COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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	**)))))**	**CASE NO. 2021-00185**

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

Filed: May 28, 2021

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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") 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. Upon the closing of the Essential acquisition in March 2020, I no longer have Treasury or Secretary responsibilities.

Q. Please briefly 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, 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. Delta expanded its business until 1977 when it 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 we began 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

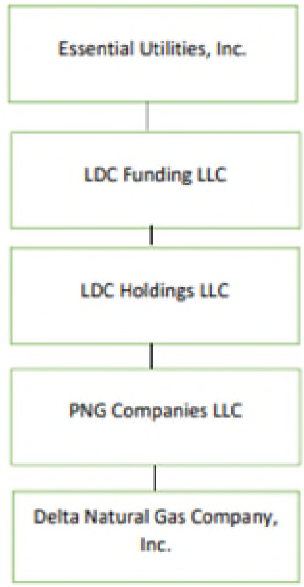
Manchester to Corbin and London. In 1989, we leased the TranEx pipeline, a 43-mile 8-inch diameter pipeline which extends from Manchester to Richmond and began operating it as a part of our transmission system. Delta expanded to Beattyville in 1992. In 1995-1996, we developed and began operating an underground 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.

Q. Can you please describe the acquisitions that have occurred in the last five years?

Certainly. 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. These acquisitions have allowed Delta to have access to technologies, economies of scale, and expertise beyond what was practicable as a standalone utility.

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 is in the process of merging the operations of PKY into Delta. PKY consisted of approximately 3,000 farm tap customers in southeastern Kentucky, and the service territory for these customers abuts Delta's existing service area.

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



PKY's operations are currently being merged into Delta's, and once complete, PKY's corporate entity will be dissolved.

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

A. Essential is one of the largest, best-in-class, publicly regulated water, wastewater, and natural gas utilities in the United States, with operations dating back to 1886. It serves approximately five million people across ten states through the Aqua water and wastewater segment and PNG natural gas segment, to which Delta belongs. With sound, investment grade credit ratings, it has strong access to capital and has a total annual capital budget of $1 billion in 2021.

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

A. PNG is comprised of gas operations in Kentucky, Pennsylvania, and West Virginia. In Pennsylvania, nearly 700,000 customers are served, in addition to 13,000 in West Virginia. PNG is the largest natural gas distribution company in Pennsylvania. Over 1,500 employees provide service to approximately two million people.

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 continue to look for opportunities to bring gas service to additional unserved areas.

Delta owns and operates 5 district offices, two warehouses, an underground natural gas storage facility with approximately 5.9 Bcf of capacity and 3.7 Bcf of working capacity, a natural gas liquids processing plant, and approximately 2,700 miles of transmission, distribution, service and gathering pipeline in 32 counties in central and southeastern Kentucky. Below is the geographic footprint of Delta's operations in Kentucky following the PKY change of control:

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. Don Cartwright is the Director of Gas

Supply and has been with Delta since 1980. Andrea Schroeder recently joined Delta as Controller and has extensive experience in the utility industry.

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(6)(a)	Pro forma adjustments
807 KAR 5:001 Section 16(6)(b)	Forecasted adjustments shall be limited to 12 months following suspension
807 KAR 5:001 Section 16(6)(c)	Capitalization and rate base based on a 13-month average
807 KAR 5:001 Section 16(6)(d)	No revisions to forecast
807 KAR 5:001 Section 16(6)(e)	Commission may require alternative forecast
807 KAR 5:001 Section 16(6)(f)	Reconciliation of rate base and capital
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)(u)	Affiliate allocations
807 KAR 5:001 Section 16(8)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase
807 KAR 5:001 Section 16(8)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base
807 KAR 5:001 Section 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account
807 KAR 5:001 Section 16(8)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors
807 KAR 5:001 Section 16(8)(i)	Comparative income statements
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 Morphew, Delta’s Director of Operations
- Andrea Schroeder, Delta’s Controller

- William Packer, Essential's Vice President, Regulatory Accounting and Regional Controller
- William Steven Seelye, Managing Partner of The Prime Group, LLC
- Paul Moul, Managing Consultant, P. Moul & Associates

Proposed Revenue Increases and Bill Impacts

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

A. Delta last filed for an increase in base rates in April 2010. When the rates proposed in this proceeding go into effect in January 2022, nearly twelve years will have elapsed since Delta last filed for an increase in rates. The length of time Delta has been able to forego a requested increase in rates is a strong testament to Delta's commitment to its customers in operating efficiently while providing reliable gas service. While Delta's prudent financial management has allowed us to delay requesting an increase in rates, a rate increase is necessary at this time.

Since the test period in Delta's last rate case, our forecasted rate base will have increased by $26,377,592, which is 24%.[1] Our utility plant in service will have increased by $110,517,634, which is 55%.[2] Delta's depreciation expense has increased by 94%[3] over the same period. The efficient management that allowed Delta to avoid a rate increase for over a decade manifests itself in comparing expenses over this same period as Delta's operation and maintenance expenses have only increased by 18.0% since 2010. The 18.0% is significantly below the Consumer Price Index for this time period, as inflation since 2009 has been 24.5%. Moreover, Delta's cost of capital has *decreased* from 8.68% to 7.65%,[4]

[1] Case No. 2010-00116, Tab 27; Case No. 2021-00185 at Tab 55, Page 1 of 2.
[2] Case No. 2010-00116, Tab 27; Case No. 2021-00185 at Tab 33.
[3] Case No. 2010-00116, Tab 27; Case No. 2021-00185 at Tab 54.
[4] Case No. 2010-00116, Tab 27.

and Delta's cost of gas has *decreased* by 12% since its last rate case.[5] These metrics make clear that the primary driver of this rate increase is the need to accurately reflect the amount of assets that are used and useful in providing exceptional natural gas service to our customers, and that Delta has operated its business at costs well below inflation increases.

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

A. No, it is not. At current rates, Delta is projected to earn only 0.21% in the forecast period. This is consistent with the steady drop Delta has experienced in its earned return over the last several years. For example, Delta's earned return in 2020 was only 7.6%. 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 2020, 82% of Delta's overall 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.

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[5] Case No.2010-00116, Tab 27; Case No. 2021-00185 at Tab 22.

A. Delta is requesting an approximately 18.6%, or $9,135,170 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 20.7 percent, or approximately $12.34, for a residential customer using an average of 3.8 Mcf of gas. Typical bill calculations for various levels of consumption are shown in the filing requirement of Section 16(8)(n).

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 August 31, 2021. The base period utilizes actual information for seven months, from September 2020 to March 2021, with five months of estimated information from April 2021 to August 2021. The forecasted period will be the twelve months ending December 31, 2022.

Budgeting Process

Q. Why has Delta elected to utilize 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. 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. The capital budget is submitted to PNG's Financial Planning and Analysis team for assistance in preparing management summaries, which are subsequently provided to PNG's Capital Review Committee. The Board of Directors then reviews the Capital Review Committee's recommendations. Once this process is complete, monthly capital budgets are loaded into SAP to allow for efficient monthly monitoring and reporting.

The expense budget also begins within Delta's departments, which includes estimating salary and benefit data. Like with the capital budget, management summaries are prepared and reviewed by senior leadership. Once all approvals are complete, each department prepares detailed monthly cost center budgets that are loaded into SAP for 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. 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. Please summarize Delta's approach to proposing adjustments to the forecasted test period.

A. Delta has exercised significant restraint in proposing adjustments to the forecasted period. Each adjustment to the forecasted test period is either based on a known and measurable change, or Delta otherwise has substantial certainty regarding the adjustment. The base period and forecast period are very similar for nearly every category of revenues and expenses, unless Delta has a known expectation for the variance. For example, Delta's customer counts, employee headcount, and the cost of gas are expected to stay flat during the forecast period. This approach is important to Delta for two reasons. First, it ensures that the Commission and Delta's customers can have a high degree of confidence in the forecasted test period revenues and expenses. Second, utilizing a restrained approach moderates the requested revenue increase.

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 that allow us to improve our efforts at operating efficiently and productively.

Q. Can you describe the technology-related programs that are aimed at improving efficiency and productivity?

A. Certainly. Delta has recently implemented the SAP data platform in order to unify customer data sources. The benefits of this software are many; the coordination of customer data in one system allows the customer service representatives and field employees to access the same data in real-time, which improves efficiency and productivity. The SAP system also increases the amount of information available to the customer, further resulting in efficiencies. By having the same data platform as PNG and Essential, Delta has access to support and assistance in operating SAP. As Delta's experience with the system grows, we expect to implement additional self-service options for our customers that will further the efficiencies associated with the technology.

Another technology-related program that is in the process of being implemented is a GIS mapping system that will allow our field technicians to have real-time access to the distribution and transmission system maps from laptops in their vehicles. Implementing this technology will allow our technicians to more efficiently resolve issues in the field by greatly reducing the lag between field work being reflected in our mapping system. This program is discussed in greater detail in Mr. Morphew's testimony.

Q. Please describe other programs that improve efficiency and productivity.

A. Essential has reorganized the Kentucky staff in order to take full advantage of the scale of a large vertically integrated utility company. My primary responsibilities involve running our Kentucky operations and maintaining state regulatory compliance. Our Accounting and Information Technology staff now report to PNG in Pittsburgh, and Human Resources is served by a very skilled and professional group at PNG. While these transitions are not easy in the short-term, this model allows more specialization of expertise which will improve efficiency and productivity.

Q. Please describe the change to the pension program this year.

A. Delta made a significant change to its pension program in May of this year, which will have a substantial impact on the cost efficiency of the program. Delta froze the pension plans for all of its employees, regardless of when the employee first entered the pension program. This reduces the amount of pension expense included in the forecast test period in this case by approximately $808,000. This savings will be partially offset by the cost of enhancing the defined contribution plan.

Tariff Changes

Q. Is Delta proposing a new rate classification for its farm tap customers?

A. Yes, it is. Delta has had a limited number of farm tap customers on its system for many years. Delta's tariff has had special terms and conditions for its farm tap customers, but the rate assessed has been the same as the residential rate. In Case No. 2020-00346, the Commission approved the transfer of control of PKY, which has approximately 3,000 farm tap customers, to Delta. The Commission approved the increase of rates of the former PKY customers to the rates that Delta is presently charging its residential customers but noted that the merger will more than triple the number of farm tap customers on Delta's system, and that the Commission would investigate the reasonableness of Delta's farm tap rates.

Given the increase in farm tap customers and the Commission's order, Delta is proposing a new classification that will apply to farm tap customers. The proposed rate is based on the cost of service study sponsored by Mr. Seelye. The new classification also includes the installation ($150.00) and reconnection fees ($25.00) set forth in 807 KAR 5:026.

Q. Are there other changes proposed for farm tap customers?

A. There is one additional proposed change. In Case No. 2020-00346, Delta proposed, and the Commission authorized, maintaining a separate gas cost recovery mechanism for farm tap customers that was based on the mechanism that had been utilized by PKY prior to the merger. Delta proposes to eliminate having two gas cost mechanisms and instead assess one gas cost adjustment for all customer classes. Delta is proposing this modification for several reasons. First, it will eliminate customer confusion as to which mechanism rate applies. Second, it will eliminate the need for Delta to file and the Commission to review two sets of gas cost filings. Other than this change to the Gas Cost Recovery tariff, Delta proposes no changes to the applicability of the other tariffed rates to farm tap customers; namely, that the Weather Normalization adjustment applies to this rate classification and the Pipe Replacement Program Rider does not.

Q. Is Delta proposing any other revisions to its Gas Cost Recovery tariff?

A. No, it is not.

Q. Is Delta proposing any revisions to its Pipe Replacement Program ("PRP") Rider?

A. Yes. Given that Delta has begun utilizing a forecasted test period in its base rate cases, it has proposed to revise its PRP Rider to also utilize a forecasted formula with a true-up period, consistent with the approach utilized by several other Kentucky local distribution companies. Specifically, Delta proposes that the Rider will be updated annually in order to reflect the expected impact on Delta's revenue requirements of forecasted net plant additions and subsequently adjusted to true up the actual costs with the projected costs. A filing to update the projected costs for the upcoming calendar year would be submitted annually by October 15 to become effective with meter readings on and after the first billing cycle of January. Delta proposes to submit a balancing adjustment annually by March 31 to true-up the actual costs. Delta also proposes to reset the PRP rate to $0 in this proceeding, consistent with the terms of its current tariff.

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 May 24, 2021. Delta also posted the notice at their offices and posted a copy on the website. Delta plans to renegotiate the rates for three special contract customers and has contacted each customer to provide notice of same.

Calculation of Revenue Deficiency

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

A. Yes. Delta has prepared this information ("Schedule A"). Schedule A is located at Tab 54 in the application and shows how Delta determined the amount of the requested revenue increases for Delta's gas operations.

Q. What does the financial summary on Schedule A show?

A. Schedule A shows that Delta's operations, at current rates, will incur a projected revenue deficiency of $9,135,170 for the forecasted test period, which is the 12-month period ending December 31, 2022. The projected revenue deficiency is based upon a required rate of return on capital of 7.65 percent. During the forecasted test period at current rates, Delta's operations are projected to earn a rate of return of only 0.21 percent.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends August 31, 2021, Delta is expected to have a revenue deficiency of $2,208,049 and an earned rate of return on capital of 4.66%. During the forecasted test period, the revenue deficiency is projected to increase and the earned rate of return of capital is projected to decline further.

Rate Base Summary

Q. Has Delta prepared a rate base summary of its utility operations for the base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(b)?

A. Yes. Delta has prepared Schedule B to satisfy the requirements of 807 KAR 5:001 Section 16(8)(b), which is located at Tab 55 of the application. Schedule B provides Delta's net original cost rate base property pursuant to KRS 278.290. The calculated rate base amounts are for the base period and for a 13-month average for the forecasted test period as required by 807 KAR 5:001 Section 16(6)(c).

Delta's rate base for the base period will be $122,344,868, which will increase to a 13-month average of $136,735,989 during the forecasted test period. When the adjusted operating income shown in Schedule A forecasted test period of $3,455,715 is divided by the 13-month average rate base for that same time period, Delta's operations will produce a rate of return on average rate base of 2.53 percent. If the Commission approves the requested increase and Delta earns its operating income shown in Schedule A for the forecasted test period of $10,311,660, Delta will earn a rate of return on average rate base of 7.54 percent.

Q. Please explain the adjustments to the base period and forecasted test period rate base as shown in Schedule B.

A. Delta calculated its $122,344,868 of rate base for the base period and $136,735,989 of rate base for the forecasted period from a 13-month average of net utility plant in service balances and relevant current assets and deferred income tax balances. Delta's projected increase in rate base is the result of planned capital expenditures of $18.8 million in 2021 and $17.6 million in 2022. Delta did not project a change in its current assets from the base period.

Operating Income Summary

Q. Has Delta prepared an operating income summary of its operations for both the base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(c)?

A. Yes. This information, which is Schedule C, is located at Tab 56 to the application. Schedule C is an operating income summary for the base period and the forecasted test period with supporting schedules that are broken down by major account group and by individual account.

Q. Please describe what Schedule C shows.

A. Schedule C reflects the change in revenues and expenses resulting from the implementation of the rates proposed in this proceeding. Schedule C also calculates projected revenues and expenses for the forecasted test period at the proposed rates. For the base period, Delta projects total net operating income of $5,291,639, which results in a return on capitalization of 4.66 percent. Total net operating income during the forecasted test period is projected to decrease to $3,455,648. Delta's rate of return on capitalization decrease during the forecasted test period to 0.21 percent unless rates are increased.

Operating Income Comparison

Q. Has Delta prepared jurisdictional adjustments to operating income by major account for both the base and forecasted test periods as required by 807 KAR 4 5:001 Section 16(8)(d)?

A. Yes. This information, which is set forth in Schedule D, is located at Tab 57 to the application. Schedule D provides the required comparisons between the base period and the forecasted test period. Schedule D-2 reconciles the base period to the forecasted period with the nine groups of adjustments. Each adjustment is shown on a corresponding work paper.

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 many of our communities have economies that have faced downturns. Because of our relatively small size, Delta truly knows its customers, and works to aid customers that are experiencing difficulties. This was true before the COVID-19 pandemic, and our team brought the same level of compassion and customer service during this difficult period. 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. Has Delta made changes to its HEA program?

A. Yes. Delta is pleased to report that the changes it implemented to the HEA program following Case No. 2019-00366 have been overwhelmingly successful in reaching and helping more of our customers. Participation during 2021 increased by 96% from 2020; a truly amazing increase. The jump in participation is attributable to several factors: (1) increasing the shareholder contribution to $45,000; (2) increasing the per customer charge to $0.30; (3) increasing awareness through website popups and local media interviews; (4) enhanced customer reminders and flyers by the local offices; and (5) sharing of best practices within the Essential family of utilities. As a result of the efforts, and utilization of carryover funds from prior years, over 340 customers participated in the three-month program, receiving $150.00 each month for a total benefit of $450.00.

Q. Has Delta supported the communities it serves in other ways?

A. Absolutely. Delta contributed $2,000 to several food pantries located throughout our service territories: Berea, Owingsville, Nicholasville, Middlesboro, and Corbin. Delta also contributed to the United Way, Lotts Creek Fire Department, Corbin Fire Department, local colleges and universities, Bluegrass Army Depot, American Heart Association, American Cancer Society, and the March of Dimes. Our contributions show that Delta is committed to be a community partner for our customers throughout our service territory.

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. The seriousness with which we make this decision is evidenced by the fact that Delta has not requested an increase in base rates in over a decade.

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 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 21st day of May, 2021.

Emily P. Bennett (SEAL)
Notary Public

Emily P. Bennett
Notary Public, ID KYNP6460
State at Large, Kentucky
My Commission Expires on June 20, 2024

My Commission Expires:
6/20/24

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

Filed: May 28, 2021

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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 SR 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 responsibilities as Director of Operations remain the same as they were when I served as Vice President – 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 describe and support Delta's request for a Certificate of Public Convenience and Necessity ("CPCN") for construction of a pipeline that will provide the Nicholasville portion of Delta's system with necessary redundancy and capacity. I am also sponsoring filing requirements that are part of Delta's application.

<u>Delta's Gas System and Operations</u>

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. The largest concentration of Delta customers is in Nicholasville.

Delta owns and operates 5 district offices, two warehouses, an underground natural gas storage facility with approximately 5.9 Bcf of capacity and 3.7 Bcf of working capacity, a natural gas liquids processing plant, and approximately 2,700 miles of transmission, distribution, service and gathering pipeline in 32 counties in central and southeastern Kentucky.

Q. Please describe the safety of Delta's system.

A. The safety of Delta's employees, customers, and the general public is Delta's highest priority. Delta operates and maintains approximately 151 miles of transmission pipeline as defined by the Department of Transportation, and approximately 1,906 miles of distribution piping. Delta strives to maintain excellence in safety performance in all aspects of its operations and pipeline safety is a key component of this process.

Q. Please describe Delta's process for ensuring pipeline safety of its transmission system.

A. The transmission portion of Delta's system is patrolled once 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. 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 construction of permanent structures, change of grade, or excavation. If any unacceptable situations exist, coordinates are given 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 which 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. 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 pipeline 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. Additionally, Delta 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 in this process are classified immediately. Any leaks identified are addressed as needed based on the severity of the analysis.

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. Did Delta recently hire a Safety & Training Specialist to further improve safety throughout the Company?

A. Yes. In March 2021, Delta hired a Safety & Training Specialist. The primary purpose of this position is to perform in-house training and coordinate outside contract training when necessary. Additionally, the Safety & Training Specialist will conduct periodic inspections of various operational functions to ensure Delta's compliance with all OSHA, state and federal safety regulations, and standards. This position will also track and document all safety functions.

Delta's Safety & Training Specialist works jointly with the Corporate safety team of Peoples Natural Gas in Pittsburgh. As a result of this positive influence from Corporate, a greater effort through safety metric reporting has been applied to the monitoring and tracking of current trends. This process provides Delta with the latest pertinent data, while providing "lessons learned" in order to better educate employees. Additionally, this promotes an environment of greater safety awareness, and an increased level of accountability among the Operations team.

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

A. Yes. Since 2010, Delta has implemented new safety policies and programs in several areas, including the following:

- Tailgate Safety meetings are conducted regularly with Delta employees and contractor employees.
- Construction employees participate in biannual flagger training and trench shoring training.
- Delta has implemented a greater emphasis toward vehicle operation safety. Each Delta vehicle has been issued a 360-degree vehicle safety cone to increase driver awareness of all surroundings.
- Automated external defibrillators ("AED") units have been installed at all Delta office locations and employees are trained on these units as part of the First Aid and Bloodborne pathogen training.

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

A. Effective August 2018, Delta was required to comply with Kentucky's new Underground Facility Damage Prevention requirements depicted in KRS 367.4901 through 367.4917. These requirements are commonly referred to as the "811" or "Call before you dig" laws. In order to enhance the overall safety performance of Delta and in compliance with code requirements, Delta immediately sought assistance for the monitoring and tracking of the 811 activity within its operations. Delta purchased a software program called "Utilisphere," which is provided by a third-party company, "Earthnet," as a management tool to aid in this process. Utilisphere is specifically designed for the tracking of historical data on all activities relating to 811 calls including natural gas line locating and tracking. As a result of utilizing Utilisphere, Delta determined that in the calendar year of 2020, Delta received 25,591 line location requests. Of these requests, 19,727 line locates actually needed to be performed. Delta performed these line location requests with 99.96% accuracy.

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

A. Yes. Delta considers the 811 process an important component of its commitment to public safety in its operations but notes that it has had to devote increased efforts and costs to promptly respond to the increased volume of line locate requests. The number of 811 line locate requests has increased significantly over the past several years. In 2017, Delta performed 8,065 line locates. In 2020, the line locates increased to 19,727, an increase of 245% in only four years. The continual increase in location requests requires additional labor to satisfy the demands. In 2020, Delta added one employee in the Nicholasville District to deal with the increased workload.

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

A. Yes. Delta is planning to implement a Geographic Information System ("GIS") using the ESRI platform. This will improve the tracking of gas assets as they are being installed and mitigate system risk by improving the identification and location of pipeline components for reporting. Currently, Delta employees in the field use map books that are only updated quarterly. The new GIS system will update in real time and improve safety, productivity, and efficiency. Delta's parent company, Peoples Natural Gas, had previously implemented this GIS system, allowing Delta to implement the system at a lower cost than if Delta had done so on a standalone basis.

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 and helped Delta avoid a rate case for ten years. Delta is not proposing operational changes to the PRP in this proceeding, and proposed revisions to the PRP adjustment filings is discussed in Mr. Brown's testimony.

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

A. Yes. Delta owns a hydrocarbon liquid processing plant in Bell County that was used to improve the quality of extracted gas before it entered the transmission and distribution systems. Because of decreased natural gas production in eastern Kentucky, Delta has turned this plant off. Delta continues to maintain it in operational condition in case the need arises, but there presently is no need to remove hydrocarbons as the gas in Delta's system is pipeline quality and turning off the plant reduces Delta's operational expense. Delta also drilled additional wells at Canada Mountain so that more gas could be removed at a time. There is no additional gas being removed and the pressure rating in the field has not changed.

<u>CPCN Request for Nicholasville Project</u>

Q. Is Delta requesting a CPCN in this proceeding?

A. Yes. Delta is requesting a CPCN to construct an 8-inch steel transmission pipeline that is approximately 17 miles in length. The pipeline will serve the Nicholasville distribution area, which serves approximately 9,100 customers and is the largest and most concentrated area of service in Delta's system.

Q. Why is the pipeline necessary?

A. The need for the pipeline is twofold: redundancy and capacity. First, the Nicholasville area is currently served only by Delta's Nicholasville Transmission Line, which delivers high pressure natural gas from Buckeye in Garrard County to the south side of Nicholasville in Jessamine County. This pipeline is 12 miles in length and lies predominantly in rural areas, which includes crossing the Kentucky River. If this pipeline experiences a failure, there is no redundancy in the Nicholasville area and the more than 9,000 customers in that area could lose gas service. There is no other area in Delta's service territory where so many customers are served from a single line.

