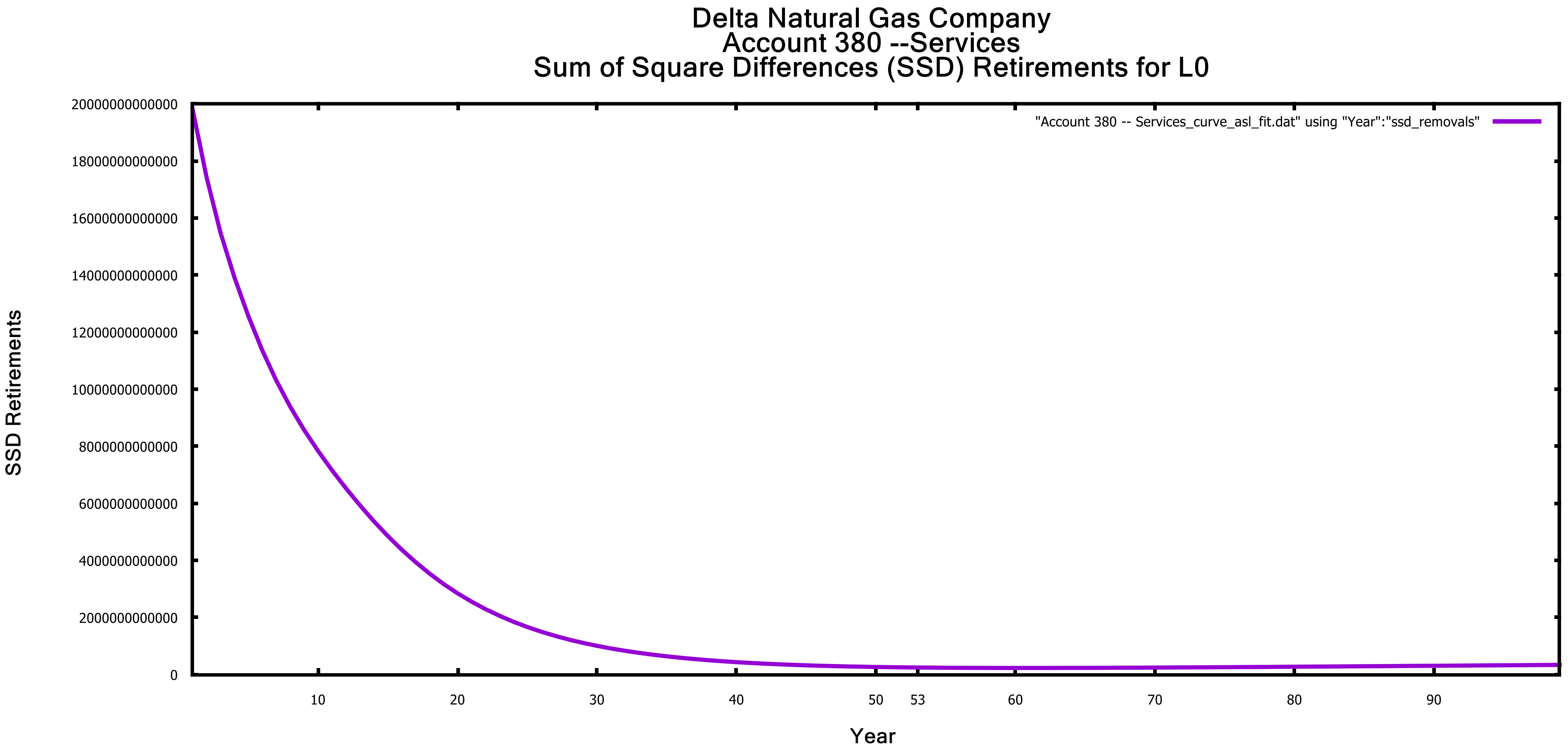
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1989	1450097	1099	1448998	0	1450097	1099	-1099
1990	591398	19776	2020620	5639	2035856	14137	-15236
1991	502230	13138	2509712	8126	2529959	5012	-20247
1992	597650	16757	3090605	11861	3115748	4896	-25143
1993	609177	20071	3679711	16773	3708152	3298	-28441
1994	791561	17854	4453418	21647	4478066	-3793	-24648
1995	777027	20972	5209473	27231	5227862	-6259	-18389
1996	825079	16854	6017698	33292	6019649	-16438	-1951
1997	871721	64886	6824533	39909	6851461	24977	-26928
1998	853325	43205	7634653	47130	7657656	-3925	-23003
1999	834050	59319	8409384	54707	8436999	4612	-27615
2000	598822	81731	8926475	62485	8973336	19246	-46861
2001	764427	91254	9599648	69732	9668031	21522	-68383
2002	639556	71940	10167264	77795	10229792	-5855	-62528
2003	728084	38495	10856853	85281	10872595	-46786	-15742
2004	692366	24586	11524633	93248	11471713	-68662	52920
2005	635566	23300	12136900	101093	12006186	-77793	130713
2006	558977	37401	12658475	108854	12456309	-71453	202166
2007	404122	154299	12908298	116376	12744055	37923	164243
2008	578423	204123	13282598	123261	13199218	80863	83381
2009	458827	179350	13562074	130710	13527334	48640	34740
2010	607893	257169	13912798	137421	13997806	119748	-85007
2011	714478	191584	14435693	144653	14567631	46931	-131938
2012	1226494	240845	15421342	152253	15641872	88591	-220530
2013	964107	310168	16075282	161868	16444112	148300	-368830
2014	1049415	77255	17047442	170706	17322820	-93451	-275379
2015	693282	184255	17556469	180619	17835484	3636	-279014
2016	872251	331700	18097020	189511	18518224	142189	-421204

Delta Natural Gas Company
Account 380 -- Services

Simulated Retirements for Iowa Curve L0 with ASL = 53

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2017	996125	220801	18872344	199256	19315092	21544	-442748
2018	1226932	231528	19867748	209270	20332754	22258	-465006
2019	1260098	58560	21069286	220200	21372652	-161640	-303366
2020	1507500	56562	22520223	231521	22648630	-174959	-128408
2021	2043312	222653	24340882	244348	24447594	-21696	-106712
2022	0	0	24340882	259721	24187873	-259721	153009
2023	2403342	120228	26623997	267816	26323400	-147588	300597


Account No. 380 -- Services
Iowa Curve: L0 ASL: 53 Years
Ratio Surviving
Year
Failure Prob
Year
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
20
40
60
80
100
120
140
0
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0
20
40
60
80
100


Delta Natural Gas Company
Account 380 --Services
Sum of Square Differences (SSD) Retirements for L0
"Account 380 -- Services_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
20000000000000
18000000000000
16000000000000
14000000000000
12000000000000
10000000000000
8000000000000
6000000000000
4000000000000
2000000000000
0
10
20
30
40
50
53
60
70
80
90
Year

Delta Natural Gas Company
Account Investment Summary

Account 380 -- Services

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1989	-	1,307,818.00	142,279.00	1,099.00	1,448,998.00
1990	1,448,998.00	-	591,398.00	19,776.00	2,020,620.00
1991	2,020,620.00	-	502,230.00	13,138.00	2,509,712.00
1992	2,509,712.00	-	597,650.00	16,757.00	3,090,605.00
1993	3,090,605.00	-	609,177.00	20,071.00	3,679,711.00
1994	3,679,711.00	-	791,561.00	17,854.00	4,453,418.00
1995	4,453,418.00	-	777,027.00	20,972.00	5,209,473.00
1996	5,209,473.00	-	825,079.00	16,854.00	6,017,698.00
1997	6,017,698.00	(1,000.00)	872,721.00	64,886.00	6,824,533.00
1998	6,824,533.00	-	853,325.00	43,205.00	7,634,653.00
1999	7,634,653.00	(350.00)	834,400.00	59,319.00	8,409,384.00
2000	8,409,384.00	3,948.00	594,874.00	81,731.00	8,926,475.00
2001	8,926,475.00	(6,556.00)	770,983.00	91,254.00	9,599,648.00
2002	9,599,648.00	-	639,556.19	71,940.00	10,167,264.19
2003	10,167,264.19	-	728,084.00	38,495.00	10,856,853.19
2004	10,856,853.19	(3,288.00)	695,654.00	24,586.00	11,524,633.19
2005	11,524,633.19	829.54	634,736.61	23,299.69	12,136,899.65
2006	12,136,899.65	-	558,976.64	37,401.28	12,658,475.01
2007	12,658,475.01	(102.28)	404,224.64	154,298.95	12,908,298.42
2008	12,908,298.42	(1,034.47)	579,457.51	204,123.29	13,282,598.17
2009	13,282,598.17	-	458,826.60	179,350.47	13,562,074.30
2010	13,562,074.30	(180.95)	608,073.62	257,168.77	13,912,798.20
2011	13,912,798.20	(6,896.47)	721,374.54	191,583.56	14,435,692.71
2012	14,435,692.71	-	1,226,494.25	240,844.74	15,421,342.22
2013	15,421,342.22	-	964,107.39	310,167.89	16,075,281.72
2014	16,075,281.72	(591.00)	1,050,006.05	77,255.04	17,047,441.73
2015	17,047,441.73	-	693,282.27	184,254.54	17,556,469.46
2016	17,556,469.46	-	872,250.66	331,700.02	18,097,020.10
2017	18,097,020.10	-	996,124.65	220,800.54	18,872,344.21
2018	18,872,344.21	-	1,226,931.78	231,528.03	19,867,747.96
2019	19,867,747.96	-	1,260,097.86	58,560.10	21,069,285.72
2020	21,069,285.72	4,910.34	1,502,589.24	56,562.36	22,520,222.94
2021	22,520,222.94	-	2,043,311.83	222,652.71	24,340,882.06
2022	24,340,882.06	-	-	-	24,340,882.06
2023	24,340,882.06	-	2,403,342.48	120,227.53	26,623,997.01

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 380
Distribution Services

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	9,599,648	91,254	1.0%	-	32,972	(32,972)	-36.1%
2002	10,167,264	71,940	0.7%	-	12,057	(12,057)	-16.8%
2003	10,856,853	38,495	0.4%	-	14,027	(14,027)	-36.4%
2004	11,524,633	24,586	0.2%	-	27,068	(27,068)	-110.1%
2005	12,136,900	23,300	0.2%	-	22,393	(22,393)	-96.1%
2006	12,658,475	37,401	0.3%	-	84,657	(84,657)	-226.3%
2007	12,908,298	154,299	1.2%	-	167,561	(167,561)	-108.6%
2008	13,282,598	204,123	1.5%	-	333,193	(333,193)	-163.2%
2009	13,562,074	179,350	1.3%	-	299,902	(299,902)	-167.2%
2010	13,912,798	257,169	1.8%	-	463,965	(463,965)	-180.4%
2011	14,435,693	191,584	1.3%	-	328,902	(328,902)	-171.7%
2012	15,421,342	240,845	1.6%	-	659,481	(659,481)	-273.8%
2013	16,075,282	310,168	1.9%	-	625,311	(625,311)	-201.6%
2014	17,047,442	77,255	0.5%	-	123,729	(123,729)	-160.2%
2015	17,556,469	184,255	1.0%	-	242,680	(242,680)	-131.7%
2016	18,097,020	331,700	1.8%	-	323,061	(323,061)	-97.4%
2017	18,872,344	220,801	1.2%	-	244,638	(244,638)	-110.8%
2018	19,867,748	231,528	1.2%	-	326,447	(326,447)	-141.0%
2019	21,069,286	58,560	0.3%	-	297,403	(297,403)	-507.9%
2020	22,520,223	56,562	0.3%	-	204,669	(204,669)	-361.8%
2021	24,340,882	222,653	0.9%	-	169,874	(169,874)	-76.3%
2022	24,340,882	-	0.0%	-	118,799	(118,799)	#DIV/0!
2023	26,623,997	120,228	0.5%	-	251,934	(251,934)	-209.5%
Total	376,878,152	3,328,055	0.9%	-	5,374,725	(5,374,725)	-161.5%

Five Year Average Net Salvage	-155.3%
Ten Year Average Net Salvage	-177.4%
Current Net Salvage	-40%
Recommend Net Salvage	-50%