With the increased construction of housing and other economic development in Jessamine County, Delta is especially concerned about the redundancy in the Nicholasville system. This brings me to the second reason why the project is necessary. As Jessamine County has grown, there is an increasing need for volume and pressure on the north side of the system near the Fayette County line. Nicholasville has also experienced minor capacity constraints and a bottleneck in the system. To address this bottleneck, Delta considered a project in Nicholasville to replace and upgrade lines at an approximate cost of $1 million. Delta will be able to avoid this project and cost if it builds the proposed pipeline.

Once completed, the proposed pipeline will supply natural gas from a separate provider. With this secondary supply, there will be a significant enhancement in the reliability of supply while simultaneously eliminating any operational concerns should there be a failure in supply from either supplier. Because this pipeline is necessary to secure the integrity of the Nicholasville system and support further growth in Jessamine County, Delta requests the Commission grant it a CPCN to construct the pipeline.

Q. Please describe the route of the proposed pipeline.

A. The pipeline route is in the preliminary design stage. Attached to my testimony as Exhibit JM-1 is a preliminary map of the route. As shown on Exhibit JM-1, Delta plans to tap into an interstate pipeline and run the pipeline approximately 17 miles to connect to the Nicholasville system from the east/southeast direction.

Q. What is the timeline for this project?

A. Delta has budgeted capital for obtaining right of way for the project in 2022. Delta expects to begin construction in 2023. Delta hopes to complete the pipeline by the end of the construction season in 2023, but inclement weather could postpone the completion to 2024.

Q. Did Delta consider alternatives instead of the proposed pipeline?

A. Yes. Delta has been concerned about the need for redundancy and additional capacity in Nicholasville for several years. As a result of these concerns, Delta has extensively researched other avenues of providing an additional natural gas supply to the area. Delta first approached two natural gas companies in relatively close proximity to the area and inquired about the possibility of tapping in to those systems to procure an additional natural gas supply. These attempts were not successful. The proposed pipeline for which Delta is seeking the CPCN is the best and least cost option.

Q. What is the cost of this project?

A. At this time, Delta estimates the project will cost approximately $19,127,805. Attached to my testimony as JM-2 is a detailed preliminary cost estimate for the project.

Q. Please describe the estimated annual cost of operation of the pipeline.

A. Delta estimates the annual cost of operation of the pipeline will be $16,050. The majority of this cost is due to right of way mowing and maintenance. The pipeline will be constructed and maintained using a right of way of approximately 40 feet in width. Delta must maintain the right of way so that the pipeline is accessible at all times in case of an emergency. Maintenance includes mowing and general vegetation removal, which is performed every two to three years depending on vegetation growth.

Additionally, Delta will patrol the entire right of way twice annually to ensure the pipeline and associated operations meet all safety compliance requirements. All regulator stations and above ground valves will be inspected annually to ensure proper condition and operation. Delta will also perform and document cathodic testing and inspection annually, which requires electric service.

To summarize, Delta estimates it will incur the following annual operational expenses for the pipeline:

- Right of way mowing/maintenance: $11,000
- Line patrol: $1,300
- Leak survey: $1,300
- Electric usage/rectifier operation: $700
- Measurement and regulation operations: $1,000
- Painting/miscellaneous maintenance: $400
- Transmission valve inspection: $350

Each of these expenses helps ensure the safety of Delta's customers and employees.

Q. Please describe the manner in which the pipeline will be constructed.

A. This project will consist of the construction of a purchase station from an interstate pipeline located approximately 17 miles southeast of the City of Nicholasville. Delta plans to construct the pipeline using 8-inch steel pipe with 0.322-inch wall thickness. All pipe joining will be welded and non-destructively tested using x-ray technology. All pipe installed below ground will be coated in its entirety, and all welded joints will be coated upon completion of the welds for protection from corrosion. Additional cathodic protection will be provided by use of rectifier voltage being applied. All piping and associated facilities installed above ground shall be painted in order to prohibit atmospheric corrosion. Upon the completion of construction, the pipeline will be hydrostatically tested to a minimum of 1,080 psi, rendering a 720 psi maximum allowable operating pressure. All fittings associated with the pipeline will be pressure rated for 720 psi or greater. The construction process will predominately include open trench excavation, excluding main line valves which will be installed above ground to help ensure safety of operation and maintenance. All underground pipeline facilities will be installed at a minimum of 36 inches of cover unless state or federal codes require greater depth. All waterway crossings deemed "navigable" by the US Army Corps of Engineers will be horizontally directional drilled to prevent any environmental damages near or in the waterway. During and upon completion of the project, all right of way shall be restored to a minimum of original condition.

Q. Has Delta obtained any permits for this project?

A. Not at this time. Delta understands that the construction of this pipeline will require several permits and will obtain these permits when necessary. Should the Commission grant the CPCN, Delta will file copies of its permits with the Commission if requested to do so.

Construction Projects

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. Is Delta planning any significant capital projects you have not already mentioned in your testimony?

A. Yes. In Case No. 2020-00001, the Commission approved a pilot program for local distribution companies like Delta for economic development extensions. In Case No. 2020-00406, Delta sought approval from the Commission for its first request pursuant to the pilot program, a joint economic development project in Lincoln and Rockcastle counties. Capital costs associated with this project are shown on Tab 19.

Q. Please describe the economic development extension.

A. The leadership of Lincoln and Rockcastle counties have long recognized the need for natural gas service in their industrial parks to spur economic development. Delta's economic development extension is a three-phase project. The first phase involves designing the entire project, acquiring the necessary right-of-way in Lincoln and Rockcastle counties, and engaging TC Energy to tap their lines in Lincoln County. The costs of the first phase of this project will be partially offset by a $500,000 Appalachian Regional Commission grant, $125,000 from the Stanford-Lincoln County Industrial Development Authority, and $125,000 from the Rockcastle County Fiscal Court.

The second phase of the project is to extend the new connection to the Lincoln County Industrial Park, which requires an extension of 1.235 miles of steel pipeline. The third and final phase of the project is building the steel transmission pipeline from the new Lincoln County tap to the Mount Vernon North/South industrial parks, the I-75 Exit 62 Development Area in the Rockcastle County—Mt. Vernon tax increment financing district, and the Renfro Valley industrial site. Delta proposed and the Commission approved the first two phases of this economic development project in Case No. 2020-00406.[1] When the project is complete, one industrial park in Lincoln County and two industrial parks in Rockcastle County will have natural gas available, as well as a separate industrial site in Mt. Vernon.

Q. Does this conclude your testimony?

A. Yes.

[1] The Commission also approved in part and denied in part Delta's request for authority to create a regulatory asset related to the project.

VERIFICATION

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

The undersigned, **Jonathan W. 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 W. MORPHEW

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of May, 2021.

Emily P. Bennett (SEAL)
Notary Public

Emily P. Bennett
Notary Public, ID KYNP6460
State at Large, Kentucky
My Commission Expires on June 20, 2024

My Commission Expires:
6/20/24

EXHIBIT JM-1
FILED UNDER SEAL PURSUANT TO THE PETITION FOR CONFIDENTIAL TREATMENT FILED ON MAY 28, 2021

DELTA NATURAL GAS CO. INC.
ESTIMATED COST SUMMARY
NICHOLASVILLE TRANSMISSION 2ND FEED - 8" STEEL
NICHOLASVILLE, KY

ITEM	ESTIMATED COST
CONTRACTOR COST	$ 6,715,880.00
LABOR COST	$ 324,000.00
MATERIAL COST	$ 3,548,658.00
ACCOUNTS PAYABLE (MISC.)	$ 3,809,508.60
SUB-TOTAL	**$ 14,398,046.60**
OVERHEAD COST 32.85%	$ 4,729,758.31
TOTAL	**$ 19,127,804.91**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

APPLICATION OF DELTA NATURAL GAS	**)**	
COMPANY, INC. FOR AN ADJUSTMENT	**)**	**CASE NO. 2021-00185**
OF RATES	**)**	

DIRECT TESTIMONY OF

PAUL R. MOUL

May 28, 2021

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 7.65%. 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 impact of the coronavirus pandemic that began in the first quarter of 2020. These events had a significant impact on the capital markets -- both debt and equity. Extraordinary events around the COVID-19 pandemic have produced significant turmoil that has rocked the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee (FOMC) to address these disruptions. I have considered these events as they impact the inputs that I used in the various models of the cost of equity. That is to say, I have analyzed the cost of equity models using input data that follows the onset of the economic recession.

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 2020 was represented by approximately 53% to residential customers, approximately 19% to commercial customers, and approximately 28% to industrial customers. Overall, throughput on the Delta's system consists of approximately 18% to sales customers and 82% 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.

[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).

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 Value Line Investment Survey, which consists of ten companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated two companies from the Value Line group. NiSource, Inc. was removed because its capital structure is atypical for a gas distribution utility. UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international 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 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	11.37%
RP	10.50%
CAPM	12.51%
Comparable Earnings	12.15%
Average	11.63%
Median	11.76%
Mid-point	11.51%

Focusing upon the market model approaches of the cost of equity (i.e., DCF, RP and CAPM), the average equity return is 11.46% (11.37% + 10.50% + 12.51% = 34.38% ÷ 3). The results for the DCF and RP methods are 10.94% (11.37% + 10.50% = 21.87% ÷ 2). The 10.95% equity return that I propose in this case is the result of the DCF and RP methods on a rounded basis. From all these measures, I recommend that the Commission set the Company's rate of return on common equity at 10.95%. My

[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.

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 witness Morphew 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 affects 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 15 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 $82,325,736 in the period 2021-2025. Over this five-year period, these capital expenditures will represent approximately 53% ($82,325,736

÷ $154,904,318) of its net utility plant at December 31, 2020. 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.

<u>FUNDAMENTAL RISK ANALYSIS</u>

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, Northwest Natural, ONE Gas, Inc, South Jersey Industries, 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 A2 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 2016-2020. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, Delta is approximately two percent of the average size of the Gas Group, and is a very much smaller than the average size of the Gas Group. 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.

Market Ratios. 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

[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).

Group was slightly higher than that of the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The average market-to-book ratios were fairly similar for the Gas Group and the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on total capital including short-term debt, were 56.5% for Delta, 48.1% for the Gas Group, and 39.7% 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 in their cycle around year-end. The financial risk for Delta is somewhat lower than for the Gas Group.

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 0.443 (3.1% ÷ 7.0%) for Delta, 0.054 (0.5% ÷ 9.2%) for the Gas Group, and 0.039 (0.4% ÷ 10.3%) 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 78.6% for Delta, 83.7% for the Gas Group, and 78.8 for the S&P Public Utilities. Delta's operating risk is somewhat lower than the Gas Group and similar to 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 4.06 times for Delta, 4.36 times for the Gas Group, and 3.02 times for the S&P Public Utilities. Delta's credit risk is fairly similar (albeit somewhat below) 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.

[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.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 60.0% for Delta, 56.7% for the Gas Group, and 69.5% for the S&P Public Utilities. On average, the Company's cash flow to construction was similar to the Gas Group and S&P Public Utilities. However, 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 .91 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 is fairly similar 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. The Company's quality of earnings, credit risk, and IGF to construction (albeit highly variable) has been fairly

[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.

similar to the Gas Group. The financial risk and operating risk for Delta has been lower. 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, 2021 corresponds with the base period for the Company. The thirteen-month average for December 31, 2022 is estimated for the fully forecasted test period. Prior to the beginning of fully forecasted test period, the Company plans to issue $25.314 million of long-term debt. The Company will also receive $9.633 million of new equity around the same time. The resulting capital structure ratios are 48.24% long-term debt, 0.00% short-term debt, and 51.76% common equity, based upon the thirteen month average balance for the 2022 test year. I should note that, for the fully forecasted test year, the average balance of short-term debt was negative for the thirteen-month average. I reset the balance to zero for capital structure purposes.

Q. Are these capital structure ratios reasonable?

A. Yes. I have verified the reasonableness of the Company's common equity ratio by considering the historical capital structure ratios for the Gas Group and with analysts' forecasts, which influence investor expectations. Historically, the Gas Group has employed 53.3% common equity excluding short-term debt. 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 Value Line. In the case of the Value Line forecasts, the common equity ratios are computed without regard to short-term debt. Those ratios are:

Company	2016	2017	2019-21
Atmos Energy Corporation	55.0%	55.0%	55.0%
Chesapeake Utilities	71.0%	71.0%	70.0%
Laclede Group, Inc.	45.5%	47.5%	48.5%
New Jersey Resources Corp.	56.5%	56.5%	59.0%
Northwest Natural Gas Co.	55.5%	55.5%	56.5%
South Jersey Industries, Inc.	51.0%	51.5%	52.5%
Southwest Gas Corporation	50.5%	50.5%	51.5%
WGL Holdings, Inc.	56.0%	55.0%	51.0%
Average	55.1%	55.3%	55.5%

Source: The Value Line Investment Survey, March 4, 2016

These forecasts show that the 51.76% common equity ratio for Delta is reasonable by reference to the forecast ratios of the Gas Group. Overall, these comparisons show that the Company's common equity ratio is reasonable.

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 forecast test period capital structure ratios of 48.24% long-term debt, 0.00% short-term debt and 51.76% 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, 2021 using thirteen month average balances. On pages 2 and 3 of Attachment PRM-6, the embedded cost of debt is shown for December 31, 2021 and December 31, 2022 using the thirteen-month average balances. For the new issue of long-term debt, I have used an estimated cost of 3.10% for the issue in November 2021.

I will adopt the 4.11% embedded cost of long-term debt, as shown on page 3 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 48.24% long-term debt ratio**.**

COST OF EQUITY – GENERAL APPROACH

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 that 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.

DISCOUNTED CASH FLOW

Q. Please describe the Discounted Cash Flow 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

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

Attachment PRM-1, page 2, for the Gas Group. The DCF return is 11.37%, excluding flotation costs, for the Gas Group.

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.

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 twelve months ended March 2021, the monthly dividend yields are shown on Attachment 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 twelve months ended March 2021 the average dividend yield was 3.47% 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 3.56% and 3.47%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.56% 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. This adjustment adds thirteen basis points to the six-month average historical yield, thus producing the 3.69% adjusted dividend yield for the Gas Group.

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 price-earnings 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 of 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 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 where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity 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, which are those used by investors when pricing common stocks.

Q. How did you determine 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 price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides those data. While historical data cannot be ignored, it is much less significant in 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 price-earnings (P-E) multiple. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research focuses also 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 in order 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 in order 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 Value Line. 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 Value Line forecasts also are 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 (4.99%), Zacks (5.45%), and Value Line (7.06%).

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

A. Yes. While a variety of 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 Myron 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.[7] Consistent with Professor Gordon's findings, 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 4.99% to 7.06%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.75% 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 and is above the midpoint of that data set. The

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

reasonableness of this growth rate is also supported by the earnings growth associated with the continuation of elevated 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 42.04% long-term debt, 0.51% preferred stock, and 57.45% 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 that 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 rate setting 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 rate-setting 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," provides a return of 7.70% 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 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 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 existed.

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 expressed 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 7.70%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.65% to compensate investors for the risk of a 49.27% debt ratio and 0.02% for the 0.60% preferred stock rate. Under this approach, the parts sum to 11.37% (7.70% + 3.65% + 0.02%), 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 summed the 3.69% dividend yield, the 6.75% growth rate, and 0.93% for the leverage adjustment in order to arrive at the same 11.37% (3.69% + 6.75% + 0.93%) return. I know of no means to mathematically solve for the 0.93% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.93% adjustment is merely a convenient way to compare the 11.37% return computed using the Modigliani & Miller formulas to the 10.44% 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, page 1) based on a market-value capital structure. A 10.44% 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 rate-setting process rather than the market value equity ratio related to the price of stock. The cost of equity should 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 3.9% issuance and selling expenses shown on Attachment PRM-11 to 1.5%. I did this because I applied the adjustment factor (i.e., 1.000 + 0.015) to the entire DCF return, rather than to just the dividend yield component. The resulting DCF cost rate is 11.54%, computed as follows:

$$D_1/P_0 + g + lev. = k \times flot. = K$$

Gas Group 3.69% + 6.75% + 0.93% = 11.37% x 1.015 = 11.54%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.17% (11.54% - 11.37%) 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 price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant. 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 Attachment PRM-1, page 2. That result is 10.50% excluding flotation costs and somewhat higher including flotation costs.

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 3.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated 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 twelve months ended March 2021, the average monthly yield on Moody's index of A-rated public utility bonds was 2.98%. For the six and three-month periods ended March 2021, the yields were 3.00% and 3.15%, respectively. During the twelve-months ended March 2021 the range of the yields on A-rated public utility bonds was 2.73% to 3.44%. 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 1.37% on a twelve-month average basis, 1.16% on a six-month average basis, and 1.08% on a three-month average basis. Giving greater emphasis to the trend toward more narrow spreads, 1.00% represents a reasonable 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 a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on April 1, 2021, 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 also have 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
2021	Second	3.0%	3.9%	2.4%	1.00%	3.40%
2021	Third	3.1%	4.0%	2.5%	1.00%	3.50%
2021	Fourth	3.2%	4.1%	2.5%	1.00%	3.50%
2022	First	3.3%	4.2%	2.6%	1.00%	3.60%
2022	Second	3.4%	4.3%	2.7%	1.00%	3.70%
2022	Third	3.4%	4.4%	2.7%	1.00%	3.70%

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

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2020 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
2022-2026	3.6%	4.6%	2.8%
2027-2031	4.5%	5.4%	3.6%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.75% yield on A-rated public utility bonds represents a reasonable 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 those 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 2021 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 Attachment PRM-13, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.63%
Average Across All Interest Rates	5.67%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.63% when the marginal cost of long-term government bonds was low (i.e., 2.85%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.67% when the average government bond yield was 4.95%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

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), and 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	3.75%	+	6.75%	=	10.50%	+	0.17%	=	10.67%

<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 12.51%, excluding flotation costs, for the Gas Group. 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 Value Line 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 Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the rate-setting 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. 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,[8] as follows:

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

where 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 0.55 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations

[8] 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, December 27-29, 1971. (May 1972), pp. 435-452.

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 0.98 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 twelve months ended March 2021, the average yield on 30-year Treasury bonds was 1.61%. For the six- and three-months ended March 2021, the yields on 30-year Treasury bonds were 1.84% and 2.07%, respectively. During the twelve-months ended March 2021, the range of the yields on 30-year Treasury bonds was 1.27% to 2.34%. The low yields that existed during recent periods can be traced initially to weakness in business fixed investment and exports due in part to the U.S.'s trade war with China. Thereafter, extraordinary events associated with the COVID-19 pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and significant declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the FOMC acted to address these disruptions. The FOMC continues to support the money and capital markets during the recovery from the coronavirus pandemic. Presently, the Fed Funds rate is near zero. It should be noted that a meaningful increase in long-term treasury yields began in mid-February 2021 that was associated with the expected emergence from the economic recession.

As shown on page 2 of Attachment PRM-14, forecasts published by Blue Chip on April 1, 2021 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.4% to 2.7% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 2.8% from 2022 through 2026 and 3.6% from 2027 to 2031. 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 2.75% 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 Attachment PRM-14, page 2 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 Attachment PRM-13, page 1. On that schedule, the market return was 12.06% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.85% when interest rates were low. As such, I carried over to Attachment PRM-14, page 2, the average large common stock returns of 12.06% and the average yield on long-term government bonds of 2.85%. The resulting market premium is 9.21% (12.06% - 2.85%) based on historical data, as shown on Attachment PRM-14, page 2. As also shown on Attachment PRM-14, page 2, I calculated the forecast returns, which show a 11.37% total market return. With this forecast, I calculated a market premium of 8.62% (11.37% - 2.75%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 8.92% (8.62% + 9.21% = 17.83% ÷ 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 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 understate the cost of equity significantly 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. As noted previously, Delta is relatively smaller than the Gas Group. 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.

Q. What does your CAPM analysis show?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 0.98 for the Gas Group, the 8.92% market premium, 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	2.75%	+	0.98	x (	8.92%	) +	1.02%	=	12.51%	+	0.17%	=	12.68%

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 risks characteristics would need to realize in order 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 in order 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 vs. 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 market-based models 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 Attachment PRM-15, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Attachment PRM-15, page 1.

I relied upon Value Line data because they provide 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 Attachment PRM-15, page 2, 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 in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (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 12.0% using only the returns that were less than 20%, as shown on Attachment PRM-15, page 2. The average forecasted rate of return as published by Value Line is 12.3% also using values less than 20%, as provided on

Attachment PRM-15, page 2. Using the average of these data my Comparable Earnings result is 12.15%, as shown on Attachment PRM-1, page 2.

CONCLUSION ON COST OF EQUITY

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

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.95% for Delta. 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. In summary, the Company should be provided an opportunity to realize a 10.95% rate of return on common equity so that it can compete in the capital markets and attain reasonable credit quality.

Q. Does this complete your Prepared Direct Testimony?

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

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E-Signature Summary

E-Signature 1: Paul R Moul (PRM)
May 24, 2021 12:17:38 -8:00 [32A207149A03] [108.24.148.58]
prmoul@verizon.net (Principal)

E-Signature Notary: Jennifer C. Wakefield (JCW)
May 24, 2021 12:17:38 -8:00 [7BC7F89E14E7] [217.180.202.63]
jennifer.wakefield@skofirm.com
I, Jennifer C. Wakefield, did witness the participants named above electronically sign this document.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF FAYETTE)

The undersigned, **Paul R. Moul**, being duly sworn, deposes and says he is Managing Consultant for 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
Signed on 2021/05/24 12:17:38 -8:00

PAUL R. MOUL

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24 day of May, 2021.

Jennifer C. Wakefield
Signed on 2021/05/24 12:17:38 -8:00

(SEAL)

Notary Public

My Commission Expires:
June 30, 2024

JENNIFER C. WAKEFIELD
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP8355
My Commission Expires Jun 30, 2024
Notary Stamp 2021/05/24 12:17:38 PST 7BC7F89E14E7

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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. 2021-00185**
OF RATES	**)**	

ATTACHMENTS TO ACCOMPANY THE

DIRECT TESTIMONY OF

PAUL R. MOUL

May 28, 2021

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	48.24%	4.11%	1.98%
Short-Term Debt	0.00%	1.00%	0.00%
Total Debt	48.24%		1.98%
Common Equity	51.76%	10.95%	5.67%
Total	100.00%		7.65%

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

Pre-tax coverage of interest expense	4.66 x
Post-tax coverage of interest expense	3.74 x

Delta Natural Gas Company, Inc.
Cost of Equity
as of March 31, 2021

Discounted Cash Flow (DCF)					***D_1/P_0* [1]**	**+**	***g* [2]**	**+**	***lev.* [3]**	**=**	***k***
Gas Group					3.69%	+	6.75%	+	0.93%	=	11.37%
Risk Premium (RP)							***I* [4]**	**+**	***RP* [5]**	**=**	***k***
Gas Group							3.75%	+	6.75%	=	10.50%
Capital Asset Pricing Model (CAPM)	***Rf* [6]**	**+**	***ß* [7]**	***x (***	***Rm-Rf* [8]**	***) +***	***size* [9]**	**=**	***k***
Gas Group	2.75%	+	0.98	x (	8.92%	) +	1.02%	=	12.51%
***Comparable Earnings (CE)* [10]**					***Historical***		***Forecast***		***Average***
Comparable Earnings Group					12.0%		12.3%		12.15%

References:
(1) Attachment PRM-07
(2) Attachment PRM-09
(3) Attachment PRM-10
(4) A-rated public utility bond yield comprised of a 2.75% risk-free rate of return (Attachment PRM-14 page 2) and a yield spread of 1.00% (Attachment PRM-12 page 3)
(5) Attachment PRM-13 page 1
(6) Attachment PRM-14 page 2
(7) Attachment PRM-10
(8) Attachment PRM-14 page 2
(9) Attachment PRM-14 page 3
(10) Attachment PRM-15 page 2

Delta Natural Gas Company, Inc.
Capitalization and Financial Statistics
2016-2020, Inclusive

	2020	2019	2018	2017	2016	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 99.8	$ 111.8	$ 112.7	$ 118.7	$ 127.6	
Short-Term Debt	$ 15.8	$ 4.3	$ 3.3	$ -	$ -	
Total Capital	$ 115.6	$ 116.1	$ 116.0	$ 118.7	$ 127.6	
						Average
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	43.1%	39.8%	42.2%	41.3%	39.6%	41.2%
Common Equity [1]	56.9%	60.2%	57.8%	58.7%	60.4%	58.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	50.8%	42.1%	43.8%	41.3%	39.6%	43.5%
Common Equity [1]	49.2%	57.9%	56.2%	58.7%	60.4%	56.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity	8.5%	10.8%	3.6%	4.1%	8.1%	7.0%
Operating Ratio [2]	82.2%	78.4%	80.4%	76.6%	75.5%	78.6%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	3.75 x	4.86 x	3.56 x	3.21 x	4.93 x	4.06 x
Post-tax: All Interest Charges	3.45 x	4.31 x	2.09 x	2.29 x	3.55 x	3.14 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	3.75 x	4.86 x	3.56 x	3.21 x	4.93 x	4.06 x
Post-tax: All Interest Charges	3.45 x	4.31 x	2.09 x	2.29 x	3.55 x	3.14 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	11.2%	14.3%	57.5%	41.5%	35.1%	31.9%
Internal Cash Generation/Construction [4]	17.3%	75.7%	50.6%	23.8%	132.5%	60.0%
Gross Cash Flow/ Avg. Total Debt [5]	28.3%	30.8%	23.5%	15.6%	28.9%	25.4%
Gross Cash Flow Interest Coverage [6]	7.10 x	7.12 x	5.30 x	3.30 x	6.06 x	5.78 x
Common Dividend Coverage [7]	1.17 x	3.07 x	1.68 x	1.35 x	2.53 x	1.96 x

See Page 2 for Notes.