Account 381 – Meters

Delta Natural Gas Company
Account 381 -- Meters

Simulated Retirements for Iowa Curve O2   with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1940	1300	0	1300	0	1300	0	0
1941	0	0	1300	17	1283	-17	17
1942	0	0	1300	17	1266	-17	34
1943	0	0	1300	17	1249	-17	51
1944	0	0	1300	17	1232	-17	68
1945	0	0	1300	17	1215	-17	85
1946	0	0	1300	17	1198	-17	102
1947	1361	0	2661	17	2542	-17	119
1948	7200	0	9861	35	9707	-35	154
1949	12983	0	22844	129	22561	-129	283
1950	11515	0	34359	298	33778	-298	581
1951	8282	0	42641	449	41611	-449	1030
1952	25195	0	67836	557	66249	-557	1587
1953	4329	0	72165	886	69692	-886	2473
1954	6163	0	78328	943	74912	-943	3416
1955	14171	0	92499	1024	88059	-1024	4440
1956	29813	0	122312	1209	116663	-1209	5649
1957	15293	0	137605	1599	130357	-1599	7248
1958	17188	0	154793	1799	145746	-1799	9047
1959	19856	0	174649	2024	163579	-2024	11070
1960	21145	0	195794	2283	182440	-2283	13354
1961	24843	0	220637	2560	204724	-2560	15913
1962	14485	0	235122	2885	216324	-2885	18798
1963	31894	2480	264536	3074	245144	-594	19392
1964	18103	1822	280817	3491	259756	-1669	21061
1965	23944	259	304502	3728	279972	-3469	24530
1966	20427	51	324878	4041	296358	-3990	28520
1967	36960	123	361715	4308	329009	-4185	32706

Delta Natural Gas Company
Account 381 -- Meters

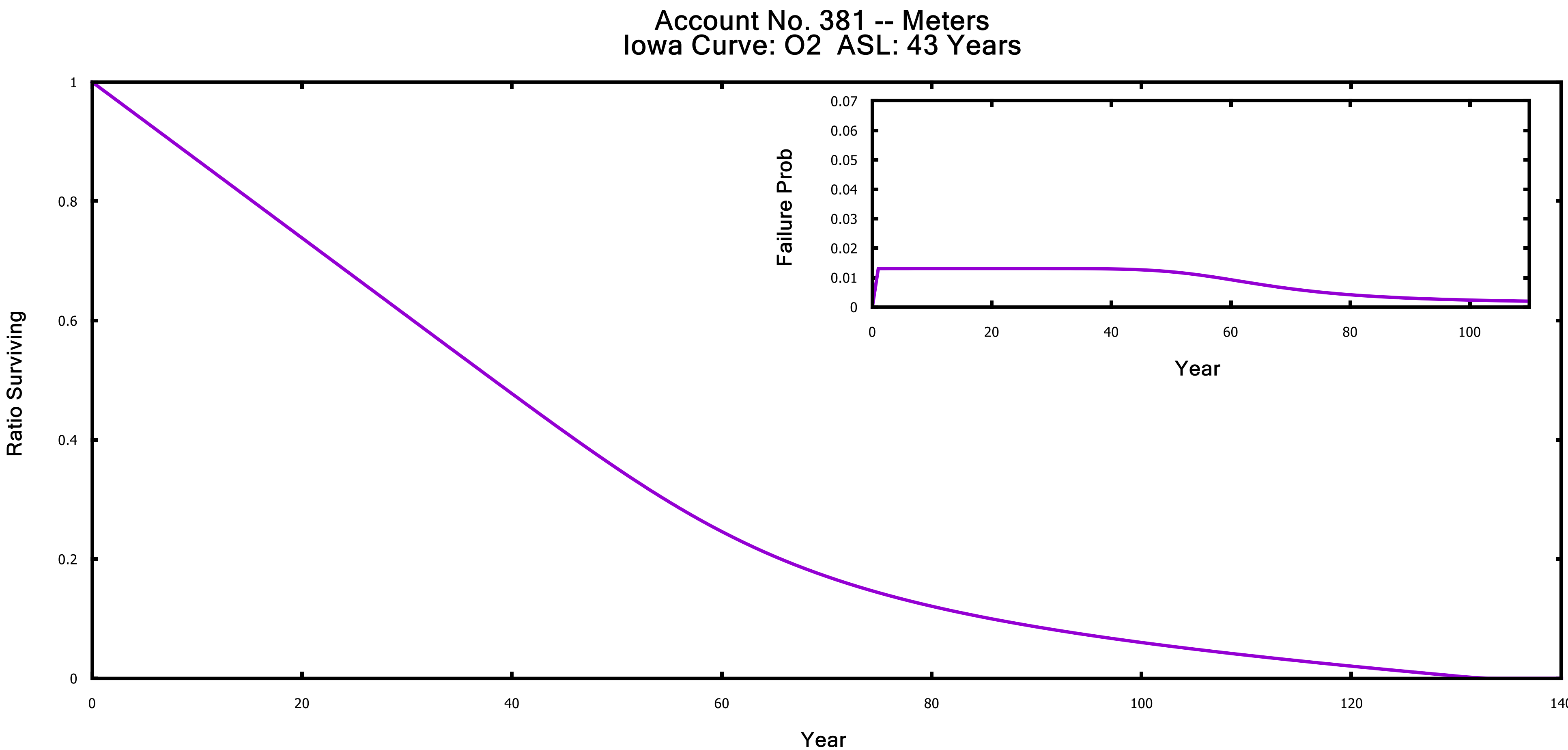
Simulated Retirements for Iowa Curve O2 with ASL = 43

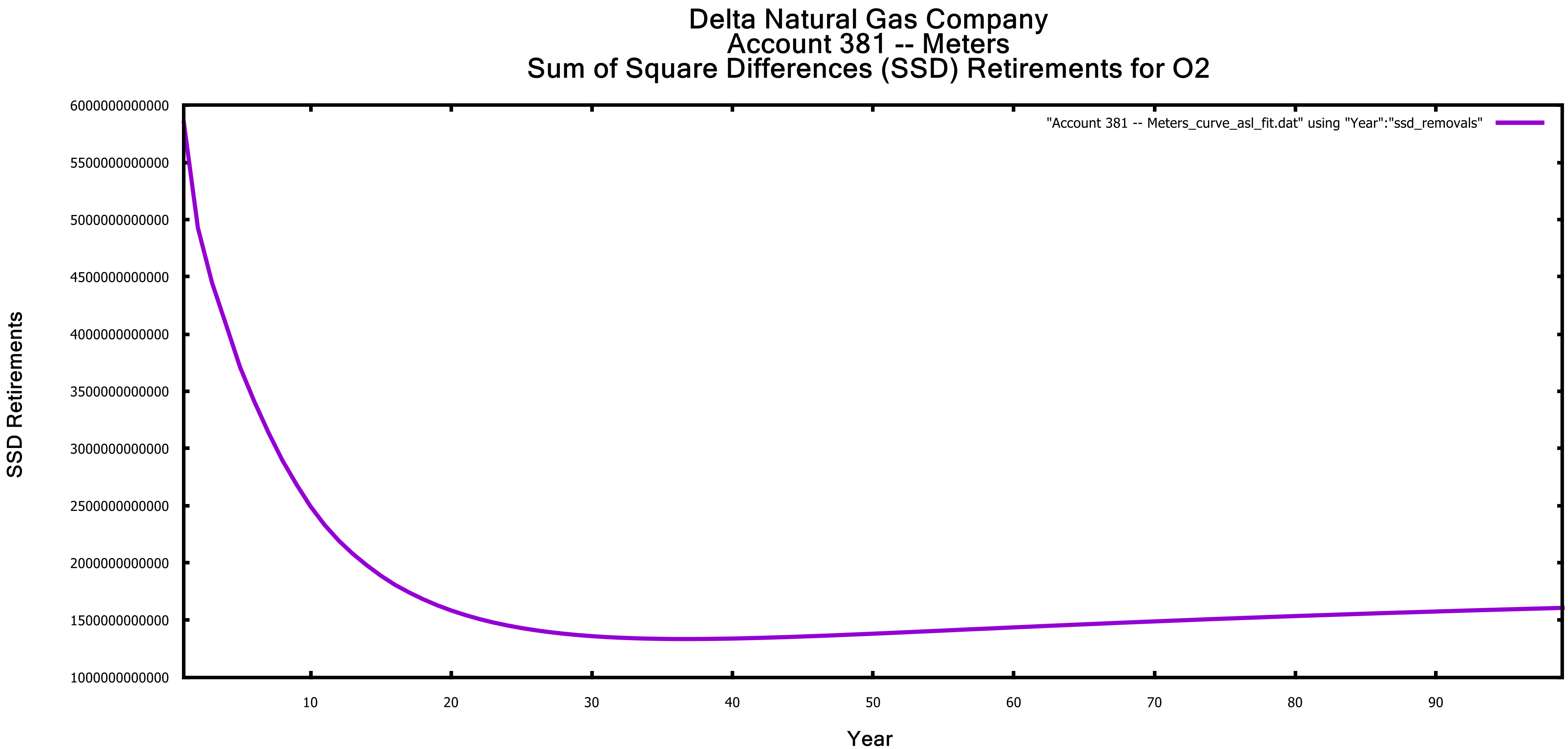
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	44180	722	405173	4791	368398	-4069	36775
1969	61872	527	466518	5369	424901	-4842	41617
1970	219572	286	685804	6178	638295	-5892	47509
1971	210607	399	896012	9046	839856	-8647	56156
1972	91736	545	987203	11797	919795	-11252	67408
1973	91823	36	1078990	12998	998620	-12962	80370
1974	58878	82	1137786	14200	1043297	-14118	94489
1975	78982	61	1216707	14972	1107308	-14911	109399
1976	48111	274	1264544	16005	1139413	-15731	125131
1977	66317	144	1330717	16636	1189094	-16492	141623
1978	67406	441	1397682	17504	1238997	-17063	158685
1979	53560	1416	1449826	18385	1274171	-16969	175655
1980	69898	185265	1334459	19086	1324983	166179	9476
1981	92069	6704	1419824	20000	1397052	-13296	22772
1982	195244	15730	1599338	21204	1571092	-5474	28246
1983	125587	12072	1712853	23754	1672925	-11682	39928
1984	147259	28342	1831770	25396	1794789	2946	36981
1985	82296	11883	1902183	27321	1849764	-15438	52419
1986	81339	15181	1968341	28397	1902706	-13216	65635
1987	122066	13487	2076920	29460	1995312	-15973	81608
1988	216913	10148	2283685	31055	2181169	-20907	102516
1989	86154	8015	2361824	33887	2233436	-25872	128388
1990	195258	7947	2549135	35012	2393681	-27065	155454
1991	142091	6556	2684670	37562	2498211	-31006	186459
1992	111792	7596	2788866	39415	2570588	-31819	218278
1993	281873	5117	3065622	40872	2811588	-35755	254034
1994	239405	6513	3298514	44549	3006444	-38036	292070
1995	297778	10650	3585642	47670	3256553	-37020	329089

Delta Natural Gas Company
Account 381 -- Meters

Simulated Retirements for Iowa Curve O2   with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	1004419	15643	4574418	51552	4209420	-35909	364998
1997	94368	21641	4647145	64660	4239128	-43019	408017
1998	828613	21341	5454417	65883	5001857	-44542	452560
1999	221392	7875	5667934	76697	5146553	-68822	521381
2000	203319	19071	5852182	79574	5270297	-60503	581885
2001	408435	15242	6245375	82214	5596519	-66972	648856
2002	577828	211869	6611334	87527	6086821	124342	524514
2003	1828445	13068	8426711	95043	7820223	-81975	606489
2004	92829	10023	8509517	118888	7794163	-108865	715354
2005	215473	14168	8710822	120066	7889570	-105898	821252
2006	225642	18888	8917576	122844	7992368	-103956	925208
2007	317640	84505	9150711	125742	8184266	-41238	966446
2008	149376	31448	9268640	129826	8203816	-98378	1064824
2009	82941	48653	9302928	131707	8155051	-83054	1147878
2010	76612	167164	9212376	132707	8098956	34458	1113420
2011	94499	108364	9198511	133610	8059846	-25246	1138665
2012	67662	62399	9203775	134732	7992776	-72333	1210999
2013	112817	59191	9257401	135491	7970102	-76301	1287299
2014	165281	427804	8994878	136824	7998559	290980	996319
2015	150933	90567	9055244	138824	8010668	-48257	1044576
2016	620069	64615	9610698	140620	8490117	-76005	1120581
2017	545644	1143633	9012709	148524	8887237	995109	125471
2018	555428	303708	9264429	155436	9287230	148272	-22801
2019	364430	312877	9315982	162457	9489203	150420	-173220
2020	400538	366700	9349821	166963	9722778	199736	-372957
2021	1240629	187269	10403181	171917	10791489	15352	-388309
2022	0	1881	10401300	187813	10603677	-185932	-202377
2023	1166856	140903	11427253	187485	11583048	-46582	-155795