Delta Natural Gas Company, Inc.
Capitalization and Financial Statistics
2016-2020, 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 PUCO

Gas Group
Capitalization and Financial Statistics [1]
2016-2020, Inclusive

	2020	2019	2018	2017	2016	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 4,726.1	$ 4,072.0	$ 3,667.8	$ 3,130.5	$ 2,900.4	
Short-Term Debt	$ 296.9	$ 400.8	$ 314.4	$ 301.8	$ 256.8	
Total Capital	$ 5,023.0	$ 4,472.8	$ 3,982.2	$ 3,432.3	$ 3,157.2	
Market-Based Financial Ratios						
Price-Earnings Multiple	23 x	26 x	20 x	22 x	22 x	23 x
Market/Book Ratio	184.6%	224.1%	220.4%	227.9%	203.8%	212.2%
Dividend Yield	3.2%	2.6%	2.7%	2.6%	2.8%	2.8%
Dividend Payout Ratio	74.5%	69.6%	52.4%	53.3%	60.4%	62.0%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	48.9%	47.2%	47.0%	45.0%	43.0%	46.2%
Preferred Stock	1.0%	0.9%	0.3%	0.0%	0.1%	0.4%
Common Equity [2]	50.1%	51.9%	52.7%	55.0%	56.9%	53.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	52.9%	52.4%	52.5%	51.2%	48.5%	51.5%
Preferred Stock	0.9%	0.8%	0.2%	0.0%	0.1%	0.4%
Common Equity [2]	46.2%	46.8%	47.3%	48.8%	51.4%	48.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	8.8%	9.0%	10.0%	8.7%	9.4%	9.2%
Operating Ratio [3]	81.9%	83.7%	85.0%	84.5%	83.3%	83.7%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	4.38 x	3.99 x	4.06 x	4.51 x	5.19 x	4.43 x
Post-tax: All Interest Charges	3.78 x	3.55 x	3.80 x	3.58 x	3.79 x	3.70 x
Overall Coverage: All Int. & Pfd. Div.	3.75 x	3.53 x	3.80 x	3.58 x	3.79 x	3.69 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.27 x	3.92 x	4.01 x	4.48 x	5.12 x	4.36 x
Post-tax: All Interest Charges	3.67 x	3.48 x	3.75 x	3.55 x	3.72 x	3.63 x
Overall Coverage: All Int. & Pfd. Div.	3.64 x	3.46 x	3.75 x	3.55 x	3.72 x	3.62 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.3%	2.8%	3.2%	-7.7%	2.0%	0.7%
Effective Income Tax Rate	16.1%	13.8%	7.8%	35.8%	33.4%	21.4%
Internal Cash Generation/Construction [5]	53.2%	45.7%	51.5%	60.1%	73.0%	56.7%
Gross Cash Flow/ Avg. Total Debt [6]	18.5%	18.4%	20.2%	22.4%	24.8%	20.9%
Gross Cash Flow Interest Coverage [7]	7.24 x	6.37 x	6.54 x	7.01 x	7.76 x	6.98 x
Common Dividend Coverage [8]	3.81 x	3.67 x	3.90 x	4.11 x	4.51 x	4.00 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2016-2020, 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, and after eliminating NiSource due to its atypical capital structure and 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	0.80
CPK	Chesapeake Utilities Corp.	NAIC "1"		NYSE	0.80
NJR	New Jersey Resources Corp.	A1	-	NYSE	0.95
NWN	Northwest Natural Holding Compa	Baa1	A+	NYSE	0.80
OGS	ONE Gas, Inc.	A3	BBB+	NYSE	0.80
SJI	South Jersey Industries, Inc.	A3	BBB	NYSE	1.05
SWX	Southwest Gas Holdings, Inc.	Baa1	A-	NYSE	0.95
SR	Spire, Inc.	A1	A-	NYSE	0.85
	Average	A2	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]
2016-2020, Inclusive

	2020	2019	2018 (Millions of Dollars)	2017	2016	Average
Amount of Capital Employed						
Permanent Capital	$ 38,743.7	$ 36,461.6	$ 32,871.6	$ 30,827.6	$ 29,173.1	
Short-Term Debt	$ 1,154.5	$ 1,221.9	$ 1,420.3	$ 1,076.1	$ 1,032.2	
Total Capital	$ 39,898.2	$ 37,683.5	$ 34,291.9	$ 31,903.7	$ 30,205.3	
Market-Based Financial Ratios						
Price-Earnings Multiple	22 x	20 x	21 x	20 x	21 x	21 x
Market/Book Ratio	218.5%	221.3%	204.7%	214.4%	196.0%	211.0%
Dividend Yield	3.6%	3.2%	3.5%	3.3%	3.5%	3.4%
Dividend Payout Ratio	77.8%	62.7%	68.7%	65.2%	74.6%	69.8%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	58.1%	56.7%	55.0%	56.8%	56.6%	56.6%
Preferred Stock	2.6%	2.4%	2.5%	1.4%	1.9%	2.1%
Common Equity [2]	39.4%	41.0%	42.5%	41.8%	41.6%	41.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	59.4%	58.1%	57.0%	58.4%	58.2%	58.2%
Preferred Stock	2.5%	2.3%	2.4%	1.4%	1.8%	2.1%
Common Equity [2]	38.1%	39.6%	40.7%	40.3%	40.1%	39.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.2%	10.3%	10.3%	10.8%	9.7%	10.3%
Operating Ratio [3]	79.8%	79.3%	79.8%	77.0%	78.2%	78.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.80 x	3.05 x	2.94 x	3.42 x	3.38 x	3.12 x
Post-tax: All Interest Charges	2.60 x	3.10 x	2.59 x	2.86 x	2.55 x	2.74 x
Overall Coverage: All Int. & Pfd. Div.	2.56 x	3.04 x	2.55 x	2.84 x	2.52 x	2.70 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.70 x	2.95 x	2.84 x	3.31 x	3.28 x	3.02 x
Post-tax: All Interest Charges	2.50 x	3.00 x	2.48 x	2.75 x	2.44 x	2.63 x
Overall Coverage: All Int. & Pfd. Div.	2.46 x	2.94 x	2.44 x	2.73 x	2.41 x	2.60 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	6.8%	6.0%	7.3%	7.3%	6.5%	6.8%
Effective Income Tax Rate	10.2%	12.2%	19.0%	28.2%	29.0%	19.7%
Internal Cash Generation/Construction [5]	58.6%	65.9%	66.2%	78.7%	78.0%	69.5%
Gross Cash Flow/ Avg. Total Debt [6]	15.9%	17.5%	17.4%	19.9%	20.5%	18.2%
Gross Cash Flow Interest Coverage [7]	4.90 x	4.97 x	4.98 x	5.57 x	5.54 x	5.19 x
Common Dividend Coverage [8]	3.52 x	5.56 x	4.80 x	4.33 x	4.31 x	4.50 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2016-2020, 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	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.85
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.85
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.15
CMS Energy	CMS	A3	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.80
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A1	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa2	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	A-	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	1.00
Eversource	ES	A3	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NYSE	0.95
FirstEnergy Corp.	FE	A3	BB+	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.90
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB+	NYSE	1.25
Pinnacle West Capital	PNW	A2	A-	NYSE	0.90
PPL Corp.	PPL	A3	A-	NYSE	1.15
Public Serv. Enterprise Inc.	PEG	A2	A-	NYSE	0.90
Sempra Energy	SRE	Baa1	BBB+	NYSE	1.00
Southern Co.	SO	Baa1	A-	NYSE	0.90
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.91

Note: (1) Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Delta Natural Gas Company, Inc.
Investor-provided Capitalization
Thirteen-month average for the Base Period ending August 31, 2021, Thirteen-month average estimated for December 31, 2021, and Thirteen-month average for the Test Period ending December 31, 2022

	Thirteen-month average for the Base Period ending August 31, 2021		Thirteen-month average estimated for December 31, 2021		Thirteen-month average for the Test Period ending December 31, 2022	
	Amount Outstanding	Ratios	Amount Outstanding	Ratios	Amount Outstanding	Ratios
Long Term Debt	$ 43,780,338	36.35%	$ 47,097,950	37.60%	$ 67,017,890	48.24%
Common Equity	61,252,085	50.85%	61,291,526	48.94%	71,903,674	51.76%
Total Permanent Capital	105,032,424	87.20%	108,389,476	86.54%	138,921,565	100.00%
Short Term Debt	15,417,368	12.80%	16,852,347	13.46%	-	0.00%
Total Capital Employed	$ 120,449,792	100.00%	$ 125,241,823	100.00%	$ 138,921,565	100.00%

Source of information: Company provided data

Delta Natural Gas Company, Inc.
Total Debt Outstanding
Thirteen-month average for the Base Period ending August 31, 2021

Issue	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
Delta - Tranche 2	December 19, 2031	4.26%	$ 43,461,538	$ 1,851,462	
Peoples KY - Tranche 2	December 19, 2023	4.10%	181,200	7,429	
Peoples KY - Tranche 3	December 19, 2025	4.25%	137,600	5,848	
Amortization of Issuance Expenses				199,147	
Long-Term Debt			43,780,338	2,063,886	4.71%
Short-Term Debt		1.00%	15,417,368	154,174	
Total Debt			$ 59,197,706	$ 2,218,059	3.75%

Source of information: Company provided data

Delta Natural Gas Company, Inc.
Total Debt Outstanding
Thirteen-month average estimated for December 31, 2021

Issue	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
Delta - Tranche 2	December 19, 2031	4.26%	$ 42,884,615	$ 1,826,885	
Peoples KY - Tranche 2	December 19, 2023	4.10%	181,200	7,429	
Peoples KY - Tranche 3	December 19, 2025	4.25%	137,600	5,848	
Delta - Tranche 3	TBD	3.10%	3,894,535	120,731	
Amortization of Issuance Expenses				196,880	
Long-Term Debt			47,097,950	2,157,772	4.58%
Short-Term Debt		1.00%	16,852,347	168,523	
Total Debt			$ 63,950,297	$ 2,326,296	3.64%

Source of information: Company provided data

Delta Natural Gas Company, Inc.
Total Debt Outstanding
Thirteen-month average for the Test Period ending December 31, 2022

Issue	Date of Maturity	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
Delta - Tranche 2	December 19, 2031	4.26%	$ 41,384,615	$ 1,762,985	
Peoples KY - Tranche 2	December 19, 2023	4.10%	181,200	7,429	
Peoples KY - Tranche 3	December 19, 2025	4.25%	137,600	5,848	
Delta - Tranche 3	TBD	3.10%	25,314,475	784,749	
Amortization of Issuance Expenses				190,080	
Long-Term Debt			67,017,890	2,751,091	4.11%
Short-Term Debt		1.00%	-	-	
Total Debt			$ 67,017,890	$ 2,751,091	4.11%

Source of information: Company provided data

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending March 2021

Company	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	2.27%	2.24%	2.32%	2.18%	2.31%	2.41%	2.74%	2.61%	2.63%	2.82%	2.96%	2.54%			
Chesapeake Utilities Corp (CPK)	2.01%	1.96%	2.10%	2.09%	2.16%	2.09%	1.81%	1.70%	1.63%	1.74%	1.67%	1.52%			
New Jersey Resources Corporation (NJR)	3.72%	3.59%	3.83%	4.31%	4.45%	4.93%	4.58%	4.06%	3.75%	3.82%	3.41%	3.34%			
Northwest Natural Holding Company (NWN)	2.93%	2.99%	3.44%	3.57%	3.75%	4.24%	4.32%	4.02%	4.21%	4.11%	4.01%	3.58%			
ONE Gas Inc (OGS)	2.72%	2.58%	2.81%	2.87%	2.92%	3.14%	3.15%	2.73%	2.82%	3.19%	3.47%	3.03%			
South Jersey Industries Inc (SJI)	4.15%	4.20%	4.73%	5.09%	5.39%	6.15%	6.34%	5.32%	5.63%	5.28%	4.87%	5.37%			
Southwest Gas Holdings Inc (SWX)	3.03%	3.01%	3.32%	3.30%	3.63%	3.63%	3.50%	3.55%	3.77%	3.83%	3.66%	3.33%			
Spire Inc. (SR)	3.43%	3.44%	3.80%	4.06%	4.32%	4.69%	4.67%	4.10%	4.07%	4.27%	3.95%	3.53%			
Average	**3.03%**	**3.00%**	**3.29%**	**3.43%**	**3.62%**	**3.91%**	**3.89%**	**3.51%**	**3.56%**	**3.63%**	**3.50%**	**3.28%**	**3.47%**	**3.56%**	**3.47%**

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
		3.56%	1.033750	3.68%
	Discrete	D_0/P_0	Adj.	D_1/P_0
		3.56%	1.041843	3.71%
	Quarterly	D_0/P_0	Adj.	D_1/P_0
		0.8904%	1.016464	3.67%
	Average			3.69%
	Growth rate			6.75%
	K			10.44%

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

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

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Gas Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
Atmos Energy Corp (ATO)	9.00%	8.00%	7.50%	5.00%	10.00%	7.50%	7.00%	5.50%
Chesapeake Utilities Corp (CPK)	8.00%	9.00%	6.50%	5.50%	10.50%	9.50%	7.00%	10.00%
New Jersey Resources Corporation (NJR)	6.00%	7.00%	6.50%	7.00%	8.50%	7.00%	7.50%	7.50%
Northwest Natural Holding Company (NWN)	-17.00%	-11.00%	0.50%	2.00%	-0.50%	1.50%	-5.50%	-3.00%
ONE Gas Inc (OGS)	9.50%	-	17.00%	-	2.50%	-	7.00%	-
South Jersey Industries Inc (SJI)	-4.00%	1.00%	5.00%	7.50%	3.50%	5.50%	2.00%	4.50%
Southwest Gas Holdings Inc (SWX)	4.50%	8.00%	9.50%	8.50%	6.50%	6.00%	1.50%	4.00%
Spire Inc. (SR)	4.50%	1.50%	6.00%	4.50%	5.50%	7.00%	8.50%	4.50%
Average	2.56%	3.36%	7.31%	5.71%	5.81%	6.29%	4.38%	4.71%

Source of Information: Value Line Investment Survey, February 26, 2021

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

			Value Line				
Gas Group	**I/B/E/S First Call**	**Zacks**	**Earnings Per Share**	**Dividends Per Share**	**Book Value Per Share**	**Cash Flow Per Share**	**Percent Retained to Common Equity**
Atmos Energy Corp (ATO)	7.00%	7.30%	7.00%	7.50%	10.50%	5.00%	3.50%
Chesapeake Utilities Corp (CPK)	4.74%	N/A	8.50%	8.00%	7.00%	10.00%	6.00%
New Jersey Resources Corporation	6.00%	6.00%	1.50%	5.50%	5.00%	2.50%	3.50%
Northwest Natural Holding Compan	3.10%	N/A	5.50%	0.50%	8.00%	4.50%	2.50%
ONE Gas Inc (OGS)	5.00%	5.00%	6.50%	7.00%	4.50%	6.00%	4.00%
South Jersey Industries Inc (SJI)	4.40%	4.40%	10.50%	4.00%	5.00%	5.50%	4.50%
Southwest Gas Holdings Inc (SWX)	4.00%	5.00%	8.00%	4.50%	6.00%	6.50%	5.00%
Spire Inc. (SR)	5.70%	5.00%	9.00%	4.50%	8.50%	7.50%	2.50%
Average	4.99%	5.45%	7.06%	5.19%	6.81%	5.94%	3.94%

Source of Information : Yahoo Finance, March 31, 2021
Zacks, March 31, 2021
Value Line Investment Survey, February 26, 2021

Gas Group
Financial Risk Adjustment

		ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year		09/30/20	12/31/20	09/30/20	12/31/20	12/31/20	12/31/20	12/31/20	09/30/20	
Capitalization at Fair Values										
	Debt(D)	5,597,183	548,500	2,417,748	1,136,311	2,000,000	3,152,224	3,148,818	2,908,600	2,613,673
	Preferred(P)	0	0	0	0	0	0	0	242,000	30,250
	Equity(E)	12,033,105	1,889,546	2,588,540	1,406,788	4,081,610	2,162,231	3,474,470	2,745,747	3,797,755
	Total	17,630,288	2,438,046	5,006,288	2,543,099	6,081,610	5,314,455	6,623,288	5,896,347	6,441,678
Capital Structure Ratios										
	Debt(D)	31.75%	22.50%	48.29%	44.68%	32.89%	59.31%	47.54%	49.33%	42.04%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.10%	0.51%
	Equity(E)	68.25%	77.50%	51.71%	55.32%	67.11%	40.69%	52.46%	46.57%	57.45%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock										
	Issued	125,882.477	17,461.841	95,949.183	30,589.000	53,166.733	100,591.940	57,192.925	51,611.789	
	Treasury	0.000	0.000	148.310	0.000	0.000	256.372	0.000	0.000	
	Outstanding	125,882.477	17,461.841	95,800.873	30,589.000	53,166.733	100,335.568	57,192.925	51,611.789	
	Market Price	$ 95.59	$ 108.21	$ 27.02	$ 45.99	$ 76.77	$ 21.55	$ 60.75	$ 53.20	
Capitalization at Carrying Amounts										
	Debt(D)	4,560,000	523,000	2,102,845	955,425	1,600,000	2,919,201	2,772,633	2,484,100	2,239,651
	Preferred(P)	0	0	0	0	0	0	0	242,000	30,250
	Equity(E)	6,791,203	697,085	1,844,692	888,733	2,233,311	1,660,881	2,674,953	2,280,300	2,383,895
	Total	11,351,203	1,220,085	3,947,537	1,844,158	3,833,311	4,580,082	5,447,586	5,006,400	4,653,795
Capital Structure Ratios		53.95	39.92	19.26	29.05	42.01	16.55	46.77	44.18	
	Debt(D)	40.17%	42.87%	53.27%	51.81%	41.74%	63.74%	50.90%	49.62%	49.27%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.83%	0.60%
	Equity(E)	59.83%	57.13%	46.73%	48.19%	58.26%	36.26%	49.10%	45.55%	50.13%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.80	0.80	0.95	0.80	0.80	1.05	0.95	0.85	0.88

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.88	=	Bu	[1+	(1-0.21)	0.7318	+	0.0089	]
	0.88	=	Bu	[1+	0.79	0.7318	+	0.0089	]
	0.88	=	Bu	1.5870					
	0.55	=	Bu						
Hamada	Bl	=	0.55	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.55	[1+	0.79	0.9827	+	0.0120	]
	Bl	=	0.55	1.7883					
	Bl	=	0.98						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	-	d	)	P	/	E
	7.70%	=	10.44%	-	(((	7.70%	-	3.00%	)	0.79	)	42.04%	/	57.45%	-	7.70%	-	5.68%	)	0.51%	/	57.45%
	7.70%	=	10.44%	-	(((	4.70%			)	0.79	)	0.7318			-	2.02%			)	0.0089		
	7.70%	=	10.44%	-	((	3.71%					)	0.7318			-	2.02%			)	0.0089		
	7.70%	=	10.44%	-		2.71%									-	0.02%						
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	-	d	)	P	/	E
	11.37%	=	7.70%	+	(((	7.70%	-	3.00%	)	0.79	)	49.27%	/	50.13%	+	7.70%	-	5.68%	)	0.60%	/	50.13%
	11.37%	=	7.70%	+	(((	4.70%			)	0.79	)	0.9827			+	2.02%			)	0.0120		
	11.37%	=	7.70%	+	((	3.71%					)	0.9827			+	2.02%			)	0.012		
	11.37%	=	7.70%	+		3.65%									+	0.02%						

Analysis of Public Offerings of Gas Distribution Company Common Stock

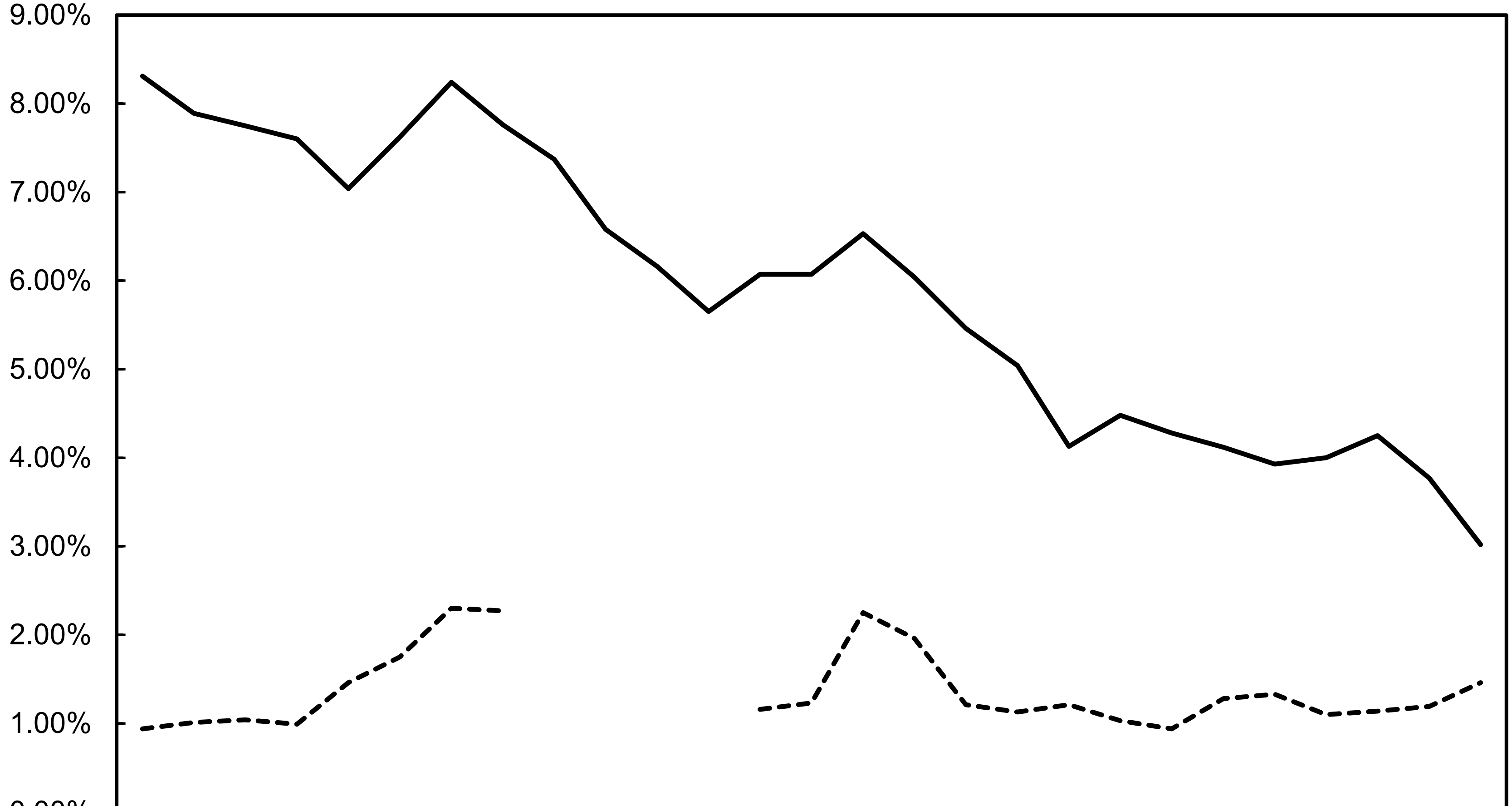
Company	Date of Offering	No. of shares offered	Dollar amount of offering	Price to public	Underwriters' discount and commission	Gross Proceeds per share	Estimated company issuance expenses	Net proceeds per share	Percent of offering price: Underwriters' discount and commission	Percent of offering price: Estimated company issuance expenses	Percent of offering price: Total Issuance and selling expense
Piedmont Natural Gas Company, Inc.	01/29/13	4,000,000	$ 128,000,000	$32.00	1.120	$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	1.103	$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	0.930	$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	0.990	$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	0.990	$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	0.871	$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	1.010	$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	1.490	$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	1.012	$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	0.770	$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	0.895	$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	1.110	$21.140	$0.058	$21.082	5.0%	0.3%	5.3%
Average									3.7%	0.2%	3.9%