Account No. 381 -- Meters
Iowa Curve: O2 ASL: 43 Years
Ratio Surviving
Year
Failure Prob
Year
0
0.2
0.4
0.6
0.8
1
0
20
40
60
80
100
120
140
0
0.01
0.02
0.03
0.04
0.05
0.06
0.07
0
20
40
60
80
100


Delta Natural Gas Company
Account 381 -- Meters
Sum of Square Differences (SSD) Retirements for O2
"Account 381 -- Meters_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
6000000000000
5500000000000
5000000000000
4500000000000
4000000000000
3500000000000
3000000000000
2500000000000
2000000000000
1500000000000
1000000000000
10
20
30
40
50
60
70
80
90
Year

Delta Natural Gas Company
Account Investment Summary

Account 381 -- Meters

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	1,300.00	-	1,300.00
1941	1,300.00	-	-	-	1,300.00
1942	1,300.00	-	-	-	1,300.00
1943	1,300.00	-	-	-	1,300.00
1944	1,300.00	-	-	-	1,300.00
1945	1,300.00	-	-	-	1,300.00
1946	1,300.00	-	-	-	1,300.00
1947	1,300.00	-	1,361.00	-	2,661.00
1948	2,661.00	-	7,200.00	-	9,861.00
1949	9,861.00	-	12,983.00	-	22,844.00
1950	22,844.00	-	11,515.00	-	34,359.00
1951	34,359.00	-	8,282.00	-	42,641.00
1952	42,641.00	-	25,195.00	-	67,836.00
1953	67,836.00	-	4,329.00	-	72,165.00
1954	72,165.00	-	6,163.00	-	78,328.00
1955	78,328.00	-	14,171.00	-	92,499.00
1956	92,499.00	-	29,813.00	-	122,312.00
1957	122,312.00	-	15,293.00	-	137,605.00
1958	137,605.00	-	17,188.00	-	154,793.00
1959	154,793.00	-	19,856.00	-	174,649.00
1960	174,649.00	-	21,145.00	-	195,794.00
1961	195,794.00	-	24,843.00	-	220,637.00
1962	220,637.00	-	14,485.00	-	235,122.00
1963	235,122.00	-	31,894.00	2,480.00	264,536.00
1964	264,536.00	-	18,103.00	1,822.00	280,817.00
1965	280,817.00	-	23,944.00	259.00	304,502.00
1966	304,502.00	-	20,427.00	51.00	324,878.00
1967	324,878.00	-	36,960.00	123.00	361,715.00
1968	361,715.00	-	44,180.00	722.00	405,173.00
1969	405,173.00	-	61,872.00	527.00	466,518.00
1970	466,518.00	-	219,572.00	286.00	685,804.00
1971	685,804.00	-	210,607.00	399.00	896,012.00
1972	896,012.00	-	91,736.00	545.00	987,203.00
1973	987,203.00	-	91,823.00	36.00	1,078,990.00
1974	1,078,990.00	-	58,878.00	82.00	1,137,786.00
1975	1,137,786.00	-	78,982.00	61.00	1,216,707.00
1976	1,216,707.00	-	48,111.00	274.00	1,264,544.00
1977	1,264,544.00	-	66,317.00	144.00	1,330,717.00
1978	1,330,717.00	-	67,406.00	441.00	1,397,682.00
1979	1,397,682.00	-	53,560.00	1,416.00	1,449,826.00
1980	1,449,826.00	-	69,898.00	185,265.00	1,334,459.00
1981	1,334,459.00	-	92,069.00	6,704.00	1,419,824.00
1982	1,419,824.00	-	195,244.00	15,730.00	1,599,338.00
1983	1,599,338.00	-	125,587.00	12,072.00	1,712,853.00
1984	1,712,853.00	-	147,259.00	28,342.00	1,831,770.00
1985	1,831,770.00	-	82,296.00	11,883.00	1,902,183.00

Delta Natural Gas Company
Account Investment Summary

Account 381 -- Meters

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1986	1,902,183.00	-	81,339.00	15,181.00	1,968,341.00
1987	1,968,341.00	(3,463.00)	125,529.00	13,487.00	2,076,920.00
1988	2,076,920.00	-	216,913.00	10,148.00	2,283,685.00
1989	2,283,685.00	-	86,154.00	8,015.00	2,361,824.00
1990	2,361,824.00	-	195,258.00	7,947.00	2,549,135.00
1991	2,549,135.00	-	142,091.00	6,556.00	2,684,670.00
1992	2,684,670.00	6,585.00	105,207.00	7,596.00	2,788,866.00
1993	2,788,866.00	-	281,873.00	5,117.00	3,065,622.00
1994	3,065,622.00	-	239,405.00	6,513.00	3,298,514.00
1995	3,298,514.00	-	297,778.00	10,650.00	3,585,642.00
1996	3,585,642.00	-	1,004,419.00	15,643.00	4,574,418.00
1997	4,574,418.00	-	94,368.00	21,641.00	4,647,145.00
1998	4,647,145.00	(295.00)	828,908.00	21,341.00	5,454,417.00
1999	5,454,417.00	-	221,392.00	7,875.00	5,667,934.00
2000	5,667,934.00	-	203,319.00	19,071.00	5,852,182.00
2001	5,852,182.00	-	408,435.00	15,242.00	6,245,375.00
2002	6,245,375.00	-	577,828.23	211,869.00	6,611,334.23
2003	6,611,334.23	-	1,828,445.00	13,068.00	8,426,711.23
2004	8,426,711.23	-	92,829.00	10,023.00	8,509,517.23
2005	8,509,517.23	-	215,472.72	14,167.84	8,710,822.11
2006	8,710,822.11	-	225,641.97	18,887.88	8,917,576.20
2007	8,917,576.20	41,917.92	275,721.80	84,504.60	9,150,711.32
2008	9,150,711.32	-	149,376.45	31,448.08	9,268,639.69
2009	9,268,639.69	-	82,941.48	48,653.08	9,302,928.09
2010	9,302,928.09	-	76,612.12	167,164.41	9,212,375.80
2011	9,212,375.80	-	94,499.41	108,364.13	9,198,511.08
2012	9,198,511.08	-	67,662.32	62,398.86	9,203,774.54
2013	9,203,774.54	-	112,817.00	59,190.73	9,257,400.81
2014	9,257,400.81	-	165,280.75	427,803.99	8,994,877.57
2015	8,994,877.57	-	150,933.38	90,567.37	9,055,243.58
2016	9,055,243.58	9,105.84	610,963.45	64,615.03	9,610,697.84
2017	9,610,697.84	-	545,644.14	1,143,633.29	9,012,708.69
2018	9,012,708.69	-	555,427.92	303,707.60	9,264,429.01
2019	9,264,429.01	-	364,430.02	312,876.79	9,315,982.24
2020	9,315,982.24	-	400,538.47	366,699.57	9,349,821.14
2021	9,349,821.14	-	1,240,628.53	187,268.69	10,403,180.98
2022	10,403,180.98	-	-	1,881.22	10,401,299.76
2023	10,401,299.76	-	1,166,856.06	140,902.94	11,427,252.88

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 381
Distribution Meters

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	6,245,375	15,242	0.2%	-	-	-	0.0%
2002	6,611,334	211,869	3.2%	-	-	-	0.0%
2003	8,426,711	13,068	0.2%	1,300	-	1,300	9.9%
2004	8,509,517	10,023	0.1%	-	-	-	0.0%
2005	8,710,822	14,168	0.2%	123	-	123	0.9%
2006	8,917,576	18,888	0.2%	-	-	-	0.0%
2007	9,150,711	84,505	0.9%	-	-	-	0.0%
2008	9,268,640	31,448	0.3%	-	-	-	0.0%
2009	9,302,928	48,653	0.5%	180	-	180	0.4%
2010	9,212,376	167,164	1.8%	116	-	116	0.1%
2011	9,198,511	108,364	1.2%	4,453	-	4,453	4.1%
2012	9,203,775	62,399	0.7%	-	-	-	0.0%
2013	9,257,401	59,191	0.6%	400	-	400	0.7%
2014	8,994,878	427,804	4.8%	658	-	658	0.2%
2015	9,055,244	90,567	1.0%	(475)	-	(475)	-0.5%
2016	9,610,698	64,615	0.7%	140	-	140	0.2%
2017	9,012,709	1,143,633	12.7%	-	-	-	0.0%
2018	9,264,429	303,708	3.3%	-	-	-	0.0%
2019	9,315,982	312,877	3.4%	-	-	-	0.0%
2020	9,349,821	366,700	3.9%	-	-	-	0.0%
2021	10,403,181	187,269	1.8%	-	-	-	0.0%
2022	10,401,300	1,881	0.0%	-	20,316	(20,316)	-1079.9%
2023	11,427,253	140,903	1.2%	-	23,421	(23,421)	-16.6%
Total	208,851,171	3,884,938	1.9%	6,894	43,737	(36,843)	-0.9%

Five Year Average Net Salvage	0.0%
Ten Year Average Net Salvage	0.2%
Current Net Salvage	0%
Recommend Net Salvage	0%

Account 382 – Meter & Reg Installations

Delta Natural Gas Company
Account 382 -- Meter & Regulator Installations

Simulated Retirements for Iowa Curve S0   with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1940	386	0	386	0	386	0	0
1941	0	0	386	1	385	-1	1
1942	0	0	386	1	385	-1	1
1943	0	0	386	1	384	-1	2
1944	0	0	386	2	382	-2	4
1945	0	0	386	2	380	-2	6
1946	0	0	386	2	378	-2	8
1947	291	0	677	2	667	-2	10
1948	543	0	1220	3	1207	-3	13
1949	1057	0	2277	4	2259	-4	18
1950	1120	0	3397	6	3373	-6	24
1951	1784	0	5181	10	5148	-10	33
1952	293	0	5474	15	5426	-15	48
1953	394	0	5868	19	5801	-19	67
1954	1666	0	7534	25	7442	-25	92
1955	2929	0	10463	32	10339	-32	124
1956	8754	0	19217	41	19052	-41	165
1957	8202	0	27419	60	27194	-60	225
1958	6222	0	33641	84	33332	-84	309
1959	4846	0	38487	115	38063	-115	424
1960	3986	0	42473	150	41899	-150	574
1961	3306	0	45779	187	45018	-187	761
1962	9394	18	55155	224	54189	-206	966
1963	1800	0	56955	270	55718	-270	1237
1964	1800	0	58755	309	57209	-309	1546
1965	2280	0	61035	355	59134	-355	1901
1966	2088	0	63123	398	60825	-398	2298
1967	4152	0	67275	438	64538	-438	2737

Delta Natural Gas Company
Account 382 -- Meter & Regulator Installations

Simulated Retirements for Iowa Curve S0 with ASL = 43

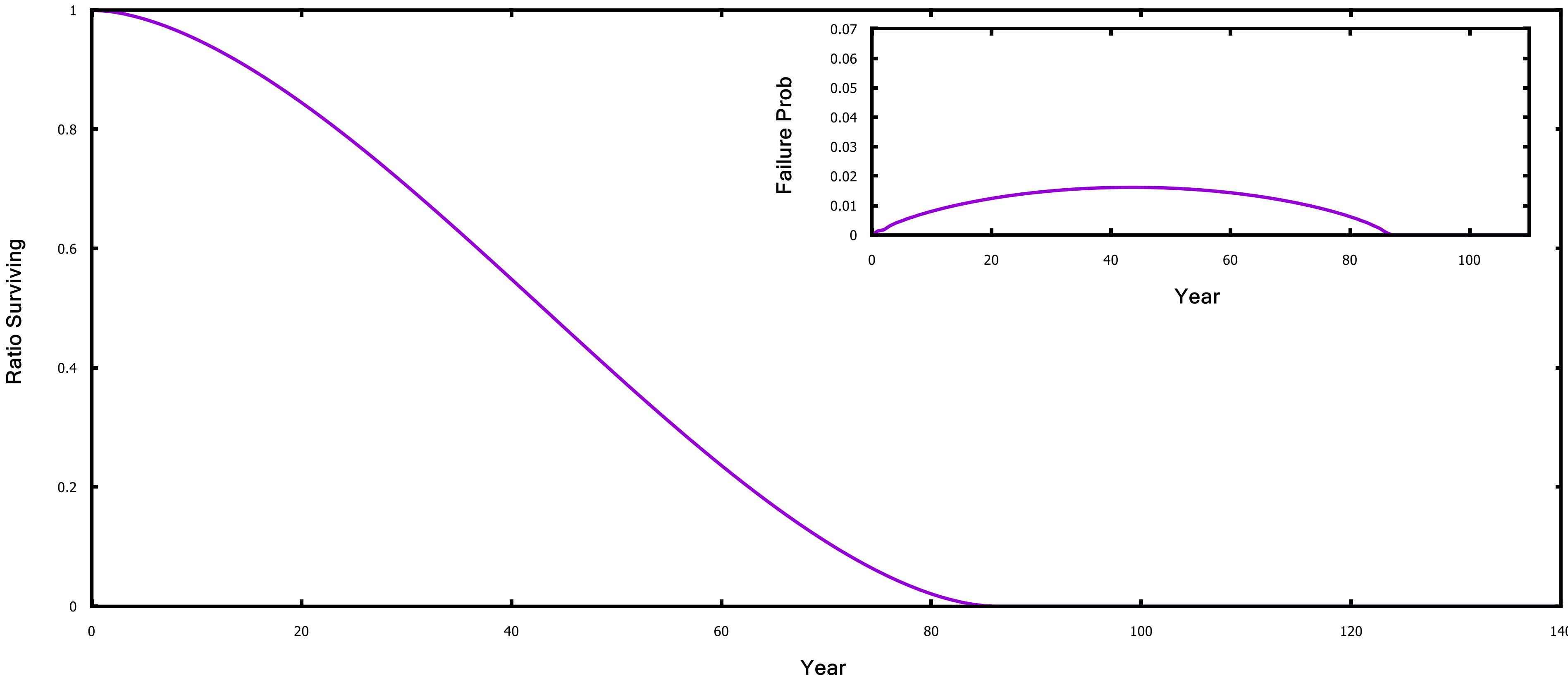
Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	5823	0	73098	483	69878	-483	3220
1969	8651	0	81749	529	78000	-529	3749
1970	8413	0	90162	584	85829	-584	4333
1971	6017	0	96179	642	91204	-642	4975
1972	6795	0	102974	705	97294	-705	5680
1973	8877	0	111851	773	105398	-773	6453
1974	5641	0	117492	845	110195	-845	7297
1975	4065	0	121557	916	113343	-916	8214
1976	2843	0	124400	990	115196	-990	9204
1977	2209	0	126609	1062	116342	-1062	10267
1978	1604	0	128213	1132	116815	-1132	11398
1979	4463	0	132676	1198	120079	-1198	12597
1980	5200	0	137876	1267	124013	-1267	13863
1981	12046	0	149922	1335	134724	-1335	15198
1982	66540	716	215746	1415	199850	-699	15896
1983	99610	0	315356	1573	297886	-1573	17470
1984	94296	0	409652	1809	390373	-1809	19279
1985	67324	0	476976	2131	455566	-2131	21410
1986	69688	1742	544922	2518	522737	-776	22185
1987	60219	41	605100	2968	579988	-2927	25112
1988	71400	1018	675482	3436	647952	-2418	27530
1989	385719	1866	1059335	3955	1029717	-2089	29618
1990	147697	3659	1203373	4934	1172480	-1275	30893
1991	118996	18430	1303939	5755	1285721	12675	18218
1992	170332	6200	1468071	6903	1449150	-703	18921
1993	142352	3428	1606995	8129	1583373	-4701	23622
1994	160617	3331	1764281	9335	1734656	-6004	29625
1995	148177	6014	1906444	10691	1872142	-4677	34302

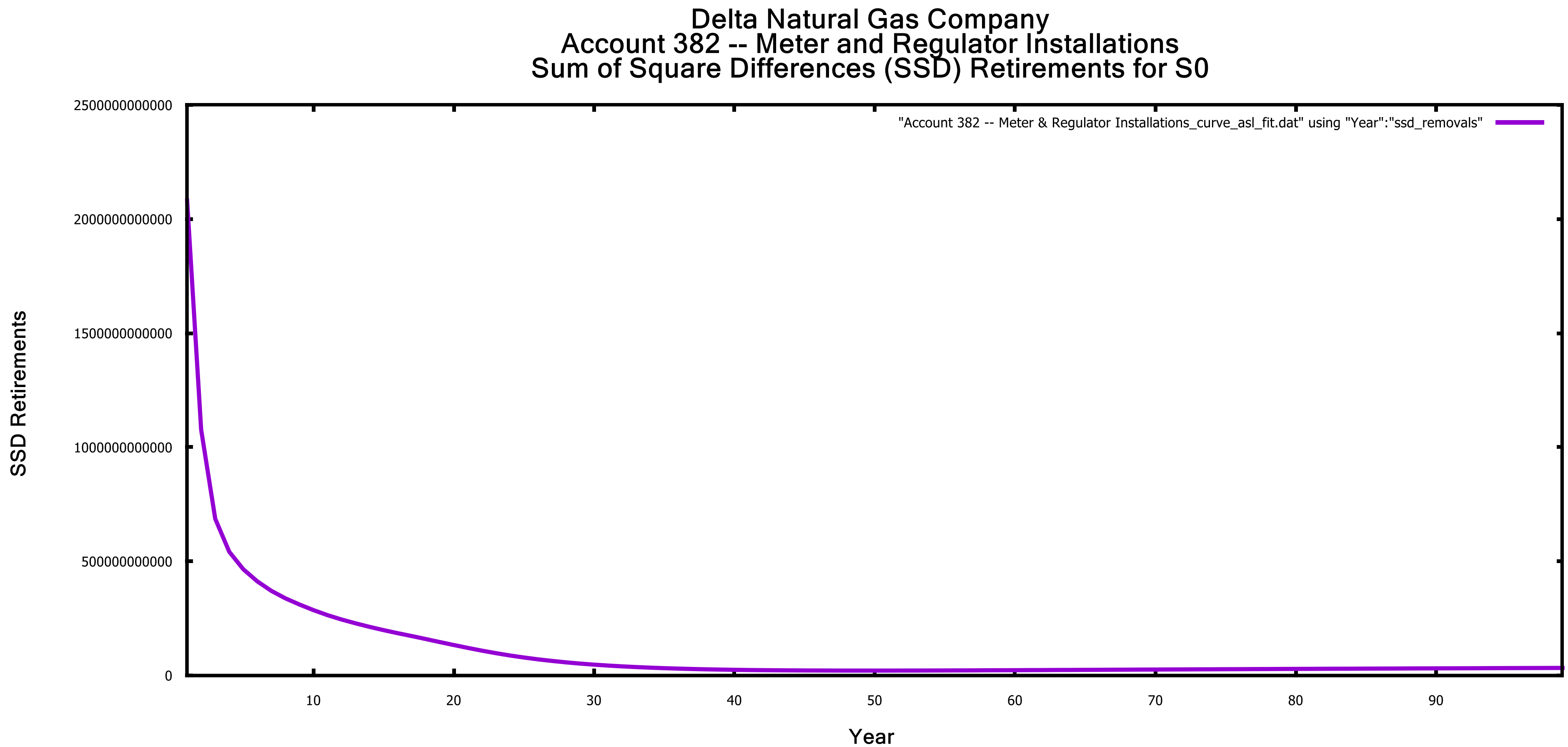
Delta Natural Gas Company
Account 382 -- Meter & Regulator Installations

Simulated Retirements for Iowa Curve S0 with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	150837	2548	2054733	12082	2010897	-9534	43836
1997	149850	5491	2199092	13567	2147180	-8076	51912
1998	172095	6032	2365155	15105	2304170	-9073	60985
1999	155766	7892	2513029	16742	2443194	-8850	69835
2000	122090	22470	2612649	18422	2546862	4048	65787
2001	98891	21077	2690463	20140	2625613	937	64850
2002	93543	10619	2773387	21865	2697292	-11246	76095
2003	102667	10963	2865091	23581	2776378	-12618	88713
2004	112534	6222	2971403	25299	2863613	-19077	107790
2005	110798	7135	3075067	27026	2947385	-19891	127682
2006	82818	12270	3145615	28771	3001432	-16501	144183
2007	90410	48870	3187154	30495	3061346	18375	125808
2008	68713	71494	3184373	32239	3097820	39255	86553
2009	54832	53168	3186037	33927	3118725	19241	67312
2010	64258	92891	3157404	35588	3147395	57303	10009
2011	90774	68248	3179931	37223	3200947	31025	-21016
2012	86818	68871	3197877	38855	3248909	30016	-51032
2013	115890	78239	3235529	40470	3324330	37769	-88801
2014	117496	19075	3333950	42137	3399688	-23062	-65739
2015	128189	31850	3430289	43814	3484063	-11964	-53774
2016	120910	61010	3490189	45540	3559433	15470	-69244
2017	127269	41963	3575495	47285	3639417	-5322	-63922
2018	101337	38547	3638285	49065	3691689	-10518	-53404
2019	187548	7460	3818373	50829	3828408	-43370	-10035
2020	294080	9430	4103023	52719	4069769	-43289	33254
2021	1628401	44148	5687276	54775	5643395	-10627	43881
2022	0	4953	5682323	58790	5584604	-53837	97718
2023	0	0	5682323	61339	5523266	-61339	159057

Account No. 382 -- Meters and Regulator Installations
Iowa Curve: S0 ASL: 43 Years




Delta Natural Gas Company
Account 382 -- Meter and Regulator Installations
Sum of Square Differences (SSD) Retirements for S0
"Account 382 -- Meter & Regulator Installations_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
2500000000000
2000000000000
1500000000000
1000000000000
500000000000
0
10
20
30
40
50
60
70
80
90
Year

Delta Natural Gas Company
Account Investment Summary

382 -- Meter Regulator Installation

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	386.00	-	386.00
1941	386.00	-	-	-	386.00
1942	386.00	-	-	-	386.00
1943	386.00	-	-	-	386.00
1944	386.00	-	-	-	386.00
1945	386.00	-	-	-	386.00
1946	386.00	-	-	-	386.00
1947	386.00	-	291.00	-	677.00
1948	677.00	-	543.00	-	1,220.00
1949	1,220.00	-	1,057.00	-	2,277.00
1950	2,277.00	-	1,120.00	-	3,397.00
1951	3,397.00	-	1,784.00	-	5,181.00
1952	5,181.00	-	293.00	-	5,474.00
1953	5,474.00	-	394.00	-	5,868.00
1954	5,868.00	-	1,666.00	-	7,534.00
1955	7,534.00	-	2,929.00	-	10,463.00
1956	10,463.00	-	8,754.00	-	19,217.00
1957	19,217.00	-	8,202.00	-	27,419.00
1958	27,419.00	-	6,222.00	-	33,641.00
1959	33,641.00	-	4,846.00	-	38,487.00
1960	38,487.00	-	3,986.00	-	42,473.00
1961	42,473.00	-	3,306.00	-	45,779.00
1962	45,779.00	-	9,394.00	18.00	55,155.00
1963	55,155.00	-	1,800.00	-	56,955.00
1964	56,955.00	-	1,800.00	-	58,755.00
1965	58,755.00	-	2,280.00	-	61,035.00
1966	61,035.00	-	2,088.00	-	63,123.00
1967	63,123.00	-	4,152.00	-	67,275.00
1968	67,275.00	-	5,823.00	-	73,098.00
1969	73,098.00	-	8,651.00	-	81,749.00
1970	81,749.00	-	8,413.00	-	90,162.00
1971	90,162.00	-	6,017.00	-	96,179.00
1972	96,179.00	-	6,795.00	-	102,974.00
1973	102,974.00	-	8,877.00	-	111,851.00
1974	111,851.00	-	5,641.00	-	117,492.00
1975	117,492.00	-	4,065.00	-	121,557.00
1976	121,557.00	-	2,843.00	-	124,400.00
1977	124,400.00	-	2,209.00	-	126,609.00
1978	126,609.00	-	1,604.00	-	128,213.00
1979	128,213.00	-	4,463.00	-	132,676.00
1980	132,676.00	-	5,200.00	-	137,876.00
1981	137,876.00	-	12,046.00	-	149,922.00
1982	149,922.00	-	66,540.00	716.00	215,746.00
1983	215,746.00	-	99,610.00	-	315,356.00