Source of Information: SNL Financial and SEC filings

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2016-2020
and the Twelve Months Ended March 2021

Years	Aa Rated	A Rated	Baa Rated	Average
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
Five-Year Average	3.61%	3.79%	4.26%	3.89%
Months				
Apr-20	2.93%	3.19%	3.82%	3.31%
May-20	2.89%	3.14%	3.63%	3.22%
Jun-20	2.80%	3.07%	3.44%	3.10%
Jul-20	2.46%	2.74%	3.09%	2.77%
Aug-20	2.49%	2.73%	3.06%	2.76%
Sep-20	2.62%	2.84%	3.17%	2.88%
Oct-20	2.72%	2.95%	3.27%	2.98%
Nov-20	2.63%	2.85%	3.17%	2.89%
Dec-20	2.57%	2.77%	3.05%	2.80%
Jan-21	2.73%	2.91%	3.18%	2.94%
Feb-21	2.93%	3.09%	3.37%	3.13%
Mar-21	3.27%	3.44%	3.72%	3.48%
Twelve-Month Average	2.75%	2.98%	3.33%	3.02%
Six-Month Average	2.81%	3.00%	3.29%	3.04%
Three-Month Average	2.98%	3.15%	3.42%	3.18%

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
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	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.77	3.02
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	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.33	1.10	1.14	1.19	1.46

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%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%		
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%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
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%
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%
Average:	12-months		1.37%
	6-months		1.16%
	3-months		1.08%

Common Equity Risk Premiums
Years 1926-2020

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.06%	5.43%	6.63%	2.85%
Average Across All Interest Rates	12.16%	6.49%	5.67%	4.95%
High Interest Rates	12.26%	7.57%	4.69%	7.09%

Source of Information: 2021 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

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%
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%
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%

Yields for Treasury Constant Maturities
Yearly for 2016-2020
and the Twelve Months Ended March 2021

Years	**1-Year**	**2-Year**	**3-Year**	**5-Year**	**7-Year**	**10-Year**	**20-Year**	**30-Year**
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
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%
Five-Year Average	1.31%	1.43%	1.52%	1.70%	1.89%	2.02%	2.33%	2.55%
Months								
Apr-20	0.18%	0.22%	0.28%	0.39%	0.55%	0.66%	1.06%	1.27%
May-20	0.16%	0.17%	0.22%	0.34%	0.53%	0.67%	1.12%	1.38%
Jun-20	0.18%	0.19%	0.22%	0.34%	0.55%	0.73%	1.27%	1.49%
Jul-20	0.15%	0.15%	0.17%	0.28%	0.46%	0.62%	1.09%	1.31%
Aug-20	0.13%	0.14%	0.16%	0.27%	0.46%	0.65%	1.14%	1.36%
Sep-20	0.13%	0.13%	0.16%	0.27%	0.46%	0.68%	1.21%	1.42%
Oct-20	0.13%	0.15%	0.19%	0.34%	0.55%	0.79%	1.34%	1.57%
Nov-20	0.12%	0.17%	0.22%	0.39%	0.63%	0.87%	1.40%	1.62%
Dec-20	0.10%	0.14%	0.19%	0.39%	0.66%	0.93%	1.47%	1.67%
Jan-21	0.10%	0.13%	0.20%	0.45%	0.77%	1.08%	1.63%	1.82%
Feb-21	0.07%	0.12%	0.21%	0.54%	0.91%	1.26%	1.88%	2.04%
Mar-21	0.08%	0.15%	0.32%	0.82%	1.27%	1.61%	2.24%	2.34%
Twelve-Month Average	0.13%	0.16%	0.21%	0.40%	0.65%	0.88%	1.40%	1.61%
Six-Month Average	0.10%	0.14%	0.22%	0.49%	0.80%	1.09%	1.66%	1.84%
Three-Month Average	0.08%	0.13%	0.24%	0.60%	0.98%	1.32%	1.92%	2.07%

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 December 1, 2020 and April 1, 2021

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2021	Second	0.1%	0.2%	0.8%	1.6%	2.4%	3.0%	3.9%
2021	Third	0.2%	0.3%	0.9%	1.7%	2.5%	3.1%	4.0%
2021	Fourth	0.2%	0.3%	1.0%	1.8%	2.5%	3.2%	4.1%
2022	First	0.2%	0.4%	1.1%	1.9%	2.6%	3.3%	4.2%
2022	Second	0.3%	0.4%	1.1%	2.0%	2.7%	3.4%	4.3%
2022	Third	0.3%	0.5%	1.2%	2.0%	2.7%	3.4%	4.4%
Long-range CONSENSUS								
2022		0.3%	0.4%	0.8%	1.3%	2.1%	2.8%	3.9%
2023		0.6%	0.8%	1.2%	1.7%	2.4%	3.2%	4.3%
2024		1.0%	1.2%	1.6%	2.0%	2.8%	3.6%	4.7%
2025		1.4%	1.6%	2.0%	2.4%	3.1%	4.0%	5.0%
2026		1.8%	1.9%	2.3%	2.6%	3.4%	4.2%	5.2%
Averages:								
2022-2026		1.0%	1.2%	1.5%	2.0%	2.8%	3.6%	4.6%
2027-2031		2.1%	2.3%	2.5%	2.8%	3.6%	4.5%	5.4%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
2-Apr-21	1.8%	+	6.78%	=	8.58%

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.47%	(	1.0630	)	+	12.60%	=	14.16%

Summary

Value Line			8.58%
S&P 500			14.16%
Average			11.37%
Risk-free Rate of Return (Rf)			2.75%
Forecast Market Premium			8.62%
Historical Market Premium			
Low Interest Rates	(Rm)	(Rf)	
1926-2020 Arith. mean	12.06%	2.85%	9.21%
Average - Forecast/Historical			8.92%

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 2, 3, 4 & 5; Safety Rank of 1, 2 & 3; Financial Strength of B++, A & A+;
Price Stability of 70 to 95; Betas of .80 to 1.05; and Technical Rank of 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AAON Inc	Machinery	3	3	B+	70	0.85	3
AbbVie Inc	Drug	2	3	A	75	0.95	3
Agilent Technologies	Precision Instrument	2	2	A	95	0.90	3
Alamo Group	Machinery	3	3	B+	70	1.05	4
Altria Group Inc	Tobacco	2	3	B++	85	0.90	5
AMERCO	Trucking	3	2	B++	90	0.95	4
AmerisourceBergen Corp	Med Supp Non-Invasive	2	2	A	70	0.90	3
AO Smith Corp	Machinery	3	2	B++	95	0.85	3
Archer Daniels Midland Company	Food Processing	3	2	A+	90	1.00	4
Assurant Inc	Financial Svcs. (Div.)	3	2	A	85	0.90	3
Badger Meter Inc	Precision Instrument	3	3	B++	70	1.05	3
BancorpSouth Bank	Bank	3	3	B++	75	1.05	3
Brady Corp	Diversified Co.	4	3	B++	80	1.00	4
Broadridge Fin'l	Information Services	2	2	B++	95	0.85	3
BWX Technologies	Power	3	3	B++	75	0.90	3
Caseys General Stores Inc	Retail/Wholesale Food	3	3	B+	80	0.90	3
Cboe Global Markets	Brokers & Exchanges	3	2	A	85	0.90	4
CDW Corp.	IT Services	3	3	B+	85	1.05	3
CME Group Inc	Brokers & Exchanges	4	2	A	90	0.95	3
Commerce Bancshares Inc	Bank (Midwest)	3	1	A	90	0.90	3
Cooper Companies Inc	Med Supp Non-Invasive	2	2	A	90	0.95	3
CSX Corporation	Railroad	3	3	B++	80	1.05	3
Dolby Laboratories Inc	Entertainment Tech	3	2	A	90	0.95	3
EchoStar Corporation	Cable TV	4	3	B+	70	0.90	4
Encore Wire	Electronics	3	3	A	70	1.00	3
Ennis Inc.	Office Equip/Supplies	4	3	B++	85	0.80	4
ESCO Technologies Inc	Diversified Co.	3	3	B+	90	1.00	4
Exponent Inc.	Information Services	3	3	B+	90	0.90	4
FactSet Research Systems Inc	Information Services	3	2	A+	85	1.00	3
Fastenal Co	Retail Building Supply	2	2	A+	80	0.90	3
Fidelity Nat'l Info.	Financial Svcs. (Div.)	2	2	B++	95	1.00	4
FirstCash Inc.	Financial Svcs. (Div.)	4	3	B++	80	0.85	5
Fiserv Inc	IT Services	2	2	B++	95	1.00	3
FleetCor Technologies Inc	Financial Svcs. (Div.)	4	3	B++	70	1.05	3
Forward Air Corp	Trucking	3	3	B++	85	1.00	4
Franklin Electric Co Inc	Electrical Equipment	3	3	A	75	0.95	3
GATX Corp	Railroad	2	3	B+	80	0.95	3
Gentex Corp	Auto Parts	3	3	B++	85	0.95	4
Gorman Rupp Co	Heavy Truck & Equip	5	3	A	75	1.00	3
Graco Inc	Machinery	2	2	A	95	1.05	3
Graphic Packaging	Packaging & Container	3	3	B+	80	1.00	3
Hanover Insurance Group Inc	Insurance (Prop/Cas.)	3	2	B++	95	0.95	3
Hill Rom Holdings	Med Supp Non-Invasive	3	3	B++	70	1.05	4
Huntington Ingalls Industries Inc	Aerospace/Defense	3	3	B++	70	1.05	5
IDEX Corporation	Machinery	3	2	B++	95	1.05	3
Ingredion Incorporated	Food Processing	3	2	B++	90	0.90	4
Innospec Inc	Chemical (Specialty)	3	3	B++	75	1.00	3
International Business Machines Corp	Computers/Peripherals	3	1	A	90	1.05	4
Intuit Inc	Computer Software	3	2	A+	85	1.00	3
Iron Mountain Inc	Industrial Services	2	3	B+	85	0.90	3
J and J Snack Foods Corp	Food Processing	4	1	A+	85	0.90	3
J B Hunt Transport Services Inc	Trucking	3	1	A+	90	0.95	3
Jack Henry and Associates Inc	IT Services	2	1	A+	95	0.85	4
Juniper Networks Inc	Telecom. Equipment	2	2	A	80	1.00	3
Kadant Inc	Diversified Co.	2	3	B+	75	1.05	4
Lennox International Inc	Machinery	3	3	B+	90	1.00	3
Lincoln Electric Holdings Inc	Machinery	3	2	A	85	1.05	3
Lindsay Corporation	Machinery	3	3	B++	75	0.85	4
MAXIMUS Inc	Industrial Services	3	1	A+	95	0.80	3
Mercury General Corp	Insurance (Prop/Cas.)	3	3	B++	75	0.90	3
MSA Safety	Machinery	3	3	B+	80	1.00	3
MSC Industrial Direct Co Inc	Machinery	3	2	A	75	0.95	3
New York Times Co	Publishing	3	3	B+	75	0.80	3
O Reilly Automotive Inc	Retail Automotive	3	3	B++	75	0.95	3
Old National Bancorp	Bank (Midwest)	2	3	B+	80	1.00	3
Omnicom Group Inc	Advertising	2	3	B+	85	1.00	4
Packaging Corp	Packaging & Container	2	2	A	80	1.00	3
Park National Corp	Bank (Midwest)	2	3	B++	80	0.85	3
Philip Morris International Inc	Tobacco	3	3	B++	80	0.95	3
Plexus Corp	Electronics	3	3	B+	80	1.05	3
Post Holdings Inc	Food Processing	3	3	B++	85	0.95	3
RLI Corp	Insurance (Prop/Cas.)	3	2	B++	90	0.80	4
S&P Global	Information Services	3	2	A	90	1.00	3
Scholastic Corporation	Publishing	5	3	B++	75	1.00	5
Selective Insurance Group Inc	Insurance (Prop/Cas.)	2	3	B+	90	0.85	3
Sensient Technologies Corp	Food Processing	3	2	B++	95	0.90	3
Service Corp International Inc	Industrial Services	3	3	B+	90	0.95	3
Sherwin Williams	Retail Building Supply	3	1	A+	90	0.90	3
Sonoco Products	Packaging & Container	3	2	A	95	1.00	3
Standard Motor Products Inc	Auto Parts	3	3	B++	75	0.80	5
Stepan Company	Chemical (Specialty)	2	3	B++	70	0.80	3
T Rowe Price Group Inc	Asset Management	3	1	A+	85	1.05	3
Tetra Tech	Environmental	2	3	B++	85	0.90	3
Toro Co	Machinery	3	2	B++	90	1.00	3
Tractor Supply Co	Retail Building Supply	3	2	A+	75	0.80	3
Trimas Corporation	Diversified Co.	2	3	B+	80	0.90	3
UniFirst Corp	Industrial Services	3	2	A	90	1.00	4
Vail Resorts	Hotel/Gaming	2	3	B+	80	0.95	3
VeriSign Inc	Internet	3	3	B++	95	0.90	3
Viavi Solutions	Electronics	3	3	B+	70	0.95	3
Walgreens Boots	Retail Store	3	3	A	80	0.85	3
Washington Federal Inc	Thrift	4	3	B+	75	1.05	5
Watsco Inc	Retail Building Supply	2	1	A+	95	0.85	3
Western Union Company	Financial Svcs. (Div.)	2	3	B+	95	0.80	3
Wiley John and Sons Inc (Class A)	Publishing	2	3	B+	80	0.90	3
WR Berkley Corp	Insurance (Prop/Cas.)	3	1	A	90	1.05	3
Xylem Inc	Machinery	2	2	B++	85	1.05	3
Zoetis Inc	Drug	4	2	B++	90	1.00	3
Average		3	2	B++	83	0.95	3
Gas Group	Average	3	2	A	86	0.88	5

Source of Information: Value Line Investment Survey for Windows, March 2021

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2016-2020 and
Projected 3-5 Year Returns

Company	2016	2017	2018	2019	2020	Average	Projected 2024-26
AAON Inc	25.9%	21.1%	17.2%	18.5%	21.5%	20.8%	24.5%
AbbVie Inc	NMF	NMF	NMF	NMF	NMF	NMF	NMF
Agilent Technologies	15.4%	15.9%	19.9%	20.8%	21.0%	18.6%	19.0%
Alamo Group	10.3%	12.1%	14.5%	11.0%	10.0%	11.6%	13.0%
Altria Group Inc	46.4%	42.5%	51.0%	NMF	NMF	46.6%	NMF
AMERCO	15.2%	9.0%	10.0%	7.0%	13.0%	10.8%	7.5%
AmerisourceBergen Corp	60.4%	63.2%	48.8%	52.2%	NMF	56.2%	70.0%
AO Smith Corp	21.5%	22.9%	26.2%	22.2%	17.0%	22.0%	20.5%
Archer Daniels Midland Company	7.4%	6.6%	9.5%	7.2%	8.0%	7.7%	9.5%
Assurant Inc	13.8%	12.2%	4.9%	6.8%	6.0%	8.7%	7.0%
Badger Meter Inc	12.6%	12.5%	14.8%	14.3%	13.6%	13.6%	18.5%
BancorpSouth Bank	7.7%	8.9%	10.1%	8.7%	7.7%	8.6%	8.0%
Brady Corp	13.3%	13.7%	14.9%	15.4%	13.0%	14.1%	14.0%
Broadridge Fin'l	29.4%	32.6%	46.1%	49.1%	43.7%	40.2%	35.0%
BWX Technologies	122.0%	71.1%	96.3%	60.4%	44.8%	78.9%	38.0%
Caseys General Stores Inc	14.9%	11.2%	14.5%	16.1%	16.0%	14.5%	15.0%
Cboe Global Markets	58.4%	12.9%	13.1%	11.1%	14.0%	21.9%	12.5%
CDW Corp.	40.6%	53.2%	65.9%	76.7%	57.5%	58.8%	61.0%
CME Group Inc	7.5%	18.1%	7.6%	8.1%	8.0%	9.9%	9.0%
Commerce Bancshares Inc	11.0%	11.8%	14.8%	13.4%	10.4%	12.3%	11.0%
Cooper Companies Inc	10.1%	11.7%	10.3%	12.9%	6.2%	10.2%	12.5%
CSX Corporation	14.7%	14.0%	26.3%	28.1%	21.0%	20.8%	33.5%
Dolby Laboratories Inc	9.4%	9.4%	12.6%	11.1%	9.5%	10.4%	13.5%
EchoStar Corporation	4.6%	2.2%	0.9%	NMF	NMF	2.6%	3.0%
Encore Wire	5.9%	10.5%	10.8%	7.5%	9.1%	8.8%	8.0%
Ennis Inc.	10.5%	12.5%	12.9%	13.0%	9.0%	11.6%	13.0%
ESCO Technologies Inc	8.3%	8.6%	9.0%	9.9%	7.5%	8.7%	9.5%
Exponent Inc.	17.4%	14.3%	23.0%	23.5%	22.0%	20.0%	29.0%
FactSet Research Systems Inc	49.7%	46.1%	50.8%	52.5%	41.6%	48.1%	42.5%
Fastenal Co	25.8%	27.6%	32.7%	29.7%	31.4%	29.4%	41.0%
Fidelity Nat'l Info.	5.8%	5.0%	8.3%	0.6%	0.5%	4.0%	7.0%
FirstCash Inc.	4.1%	7.9%	11.6%	12.2%	8.5%	8.9%	12.5%
Fiserv Inc	39.1%	40.4%	55.9%	8.4%	8.5%	30.5%	10.5%
FleetCor Technologies Inc	21.4%	20.1%	24.3%	24.1%	30.0%	24.0%	28.5%
Forward Air Corp	13.0%	13.4%	16.6%	15.1%	9.0%	13.4%	13.5%
Franklin Electric Co Inc	12.8%	12.5%	14.6%	12.3%	12.1%	12.9%	14.0%
GATX Corp	17.6%	10.4%	11.2%	10.9%	10.5%	12.1%	8.0%
Gentex Corp	18.2%	18.0%	23.5%	21.9%	17.9%	19.9%	27.0%
Gorman Rupp Co	8.2%	9.8%	15.3%	11.0%	9.0%	10.7%	11.0%
Graco Inc	35.2%	34.9%	43.6%	31.7%	26.0%	34.3%	22.0%
Graphic Packaging	21.6%	23.2%	11.9%	13.2%	11.7%	16.3%	19.5%
Hanover Insurance Group Inc	6.5%	6.8%	9.9%	11.4%	11.1%	9.1%	10.0%
Hill Rom Holdings	18.3%	19.0%	19.9%	21.9%	21.5%	20.1%	15.5%
Huntington Ingalls Industries Inc	34.7%	27.2%	55.1%	36.5%	31.6%	37.0%	17.0%
IDEX Corporation	18.5%	17.9%	21.1%	19.6%	15.0%	18.4%	21.5%
Ingredion Incorporated	20.5%	19.5%	20.8%	16.4%	13.5%	18.1%	17.5%
Innospec Inc	12.4%	7.8%	10.3%	12.2%	3.0%	9.1%	13.0%
International Business Machines Corp	65.1%	72.8%	75.4%	54.9%	37.7%	61.2%	25.0%
Intuit Inc	86.5%	84.9%	62.2%	47.5%	40.6%	64.3%	26.5%
Iron Mountain Inc	13.7%	13.3%	16.8%	20.0%	29.0%	18.6%	41.5%
J and J Snack Foods Corp	11.9%	11.6%	11.1%	11.4%	2.3%	9.7%	11.5%
J B Hunt Transport Services Inc	30.6%	22.6%	29.7%	24.9%	19.5%	25.5%	16.5%
Jack Henry and Associates Inc	25.0%	23.8%	22.3%	19.0%	19.1%	21.8%	24.0%
Juniper Networks Inc	12.9%	17.3%	13.8%	13.0%	11.4%	13.7%	31.5%
Kadant Inc	12.2%	15.3%	16.3%	14.4%	10.5%	13.7%	11.5%
Lennox International Inc	NMF	NMF	NMF	NMF	NMF	NMF	NMF
Lincoln Electric Holdings Inc	31.6%	27.1%	35.7%	35.8%	27.5%	31.5%	27.0%
Lindsay Corporation	11.4%	8.6%	11.4%	5.8%	12.9%	10.0%	12.5%
MAXIMUS Inc	23.8%	22.3%	20.4%	19.3%	17.3%	20.6%	19.5%
Mercury General Corp	5.4%	5.1%	6.2%	8.0%	15.1%	8.0%	14.0%
MSA Safety	18.8%	23.6%	27.7%	25.9%	21.0%	23.4%	26.5%
MSC Industrial Direct Co Inc	21.1%	18.7%	20.8%	20.0%	20.0%	20.1%	22.0%
New York Times Co	3.7%	0.5%	12.1%	11.9%	12.0%	8.0%	20.5%
O Reilly Automotive Inc	63.8%	NMF	NMF	NMF	NMF	63.8%	NMF
Old National Bancorp	7.4%	6.0%	7.1%	8.4%	7.6%	7.3%	8.5%
Omnicom Group Inc	53.1%	46.0%	52.1%	46.9%	31.5%	45.9%	34.5%
Packaging Corp	25.5%	25.0%	27.6%	22.7%	16.9%	23.5%	18.5%
Park National Corp	11.6%	11.3%	13.3%	10.6%	12.3%	11.8%	10.5%
Philip Morris International Inc	NMF	NMF	NMF	NMF	NMF	NMF	NMF
Plexus Corp	9.9%	10.9%	11.9%	12.3%	12.5%	11.5%	12.5%
Post Holdings Inc	7.2%	7.6%	10.1%	12.7%	6.7%	8.9%	11.5%
RLI Corp	11.3%	8.7%	11.4%	11.8%	10.3%	10.7%	11.0%
S&P Global	NMF	NMF	NMF	NMF	NMF	NMF	NMF
Scholastic Corporation	4.7%	5.0%	3.9%	2.6%	NMF	4.1%	5.5%
Selective Insurance Group Inc	10.6%	10.8%	12.2%	12.0%	9.1%	10.9%	11.0%
Sensient Technologies Corp	17.2%	17.7%	18.3%	14.2%	12.0%	15.9%	14.0%
Service Corp International Inc	16.2%	21.2%	20.4%	19.4%	22.0%	19.8%	13.0%
Sherwin Williams	60.3%	38.7%	47.1%	47.9%	62.6%	51.3%	39.0%
Sonoco Products	18.1%	16.5%	19.4%	19.8%	18.2%	18.4%	16.0%
Standard Motor Products Inc	14.2%	13.5%	12.2%	13.7%	14.6%	13.6%	13.5%
Stepan Company	13.6%	12.4%	14.4%	11.6%	12.5%	12.9%	13.0%
T Rowe Price Group Inc	24.6%	26.4%	29.0%	30.0%	30.5%	28.1%	27.0%
Tetra Tech	12.8%	13.3%	15.4%	17.8%	17.0%	15.3%	22.0%
Toro Co	42.0%	43.4%	40.7%	31.9%	29.6%	37.5%	35.5%
Tractor Supply Co	30.1%	30.1%	34.1%	36.0%	41.9%	34.4%	38.0%
Trimas Corporation	11.6%	11.8%	13.1%	9.5%	10.0%	11.2%	14.0%
UniFirst Corp	8.5%	7.4%	10.2%	10.0%	7.8%	8.8%	7.5%
Vail Resorts	17.1%	13.4%	23.9%	20.1%	7.5%	16.4%	26.0%
VeriSign Inc	-	-	-	-	-	-	NMF
Viavi Solutions	13.1%	11.8%	14.8%	21.5%	24.1%	17.1%	14.5%
Walgreens Boots	16.8%	20.0%	23.0%	23.5%	19.8%	20.6%	22.0%
Washington Federal Inc	8.3%	8.7%	10.2%	10.3%	8.6%	9.2%	9.5%
Watsco Inc	18.2%	15.3%	18.0%	17.1%	18.1%	17.3%	20.0%
Western Union Company	91.4%	NMF	NMF	NMF	NMF	91.4%	NMF
Wiley John and Sons Inc (Class A)	17.4%	16.6%	14.2%	NMF	12.5%	15.2%	13.0%
WR Berkley Corp	8.9%	6.1%	9.5%	9.6%	6.5%	8.1%	12.5%
Xylem Inc	11.9%	17.1%	18.9%	18.5%	11.0%	15.5%	16.0%
Zoetis Inc	65.4%	66.8%	69.8%	64.8%	53.0%	64.0%	46.5%
Average						21.9%	19.5%
Median						15.9%	14.8%
Average (excluding companies with values >20%)						12.0%	12.3%

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 ADJUSTMENT OF ITS RATES AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2021-00185**

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

Filed: May 28, 2021

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"), 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 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 Aqua 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 Aqua, 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 the Company's Aqua North Carolina, Inc. subsidiary.