Delta Natural Gas Company
Account Investment Summary

382 -- Meter Regulator Installation

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1984	315,356.00	-	94,296.00	-	409,652.00
1985	409,652.00	-	67,324.00	-	476,976.00
1986	476,976.00	-	69,688.00	1,742.00	544,922.00
1987	544,922.00	-	60,219.00	41.00	605,100.00
1988	605,100.00	-	71,400.00	1,018.00	675,482.00
1989	675,482.00	296,457.00	89,262.00	1,866.00	1,059,335.00
1990	1,059,335.00	-	147,697.00	3,659.00	1,203,373.00
1991	1,203,373.00	-	118,996.00	18,430.00	1,303,939.00
1992	1,303,939.00	-	170,332.00	6,200.00	1,468,071.00
1993	1,468,071.00	-	142,352.00	3,428.00	1,606,995.00
1994	1,606,995.00	-	160,617.00	3,331.00	1,764,281.00
1995	1,764,281.00	-	148,177.00	6,014.00	1,906,444.00
1996	1,906,444.00	-	150,837.00	2,548.00	2,054,733.00
1997	2,054,733.00	-	149,850.00	5,491.00	2,199,092.00
1998	2,199,092.00	-	172,095.00	6,032.00	2,365,155.00
1999	2,365,155.00	-	155,766.00	7,892.00	2,513,029.00
2000	2,513,029.00	-	122,090.00	22,470.00	2,612,649.00
2001	2,612,649.00	-	98,891.00	21,077.00	2,690,463.00
2002	2,690,463.00	-	93,543.33	10,619.00	2,773,387.33
2003	2,773,387.33	-	102,667.00	10,963.00	2,865,091.33
2004	2,865,091.33	-	112,534.00	6,222.00	2,971,403.33
2005	2,971,403.33	-	110,798.33	7,134.94	3,075,066.72
2006	3,075,066.72	-	82,817.67	12,269.81	3,145,614.58
2007	3,145,614.58	-	90,409.65	48,870.32	3,187,153.91
2008	3,187,153.91	-	68,712.80	71,493.87	3,184,372.84
2009	3,184,372.84	-	54,832.10	53,167.62	3,186,037.32
2010	3,186,037.32	180.95	64,077.33	92,891.47	3,157,404.13
2011	3,157,404.13	-	90,774.29	68,247.50	3,179,930.92
2012	3,179,930.92	-	86,817.51	68,871.20	3,197,877.23
2013	3,197,877.23	-	115,890.21	78,238.54	3,235,528.90
2014	3,235,528.90	-	117,495.87	19,075.19	3,333,949.58
2015	3,333,949.58	-	128,188.90	31,849.94	3,430,288.54
2016	3,430,288.54	(9,105.84)	130,015.77	61,009.54	3,490,188.93
2017	3,490,188.93	-	127,268.98	41,962.95	3,575,494.96
2018	3,575,494.96	-	101,336.85	38,547.03	3,638,284.78
2019	3,638,284.78	-	187,547.72	7,459.67	3,818,372.83
2020	3,818,372.83	-	294,080.24	9,430.49	4,103,022.58
2021	4,103,022.58	-	1,628,401.25	44,148.02	5,687,275.81
2022	5,687,275.81	-	-	4,953.07	5,682,322.74
2023	5,682,322.74	-	-	-	5,682,322.74

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 382
Distribution Meter & Reg Insallations

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	2,690,463	21,077	0.8%	-	14,876	(14,876)	-70.6%
2002	2,773,387	10,619	0.4%	-	5,170	(5,170)	-48.7%
2003	2,865,091	10,963	0.4%	-	5,990	(5,990)	-54.6%
2004	2,971,403	6,222	0.2%	-	11,601	(11,601)	-186.4%
2005	3,075,067	7,135	0.2%	-	9,597	(9,597)	-134.5%
2006	3,145,615	12,270	0.4%	-	36,282	(36,282)	-295.7%
2007	3,187,154	48,870	1.5%	-	42,573	(42,573)	-87.1%
2008	3,184,373	71,494	2.2%	-	84,762	(84,762)	-118.6%
2009	3,186,037	53,168	1.7%	-	69,978	(69,978)	-131.6%
2010	3,157,404	92,891	2.9%	-	125,090	(125,090)	-134.7%
2011	3,179,931	68,248	2.1%	-	72,394	(72,394)	-106.1%
2012	3,197,877	68,871	2.2%	-	142,413	(142,413)	-206.8%
2013	3,235,529	78,239	2.4%	-	121,150	(121,150)	-154.8%
2014	3,333,950	19,075	0.6%	-	22,386	(22,386)	-117.4%
2015	3,430,289	31,850	0.9%	-	51,649	(51,649)	-162.2%
2016	3,490,189	61,010	1.7%	-	60,799	(60,799)	-99.7%
2017	3,575,495	41,963	1.2%	-	40,438	(40,438)	-96.4%
2018	3,638,285	38,547	1.1%	13,015	51,544	(38,530)	-100.0%
2019	3,818,373	7,460	0.2%	-	15,828	(15,828)	-212.2%
2020	4,103,023	9,430	0.2%	-	14,540	(14,540)	-154.2%
2021	5,687,276	44,148	0.8%	2,168	7,121	(4,953)	-11.2%
2022	5,682,323	4,953	0.1%	-	-	-	0.0%
2023	5,682,323	-	0.0%	-	-	-	#DIV/0!
Total	82,290,855	808,502	1.0%	15,182	1,006,181	(990,998)	-122.6%

Five Year Average Net Salvage	-107.4%
Ten Year Average Net Salvage	-136.6%
Current Net Salvage	-12.00%
Recommend Net Salvage	-15%

Account 383 – House Regulators

Delta Natural Gas Company
Account 383 -- House Regulators

Simulated Retirements for Iowa Curve S3 with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1940	563	0	563	0	563	0	0
1941	0	0	563	0	563	0	0
1942	0	0	563	0	563	0	0
1943	0	0	563	0	563	0	0
1944	0	0	563	0	563	0	0
1945	0	0	563	0	563	-0	0
1946	0	0	563	0	563	-0	0
1947	6423	0	6986	0	6986	-0	0
1948	560	0	7546	0	7546	-0	0
1949	508	0	8054	0	8054	-0	0
1950	1192	0	9246	0	9246	-0	0
1951	3347	0	12593	0	12593	-0	0
1952	1274	0	13867	0	13867	-0	0
1953	1063	0	14930	0	14930	-0	0
1954	1689	0	16619	0	16618	-0	1
1955	4186	0	20805	0	20804	-0	1
1956	8755	0	29560	1	29558	-1	2
1957	6486	0	36046	1	36043	-1	3
1958	4537	0	40583	2	40578	-2	5
1959	4836	0	45419	3	45411	-3	8
1960	5466	0	50885	4	50873	-4	12
1961	10139	0	61024	6	61007	-6	17
1962	4564	0	65588	8	65562	-8	26
1963	8161	0	73749	12	73712	-12	37
1964	5251	69	78931	16	78947	53	-16
1965	9372	432	87871	22	88297	410	-426
1966	5883	122	93632	29	94151	93	-519
1967	8100	423	101309	38	102213	385	-904

Delta Natural Gas Company
Account 383 -- House Regulators

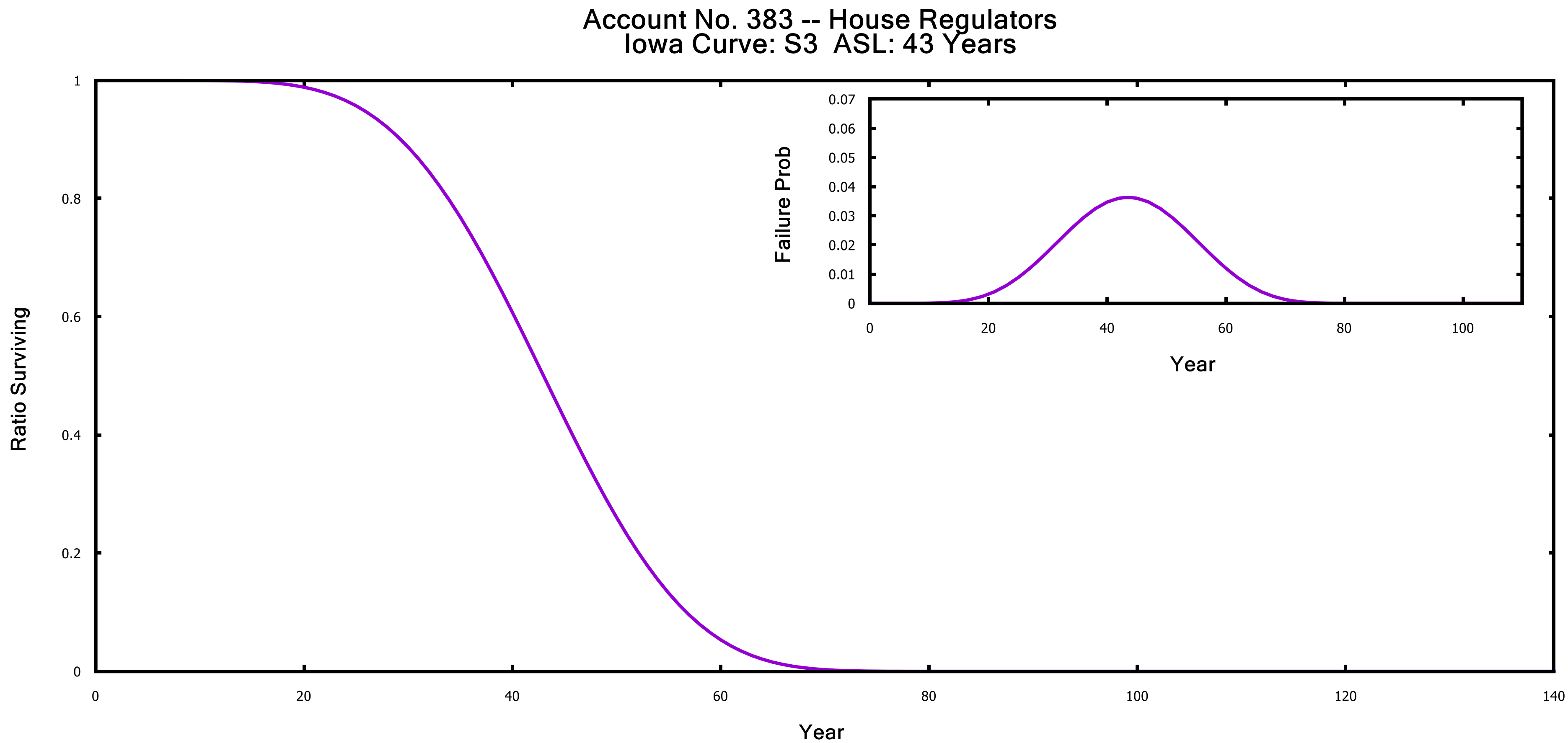
Simulated Retirements for Iowa Curve S3 with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	10199	152	111356	50	112362	102	-1006
1969	15644	492	126508	65	127941	427	-1433
1970	15245	648	141105	82	143105	566	-2000
1971	44148	790	184463	104	187148	686	-2685
1972	18706	1365	201804	130	205725	1235	-3921
1973	18408	483	219729	161	223971	322	-4242
1974	29340	320	248749	198	253113	122	-4364
1975	12375	134	260990	242	265247	-108	-4257
1976	18467	432	279025	293	283421	139	-4396
1977	29083	482	307626	351	312153	131	-4527
1978	20730	706	327650	419	332464	287	-4814
1979	17688	538	344800	496	349657	42	-4857
1980	44258	1493	387565	584	393331	909	-5766
1981	46611	737	433439	683	439259	54	-5820
1982	62018	1601	493856	795	500482	806	-6626
1983	79203	15010	558049	921	578763	14089	-20714
1984	68536	16724	609861	1061	646238	15663	-36377
1985	82809	9800	682870	1219	727828	8581	-44958
1986	45980	2698	726152	1392	772416	1306	-46264
1987	110848	6289	830711	1588	881676	4701	-50965
1988	84581	2547	912745	1799	964458	748	-51713
1989	114666	10651	1016760	2038	1077087	8613	-60327
1990	112102	5576	1123286	2295	1186893	3281	-63607
1991	63398	1521	1185163	2584	1247708	-1063	-62545
1992	95099	3162	1277100	2896	1339911	266	-62811
1993	152812	418	1429494	3241	1489482	-2823	-59988
1994	115494	1675	1543313	3618	1601358	-1943	-58045
1995	126610	608	1669315	4032	1723936	-3424	-54621

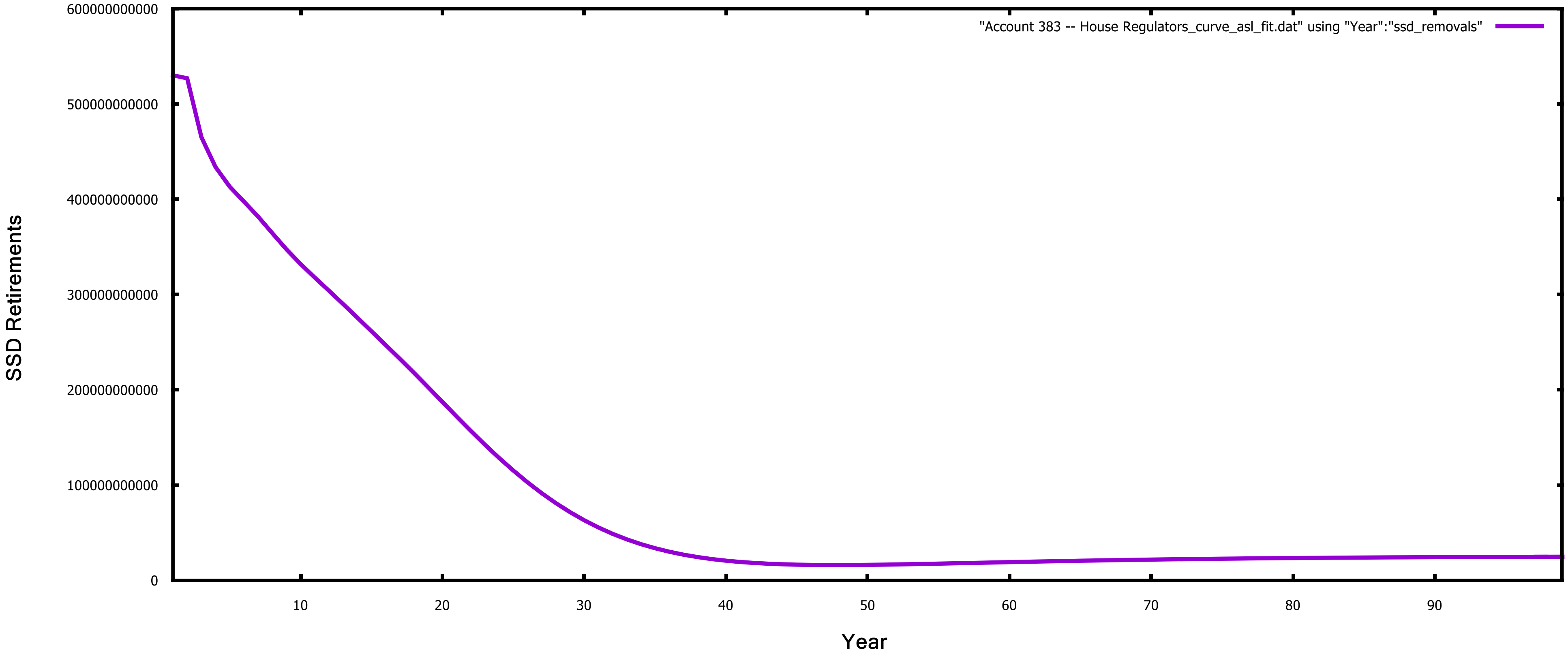
Delta Natural Gas Company
Account 383 -- House Regulators

Simulated Retirements for Iowa Curve S3 with ASL = 43

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	114577	609	1783283	4486	1834027	-3877	-50744
1997	85933	18843	1850373	4981	1914979	13862	-64606
1998	341027	821	2190579	5529	2250477	-4708	-59898
1999	161756	95069	2257266	6124	2406109	88945	-148843
2000	136617	7192	2386691	6784	2535942	408	-149251
2001	84144	4732	2466103	7503	2612583	-2771	-146480
2002	114466	10024	2570545	8296	2718754	1728	-148209
2003	108820	52	2679313	9168	2818406	-9116	-139093
2004	115491	14468	2780336	10120	2923777	4348	-143441
2005	142384	5343	2917377	11174	3054987	-5831	-137610
2006	181209	5286	3093300	12318	3223878	-7031	-130579
2007	181408	9050	3265658	13586	3391701	-4536	-126043
2008	161646	25044	3402259	14955	3538392	10090	-136133
2009	98027	21736	3478550	16471	3619948	5265	-141398
2010	93242	29841	3541951	18100	3695091	11742	-153139
2011	67443	42986	3566408	19895	3742638	23091	-176231
2012	121578	37928	3650058	21819	3842398	16109	-192340
2013	91756	48416	3693398	23915	3910239	24501	-216841
2014	207774	16493	3884678	26165	4091848	-9672	-207170
2015	85352	39381	3930649	28578	4148621	10803	-217972
2016	105111	24045	4011714	31174	4222558	-7129	-210844
2017	147304	31472	4127547	33913	4335949	-2441	-208403
2018	98425	25475	4200497	36853	4397522	-11378	-197025
2019	124266	26172	4298591	39917	4481871	-13745	-183280
2020	174269	16554	4456306	43180	4612960	-26626	-156654
2021	283809	45027	4695088	46552	4850217	-1525	-155129
2022	0	0	4695088	50096	4800121	-50096	-105033
2023	0	0	4695088	53739	4746382	-53739	-51293


Account No. 383 -- House Regulators
Iowa Curve: S3 ASL: 43 Years
Ratio Surviving
Year
Failure Prob
Year

Delta Natural Gas Company
Account 383 -- House Regulators
Sum of Square Differences (SSD) Retirements for S3



Delta Natural Gas Company
Account Investment Summary

Account 383 -- House Regulators

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	563.00	-	563.00
1941	563.00	-	-	-	563.00
1942	563.00	-	-	-	563.00
1943	563.00	-	-	-	563.00
1944	563.00	-	-	-	563.00
1945	563.00	-	-	-	563.00
1946	563.00	-	-	-	563.00
1947	563.00	-	6,423.00	-	6,986.00
1948	6,986.00	-	560.00	-	7,546.00
1949	7,546.00	-	508.00	-	8,054.00
1950	8,054.00	-	1,192.00	-	9,246.00
1951	9,246.00	-	3,347.00	-	12,593.00
1952	12,593.00	-	1,274.00	-	13,867.00
1953	13,867.00	-	1,063.00	-	14,930.00
1954	14,930.00	-	1,689.00	-	16,619.00
1955	16,619.00	-	4,186.00	-	20,805.00
1956	20,805.00	-	8,755.00	-	29,560.00
1957	29,560.00	-	6,486.00	-	36,046.00
1958	36,046.00	-	4,537.00	-	40,583.00
1959	40,583.00	-	4,836.00	-	45,419.00
1960	45,419.00	-	5,466.00	-	50,885.00
1961	50,885.00	-	10,139.00	-	61,024.00
1962	61,024.00	-	4,564.00	-	65,588.00
1963	65,588.00	-	8,161.00	-	73,749.00
1964	73,749.00	-	5,251.00	69.00	78,931.00
1965	78,931.00	-	9,372.00	432.00	87,871.00
1966	87,871.00	-	5,883.00	122.00	93,632.00
1967	93,632.00	-	8,100.00	423.00	101,309.00
1968	101,309.00	-	10,199.00	152.00	111,356.00
1969	111,356.00	-	15,644.00	492.00	126,508.00
1970	126,508.00	-	15,245.00	648.00	141,105.00
1971	141,105.00	-	44,148.00	790.00	184,463.00
1972	184,463.00	-	18,706.00	1,365.00	201,804.00
1973	201,804.00	-	18,408.00	483.00	219,729.00
1974	219,729.00	-	29,340.00	320.00	248,749.00
1975	248,749.00	-	12,375.00	134.00	260,990.00
1976	260,990.00	-	18,467.00	432.00	279,025.00
1977	279,025.00	-	29,083.00	482.00	307,626.00
1978	307,626.00	-	20,730.00	706.00	327,650.00
1979	327,650.00	-	17,688.00	538.00	344,800.00
1980	344,800.00	-	44,258.00	1,493.00	387,565.00
1981	387,565.00	-	46,611.00	737.00	433,439.00
1982	433,439.00	-	62,018.00	1,601.00	493,856.00
1983	493,856.00	-	79,203.00	15,010.00	558,049.00
1984	558,049.00	-	68,536.00	16,724.00	609,861.00

Delta Natural Gas Company
Account Investment Summary

Account 383 -- House Regulators

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1985	609,861.00	-	82,809.00	9,800.00	682,870.00
1986	682,870.00	-	45,980.00	2,698.00	726,152.00
1987	726,152.00	3,463.00	107,385.00	6,289.00	830,711.00
1988	830,711.00	-	84,581.00	2,547.00	912,745.00
1989	912,745.00	-	114,666.00	10,651.00	1,016,760.00
1990	1,016,760.00	-	112,102.00	5,576.00	1,123,286.00
1991	1,123,286.00	-	63,398.00	1,521.00	1,185,163.00
1992	1,185,163.00	-	95,099.00	3,162.00	1,277,100.00
1993	1,277,100.00	-	152,812.00	418.00	1,429,494.00
1994	1,429,494.00	-	115,494.00	1,675.00	1,543,313.00
1995	1,543,313.00	-	126,610.00	608.00	1,669,315.00
1996	1,669,315.00	-	114,577.00	609.00	1,783,283.00
1997	1,783,283.00	-	85,933.00	18,843.00	1,850,373.00
1998	1,850,373.00	295.00	340,732.00	821.00	2,190,579.00
1999	2,190,579.00	-	161,756.00	95,069.00	2,257,266.00
2000	2,257,266.00	-	136,617.00	7,192.00	2,386,691.00
2001	2,386,691.00	-	84,144.00	4,732.00	2,466,103.00
2002	2,466,103.00	-	114,466.04	10,024.00	2,570,545.04
2003	2,570,545.04	-	108,820.00	52.00	2,679,313.04
2004	2,679,313.04	-	115,491.00	14,468.00	2,780,336.04
2005	2,780,336.04	-	142,383.50	5,342.74	2,917,376.80
2006	2,917,376.80	-	181,209.17	5,286.39	3,093,299.58
2007	3,093,299.58	(41,917.92)	223,326.10	9,049.99	3,265,657.77
2008	3,265,657.77	-	161,645.85	25,044.49	3,402,259.13
2009	3,402,259.13	-	98,026.69	21,735.83	3,478,549.99
2010	3,478,549.99	-	93,242.44	29,841.19	3,541,951.24
2011	3,541,951.24	-	67,442.70	42,986.23	3,566,407.71
2012	3,566,407.71	-	121,578.13	37,927.94	3,650,057.90
2013	3,650,057.90	-	91,755.58	48,415.89	3,693,397.59
2014	3,693,397.59	-	207,774.30	16,493.47	3,884,678.42
2015	3,884,678.42	-	85,351.52	39,381.06	3,930,648.88
2016	3,930,648.88	-	105,110.53	24,045.39	4,011,714.02
2017	4,011,714.02	-	147,304.43	31,471.89	4,127,546.56
2018	4,127,546.56	-	98,425.28	25,475.10	4,200,496.74
2019	4,200,496.74	-	124,266.38	26,172.17	4,298,590.95
2020	4,298,590.95	-	174,269.10	16,553.80	4,456,306.25
2021	4,456,306.25	-	283,808.99	45,026.83	4,695,088.41
2022	4,695,088.41	-	-	-	4,695,088.41
2023	4,695,088.41	-	-	-	4,695,088.41

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 383
Distribution Regulators