In addition to my corporate experience, I was elected as Mayor of the Borough of Woodbury Heights in November of 2018 and was sworn in on January 5, 2019. The Borough of Woodbury Heights is one of 565 municipalities in New Jersey and has a population of approximately 3,000 residents. I have been an elected official since 2010 and the Borough owns and operates both its water and wastewater utilities, thus giving me a unique perspective to the considerations municipalities face when it comes to providing utility service to its residents.

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 the Company'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. No, I have not. As stated earlier in my testimony, I have testified before the Pennsylvania Public Utility Commission, New Jersey Board of Public Utilities, and North Carolina Utilities Commission.

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) 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 the following filing requirements:

807 KAR 5:001 Section 16(6)(f)	Reconciliation of the rate base and capital used to determine its revenue 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)(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. Does Essential utilize a budgeting process for the utilities within its family of companies?

A. Yes. Essential, in coordination with all of its subsidiaries, annually prepares the Operating Budget for the most current year and then prepares a multi-year Strategic Business Plan.

Q. Could you provide an overview of the process?

A. Yes. At Essential, 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 their 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. Is the use of Essential's budgeting process one of the reasons that Delta elected to utilize 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 2020, as Delta's revenues continue to be quite flat. The Company's analysis of 10 years of billing determinants, volumes, and weather is supported by Mr. Seelye. The conclusions drawn from that analysis support utilizing the actual billing determinants from 2020 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 August 31, 2021, are constructed utilizing 7 months of actual results through March 2021 and 5 months of projections. The base year is adjusted for specific line items for payroll, rate case expense, advertising, lobbying, medical, dental, 401(k), and pension, 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.

Capitalization and Rate Base

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)(f). This schedule reconciles capitalization versus rate base. As shown in Tab 13, Delta's pro forma rate base is $136,735,989, which reconciles to capitalization of $138,921,565 due to the 13-month average short-term debt.

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 48.24 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 subsidiaries financial operating needs considering their costs and investment activities.

<u>Cost of Capital Summary</u>

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 August 31, 2021, Delta's 13-month average capitalization is 45.64% equity, 33.68% long term debt, and 20.68% short term debt. For the purposes of the forecasted test period, the Company has updated its 13-month average projection through December 31, 2022, which is the first full year rates would be in effect from this case and arrived at a proposed capital structure of 51.76% equity, 48.24% long term debt, and zero percent short term debt.

<u>Federal and State Income Tax Summary</u>

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.

Q. Do Delta's tax rates reflect all recent tax reform at the federal and state level?

A. Yes, Delta's rates reflect both federal and state tax reform. Delta considered the reduced income tax expense and excess deferred tax amortization in calculating the revenue requirement in this proceeding. Delta also updated the gross revenue conversion factors for the lower tax rates.

Q. Please summarize the federal tax reform that was considered by Delta in developing the revenue requirement.

A. The Tax Cuts and Jobs Act ("TCJA") was enacted on December 22, 2017. The TCJA reduces the maximum federal corporate income tax rate from 35% to 21% effective January 1, 2018. The Commission investigated the impact of the TCJA on Delta in Case No. 2018-00040. The Commission's order established the appropriate surcredit to ratepayers as a result of the revised annual revenue reduction as a result of the TCJA. The Commission's December 21, 2018 Order stated that "the tax reduction surcredits approved by this Order will continue in effect until new base rates are established in Delta's next general rate case." Delta has proposed eliminating the TCJA surcredit in this proceeding, consistent with the Commission's Order.

Q. Please summarize the state tax reform that was considered by Delta in developing the revenue requirement.

A. In 2018, the Kentucky General Assembly enacted two bills that made substantial changes to Kentucky's tax code. House Bill ("H.B.") 366 (which was adopted in its entirety in H.B. 487) and H.B. 487 make a number of changes to Kentucky's income and sales and use taxes, as well as reforms streamlining compliance with the administration of Kentucky's tax statutes. H.B. 487 reduces the applicable corporate and individual income tax rates, makes certain changes to the corporate and individual income tax bases, and adopts single sales factor apportionment for multistate companies. Prior to the passage of H.B. 487, Delta paid a state corporate income tax rate of 6%. For taxable years beginning on or after January 1, 2018, Delta has paid a 5% tax rate. Delta has reflected the 5% rate in its calculation of its forecasted state income taxes.

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:

- Corporate Governance
- Human Resources

- Treasury
- Legal
- Financial and Administrative
- Safety
- Environmental, Social, & Corporate Governance
- Risk Management
- Audit
- Regulatory and Government Affairs
- Information Technology

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

A. Yes. Delta has a utility services agreement with 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.

Employee Compensation

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. As shown in Tab 30 to the application, Delta employs approximately 162 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. 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. At Essential and its subsidiaries including Delta, we benchmark the reasonableness to market conditions on an all-in, total compensation basis. The primary component of an employee's pay is their 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 employee 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: financial performance (50%), safety (25%), customer satisfaction (10%), environmental stewardship (5%), and individual goals (10%). 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. Does Essential perform reviews of its affiliates' compensation expense to ensure it is reasonable?

A. Yes. Within Essential 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 2021, 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 3,000 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. As discussed in Mr. Brown's testimony, the pension plan was frozen to new hires thirteen years ago. 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 will be afforded the option to participate in the 401K plan.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

State of New Jersey)
) SS:
COUNTY OF GLOUCESTER)

The undersigned, **William C. Packer**, being duly sworn, deposes and says he is Vice President, Rates and Regulatory Accounting 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 C. PACKER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May, 2021.

_______________________(SEAL)
Notary Public

My Commission Expires:

SHANNON ELTON
NOTARY PUBLIC OF NEW JERSEY
My Commission Expires June 17, 2026

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DELTA	**)**	
NATURAL GAS COMPANY, INC. FOR AN	**)**	**CASE NO. 2021-00185**
ADJUSTMENT OF GAS RATES	**)**	

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: May 28, 2021

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Exhibit WSS-7 – Depreciation Study
Exhibit WSS-8 – Summary of Current and Proposed Depreciation Rates

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. 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 December 31, 2022; 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; to sponsor Delta's proposed rate schedules for natural gas sales and transportation service; and to sponsor Delta's depreciation study supporting the proposed depreciation rates and the pro-forma adjustment to depreciation expenses.

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 December 31, 2022. 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 2010 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 ten-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 ten-year period, after adjusting for normal temperatures. This analysis supports the use of actual billing data for the 12 months ended December 31, 2020, 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 high rate of return for Interruptible Service supports not increasing this rate. The cost of service study supports a higher percentage increase for Residential Service than for Small Non-Residential Service, Large Non-Residential Service, and for Farm Tap Service. For competitive reasons, Delta is proposing a lower percentage increase for Off-System Transportation Service. The cost of service study supported a relatively higher increase for the Special Contracts.

- **Proposed Rates.** For each rate schedule, Delta is effectively proposing to increase the Customer Charges and the Delivery Charges by the same percentage.

- **Pipe Replacement Program**. Delta is proposing to modify its Pipe Replacement Program to operate on a forward cost basis. The Commission has approved forward-looking Pipe Replacement Programs for LG&E, Columbia Gas of Kentucky and Atmos Energy Corporation. Using a forward-looking Pipeline Replacement Program aligns with the use of a forecasted test year in Delta's current rate case proceeding.

- **Depreciation Study.** I performed 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 and 2010-00116.

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
• Summary of Latest Depreciation Study	Section 16(7)(s)	Tab 49
• 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, (VII) Pipe Replacement Program, and (VIII) Depreciation Study.

II. QUALIFICATIONS

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From 2014 through 2015 I completed an additional 12 hours of Electrical Engineering coursework at the University of Louisville's Speed School of Engineering (courses in computer design, microcontroller programming, digital signal processing, and computer communications). In addition, from 2012 through 2015, I was an instructor at Louisville's Walden School and a private tutor and instructor in advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.

Concerning my professional background, from May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed or supervised the preparation of cost of service and rate studies for over 150 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 40 years of experience in the utility industry. A more detailed description of my qualifications is included in Exhibit WSS-1.

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

A. Yes. I have testified in over 75 regulatory and court proceedings in 13 different jurisdictions. I have testified before the Kentucky Public Service Commission on behalf of Delta, as well as on behalf of other utilities, on numerous occasions. A listing of my testimony in other proceedings is included in Exhibit WSS-1.

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 cost of service and rate studies for over 150 utilities throughout North America. I have testified on numerous occasions regarding the rates proposed by gas, electric, and water utilities, including Delta. I have also testified on numerous occasions regarding depreciation studies. I sponsored the last three depreciation studies performed for Delta.

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 December 31, 2022.

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 service rates 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 150 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. 2010-00116?

A. Yes. The cost of service study was accepted by the Commission in Case No. 2010-00116, which was a fully litigated case. In 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?

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

A. Yes. 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, and a new class was included in the cost of service study for Farm Tap customers. The addition of the Farm Tap class relates to the transfer of ownership of Peoples Gas KY LLC ("Peoples KY") to Delta which was approved by the Commission in its Order in Case No. 2020-00346. In its Order in that proceeding, the Commission found that an investigation into the reasonableness of Delta's farm-tap rates is necessary.[2] Prior to the transfer of Peoples KY to Delta, Peoples KY served almost 3,000 farm tap customers, and Delta served approximately 350 farm tap customers (customers which were not served through a distribution or transmission delivery system owned by Delta). The former Peoples KY and Delta farm tap customers receive similar service, which does not involve the use of Delta's transmission and distribution systems to deliver gas to these customers. Therefore, to evaluate the reasonableness of the rates for these customers, the former Peoples KY farm tap customers and Delta's similarly served farm tap customers are grouped together as Farm Tap customers in the cost of service study.

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

[2] Case No. 2020-00346, Order (Ky. P. S. C. Feb. 22, 2021), at 9.

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 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 WSS-2 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 WSS-2, 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 WSS-2. 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 WSS-2. 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 WSS-3. The costs shown in the column labeled "Total System" in Exhibit WSS-3 were carried forward from the functionally assigned and classified costs shown in Exhibit WSS-2. The column labeled "Ref" in Exhibit WSS-3 provides a reference to the results included in Exhibit WSS-2.

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 WSS-4.

- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the basis of design-day demands determined at Delta's -3 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 -3 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 year-end 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 year-end 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:

$\boldsymbol{y}$ is the unit cost of the pipe,

$\boldsymbol{x}$ is the size of the pipe, and

$\boldsymbol{a}, \boldsymbol{b}$ 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 111 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 ***w*** is the weighting factor (in this case the feet of pipe) for each size of pipe, and ***y*** is the observed value and $\hat{y}$ is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Exhibit WSS-5 is the zero-intercept analysis used in this study. The zero-intercept unit cost of $4.14 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 0.9457. 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	1.14%
Farm Tap Service	5.57%
Small Non-Residential Service	4.92%
Large Non-Residential Service	4.84%
Interruptible Service	54.76%
Special Contracts	-15.81%
Off-System Transportation Service	-3.89%
Total System	2.42%

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, Off-System Transportation and the Special Contracts are significantly below the overall rate of return. The rates of return for Farm Tap Service, Small Non-Residential Service, and Large Non-Residential Service are somewhat above the overall rate of return, and the rate of return for Interruptible Service is 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

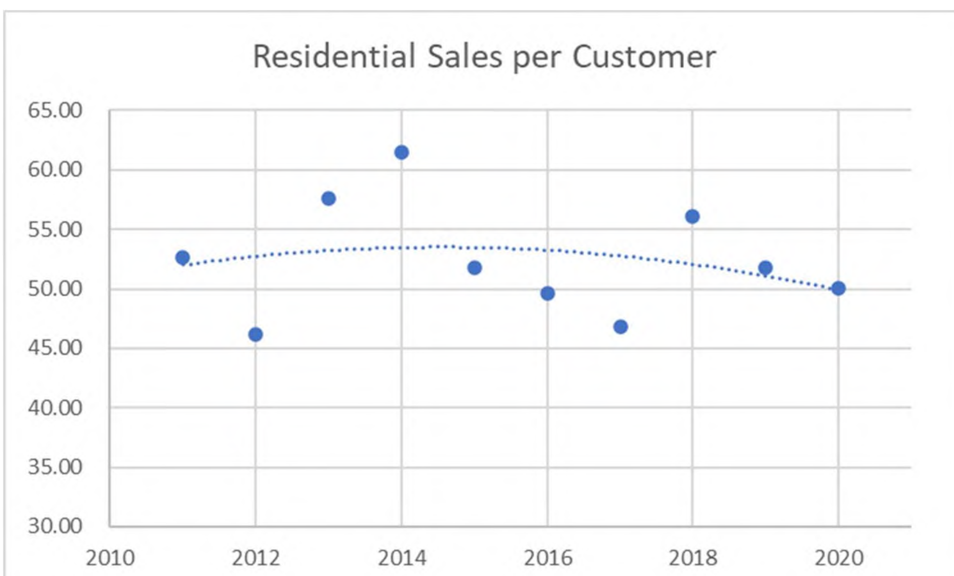
Q. Please summarize the development of the forecasted billing determinants for the test year.

A. In developing billing determinants for the forecasted test year, an analysis was performed for the period 2011 through 2020 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.

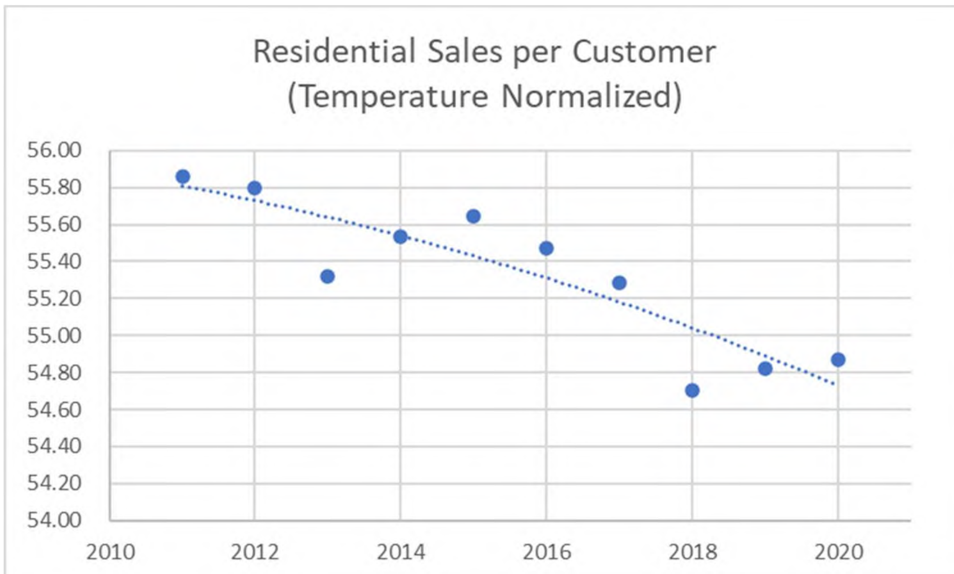
A. In 2011, Delta served approximately 30,200 residential customers, and in 2020, Delta served approximately 30,500 customers. Thus, there has been essentially no growth in the number residential customers over the ten-year period. Over this period, residential sales per customer have also remained relatively 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



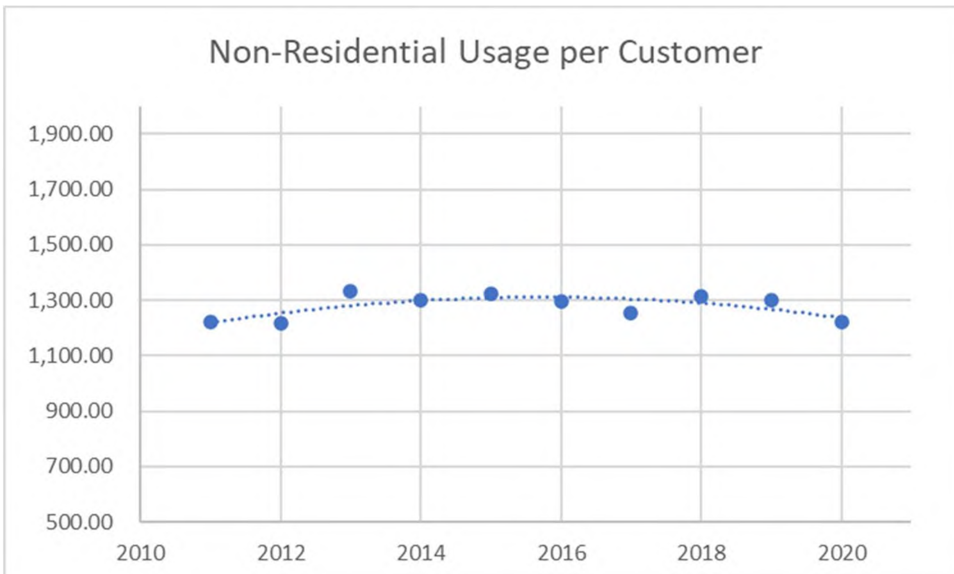
As can be seen in this graph, even though there is downward trend in the data, the decrease in temperature normalized usage per customer appears to have leveled off.

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

A. In 2011, Delta served approximately 4,980 non-residential customers, and in 2020, Delta served approximately 5,073 non-residential customers. Therefore, there has been essentially no growth in the number non-residential customers over the ten-year period. There has also been little or no discernable change in usage per customer.

The average non-residential usage per customer was 1,220.19 Mcf per customer in 2011 and was 1,220.09 Mcf per customer in 2020. Non-residential customers are less temperature sensitive than residential customers. The following graph (GRAPH 3) shows non-residential usage per customer over the ten-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. The amount of gas transported through Delta's transmission system is extremely price sensitive and heavily dependent on the price that Delta charges for the service as well as the prevailing price of the natural gas commodity in the market. The producers that utilize Delta's off-system transportation service have other options besides Delta for transporting their gas to market. Therefore, the price that Delta charges for this service can have a major impact on the utilization of this service by producers. Over the past few years, Delta has experienced a reduction in off-system transportation volumes. As will be discussed below, Delta is proposing to increase the off-system transportation rate from $0.28260/Mcf to $0.3259/Mcf. While this increase is fully supported by the class cost of service study, there is a concern that the increase could cause off-system transportation customers to reduce their utilization of Delta's transportation service.

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 ten years, it was my recommendation to use temperature normalized billing determinants for the 12 months ended December 31, 2020, as the basis for Delta's forecasted sales and transportation volumes for the test year. Considering that the number of residential and non-residential customers and the average usage per customer have remained essentially flat over the ten-year period, I concluded that it was reasonable to use billing determinants for the 12 months ended December 31, 2020, 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.[3]

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 $9,135,170, which corresponds to an 18.6% increase in revenues from sales to ultimate customers (base rates). Delta is not proposing changes to other miscellaneous charges which will result in no additional operating revenue.[4] In this proceeding, Delta is proposing to transfer all costs currently recovered through its Pipe Replacement Program (PRP) into base rates. Therefore, for calendar year 2022, the PRP Rate will be zero.[5]

I relied on the results of the cost-of-service study 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, Off-System Transportation and the Special Contracts are significantly below the overall rate of return. As mentioned earlier, the rates of return for Farm Tap Service, Small Non-Residential Service, and Large Non-Residential Service are somewhat above the overall rate of return, and the rate of return for Interruptible Service is significantly

[3] 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.

[4] Delta is including a $150.00 installation fee and $25.00 reconnection fee for its farm tap customers, but these charges are not projected to result in increased test year revenues.

[5] While the Pipe Replacement Program is being set to zero in 2022 for program recovery costs, there could be an over or under cost recovery balances from prior periods that will be reflected for 2022.

above the overall rate of return.

With a rate of return of 54.76% for Interruptible Service, Delta is not proposing a net increase to Interruptible Service. The charges will be adjusted to reflect the transfer of costs recovered through the Pipe Replacement Program into base rates, but within rounding, there is no net increase proposed for this rate class.

Because of a low class rate of return of 1.14% for Residential Service, Delta is proposing approximately a one percentage point increase for Residential Service above the increases for Small Non-Residential Service and Large Non-Residential Service. Therefore, Delta is proposing an increase of 21.1% for Residential Service, an increase of 19.4% for Small Non-Residential Service, and 20.6% for Large Non-Residential Service.

The current base charges for the farm tap customers formerly served by Peoples KY are currently the same as Delta's Residential Service rate. As mentioned earlier, Delta proposes to include its farm tap customers in the same rate class with the farm tap customers formerly served by People KY. Because the rate of return for Farm Tap customers is higher than the rate of return for Residential Service, Delta is proposing to increase the Farm Tap rate at a lower percentage than for Residential Service. In determining the increase for Farm Tap Service, a percentage increase was applied that produced a class rate of return (at proposed rates) approximately equal to the proposed class rate of return for Small Non-Residential Service and Large Non-Residential Service. This approach resulted in an increase of 2.3% for Farm Tap Service.

Because of the low rate of return for the Special Contracts, Delta is proposing to increase the base rates for these contracts by 33.2%. It is also important to consider that these special contract customers are located near an interstate pipeline and therefore could potentially by-pass Delta by connecting directly to the pipeline. For this reason, and in consideration of the ratemaking principles of rate continuity and gradualism, Delta is proposing a lower increase for these special contracts than would be necessary to bring the rate of return for this customer class to the overall rate of return.