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	2,466,103	4,732	0.2%	-	-	-	0.0%
2002	2,570,545	10,024	0.4%	255	-	255	2.5%
2003	2,679,313	52	0.0%	72	-	72	138.5%
2004	2,780,336	14,468	0.5%	269	-	269	1.9%
2005	2,917,377	5,343	0.2%	651	-	651	12.2%
2006	3,093,300	5,286	0.2%	-	-	-	0.0%
2007	3,265,658	9,050	0.3%	554	-	554	6.1%
2008	3,402,259	25,044	0.7%	712	-	712	2.8%
2009	3,478,550	21,736	0.6%	369	-	369	1.7%
2010	3,541,951	29,841	0.8%	1,507	-	1,507	5.0%
2011	3,566,408	42,986	1.2%	1,027	-	1,027	2.4%
2012	3,650,058	37,928	1.0%	148	-	148	0.4%
2013	3,693,398	48,416	1.3%	-	-	-	0.0%
2014	3,884,678	16,493	0.4%	297	-	297	1.8%
2015	3,930,649	39,381	1.0%	340	-	340	0.9%
2016	4,011,714	24,045	0.6%	153	-	153	0.6%
2017	4,127,547	31,472	0.8%	4,107	-	4,107	13.0%
2018	4,200,497	25,475	0.6%	270	-	270	1.1%
2019	4,298,591	26,172	0.6%	-	-	-	0.0%
2020	4,456,306	16,554	0.4%	-	-	-	0.0%
2021	4,695,088	45,027	1.0%	-	-	-	0.0%
2022	4,695,088	-	0.0%	-	-	-	#DIV/0!
2023	4,695,088	-	0.0%	-	-	-	#DIV/0!
Total	84,100,502	479,526	0.6%	10,731	-	10,731	2.2%

Five Year Average Net Salvage	3.7%
Ten Year Average Net Salvage	2.1%
Current Net Salvage	3%
Recommend Net Salvage	2%

Account 385 – Industrial Meter Sets

Delta Natural Gas Company
Account 385 -- Industrial Meter Sets

Simulated Retirements for Iowa Curve L0 with ASL = 49

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1956	702	0	702	0	702	0	0
1957	1860	0	2562	3	2559	-3	3
1958	1172	0	3734	11	3720	-11	14
1959	366	0	4100	17	4069	-17	31
1960	1596	0	5696	23	5642	-23	54
1961	941	0	6637	34	6548	-34	89
1962	168	0	6805	43	6674	-43	131
1963	1767	0	8572	49	8392	-49	180
1964	308	0	8880	62	8638	-62	242
1965	1098	753	9225	68	9668	685	-443
1966	1847	0	11072	79	11435	-79	-363
1967	2885	321	13636	94	14227	227	-591
1968	2179	993	14822	112	16294	881	-1472
1969	1759	0	16581	130	17922	-130	-1341
1970	3485	596	19470	149	21258	447	-1788
1971	3084	439	22115	176	24166	263	-2051
1972	2554	696	23973	202	26518	494	-2545
1973	3174	358	26789	228	29464	130	-2675
1974	2543	581	28751	259	31748	322	-2997
1975	1682	0	30433	288	33143	-288	-2710
1976	6518	703	36248	314	39347	389	-3099
1977	0	0	36248	360	38987	-360	-2739
1978	4035	1645	38638	380	42642	1265	-4004
1979	3969	0	42607	421	46191	-421	-3584
1980	4307	1883	45031	459	50039	1424	-5008
1981	33109	913	77227	499	82648	414	-5421
1982	19688	0	96915	664	101673	-664	-4758
1983	17371	0	114286	781	118262	-781	-3976

Delta Natural Gas Company
Account 385 -- Industrial Meter Sets

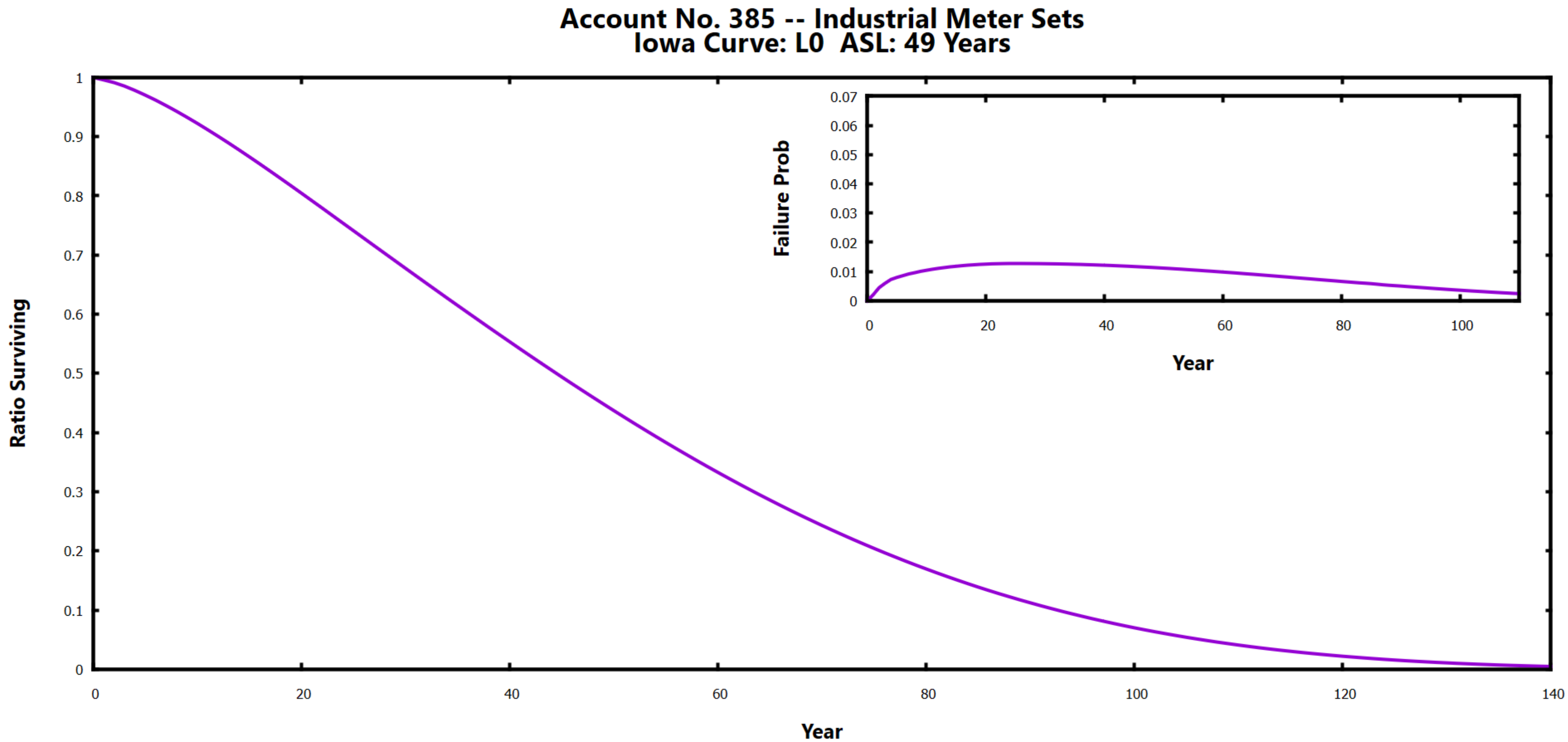
Simulated Retirements for Iowa Curve L0 with ASL = 49

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1984	26528	0	140814	929	143861	-929	-3047
1985	39740	3274	177280	1135	182466	2139	-5186
1986	70515	2760	245035	1398	251582	1362	-6547
1987	58538	5658	297915	1814	308307	3844	-10392
1988	109462	1986	405391	2226	415543	-240	-10152
1989	141310	22354	524347	2923	553930	19431	-29583
1990	97373	3868	617852	3811	647492	57	-29640
1991	71191	0	689043	4620	714063	-4620	-25020
1992	48640	4492	733191	5450	757253	-958	-24062
1993	79131	316	812006	6216	830168	-5900	-18162
1994	89330	90	901246	7078	912420	-6988	-11174
1995	89881	288	990839	7962	994339	-7674	-3500
1996	72772	584	1063027	8876	1058236	-8292	4791
1997	57974	7658	1113343	9770	1106440	-2112	6903
1998	91757	2732	1202368	10631	1187566	-7899	14802
1999	59589	23578	1238379	11626	1235528	11952	2851
2000	54409	14998	1277790	12476	1277462	2522	328
2001	70925	14054	1334661	13327	1335059	727	-398
2002	13370	0	1348031	14242	1334188	-14242	13843
2003	54587	1839	1400779	14886	1373889	-13047	26890
2004	53260	3645	1450394	15698	1411450	-12053	38944
2005	31213	0	1481607	16447	1426217	-16447	55391
2006	51486	2876	1530217	17083	1460620	-14207	69597
2007	24432	26086	1528563	17816	1467236	8270	61327
2008	51360	12759	1567164	18398	1500198	-5639	66966
2009	11085	11142	1567108	19076	1492207	-7934	74901
2010	51515	24800	1593823	19561	1524161	5238	69662
2011	15488	3094	1606217	20195	1519454	-17101	86763

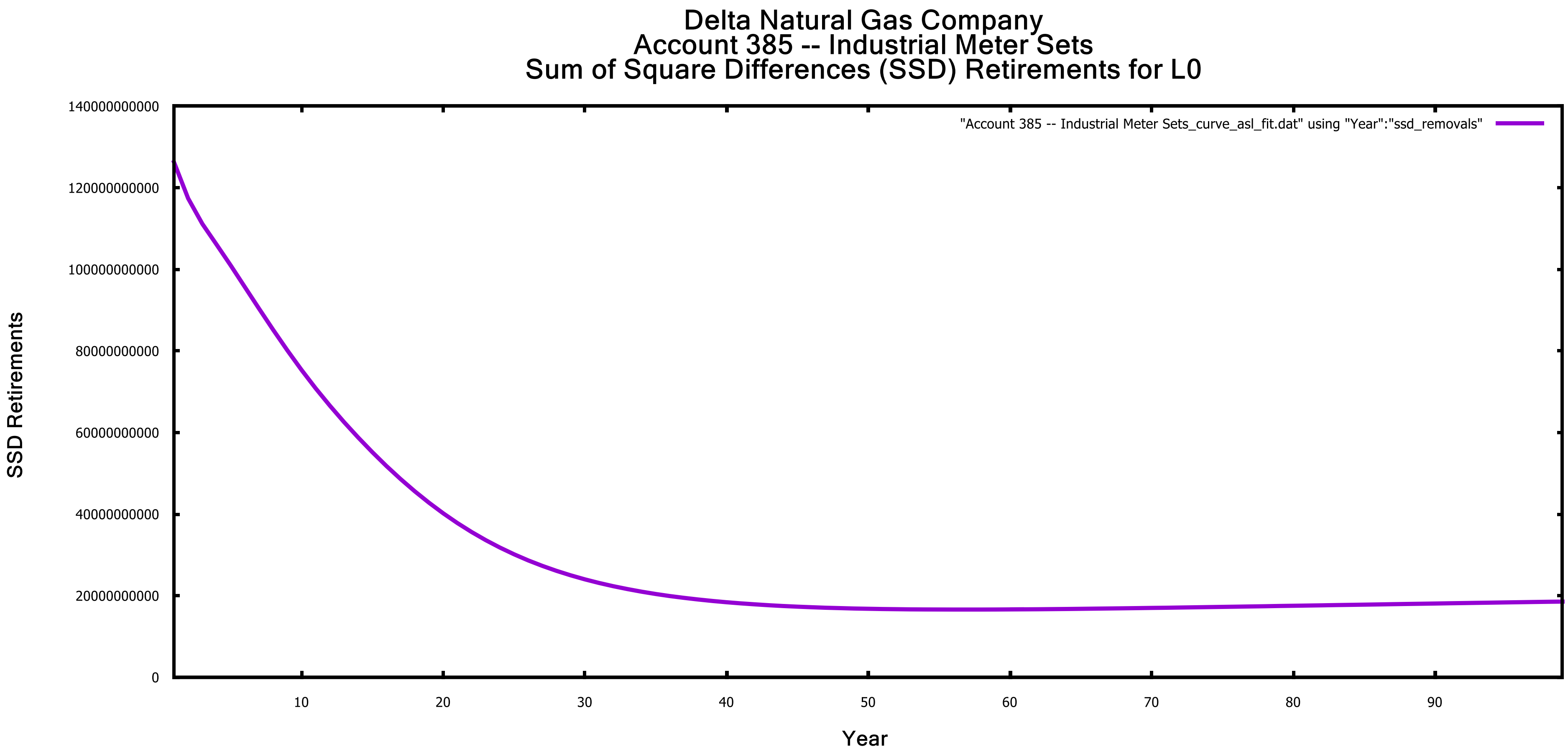
Delta Natural Gas Company
Account 385 -- Industrial Meter Sets