Delta is proposing to increase the rates for off-system transportation by 15.3%. As mentioned earlier, there is a very real risk that off-system transportation will simply by-pass Delta and use other transportation providers to deliver production gas to the market. Because of the risk of economic by-pass, Delta is concerned that increasing the rates for off-system transportation service by too large of a percentage will drive the revenues collected from these customers off of its system. It is important to consider that because there are no marginal costs associated with serving these customers, any revenues collected from off-system transportation customers help spread Delta's fixed costs over a larger sales base and thereby serve to reduce the base rates of other customers. While Delta believes that it is appropriate to increase the rates to off-system transportation customers, the Company needs to be careful not to increase the rates to a level that will significantly reduce the revenue collected from these customers.

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	1.14%	5.73%
Farm Tap Service	5.57%	11.31%
Small Non-Residential	4.92%	10.98%
Large Non-Residential	4.84%	11.38%
Interruptible	54.76%	54.76%
Special Contracts	-15.81%	-12.36%
Off-System Transportation	-3.89%	-0.42%
Total System	2.42%	7.44%

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.

Approximately 30,500 residential customers are served under this rate schedule. 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 $20.70 per month[6]. Delta currently collects an additional $5.10 per customer per month as a customer-based charge through the Pipe Replacement Program and provides a credit of $3.83 per customer per month as a customer-based credit for the Tax Cuts and Jobs Act Surcredit. Therefore, the *effective* customer charge excluding the Energy Assistance Program is $21.97 per customer per month. Delta is proposing to increase the Customer Charge from the effective level of $21.97 to $29.03 per month, with the Pipe Replacement Program and Tax Cut and Job Act Surcredit set to zero and with all associated costs and credits recovered through, or reflected in, base rates. This increase in the Customer Charge corresponds to a 32% increase. Delta is also proposing to increase the Distribution Charge from $4.31850 per Mcf to $5.7072 per Mcf, which also corresponds to a 32% increase in the charge.

Q. So, both the customer charge and the delivery charge per Mcf are being increased by the same percentage. Is that correct?

A. Yes, effectively. Delta's effective charges $21.97 per customer including a base customer charge of $20.70, a Pipeline replace customer charge of $5.10 and a customer charge credit of $3.83. Delta is proposing to increase the $21.97 effective

[6] $0.30 is added to charge for an amount collected under Delta's Energy Assistance Program Tariff.

customer charge by 32%, which is approximately the same percentage increase that is being proposed for the Delivery Charge.

Q. Did you prepare an analysis calculating the customer-related costs for Residential Service from the cost of service study?

A. Yes. This calculation is shown in Exhibit WSS-6. This exhibit shows the calculation of each cost component for Residential Service.

Q. What does this analysis indicate?

A. Exhibit WSS-6 shows that the customer-related costs for Residential Service derived from the cost of service study is $37.07 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 $29.03 is significantly below the customer-related cost of $37.07 that can be supported by the cost of service study.

B. FARM TAP SERVICE

Q. Please describe Delta's Farm Tap Service.

A. Delta's Farm Tap Service is currently applicable to farm tap customers previously served by Peoples KY. Delta is proposing to modify the service schedule so that in addition to the former Peoples KY farm tap customers, the schedule would also apply to approximately 350 farm tap customers currently served under Delta's Residential Service, and which were served by Delta prior to the transfer of ownership of Peoples KY to Delta. Farm Tap Service would be applicable to farm tap customers that are served directly from a transmission system or gathering system. Therefore, Farm Tap Service would apply to approximately 3,350 customers, which includes approximately 3,000 farm tap customers formerly served by Peoples KY and 350 farm tap customers currently served by Delta under Residential Service.

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

A. Delta determined the revenue requirement for the class of service by setting the rate of return for Farm Tap Service in the cost of service study to a level approximately equal to the class rates of return for Small Non-Residential Service and Large Non-Residential Service. This resulted in a revenue increase for the rate of 2.3%. Delta is proposing a Customer Charge for Farm Tap Service of $29.03, which corresponds to the proposed customer charge for Residential Service, and a Delivery Charge of $2.3570. The proposed reduction in the Delivery Charge from $4.3185 per Mcf to $2.3570 per Mcf for Farm Tap Service represents a 45.4% reduction in the charge.

Q. Is Delta proposing any other changes to Farm Tap Service?

A. Yes. Delta is proposing to apply its GCR to all sales service schedules, including farm tap customers. Delta believes that it is appropriate to unify its service schedules as much as practicable and to charge the same service rates for like and contemporaneous service. Delta believes that this approach comports with KRS 278.170 which generally prohibits establishing or maintaining unreasonable differences between classes of service for providing like and contemporaneous service.

C. SMALL NON-RESIDENTIAL SERVICE

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

A. Delta is proposing a Customer Charge of $44.40 per customer per month and a Delivery Charge of $5.6931 per Mcf. As with Residential Service, Delta is proposing to increase the effective Customer Charge and Delivery Charge by approximately the same percentages.

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 a Customer Charge of $195.04 per customer per month and a Delivery Charge of $5.6935 for the first 200 Mcf, $3.5196 for the next 800 Mcf, $2.4700 for the next 4000 Mcf, $1.9427 for the next 5,000 Mcf, and $1.6790 for all usage over 10,000 Mcf. As with Residential Service, Delta is proposing to increase the effective Customer Charge and Delivery Charge by approximately the same percentages.

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 not proposing to increase the revenue for this class. The unit charges for Interruptible will change, however, because Delta is proposing to transfer the recovery of the Pipe Replacement and the revenue credits for the Tax Cuts and Jobs Act Surcredit into base rates, but the net impact on revenues associated with these transfers is approximately zero. Delta is proposing a Customer Charge of $267.85 per customer per month and a Delivery Charge of $1.7143 for the first 1,000 Mcf, $1.2857 for the next 4000 Mcf, $0.8571 for the next 5000 Mcf, and $0.6428 for all usage over 10,000 Mcf. As with Residential Service, Delta is proposing to increase the effective Customer Charge and Delivery Charge by approximately the same percentages.

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.

Q. Is Delta proposing any changes to the On-System Transportation rate schedule?

A. Yes. Delta is proposing to change the Availability section of the rate schedule to indicate that the rate will also be available to government or university-owned housing facilities that may be served as residential.

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. As mentioned earlier in my testimony, customers taking service under Off-System Transportation Service are extremely sensitive to the price of this service. Customers utilizing this service are generally gas producers located in the eastern part of Kentucky who can use other transportation providers to deliver their gas to market. A significant increase in the charges for this service could possibly cause customers to by-pass Delta and deliver their gas to market with other transmission service providers.

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 $0.2826 to $0.3259 per Mcf. While this increase can be supported by the cost of service study, there is a concern that even this level of increase could drive transportation volumes off of Delta's system.

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 $0.1100 per Mcf. Delta is proposing to increase this Delivery Charge to

$0.1465 per Mcf, which corresponds to an increase of 33.2%. The other two Special Contracts ("SC 2 & SC 3") have a blocked rate structure, with a rate of $0.4800/Mcf for the first usage block, $0.2400/Mcf for the second block, and $0.0800/Mcf for all excess Mcf. Delta is proposing to increase these charges by 33.3%, so that they would be $0.6392/Mcf for the first block, $0.3196 for the second block, and $0.1065 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. Please describe the changes to the Pipe Replacement Program.

A. Delta is proposing to modify the Pipe Replacement Program so that it operates on a forward-looking cost basis (i.e., on a projected program cost basis) rather than on a historical cost basis. The Commission has approved pipeline replacement programs that operate on a forward-looking basis for LG&E, Columbia Gas of Kentucky and Atmos Energy Corporation. The use of forecasted costs for the Pipe Replacement Program is more consistent with the use of a forecasted test year for setting Delta's base rates. Under Delta's proposed modifications to its Pipe Replacement Program, Delta would submit a filing by October 15 of each year updating its projected costs for the subsequent year. Delta would submit a balancing adjustment by March 31 to true-up the actual costs for the most recent 12 month period ended December 31. Therefore, under Delta's proposal, program cost recovery would be trued-up to actual costs, as is done by the other utilities.

Q. When would Delta make its first forecasted Pipe Replacement Program filing for projected costs?

A. Because Delta is using a forecasted test-year for its current rate case, all pipe replacement costs are fully reflected in forecasted revenue requirements in this proceeding and will be recovered through base rates. For the calendar year 2022, the pipeline replacement program would be set to zero, except for any carryover of over- or under-recoveries from the normal operation of the current Pipe Replacement Program for 2021. Under its proposed Pipe Replacement Program, Delta would make its first filing under the new forward-looking program on or before October 15, 2022, for the recovery of any Pipe Recovery Program costs for the 12 months ended December 31, 2023.

VIII. DEPRECIATION STUDY

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

A. Yes.

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 WSS-7.

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

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 WSS-7 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 WSS-8 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 WSS-8.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF BUNCOMBE)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and says he a Principal of 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.

WILLIAM STEVEN SEELYE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 26th day of May, 2021.

Notary Public (SEAL)

My Commission Expires:
7/29/2023

Kyle Mello
NOTARY PUBLIC
BUNCOMBE COUNTY, NC
MY COMMISSION EXPIRES 7/29/2023

Exhibit WSS-1

Qualifications

WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, municipal utilities, and public service commissions regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base. Mr. Seelye has performed or supervised the preparation of cost of service studies and rate design studies for over 150 electric, gas and water utilities.

Employment

Principal and Managing Partner
The Prime Group, LLC
(1996 to 2012) (2015-Present)
(Associate Member 2012-2015)

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service studies, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic resource and marketing plans. Assist with resource planning and cost benefit analyses for generation investment projects. Performs economic analyses evaluating the costs and benefits of an electric generation projects; performs business practice audits for electric utilities, gas utilities, and independent transmission organizations, including audits of production cost modeling, fuel procurement practices and controls, and wholesale marketing procedures. Assists investor-owned utilities in the development of testimony regarding the prudence of power supply decisions and of investments in specific generation and distribution assets.

Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives;

unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Instructor in Mathematics
Walden School and Private Instruction
(2012-2015)

Taught advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
66 Hours of Graduate Level Course Work in Electrical and Industrial Engineering and Physics.

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

Submitted expert report in No. 14-CV-30031 before District Court, Prowers County, State of Colorado, on behalf of Arkansas River Power Authority in the *City of Lamar et al v. Arkansas River Power Authority regarding* power planning and operations.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER11-2127-000 concerning transmission rates proposed by Terra-Gen Dixie Valley, LLC.

Submitted testimony in Docket No. ER11-2779 on behalf of Southern Illinois Power Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Submitted testimony in Docket No. ER11-2786 on behalf of Norris Electric Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and cross answering testimony in Cause No. 45125 on behalf of the City of New Haven regarding Fort Wayne's revenue requirement, cost of service study and the apportionment of the water rate increase.

Submitted direct and cross answering testimony in Cause No. 45142 on behalf of the City of Crown Point regarding Indiana-American Water Company's cost of service study, apportionment of the revenue increase, interruptible service rates and transportation service rates.

Submitted direct and cross answering testimony in Cause No. 45235 on behalf of the City of South Bend regarding Indiana-Michigan Power Company's cost of service study, apportionment of the revenue increase and rate design.

Submitted direct and cross answering testimony in Cause No. 45285 on behalf of the City of South Bend regarding Indiana-Michigan Power Company's demand side management (DSM) plan.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning revenue requirements, cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding revenue requirements, pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2010-00116 on behalf of Delta Natural Gas Company concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony in Case No. 2011-00036 on behalf of Big Rivers Electric Cooperative concerning cost of service, rate design, pro-forma TIER adjustments, temperature normalization, and support of MISO Attachment O.

Submitted testimony in Case No. 2016-00107 on behalf of Columbia Gas Company of Kentucky regarding a tariff application to continue its energy efficiency and conservation rider and programs.

Submitted testimony in Case No. 2016-00274 on behalf of Kentucky Utilities Company and Louisville Gas and Electric Company in support of community solar rates.

Submitted direct and rebuttal testimony in Case No. 2016-00370 on behalf of Kentucky Utilities Company and in Case No. 2016-00371 on behalf of Louisville Gas and Electric Company regarding electric and gas class cost of service studies and proposed rates.

Submitted rebuttal testimony in Case No. 2018-00050 on behalf of South Kentucky Rural Electric Cooperative Corporation regarding the regulatory application of the filed rate doctrine and cost shifts to other electric cooperatives related to a proposed purchased power agreement.

Submitted testimony in Case No. 2018-00044 on behalf of Columbia Gas Company of Kentucky regarding an assessment of its energy efficiency and conservation rider and programs.

Submitted direct and rebuttal testimony in Case No. 2018-00294 on behalf of Kentucky Utilities Company and in Case No. 2018-00295 on behalf of Louisville Gas and Electric Company regarding electric and gas class cost of service studies, apportionment of the revenue increase, pilot school rates, demand ratchets, late payment charges, residential customer charges, excess facilities charges, LED lighting rates, and lead-lag studies.

Submitted direct and rebuttal testimony in Case No. 2020-00349 on behalf of Kentucky Utilities Company and in Case No. 2020-00350 on behalf of Louisville Gas and Electric Company regarding electric and gas class cost of service studies, apportionment of the revenue increase, residential demand rates, electric vehicle rates, net metering, late payment charges, residential customer charges, excess facilities charges, LED lighting rates, and lead-lag studies.

Submitted direct testimony in Case No. 2021-00066 in support of a depreciation study performed on behalf of Kenergy Corp.

Maryland — Submitted direct testimony in PSC Case No. 9234 on behalf of Southern Maryland Electric Cooperative regarding a class cost of service study.

Nevada: — Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital, depreciation adjustments, and other rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 10-06001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate cases.

Submitted direct testimony in Case No. Docket No. 11-06006 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

New Mexico Submitted testimony in support of filing of Advice Notice No. 60 on behalf of Kit Carson Electric Cooperative, Inc.

Submitted direct testimony in Case No. 15-00375-UT on behalf of Kit Carson Electric Cooperative, Inc. regarding revenue requirements, the need for a rate increase, class cost of service study, apportionment of the revenue increase to the classes of service, and rate design.

Submitted testimony in Advice Notices in Case No. 15-00087-UT on behalf of Jemez Mountain Electric Cooperative in support of tribal right of way cost recovery surcharge mechanisms.

Submitted direct testimony in Case. No. 16-00065-UT on behalf of Kit Carson Electric Cooperative in support of an application for continuation of its fuel and purchased power cost adjustment clause.

Submitted direct testimony, rebuttal testimony, and testimony in support of an uncontested comprehensive stipulation in Case No. 19-00170-UT on behalf of the New Mexico Public Regulation Commission Utility Division Staff regarding revenue requirements, depreciation rates, class cost of service, allocation of the revenue increase, and rate design in a Southwest Power Company rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2011-00013 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, and rate design.

Exhibit WSS-2

Cost of Service Study
Functional Assignment and Classification

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 30,583,229	-	-	30,583,229	-	-	-	-
Total Storage Plant		PTST		$ 30,583,229	$ -	$ -	$ 30,583,229	$ -	$ -	$ -	$ -
Transmission Plant											
325-371	Transmission	PT365	F005	$ 73,172,523	-	-	-	-	73,172,523	-	-
Distribution Plant											
374 & 304	Land and Land Rights	PT374	F008	$ 364,910	-	-	-	-	-	-	-
375	Structures & Improvements	PT375	F008	117,407	-	-	-	-	-	-	-
376	Mains	PT376	F009	105,203,374	-	-	-	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	2,282,461	-	-	-	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	965,612	-	-	-	-	-	-	-
380	Services	PT380	F010	24,828,093	-	-	-	-	-	-	-
381	Meters	PT381	F011	11,164,356	-	-	-	-	-	-	-
382	Meter Installations	PT382	F011	5,799,163	-	-	-	-	-	-	-
383	House Regulators	PT383	F011	4,659,055	-	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	1,843,633	-	-	-	-	-	-	-
387	Other Equipment	PT387	F011	-	-	-	-	-	-	-	-
	Mt. Olivet	MTOVT		-	-	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$ 157,228,063	-	-	-	-	-	-	-
Transmission & Distribution Subtotal		TDSUB		$ 230,400,586	$ -	$ -	$ -	$ -	$ 73,172,523	$ -	$ -
U-T-D Subtotal		PTSUB		$ 260,983,815	-	-	30,583,229	-	73,172,523	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	$ 4,208,069	-	-	4,208,069	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	7,677,340	-	-	899,664	-	2,152,510	-	-
389-399	General Plant	PT389	PTSUB	24,289,867	-	-	2,846,393	-	6,810,196	-	-
	Common Utility Plant	PTCP	PTSUB	-	-	-	-	-	-	-	-
Total Plant in Service		PTIS		$ 297,159,092	-	-	38,537,356	-	82,135,229	-	-
				$ 292,951,022							

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	364,910	-	-	-	-	-	-
375	Structures & Improvements	PT375	F008	117,407	-	-	-	-	-	-
376	Mains	PT376	F009	-	30,424,816	74,778,558	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	2,282,461	-	-	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	965,612	-	-	-	-	-	-
380	Services	PT380	F010	-	-	-	24,828,093	-	-	-
381	Meters	PT381	F011	-	-	-	-	11,164,356	-	-
382	Meter Installations	PT382	F011	-	-	-	-	5,799,163	-	-
383	House Regulators	PT383	F011	-	-	-	-	4,659,055	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	-	-	-	1,843,633	-	-
387	Other Equipment	PT387	F011	-	-	-	-	-	-	-
	Mt. Olivet	MTOVT		-	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		3,730,390	30,424,816	74,778,558	24,828,093	23,466,207	-	-
Transmission & Distribution Subtotal		TDSUB		$ 3,730,390	$ 30,424,816	$ 74,778,558	$ 24,828,093	$ 23,466,207	$ -	$ -
U-T-D Subtotal		PTSUB		3,730,390	30,424,816	74,778,558	24,828,093	23,466,207	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	109,737	895,004	2,199,755	730,366	690,304	-	-
389-399	General Plant	PT389	PTSUB	347,189	2,831,650	6,959,670	2,310,760	2,184,009	-	-
	Common Utility Plant	PTCP	PTSUB	-	-	-	-	-	-	-
Total Plant in Service		PTIS		4,187,315	34,151,470	83,937,983	27,869,219	26,340,520	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$	4,096,614	-	-	-	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	$	-	-	-	-	-	-	-	-
General	CWIPCO	PT389	$	-	-	-	-	-	-	-	-
Total CWIP	CWIP		$	4,096,614	-	-	-	-	-	-	-
Total Gas Plant at Original Cost	PTT		$	301,255,706	-	-	38,537,356	-	82,135,229	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	-	1,184,741	2,911,873	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	-	-	-	-	-	-	-
General	CWIPCO	PT389	-	-	-	-	-	-	-
Total CWIP	CWIP		-	1,184,741	2,911,873	-	-	-	-
Total Gas Plant at Original Cost	PTT		4,187,315	35,336,210	86,849,856	27,869,219	26,340,520	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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			$	301,255,706	$ -	$ -	$ 38,537,356	$ -	$ 82,135,229	$ -	$ -
Less:											
Reserve for Depreciation											
Underground Storage	DEPRUS	PTST	$	14,347,457	-	-	14,347,457	-	-	-	-
Transmission	DEPTR	F005		37,098,821	-	-	-	-	37,098,821	-	-
Distribution	DEPRDI	PTDSUB		65,102,139	-	-	-	-	-	-	-
General	DEPRGE	PT389		9,062,718	-	-	1,062,009	-	2,540,931	-	-
Common	DEPRCO	PTSUB		2,245,908	-	-	263,185	-	629,689	-	-
Total Depreciation Reserve	DEPR		$	127,857,043	$ -	$ -	$ 15,672,651	$ -	$ 40,269,442	$ -	$ -
Depreciation Adjustment		DEPR	$	-	-	-	-	-	-	-	-
Customer Advances For Construction	CAD	CADAL	$	457,600	-	-	-	-	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB		42,774,952	-	-	5,012,557	-	11,992,894	-	-
Investment Tax Credit	ITC	PTSUB		-	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB		-	-	-	-	-	-	-	-
PLUS:											
Materials and Supplies	MSP	PTSUB	$	604,905	-	-	70,885	-	169,598	-	-
Prepayments	PPY	PTSUB		1,072,741	-	-	125,708	-	300,766	-	-
Gas Stored Underground	GSU	F003		1,143,702	-	-	1,143,702	-	-	-	-
Cash Working Capital	CWC	OMT		2,000,869	-	-	54,373	30,053	968,532	21,502	86,242
Adjustments:											
Unamortized Debt		PTSUB	$	1,747,661	-	-	204,799	-	489,995	-	-
Utility ARO Assets		PTT	$	-	-	-	-	-	-	-	-
A/D on ARO Assets		DEPR	$	-	-	-	-	-	-	-	-
Net Cost Rate Base	NCRB		$	136,735,988	$ -	$ -	$ 19,451,616	$ 30,053	$ 31,801,785	$ 21,502	$ 86,242

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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			$ 4,187,315	$ 35,336,210	$ 86,849,856	$ 27,869,219	$ 26,340,520	$ -	$ -
Less:									
Reserve for Depreciation									
Underground Storage	DEPRUS	PTST	-	-	-	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-	-	-	-
Distribution	DEPRDI	PTDSUB	1,544,612	12,597,755	30,962,946	10,280,365	9,716,461	-	-
General	DEPRGE	PT389	129,539	1,056,508	2,596,701	862,161	814,869	-	-
Common	DEPRCO	PTSUB	32,102	261,822	643,510	213,659	201,939	-	-
Total Depreciation Reserve	DEPR		$ 1,706,253	$ 13,916,085	$ 34,203,158	$ 11,356,185	$ 10,733,269	$ -	$ -
Depreciation Adjustment		DEPR	-	-	-	-	-	-	-
Customer Advances For Construction	CAD	CADAL	-	107,069	263,157	87,374	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	611,407	4,986,593	12,256,121	4,069,296	3,846,085	-	-
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-	-	-
PLUS:									
Materials and Supplies	MSP	PTSUB	8,646	70,518	173,321	57,546	54,390	-	-
Prepayments	PPY	PTSUB	15,333	125,057	307,368	102,053	96,455	-	-
Gas Stored Underground	GSU	F003	-	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	12,412	97,054	238,541	90,915	135,871	265,205	168
Adjustments:									
Unamortized Debt		PTSUB	24,980	203,738	500,750	166,260	157,140	-	-
Utility ARO Assets		PTT	-	-	-	-	-	-	-
A/D on ARO Assets		DEPR	-	-	-	-	-	-	-
Net Cost Rate Base	NCRB		$ 1,931,028	$ 16,822,830	$ 41,347,399	$ 12,773,137	$ 12,205,021	$ 265,205	$ 168

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	138,715	-	-	-	-	-	138,715	-
754	Compressor Station	LB754	F006	-	-	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	LB764	F006	-	-	-	-	-	-	-	-
765	Maintenance of Compressor Station	LB765	F006	32,395	-	-	-	-	-	32,395	-
Total Production Operation & Maintenance Expenses				171,110	-	-	-	-	-	171,110	-
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	60,925	-	-	60,925	-	-	-	-
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		$ 60,925	$ -	$ -	$ 60,925	$ -	$ -	$ -	$ -
Storage Expense											
Maintenance											
830	Maintenance Super and Eng.	LB830	MSE	$ -	-	-	-	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	19,152	-	-	19,152	-	-	-	-
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		$ 19,152	$ -	$ -	$ 19,152	$ -	$ -	$ -	$ -
Total Storage Labor		LBS		$ 80,076	-	-	80,076	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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 December 31, 2022

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	$ 4,021,758	-	-	-	-	4,021,758	-	-
Distribution Expenses											
Operation											
870	Operation Supr and Engr	LB870	DOES	$ -	-	-	-	-	-	-	-
871	Dist Load Dispatching	LB871	F007	-	-	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007	304,380	-	-	-	-	-	-	304,380
873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	769,478	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-
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	127,874	-	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011	94,621	-	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB	309,737	-	-	-	-	-	-	-
881	Rents	LB881	PTDSUB	-	-	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$ 1,606,091	$ -	$ -	$ -	$ -	$ -	$ -	$ 304,380
Total Operations Transmission and Distribution Labor		LBTDO		$ 5,766,564	$ -	$ -	$ -	$ -	$ 4,021,758	$ 138,715	$ 304,380

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	-	-	-	-	-	-	-
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	-	180,043	442,512	146,923	-	-	-
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	-	-	-	-	-	-	-
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	-	-	-	-	127,874	-	-
879	Customer Installation Expense	LB879	F011	-	-	-	-	94,621	-	-
880	Other Expenses	LB880	PTDSUB	7,349	59,936	147,313	48,911	46,228	-	-
881	Rents	LB881	PTDSUB	-	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$ 7,349	$ 239,979	$ 589,824	$ 195,834	$ 268,723	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ 7,349	$ 239,979	$ 589,824	$ 195,834	$ 268,723	$ -	$ -

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	$	16,433	-	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008		5,053	-	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009		-	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007		-	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008		1	-	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011		-	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008		-	-	-	-	-	-	-	-
892	Maintenance Services	LB892	F010		7,708	-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011		27,131	-	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB		28,725	-	-	-	-	-	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB		-	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB		-	-	-	-	-	-	-	-
Total Maintenance Labor		LBDM		$	85,051	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$	5,884,010	$ -	$ -	$ -	$ -	$ 4,021,758	$ 171,110	$ 304,380
Customer Accounts Expense												
901	Supervision	LB901	F012	$	-	-	-	-	-	-	-	-
902	Meter Reading	LB902	F012		-	-	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	$	531,669	-	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012		-	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012		-	-	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$	531,669	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses												
907-910	Customer Service	LB907	F013	$	-	-	-	-	-	-	-	-
Sales Expenses												
911-916	Sales Expenses	LB911	F013	$	-	-	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	1,374	1,331	3,272	2,932	7,524	-	-
886	Maintenance Structures	LB886	F008	5,053	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	1	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	7,708	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-	27,131	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	682	5,558	13,662	4,536	4,287	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB	-	-	-	-	-	-	-
Total Maintenance Labor		LBDM		$ 7,109	$ 6,890	$ 16,933	$ 15,176	$ 38,943	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 14,458	$ 246,869	$ 606,758	$ 211,010	$ 307,666	$ -	$ -
Customer Accounts Expense										
901	Supervision	LB901	F012	-	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	-	-	-	-	-	531,669	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ -	$ -	$ -	$ 531,669	$ -
Customer Service Expenses										
907-910	Customer Service	LB907	F013	-	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	LB911	F013	-	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 429,259	-	-	5,292	-	265,770	11,307	20,114
921	Office Supplies and Expense	LB921	LBSUB	411,818	-	-	5,077	-	254,972	10,848	19,297
922	Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-	-	-
923	Outside Services Employed	LB923	OMSUB	256,383	-	-	4,544	6,446	115,753	1,201	12,430
924	Property Insurance	LB924	PTT	50,009	-	-	6,397	-	13,635	-	-
925	Injuries and Damages	LB925	PTT	212,887	-	-	27,233	-	58,042	-	-
926	Employee Pensions and Benefits	LB926	LBSUB	452,852	-	-	5,583	-	280,377	11,929	21,220
927	Franxhise Requirement	LB927	PTT	-	-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	38,861	-	-	4,971	-	10,595	-	-
929	Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB	21,704	-	-	385	546	9,799	102	1,052
931	Rents	LB931	PTT	-	-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	11,091	-	-	1,300	-	3,110	-	-
Total Administrative and General Labor		LBAG		$ 1,884,864	$ -	$ -	$ 60,781	$ 6,992	$ 1,012,052	$ 35,387	$ 74,114
Total Labor Expense		LBTOT		$ 8,380,620	$ -	$ -	$ 140,858	$ 6,992	$ 5,033,811	$ 206,497	$ 378,495

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	955	16,314	40,096	13,944	20,332	35,134	-
921	Office Supplies and Expense	LB921	LBSUB	917	15,651	38,467	13,378	19,505	33,707	-
922	Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-	-
923	Outside Services Employed	LB923	OMSUB	1,772	10,819	26,590	11,285	19,221	46,285	36
924	Property Insurance	LB924	PTT	695	5,866	14,417	4,626	4,373	-	-
925	Injuries and Damages	LB925	PTT	2,959	24,971	61,374	19,694	18,614	-	-
926	Employee Pensions and Benefits	LB926	LBSUB	1,008	17,210	42,300	14,711	21,449	37,065	-
927	Franxhise Requirement	LB927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	540	4,558	11,203	3,595	3,398	-	-
929	Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB	150	916	2,251	955	1,627	3,918	3
931	Rents	LB931	PTT	-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	159	1,293	3,178	1,055	997	-	-
Total Administrative and General Labor		LBAG		$ 9,154	$ 97,598	$ 239,878	$ 83,243	$ 109,515	$ 156,110	$ 39
Total Labor Expense		LBTOT		$ 23,612	$ 344,467	$ 846,635	$ 294,253	$ 417,181	$ 687,780	$ 39

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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		-	-	-	-	-	-	-	-
754	Compressor Station	OM754	F006		-	-	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	OM764	F006		1,075	-	-	-	-	-	1,075	-
765	Maintenance of Compressor Station	OM765	F006		37,030	-	-	-	-	-	37,030	-
Total Production Operation & Maintenance Expenses					38,105	-	-	-	-	-	38,105	-
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		75,650	-	-	75,650	-	-	-	-
817	Lines Expenses	OM817	F003		-	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004		87,868	-	-	-	87,868	-	-	-
819	Compressor Station Fuel and Power	OM819	F004		-	-	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003		-	-	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004		102,594	-	-	-	102,594	-	-	-
823	Gas losses	OM823	F004		1,686	-	-	-	1,686	-	-	-
824	Other Expenses	OM824	F004		3,546	-	-	-	3,546	-	-	-
825	Storage Well Royalities	OM825	F003		50,569	-	-	50,569	-	-	-	-
826	Rents	OM826	F003		-	-	-	-	-	-	-	-
Total Operation Expenses		OMOE		$	321,913	$ -	$ -	$ 126,219	$ 195,694	$ -	$ -	$ -
Storage Expense												
Maintenance												
830	Maintenance Super and Eng.	OM830	MSE	$	-	-	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003		2,525	-	-	2,525	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003		14,796	-	-	14,796	-	-	-	-
833	Maintenance of Lines	OM833	F003		-	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004		8,819	-	-	-	8,819	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003		189	-	-	189	-	-	-	-
836	Main of Purification Equip	OM836	F004		-	-	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003		444	-	-	444	-	-	-	-
Total Maintenance Expense		OMME		$	26,773	$ -	$ -	$ 17,954	$ 8,819	$ -	$ -	$ -
Total Storage Expense		OMS		$	348,686	-	-	144,173	204,513	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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		-	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$	3,672,420	-	-	-	-	3,672,420	-	-
Distribution Expenses												
Operation												
870	Operation Supr and Engr	OM870	DOES	$	(23,722)	-	-	-	-	-	-	(4,496)
871	Dist Load Dispatching	OM871	F007		-	-	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007		398,869	-	-	-	-	-	-	398,869
873	Compr. Station Fuel and Power	OM873	F007		-	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL		1,028,079	-	-	-	-	-	-	-
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		-	-	-	-	-	-	-	-
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		170,849	-	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011		126,421	-	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB		413,831	-	-	-	-	-	-	-
881	Rents	OM881	PTDSUB		-	-	-	-	-	-	-	-
Total Operations Distribution Expense		OMDO		$	2,114,327	-	-	-	-	-	-	394,374
Total Transmission and Distribution Oper Exp		OMTDO		$	5,786,747	$ -	$ -	$ -	$ -	$ 3,672,420	$ -	$ 394,374
				$	2,138,049							

DELTA NATURAL GAS COMPANY

Cost of Service Study
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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
<u>Operation & Maintenance Expenses (Continued)</u>										
Transmission										
850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-	-
Distribution Expenses										
Operation										
870	Operation Supr and Engr	OM870	DOES	(109)	(3,544)	(8,712)	(2,892)	(3,969)	-	-
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	-	240,550	591,228	196,300	-	-	-
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	-	-	-	-	-	-	-
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	-	-	-	-	170,849	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	126,421	-	-
880	Other Expenses	OM880	PTDSUB	9,819	80,079	196,820	65,349	61,764	-	-
881	Rents	OM881	PTDSUB	-	-	-	-	-	-	-
Total Operations Distribution Expense		OMDO		9,710	317,085	779,337	258,757	355,065	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 9,710	$ 317,085	$ 779,337	$ 258,757	$ 355,065	$ -	$ -

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	$	107,158	-	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008		33,078	-	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009		(65,395)	-	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007		-	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008		5	-	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011		-	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-	-	-	-	-	-	-	-
892	Maintenance Services	OM892	F010		50,454	-	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011		177,602	-	-	-	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB		188,033	-	-	-	-	-	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB		-	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	OM900	TDSUB		-	-	-	-	-	-	-	-
Total Maintenance Expenses		OMME		$	490,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$	6,315,788	$ -	$ -	$ -	$ -	$ 3,672,420	$ 38,105	$ 394,374
Customer Accounts Expense												
901	Supervision	OM901	F012	$	-	-	-	-	-	-	-	-
902	Meter Reading	OM902	F012		410,092	-	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	$	896,661	-	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	F012		161,710	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	OM905	F012		-	-	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$	1,468,463	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses												
907-910	Customer Service	OM907	F013	$	592	-	-	-	-	-	-	-
Sales Expenses												
911-916	Sales Expenses	OM911	F013	$	553	-	-	-	-	-	-	-

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	8,957	8,680	21,335	19,120	49,065	-	-
886	Maintenance Structures	OM886	F008	33,078	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009	-	(18,912)	(46,483)	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	5	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-	-	-	-
892	Maintenance Services	OM892	F010	-	-	-	50,454	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	-	177,602	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	4,461	36,386	89,430	29,693	28,064	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB	-	-	-	-	-	-	-
900	Trans & Distribution Expenses	OM900	TDSUB	-	-	-	-	-	-	-
Total Maintenance Expenses		OMME		$ 46,501	$ 26,154	$ 64,282	$ 99,267	$ 254,731	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 56,211	$ 343,239	$ 843,619	$ 358,024	$ 609,796	$ -	$ -
Customer Accounts Expense										
901	Supervision	OM901	F012	-	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	410,092	-
903	Customer Records and Collections	OM903	F012	-	-	-	-	-	896,661	-
904	Uncollectible Accounts	OM904	F012	-	-	-	-	-	161,710	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ -	$ 1,468,463	$ -
Customer Service Expenses										
907-910	Customer Service	OM907	F013	-	-	-	-	-	-	592
Sales Expenses										
911-916	Sales Expenses	OM911	F013	-	-	-	-	-	-	553

DELTA NATURAL GAS COMPANY

Cost of Service Study
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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	$	2,195,736	-	-	27,068	-	1,359,460	57,840	102,889
921	Office Supplies and Expense	OM921	LBSUB		2,115,310	-	-	26,076	-	1,309,665	55,721	99,120
922	Admin. Expenses Transferred	OM922	LBSUB		(1,930,381)	-	-	(23,797)	-	(1,195,169)	(50,850)	(90,454)
923	Outside Services Employed	OM923	OMSUB		1,316,913	-	-	23,342	33,111	594,567	6,169	63,849
924	Property Insurance	OM924	PTT		256,870	-	-	32,859	-	70,034	-	-
925	Injuries and Damages	OM925	PTT		1,093,498	-	-	139,883	-	298,134	-	-
926	Employee Pensions and Benefits	OM926	LBSUB		2,449,031	-	-	30,190	-	1,516,284	64,512	114,758
927	Franchise Requirement	OM927	PTT		-	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT		199,612	-	-	25,535	-	54,423	-	-
929	Duplicate Charges -Dredit	OM929	PTT		-	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT		-	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB		111,482	-	-	1,976	2,803	50,333	522	5,405
931	Rents	OM931	PTT		7,828	-	-	1,001	-	2,134	-	-
932	Maintenance of General Plant	OM932	PT389		56,968	-	-	6,676	-	15,972	-	-
Total Administrative and General Expense		OMAGT		$	7,872,866	$ -	$ -	$ 290,810	$ 35,914	$ 4,075,837	$ 133,915	$ 295,566
Total Operation & Maintenance Expense		OMT		$	16,006,948	$ -	$ -	$ 434,983	$ 240,427	$ 7,748,257	$ 172,020	$ 689,940
				$	9,795,419							

DELTA NATURAL GAS COMPANY

Cost of Service Study
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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	4,887	83,448	205,100	71,327	103,999	179,718	-
921	Office Supplies and Expense	OM921	LBSUB	4,708	80,392	197,588	68,714	100,190	173,135	-
922	Admin. Expenses Transferred	OM922	LBSUB	(4,297)	(73,363)	(180,314)	(62,707)	(91,431)	(157,999)	-
923	Outside Services Employed	OM923	OMSUB	9,101	55,571	136,582	57,964	98,726	237,745	185
924	Property Insurance	OM924	PTT	3,570	30,130	74,054	23,763	22,460	-	-
925	Injuries and Damages	OM925	PTT	15,199	128,263	315,248	101,160	95,611	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	5,451	93,075	228,760	79,555	115,996	200,450	-
927	Franchise Requirement	OM927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	2,775	23,414	57,547	18,466	17,453	-	-
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	770	4,704	11,562	4,907	8,358	20,126	16
931	Rents	OM931	PTT	109	918	2,257	724	684	-	-
932	Maintenance of General Plant	OM932	PT389	814	6,641	16,323	5,420	5,122	-	-
Total Administrative and General Expense		OMAGT		$ 43,088	$ 433,192	$ 1,064,706	$ 369,293	$ 477,169	$ 653,176	$ 201
Total Operation & Maintenance Expense		OMT		$ 99,299	$ 776,432	$ 1,908,325	$ 727,317	$ 1,086,965	$ 2,121,639	$ 1,346

DELTA NATURAL GAS COMPANY

Cost of Service Study
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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	$	788,193	-	-	788,193	-	-	-	-
Transmission												
365-371	Transmission Plant	DP365	F005	$	1,968,476	-	-	-	-	1,968,476	-	-
Distribution												
374	Land & Land Rights	DP374	F008	$	-	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008		2,747	-	-	-	-	-	-	-
376	Mains	DP376	F009		3,208,703	-	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008		72,582	-	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008		20,954	-	-	-	-	-	-	-
380	Services	DP380	F010		769,671	-	-	-	-	-	-	-
381	Meters	DP381	F011		319,301	-	-	-	-	-	-	-
382	Meter Installations	DP382	F011		231,967	-	-	-	-	-	-	-
383	House Regulators	DP383	F011		184,499	-	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011		-	-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011		48,672	-	-	-	-	-	-	-
387	Other Equipment	DP387	F011		-	-	-	-	-	-	-	-
	Other		PTSUB		-	-	-	-	-	-	-	-
Total Distribution				$	4,859,096	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	Gas Stored Underground	DP117	F003	$	-	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB		625,853	-	-	73,340	-	175,472	-	-
389-399	General Plant	DP389	PTSUB		1,127,741	-	-	132,154	-	316,187	-	-
325-334	Production	DPCP	PTSUB		103,893	-	-	12,175	-	29,129	-	-
Amortization of Gas Plant		AMORT	PTSUB		429,778	-	-	50,363	-	120,498	-	-
Accretion Expense		ACCRTN	PTSUB		-	-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$	9,903,030	$ -	$ -	$ 1,056,225	$ -	$ 2,609,761	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	2,747	-	-	-	-	-	-
376	Mains	DP376	F009	-	927,957	2,280,746	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	72,582	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	20,954	-	-	-	-	-	-
380	Services	DP380	F010	-	-	-	769,671	-	-	-
381	Meters	DP381	F011	-	-	-	-	319,301	-	-
382	Meter Installations	DP382	F011	-	-	-	-	231,967	-	-
383	House Regulators	DP383	F011	-	-	-	-	184,499	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	-	48,672	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-	-
	Other		PTSUB	-	-	-	-	-	-	-
Total Distribution				$ 96,283	$ 927,957	$ 2,280,746	$ 769,671	$ 784,439	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	8,946	72,960	179,323	59,539	56,273	-	-
389-399	General Plant	DP389	PTSUB	16,119	131,469	323,127	107,285	101,400	-	-
325-334	Production	DPCP	PTSUB	1,485	12,112	29,768	9,884	9,341	-	-
Amortization of Gas Plant		AMORT	PTSUB	6,143	50,102	123,142	40,886	38,643	-	-
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 128,976	$ 1,194,600	$ 2,936,106	$ 987,265	$ 990,097	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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		3,893,352	-	-	498,047	-	1,061,495	-	-
Payroll Taxes	OTUN	LBTOT		-	-	-	-	-	-	-	-
Total Taxes Other Than Income Taxes	OTT		$	3,893,352	$ -	$ -	$ 498,047	$ -	$ 1,061,495	$ -	$ -
Interest on Long Term Debt	INT	PTT	$	2,639,800	-	-	337,690	-	719,723	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	54,116	456,676	1,122,425	360,175	340,418	-	-
Payroll Taxes	OTUN	LBTOT	-	-	-	-	-	-	-
Total Taxes Other Than Income Taxes	OTT		$ 54,116	$ 456,676	$ 1,122,425	$ 360,175	$ 340,418	$ -	$ -
Interest on Long Term Debt	INT	PTT	36,692	309,639	761,035	244,208	230,813	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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		$ 178,375,896	$ -	$ -	$ -	$ -	$ 73,172,523	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	0.289200	0.710800	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		$ -	$ 30,424,816	$ 74,778,558	$ -	$ -	$ -	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	-	-	0.117184	-	0.280372	-	-
Total Storage Plant		PTST	1.000000	-	-	1.000000	-	-	-	-
Transmission Plant		PT365	1.000000	-	-	-	-	1.000000	-	-
General Plant		PT389	1.000000	-	-	0.117184	-	0.280372	-	-
Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	-	-
Sub-Total CWIP		CWIP	1.000000	-	-	-	-	-	-	-
Total Depreciation Reserve		DEPR	1.000000	-	-	0.122579	-	0.314957	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1.000000	-	-	0.117184	-	0.280372	-	-
Transmission and Distribution Payroll		LBTD	1.000000	-	-	-	-	0.683506	0.029081	0.051730
Transmission and Distribution Mains		TDMSUB	1.000000	-	-	-	-	0.410215	-	-
Storage Operation Expenses Subtotal	OSE		60,925	-	-	60,925	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		19,152	-	-	19,152	-	-	-	-
Mains & Services	CADAL		130,031,466	-	-	-	-	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1.00000	0.5	0.5					
Distribution Operation Expenses Subtotal	DOES		1,606,091	-	-	-	-	-	-	304,380
Distribution Maintenance Expenses Subtotal	DMES		68,618	-	-	-	-	-	-	-
Subtotal Labor Expenses	LBSUB		$ 6,495,756	$ -	$ -	$ 80,076	$ -	$ 4,021,758	$ 171,110	$ 304,380
Subtotal O&M Expenses	OMSUB		$ 8,134,082	$ -	$ -	$ 144,173	$ 204,513	$ 3,672,420	$ 38,105	$ 394,374

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	0.023726	0.193508	0.475606	0.157911	0.149249	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0.014294	0.116577	0.286526	0.095133	0.089914	-	-
Total Storage Plant		PTST	-	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-	-
General Plant		PT389	0.014294	0.116577	0.286526	0.095133	0.089914	-	-
Total Distribution Plant		PTDSUB	0.023726	0.193508	0.475606	0.157911	0.149249	-	-
Sub-Total CWIP		CWIP	-	0.289200	0.710800	-	-	-	-
Total Depreciation Reserve		DEPR	0.013345	0.108841	0.267511	0.088819	0.083947	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.014294	0.116577	0.286526	0.095133	0.089914	-	-
Transmission and Distribution Payroll		LBTD	0.002457	0.041956	0.103120	0.035862	0.052289	-	-
Transmission and Distribution Mains		TDMSUB	-	0.170566	0.419219	-	-	-	-
Storage Operation Expenses Subtotal	OSE		-	-	-	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		-	-	-	-	-	-	-
Mains & Services	CADAL		-	30,424,816	74,778,558	24,828,093	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM								
Distribution Operation Expenses Subtotal	DOES		7,349	239,979	589,824	195,834	268,723	-	-
Distribution Maintenance Expenses Subtotal	DMES		5,735	5,558	13,662	12,244	31,418	-	-
Subtotal Labor Expenses	LBSUB		$ 14,458	$ 246,869	$ 606,758	$ 211,010	$ 307,666	$ 531,669	$ -
Subtotal O&M Expenses	OMSUB		$ 56,211	$ 343,239	$ 843,619	$ 358,024	$ 609,796	$ 1,468,463	$ 1,145

Exhibit WSS-3

Cost of Service Study
Class Allocation

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 38,537,356	$ 16,370,125	$ -	$ 5,713,153	$ 16,454,078	$ -	$ -	$ -
Commodity	PTIS	PTISSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage				$ 38,537,356	$ 16,370,125	$ -	$ 5,713,153	$ 16,454,078	$ -	$ -	$ -
Transmission											
Demand	PTIS	PTISTD	TDEM	$ 82,135,229	$ 22,272,659	$ -	$ 7,738,805	$ 21,092,214	$ 1,683,972	$ 6,280,966	$ 23,066,613
Commodity	PTIS	PTISTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission				$ 82,135,229	$ 22,272,659	$ -	$ 7,738,805	$ 21,092,214	$ 1,683,972	$ 6,280,966	$ 23,066,613
Distribution Expenses											
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	PTIS	PTISDSD	DEM04	$ 4,187,315	$ 1,758,055	$ -	$ 610,850	$ 1,664,878	$ 132,921	$ 20,611	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 34,151,470	$ 15,016,808	$ -	$ 5,187,293	$ 12,631,869	$ 1,138,901	$ 176,598	$ -
Customer	PTIS	PTISDMC	CUST01	83,937,983	$ 71,390,493	$ -	$ 10,049,514	$ 2,336,668	$ 154,395	$ 6,913	$ -
Total Distribution Mains				118,089,453	$ 86,407,301	$ -	$ 15,236,807	$ 14,968,537	$ 1,293,296	$ 183,511	$ -
Services											
Customer	PTIS	PTISSC	CUST02	$ 27,869,219	$ 22,815,342	$ -	$ 2,992,565	$ 1,928,202	$ 127,406	$ 5,705	$ -
Meters											
Customer	PTIS	PTISMC	CUST03	$ 26,340,520	$ 16,246,119	$ 1,733,689	$ 3,675,110	$ 3,882,782	$ 748,817	$ 54,003	$ -
Customer Accounts											
Customer	PTIS	PTISCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service											
Customer	PTIS	PTISCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 297,159,092	$ 165,869,601	$ 1,733,689	$ 35,967,290	$ 59,990,691	$ 3,986,413	$ 6,544,795	$ 23,066,613