Simulated Retirements for Iowa Curve L0 with ASL = 49

Year	Additions	Actual Retirements	Balance	Simulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2012	69141	33341	1642017	20641	1567953	12699	74064
2013	41974	127365	1556626	21303	1588623	106062	-31998
2014	96823	6796	1646653	21828	1663618	-15033	-16965
2015	35424	14165	1667912	22614	1676429	-8448	-8517
2016	18092	23447	1662557	23148	1671373	299	-8816
2017	12747	4093	1671211	23664	1660456	-19572	10755
2018	12655	30809	1653058	24115	1648996	6694	4062
2019	35645	3042	1685661	24497	1660145	-21455	25517
2020	138306	42334	1781633	24919	1773532	17415	8102
2021	14555	978	1795210	25748	1762339	-24770	32872
2022	0	9096	1786114	26087	1736252	-16991	49862
2023	0	0	1786114	26490	1709763	-26490	76352



Account No. 385 -- Industrial Meter Sets
Iowa Curve: L0 ASL: 49 Years
Ratio Surviving
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
20
40
60
80
100
120
140
Year
Failure Prob
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0
20
40
60
80
100
Year


Delta Natural Gas Company
Account 385 -- Industrial Meter Sets
Sum of Square Differences (SSD) Retirements for L0
"Account 385 -- Industrial Meter Sets_curve_asl_fit.dat" using "Year":"ssd_removals"
SSD Retirements
Year
140000000000
120000000000
100000000000
80000000000
60000000000
40000000000
20000000000
0
10
20
30
40
50
60
70
80
90

Delta Natural Gas Company
Account Investment Summary

Account 385 -- Industrial Meter Sets

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1940	-	-	-	-	-
1941	-	-	-	-	-
1942	-	-	-	-	-
1943	-	-	-	-	-
1944	-	-	-	-	-
1945	-	-	-	-	-
1946	-	-	-	-	-
1947	-	-	-	-	-
1948	-	-	-	-	-
1949	-	-	-	-	-
1950	-	-	-	-	-
1951	-	-	-	-	-
1952	-	-	-	-	-
1953	-	-	-	-	-
1954	-	-	-	-	-
1955	-	-	-	-	-
1956	-	-	702.00	-	702.00
1957	702.00	-	1,860.00	-	2,562.00
1958	2,562.00	-	1,172.00	-	3,734.00
1959	3,734.00	-	366.00	-	4,100.00
1960	4,100.00	-	1,596.00	-	5,696.00
1961	5,696.00	-	941.00	-	6,637.00
1962	6,637.00	-	168.00	-	6,805.00
1963	6,805.00	-	1,767.00	-	8,572.00
1964	8,572.00	-	308.00	-	8,880.00
1965	8,880.00	-	1,098.00	753.00	9,225.00
1966	9,225.00	-	1,847.00	-	11,072.00
1967	11,072.00	-	2,885.00	321.00	13,636.00
1968	13,636.00	-	2,179.00	993.00	14,822.00
1969	14,822.00	-	1,759.00	-	16,581.00
1970	16,581.00	-	3,485.00	596.00	19,470.00
1971	19,470.00	-	3,084.00	439.00	22,115.00
1972	22,115.00	-	2,554.00	696.00	23,973.00
1973	23,973.00	-	3,174.00	358.00	26,789.00
1974	26,789.00	-	2,543.00	581.00	28,751.00
1975	28,751.00	-	1,682.00	-	30,433.00
1976	30,433.00	-	6,518.00	703.00	36,248.00
1977	36,248.00	-	-	-	36,248.00
1978	36,248.00	-	4,035.00	1,645.00	38,638.00
1979	38,638.00	-	3,969.00	-	42,607.00
1980	42,607.00	-	4,307.00	1,883.00	45,031.00
1981	45,031.00	-	33,109.00	913.00	77,227.00
1982	77,227.00	-	19,688.00	-	96,915.00
1983	96,915.00	-	17,371.00	-	114,286.00
1984	114,286.00	-	26,528.00	-	140,814.00
1985	140,814.00	-	39,740.00	3,274.00	177,280.00

Delta Natural Gas Company
Account Investment Summary

Account 385 -- Industrial Meter Sets

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Ending
1986	177,280.00	-	70,515.00	2,760.00	245,035.00
1987	245,035.00	-	58,538.00	5,658.00	297,915.00
1988	297,915.00	-	109,462.00	1,986.00	405,391.00
1989	405,391.00	-	141,310.00	22,354.00	524,347.00
1990	524,347.00	(947.00)	98,320.00	3,868.00	617,852.00
1991	617,852.00	-	71,191.00	-	689,043.00
1992	689,043.00	5,968.00	42,672.00	4,492.00	733,191.00
1993	733,191.00	-	79,131.00	316.00	812,006.00
1994	812,006.00	-	89,330.00	90.00	901,246.00
1995	901,246.00	-	89,881.00	288.00	990,839.00
1996	990,839.00	-	72,772.00	584.00	1,063,027.00
1997	1,063,027.00	-	57,974.00	7,658.00	1,113,343.00
1998	1,113,343.00	-	91,757.00	2,732.00	1,202,368.00
1999	1,202,368.00	(1,125.00)	60,714.00	23,578.00	1,238,379.00
2000	1,238,379.00	-	54,409.00	14,998.00	1,277,790.00
2001	1,277,790.00	-	70,925.00	14,054.00	1,334,661.00
2002	1,334,661.00	-	13,369.99	-	1,348,030.99
2003	1,348,030.99	-	54,587.00	1,839.00	1,400,778.99
2004	1,400,778.99	-	53,260.00	3,645.00	1,450,393.99
2005	1,450,393.99	-	31,213.15	-	1,481,607.14
2006	1,481,607.14	-	51,485.82	2,875.96	1,530,217.00
2007	1,530,217.00	-	24,432.03	26,085.95	1,528,563.08
2008	1,528,563.08	-	51,360.09	12,758.69	1,567,164.48
2009	1,567,164.48	-	11,085.35	11,141.81	1,567,108.02
2010	1,567,108.02	-	51,514.76	24,799.80	1,593,822.98
2011	1,593,822.98	-	15,487.69	3,093.57	1,606,217.10
2012	1,606,217.10	-	69,140.55	33,340.88	1,642,016.77
2013	1,642,016.77	-	41,973.77	127,365.04	1,556,625.50
2014	1,556,625.50	-	96,823.14	6,795.55	1,646,653.09
2015	1,646,653.09	-	35,424.21	14,165.43	1,667,911.87
2016	1,667,911.87	-	18,092.11	23,447.34	1,662,556.64
2017	1,662,556.64	-	12,747.36	4,092.75	1,671,211.25
2018	1,671,211.25	-	12,655.09	30,808.77	1,653,057.57
2019	1,653,057.57	-	35,645.46	3,041.63	1,685,661.40
2020	1,685,661.40	-	138,306.35	42,334.31	1,781,633.44
2021	1,781,633.44	-	14,555.29	978.38	1,795,210.35
2022	1,795,210.35	-	-	9,096.11	1,786,114.24
2023	1,786,114.24	-	-	-	1,786,114.24

Delta Natural Gas Company
Annual Retirements and Net Salvage

Acct 385
Distribution Industrial Meter

	Plant in Service	Retirements	Retirement Ratio	Gross Salvage	Cost of Removal	Net Salvage	Net Salvage Percent
2001	1,334,661	14,054	1.1%	-	5,355	(5,355)	-38.1%
2002	1,348,031	-	0.0%	-	-	-	0.0%
2003	1,400,779	1,839	0.1%	-	-	-	0.0%
2004	1,450,394	3,645	0.3%	-	-	-	0.0%
2005	1,481,607	-	0.0%	-	-	-	0.0%
2006	1,530,217	2,876	0.2%	-	368	(368)	-12.8%
2007	1,528,563	26,086	1.7%	-	-	-	0.0%
2008	1,567,164	12,759	0.8%	-	1,471	(1,471)	-11.5%
2009	1,567,108	11,142	0.7%	-	750	(750)	-6.7%
2010	1,593,823	24,800	1.6%	-	2,241	(2,241)	-9.0%
2011	1,606,217	3,094	0.2%	1,051	1,359	(309)	-10.0%
2012	1,642,017	33,341	2.0%	-	6,382	(6,382)	-19.1%
2013	1,556,626	127,365	8.2%	-	4,981	(4,981)	-3.9%
2014	1,646,653	6,796	0.4%	-	2,977	(2,977)	-43.8%
2015	1,667,912	14,165	0.8%	-	2,503	(2,503)	-17.7%
2016	1,662,557	23,447	1.4%	-	1,746	(1,746)	-7.4%
2017	1,671,211	4,093	0.2%	-	3,606	(3,606)	-88.1%
2018	1,653,058	30,809	1.9%	-	2,520	(2,520)	-8.2%
2019	1,685,661	3,042	0.2%	-	1,739	(1,739)	-57.2%
2020	1,781,633	42,334	2.4%	-	1,234	(1,234)	-2.9%
2021	1,795,210	978	0.1%	-	1,348	(1,348)	-137.8%
2022	1,786,114	9,096	0.5%	-	-	-	0.0%
2023	1,786,114	-	0.0%	-	-	-	0.0%
Total	36,743,331	395,760	1.1%	1,051	40,580	(39,529)	-10.0%

Five Year Average Net Salvage	-10.5%
Ten Year Average Net Salvage	-9.7%
Current Net Salvage	0%
Recommend Net Salvage	-5%

Exhibit JWW-2

Summary of Current and Proposed Depreciation Rates

Delta Natural Gas Company
Analysis of Depreciation Rates

Account	Description	Survivor Curve		Average Srervice Life (ASL)		Remaining Life		Net Salvage		Depreciation Rates	
		Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	Current	Recommended
367	TRANSMISSION MAINS	S3	S3	53	55	35.5	30.63	-2.3	-2.5	2.88%	3.35%
368	COMPRESSOR STATION EQUIPMENT	S5	S5	48	46	31.6	26.3	-1	-0.7	3.20%	3.83%
369	MEASURING & REG STAT EQUIPMENT	L2	L2	44	34	30	23.8	-5	-7	3.50%	4.50%
376	DISTRIBUTION MAINS	R5	R5	53	55	32.82	34.51	0	-3	3.05%	2.98%
378	MEAS & REG STAT - GENERAL	L1	L5	49	50	34.9	29.12	-11	-15	3.18%	3.95%
380	SERVICES	L0	L0	53	53	45.1	44.88	-40	-50	3.10%	3.34%
381	METERS	O2	O2	46	43	35	31.4	0	0	2.86%	3.18%
382	METER & REGULATOR INSTALLATION	S0	S0	43	43	28	29.81	-12	-15	4.00%	3.86%
383	HOUSE REGULATORS	S3	S3	43	43	24.5	22.77	3	2	3.96%	4.30%
385	INDUSTRIAL METER SETS	L0	L0	49	49	37.9	36.73	0	-5	2.64%	2.86%

Exhibit JWW-3

Lead-Lag Study Summary

Delta Natural Gas Company
Cash Working Capital Analysis
2024 Rate Case
Revenue Lag Days Based on the Year Ended December 31, 2023
Expense Lead Days Based on the Year Ended December 31, 2023

Lead/Lag Days Summary	
Revenue	**Lag Days**
Meter Reading	15.21
Billing	7.00
Collection	31.33
Bank	1.00
Total	**54.54**
O&M Expense	**Lead Days**
Purchased Gas and Transportation	41.76
Payroll Expense	11.01
Annual Performance Incentives	256.70
401k Match Expense	11.01
Uncollectible Expense	6.62
Charges from Affiliates	36.75
Other O&M	16.57
Income Tax Expense	
Current: Federal and State	37.75
Deferred: Federal and State (Including ITC)	-
Taxes Other Than Income	
Property Tax Expense	297.14
Payroll Tax Expense	11.01
Other Taxes	(180.92)
Interest Expense	27.99
Sales Taxes	50.30
School Taxes	34.58
Franchise Fees	76.25