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	NCRB	RBGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	NCRB	RBSD	DEM02	$ 19,451,616	$ 8,262,772	$ -	$ 2,883,697	$ 8,305,147	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	30,053	$ 12,766	$ -	$ 4,455	$ 12,832	$ -	$ -	$ -
Total Storage				$ 19,481,669	$ 8,275,538	$ -	$ 2,888,152	$ 8,317,979	$ -	$ -	$ -
Transmission											
Demand	NCRB	RBTD	TDEM	$ 31,801,785	$ 8,623,709	$ -	$ 2,996,373	$ 8,166,655	$ 652,014	$ 2,431,915	$ 8,931,119
Commodity	NCRB	RBTC	COM03	21,502	$ 1,693	$ -	$ 621	$ 2,746	$ 1,991	$ 2,787	$ 11,665
Total Transmission				$ 31,823,287	$ 8,625,402	$ -	$ 2,996,994	$ 8,169,401	$ 654,005	$ 2,434,702	$ 8,942,783
Distribution Expenses											
Commodity	NCRB	RBDEC	COM04	$ 86,242	$ 20,372	$ -	$ 7,469	$ 33,041	$ 23,959	$ 1,402	$ -
Distribution Structures & Equipment											
Demand	NCRB	RBDSD	DEM04	$ 1,931,028	$ 810,747	$ -	$ 281,700	$ 767,778	$ 61,298	$ 9,505	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 16,822,830	$ 7,397,199	$ -	$ 2,555,233	$ 6,222,391	$ 561,017	$ 86,991	$ -
Customer	NCRB	RBDMC	CUST01	41,347,399	$ 35,166,573	$ -	$ 4,950,337	$ 1,151,030	$ 76,054	$ 3,405	$ -
Total Distribution Mains				58,170,229	$ 42,563,772	$ -	$ 7,505,569	$ 7,373,421	$ 637,071	$ 90,397	$ -
Services											
Customer	NCRB	RBSC	CUST02	$ 12,773,137	$ 10,456,823	$ -	$ 1,371,565	$ 883,742	$ 58,393	$ 2,615	$ -
Meters											
Customer	NCRB	RBMC	CUST03	$ 12,205,021	$ 7,527,727	$ 803,314	$ 1,702,882	$ 1,799,108	$ 346,968	$ 25,023	$ -
Customer Accounts											
Customer	NCRB	RBCAC	CUST04	$ 265,205	$ 190,732	$ 20,556	$ 27,080	$ 25,115	$ 895	$ 75	$ 751
Customer Service											
Customer	NCRB	RBCSC	CUST05	$ 168	$ 131	$ 14	$ 19	$ 4	$ 0	$ 0	$ -
Total		RBT		$ 136,735,988	$ 78,471,243	$ 823,884	$ 16,781,431	$ 27,369,587	$ 1,782,590	$ 2,563,718	$ 8,943,535

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OMT	OMGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		OMGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	OMT	OMSD	DEM02	$ 434,983	$ 184,775	$ -	$ 64,486	$ 185,722	$ -	$ -	$ -
Commodity	OMT	OMSC	COM02	240,427	$ 102,130	$ -	$ 35,643	$ 102,654	$ -	$ -	$ -
Total Storage		OMST		$ 675,410	$ 286,905	$ -	$ 100,129	$ 288,376	$ -	$ -	$ -
Transmission											
Demand	OMT	OMTD	TDEMOM	$ 7,748,257	$ 2,092,207	$ -	$ 726,953	$ 1,981,321	$ 158,186	$ 622,802	$ 2,166,788
Commodity	OMT	OMTC	COM03	172,020	$ 13,544	$ -	$ 4,966	$ 21,967	$ 15,929	$ 22,296	$ 93,319
Total Transmission		OMTRT		$ 7,920,276	$ 2,105,751	$ -	$ 731,919	$ 2,003,287	$ 174,115	$ 645,098	$ 2,260,107
Distribution Expenses											
Commodity	OMT	OMDEC	COM04	$ 689,940	$ 162,972	$ -	$ 59,754	$ 264,324	$ 191,671	$ 11,217	$ -
Distribution Structures & Equipment											
Demand	OMT	OMDSD	DEM04OM	$ 99,299	$ 18,613	$ 54,967	$ 6,467	$ 17,626	$ 1,407	$ 218	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$	776,432	$	340,927	$	1,090	$	117,767	$	286,782	$	25,856	$	4,009	$	-
Customer	OMT	OMDMC	CUST01OM		1,908,325	$	1,620,211	$	2,679	$	230,036	$	53,337	$	1,901	$	160	$	-
Total Distribution Mains					2,684,756	$	1,961,138	$	3,769	$	347,804	$	340,118	$	27,758	$	4,169	$	-
Services																			
Customer	OMT	OMSC	CUST02OM	$	727,317	$	541,421	$	65,964	$	71,015	$	45,757	$	3,023	$	135	$	-
Meters																			
Customer	OMT	OMMC	CUST03OM	$	1,086,965	$	469,381	$	376,027	$	106,181	$	112,181	$	21,635	$	1,560	$	-
Customer Accounts																			
Customer	OMT	OMCAC	CUST04OM	$	2,121,639	$	922,496	$	938,367	$	130,975	$	121,473	$	4,330	$	363	$	3,634
Customer Service																			
Customer	OMT	OMCSC	CUST05	$	1,346	$	1,050	$	113	$	148	$	33	$	1	$	0	$	-
Total		OMTT		$	16,006,948	$	6,469,727	$	1,439,208	$	1,554,394	$	3,193,177	$	423,940	$	662,761	$	2,263,741

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	LBTOT	LBGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		LBGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	LBTOT	LBSD	DEM02	$ 140,858	$ 59,834	$ -	$ 20,882	$ 60,141	$ -	$ -	$ -
Commodity	LBTOT	LBSC	COM02	6,992	$ 2,970	$ -	$ 1,037	$ 2,985	$ -	$ -	$ -
Total Storage		LBST		$ 147,849	$ 62,804	$ -	$ 21,919	$ 63,126	$ -	$ -	$ -
Transmission											
Demand	LBTOT	LBTD	TDEM	$ 5,033,811	$ 1,365,021	$ -	$ 474,287	$ 1,292,676	$ 103,205	$ 384,941	$ 1,413,680
Commodity	LBTOT	LBTC	COM03	206,497	$ 16,258	$ -	$ 5,961	$ 26,369	$ 19,121	$ 26,764	$ 112,023
Total Transmission		LBTRT		$ 5,240,308	$ 1,381,280	$ -	$ 480,248	$ 1,319,045	$ 122,327	$ 411,705	$ 1,525,703
Distribution Expenses											
Commodity	LBTOT	LBDEC	COM04	$ 378,495	$ 89,405	$ -	$ 32,781	$ 145,006	$ 105,149	$ 6,154	$ -
Distribution Structures & Equipment											
Demand	LBTOT	LBDSD	DEM04	$ 23,612	$ 9,914	$ -	$ 3,445	$ 9,388	$ 750	$ 116	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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																			
Distribution Mains																			
Demand	LBTOT	LBDMD	DEM05	$	344,467	$	151,466	$	-	$	52,321	$	127,411	$	11,487	$	1,781	$	-
Customer	LBTOT	LBDMC	CUST01		846,635	$	720,076	$	-	$	101,364	$	23,569	$	1,557	$	70	$	-
Total Distribution Mains					1,191,102	$	871,542	$	-	$	153,685	$	150,979	$	13,045	$	1,851	$	-
Services																			
Customer	LBTOT	LBSC	CUST02	$	294,253	$	240,893	$	-	$	31,597	$	20,359	$	1,345	$	60	$	-
Meters																			
Customer	LBTOT	LBMC	CUST03	$	417,181	$	257,306	$	27,458	$	58,206	$	61,496	$	11,860	$	855	$	-
Customer Accounts																			
Customer	LBTOT	LBCAC	CUST04	$	687,780	$	494,642	$	53,310	$	70,229	$	65,134	$	2,322	$	195	$	1,948
Customer Service																			
Customer	LBTOT	LBCSC	CUST05	$	39	$	31	$	3	$	4	$	1	$	0	$	0	$	-
Total		LBTT		$	8,380,620	$	3,407,816	$	80,771	$	852,114	$	1,834,534	$	256,797	$	420,936	$	1,527,652

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 1,056,225	$ 448,669	$ -	$ 156,585	$ 450,970	$ -	$ -	$ -
Commodity	DEPREX	DESC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		DEST		$ 1,056,225	$ 448,669	$ -	$ 156,585	$ 450,970	$ -	$ -	$ -
Transmission											
Demand	DEPREX	DETD	TDEM	$ 2,609,761	$ 707,690	$ -	$ 245,892	$ 670,183	$ 53,506	$ 199,571	$ 732,917
Commodity	DEPREX	DETC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		DETT		$ 2,609,761	$ 707,690	$ -	$ 245,892	$ 670,183	$ 53,506	$ 199,571	$ 732,917
Distribution Expenses											
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	DEPREX	DEDSD	DEM04	$ 128,976	$ 54,151	$ -	$ 18,815	$ 51,281	$ 4,094	$ 635	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 1,194,600	$ 525,280	$ -	$ 181,449	$ 441,856	$ 39,838	$ 6,177	$ -
Customer	DEPREX	DEDMC	CUST01	2,936,106	$ 2,497,202	$ -	$ 351,527	$ 81,735	$ 5,401	$ 242	$ -
Total Distribution Mains				4,130,707	$ 3,022,482	$ -	$ 532,975	$ 523,591	$ 45,239	$ 6,419	$ -
Services											
Customer	DEPREX	DESC	CUST02	$ 987,265	$ 808,232	$ -	$ 106,011	$ 68,306	$ 4,513	$ 202	$ -
Meters											
Customer	DEPREX	DEMC	CUST03	$ 990,097	$ 610,665	$ 65,167	$ 138,141	$ 145,947	$ 28,147	$ 2,030	$ -
Customer Accounts											
Customer	DEPREX	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service											
Customer	DEPREX	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 9,903,030	$ 5,651,889	$ 65,167	$ 1,198,421	$ 1,910,280	$ 135,500	$ 208,857	$ 732,917

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OTT	OTTGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		OTTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage											
Demand	OTT	OTTSD	DEM02	$ 498,047	$ 211,563	$ -	$ 73,835	$ 212,648	$ -	$ -	$ -
Commodity	OTT	OTTSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		OTTST		$ 498,047	$ 211,563	$ -	$ 73,835	$ 212,648	$ -	$ -	$ -
Transmission											
Demand	OTT	OTTTD	TDEM	$ 1,061,495	$ 287,846	$ -	$ 100,014	$ 272,590	$ 21,763	$ 81,174	$ 298,107
Commodity	OTT	OTTTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		OTTTT		$ 1,061,495	$ 287,846	$ -	$ 100,014	$ 272,590	$ 21,763	$ 81,174	$ 298,107
Distribution Expenses											
Commodity	OTT	OTTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	OTT	OTTDSD	DEM04	$ 54,116	$ 22,721	$ -	$ 7,894	$ 21,516	$ 1,718	$ 266	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$	456,676	$	200,806	$	-	$	69,365	$	168,914	$	15,229	$	2,361	$	-
Customer	OTT	OTTDMC	CUST01		1,122,425	$	954,639	$	-	$	134,383	$	31,246	$	2,065	$	92	$	-
Total Distribution Mains					1,579,102	$	1,155,445	$	-	$	203,748	$	200,160	$	17,294	$	2,454	$	-
Services																			
Customer	OTT	OTTSC	CUST02	$	360,175	$	294,860	$	-	$	38,675	$	24,920	$	1,647	$	74	$	-
Meters																			
Customer	OTT	OTTMC	CUST03	$	340,418	$	209,961	$	22,406	$	47,496	$	50,180	$	9,678	$	698	$	-
Customer Accounts																			
Customer	OTT	OTTCAC	CUST04	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service																			
Customer	OTT	OTTCSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		OTTT		$	3,893,352	$	2,182,396	$	22,406	$	471,663	$	782,015	$	52,099	$	84,666	$	298,107

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 337,690	$ 143,446	$ -	$ 50,062	$ 144,181	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		INTST		$ 337,690	$ 143,446	$ -	$ 50,062	$ 144,181	$ -	$ -	$ -
Transmission											
Demand	INT	INTTD	TDEM	$ 719,723	$ 195,168	$ -	$ 67,812	$ 184,824	$ 14,756	$ 55,038	$ 202,125
Commodity	INT	INTTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		INTTT		$ 719,723	$ 195,168	$ -	$ 67,812	$ 184,824	$ 14,756	$ 55,038	$ 202,125
Distribution Expenses											
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment											
Demand	INT	INTDSD	DEM04	$ 36,692	$ 15,405	$ -	$ 5,353	$ 14,589	$ 1,165	$ 181	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	$ 309,639	$ 136,152	$ -	$ 47,031	$ 114,529	$ 10,326	$ 1,601	$ -
Customer	INT	INTDMC	CUST01	761,035	$ 647,272	$ -	$ 91,115	$ 21,186	$ 1,400	$ 63	$ -
Total Distribution Mains				1,070,674	$ 783,424	$ -	$ 138,147	$ 135,714	$ 11,726	$ 1,664	$ -
Services											
Customer	INT	INTSC	CUST02	$ 244,208	$ 199,923	$ -	$ 26,223	$ 16,896	$ 1,116	$ 50	$ -
Meters											
Customer	INT	INTMC	CUST03	$ 230,813	$ 142,359	$ 15,192	$ 32,204	$ 34,023	$ 6,562	$ 473	$ -
Customer Accounts											
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service											
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 2,639,800	$ 1,479,725	$ 15,192	$ 319,801	$ 530,228	$ 35,325	$ 57,406	$ 202,125

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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	33,290,131	14,938,616	1,576,167	4,254,660	7,496,034	1,970,008	354,922	2,699,723
Miscellaneous Service Revenues		RCTREV	REVUC	82,420	$ 36,985	$ 3,902	$ 10,534	$ 18,559	$ 4,877	$ 879	$ 6,684
Other Gas Revenues		BDCH	REVUC	114,359	$ 51,317	$ 5,414	$ 14,616	$ 25,751	$ 6,767	$ 1,219	$ 9,274
Total Operating Revenues -- Per Books		TOR		$ 33,486,910	$ 15,026,919	$ 1,585,484	$ 4,279,809	$ 7,540,343	$ 1,981,653	$ 357,020	$ 2,715,682
Pro-Forma Adjustments to Revenues											
Temperature normalization		REVADJ1		$ (86,921)	$ (70,158)	$ -	$ (16,763)	$ -	$ -	$ -	$ -
Total Revenue Adjustments				$ (86,921)	$ (70,158)	$ -	$ (16,763)	$ -	$ -	$ -	$ -
Total Adjusted Revenue				$ 33,399,989	$ 14,956,760	$ 1,585,484	$ 4,263,046	$ 7,540,343	$ 1,981,653	$ 357,020	$ 2,715,682
Expenses											
Operation and Maintenance Expenses				$ 16,006,948	$ 6,469,727	$ 1,439,208	$ 1,554,394	$ 3,193,177	$ 423,940	$ 662,761	$ 2,263,741
Depreciation and Amortization Expenses				$ 9,903,030	5,651,889	65,167	1,198,421	1,910,280	135,500	208,857	732,917
Other Taxes				$ 3,893,352	2,182,396	22,406	471,663	782,015	52,099	84,666	298,107
Total Operating Expenses		TOE		$ 29,803,330	$ 14,304,012	$ 1,526,780	$ 3,224,478	$ 5,885,472	$ 611,539	$ 956,284	$ 3,294,765

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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 Test Period (Cont.)</u>											
Pro-Forma Adjustments to Expenses											
	EXADJ10	INTT		-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expense Adjustments	ADJTOT			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income Before Income Taxes				$ 3,596,659	$ 652,748	$ 58,704	$ 1,038,569	$ 1,654,871	$ 1,370,114	$ (599,264)	$ (579,084)
Income Taxes		TXINC		$ 282,424	$ (242,250)	$ 12,781	$ 212,234	$ 331,151	$ 393,947	$ (194,038)	$ (231,402)
Net Operating Income (Adjusted)	TOM			$ 3,314,235	$ 894,998	$ 45,923	$ 826,334	$ 1,323,720	$ 976,167	$ (405,226)	$ (347,682)
Net Cost Rate Base				$ 136,735,988	$ 78,471,243	$ 823,884	$ 16,781,431	$ 27,369,587	$ 1,782,590	$ 2,563,718	$ 8,943,535
Rate of Return -- Actual				2.42%	1.14%	5.57%	4.92%	4.84%	54.76%	-15.81%	-3.89%

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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 For Increase											
Test Year Operating Income				$ 3,314,235	$ 894,998	$ 45,923	$ 826,334	$ 1,323,720	$ 976,167	$ (405,226)	$ (347,682)
Proposed Increase				$ 9,135,170	$ 4,802,026	63,004	1,354,251	2,384,550	(24)	117,711	413,652
Increase To Misc Revenue			RCNCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Increase		CLSINC		$ 9,135,170	$ 4,802,026	$ 63,004	$ 1,354,251	$ 2,384,550	$ (24)	$ 117,711	$ 413,652
Incremental Income Taxes (@39.4445)			CLSINC	2,279,225	1,198,106	15,719	337,886	594,945	(6)	29,369	103,206
Net Operating Income Adjusted for Increase				10,170,179	4,498,919	93,207	1,842,700	3,113,325	976,149	(316,884)	(37,236)
Net Cost Rate Base				$ 136,735,988	$ 78,471,243	$ 823,884	$ 16,781,431	$ 27,369,587	$ 1,782,590	$ 2,563,718	$ 8,943,535
Rate of Return -- Proposed				7.44%	5.73%	11.31%	10.98%	11.38%	54.76%	-12.36%	-0.42%
				27.4%	32.1%	4.0%	31.8%	31.8%	0.0%	33.2%	15.3%

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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				27.4%	27.9%	-0.2%	25.9%	25.9%	0.0%	27.9%	16.3%
				9136208	$ 4,167,874	$ (2,739.65)	$ 1,101,957	$ 1,941,473	$ -	$ 99,023	440000
Commodity											
Procurement Expenses		COM01		17,821,882	1,386,493	212,047	508,362	2,248,749	1,630,649	2,282,421	9,553,161
					0.077797	0.011898	0.028525	0.126179			
Storage (Dec thru March)		COM02		2,901,000	1,232,304	-	430,072	1,238,624	-	-	-
Transmission		COM03		17,609,834	1,386,493	-	508,362	2,248,749	1,630,649	2,282,421	9,553,161
Distribution		COM04		5,869,685	1,386,493	-	508,362	2,248,749	1,630,649	95,433	-
				-	-	-	-	-	-	-	-
Demand									4,467.53		
Procurement Expenses		DEM01		85,288	22,302	3,081	7,749	21,120	1,686	6,253	23,097
Storage		DEM02		1.0000	0.4248	-	0.1482	0.4270	-	-	-
					0.4248	-	0.1482	0.4270			
Transmission		DEM03		82,207	22,302	-	7,749	21,120	1,686	6,253	23,097
Distribution Structures (Plant)		DEM04		53,119	22,302	-	7,749	21,120	1,686	261	-
Distribution Structures (O&M)											
Dist Structures Demand Allocator		DEMSTOM		53,119	22,302	-	7,749	21,120	1,686	261	-
Dist Structures O&M				99,299							
Specific Assignment				54,967	-	54,967	-	-	-	-	-
Residual Dist Structures O&M			DEMSTOM	44,332	$ 18,613	$ -	$ 6,467	$ 17,626	$ 1,407	$ 218	$ -
Total Allocation of Dist Structures O&M				99,299	18,613	54,967	6,467	17,626	1,407	218	-
Dist Structures Allocator		DEM04OM		1.0000	0.18744	0.55355	0.06513	0.17751	0.01417	0.00220	-
Distribution Mains		DEM05		50,563	22,233.0	-	7,680.0	18,702.0	1,686	261.460	-
Distribution Mains (O&M)											
Dist Mains Demand Allocator		DEMMNOM		50,563	22,233	-	7,680	18,702	1,686	261	-
Dist Mains O&M				776,432							
Specific Assignment				1,090	-	1,090	-	-	-	-	-
Residual Dist Mains O&M			DEMMNOM	775,341	$ 340,927	$ -	$ 117,767	$ 286,782	$ 25,856	$ 4,009	$ -
Total Allocation of Dist Mains O&M				776,432	340,927	1,090	117,767	286,782	25,856	4,009	-
Dist Mains Allocator		DEM05OM		1.0000	0.43909	0.00140	0.15168	0.36936	0.03330	0.00516	-
Customer											
Distribution Mains (Year-end Customers)		CUST01		36,425	30,980	-	4,361	1,014	67	3	-
Distribution Mains (O&M)											
Dist Mains Customer Allocator		CUSTMNOM		35,832	30,465	-	4,325	1,003	36	3	-
Dist Mains O&M				1,908,325							
Specific Assignment				2,679	-	2,679	-	-	-	-	-
Residual Dist Mains O&M			CUSTMNOM	1,905,646	$ 1,620,211	$ -	$ 230,036	$ 53,337	$ 1,901	$ 160	$ -
Total Allocation of Dist Mains O&M				1,908,325	1,620,211	2,679	230,036	53,337	1,901	160	-
Dist Mains Allocator		CUST01OM		1.0000	0.84902	0.00140	0.12054	0.02795	0.00100	0.00008	-
Services		CUST02		52,364,335	42,868,449	-	5,622,822	3,622,958	239,387	10,719	-
Services (O&M)											
Dist Services Allocator		CUSTSEROM		52,364,335	42,868,449	-	5,622,822	3,622,958	239,387	10,719	-
Dist Services O&M				727,317							
Specific Assignment				65,964	-	65,964	-	-	-	-	-
Residual Dist Services O&M			CUSTSEROM	661,353	$ 541,421	$ -	$ 71,015	$ 45,757	$ 3,023	$ 135	$ -
Total Allocation of Dist Services O&M				727,317	541,421	65,964	71,015	45,757	3,023	135	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

Class Allocation

Description	Ref	Allocation 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	0.74441	0.09070	0.09764	0.06291	0.00416	0.00019	-
Meters Plant Allocator		CUST03		26,773,352	16,513,078	1,762,177	3,735,500	3,946,585	761,122	54,890	-
Meters (O&M)											
Dist Meter Allocator		CUSTMTROM		25,011,175	16,513,078	-	3,735,500	3,946,585	761,122	54,890	-
Dist Meter O&M				1,086,965							
Specific Assignment				376,027	-	376,027	-	-	-	-	-
Residual Dist Meter O&M			CUSTMTROM	710,938	$ 469,381	$ -	$ 106,181	$ 112,181	$ 21,635	$ 1,560	$ -
Total Allocation of Dist Meter O&M				1,086,965	469,381	376,027	106,181	112,181	21,635	1,560	-
Dist Meter Allocator		CUST03OM		1.0000	0.43183	0.34594	0.09769	0.10321	0.01990	0.00144	-
Customer Count (Average)				39,115	30,465	3,283	4,325	1,003	36	3	-
Customer Accounts		CUST04		42,360	30,465	3,283	4,325	4,012	143	12	120
Customer Accounts (O&M)											
Cust Acc Allocator		CUSTACOM		39,077	30,465	-	4,325	4,012	143	12	120
Cust Acc O&M				2,121,639							
Specific Assignment				938,367	-	938,367	-	-	-	-	-
Residual Cust Acc O&M			CUSTACOM	1,183,271	$ 922,496	$ -	$ 130,975	$ 121,473	$ 4,330	$ 363	$ 3,634
Total Allocation of Cust Acc				2,121,639	922,496	938,367	130,975	121,473	4,330	363	3,634
Cust Accounts Allocator		CUST04OM		1.0000	0.43480	0.44228	0.06173	0.05725	0.00204	0.00017	0.00171
Customer Count (Average)				39,018	30,441	3,283	4,304	963	24	3	-
Customer Accounts		CUST04		42,107	30,441	3,283	4,304	3,852	94	12	120
Customer Service		CUST05		39,018	30,441	3,283	4,304	963	24	3	-
Customer Service (O&M)											
Cust Serv Allocator		CUSTSEROM		35,735	30,441	-	4,304	963	24	3	-
Cust Serv O&M				1,346							
Specific Assignment				1,573	-	1,573	-	-	-	-	-
Residual Cust Serv O&M			CUSTSEROM	(227)	$ (186)	$ -	$ (24)	$ (16)	$ (1)	$ (0)	$ -
Total Allocation of Cust Serv				1,346	(186)	1,573	(24)	(16)	(1)	(0)	-
Cust Service Allocator		CUST05OM		1.0000	(0.13796)	1.16851	(0.01809)	(0.01166)	(0.00077)	(0.00003)	-
Forfeited Discounts		REVFD		1	1	-	-	-	-	-	-

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2022

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			$ 3,596,659	$ 652,748	$ 58,704	$ 1,038,569	$ 1,654,871	$ 1,370,114	$ (599,264)	$ (579,084)
Interest Expense	INT	PLT		$ 2,639,800	$ 1,473,495	$ 15,401	$ 319,514	$ 532,925	$ 35,413	$ 58,140	$ 204,911
Interest Adjustment		PLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable Income	TXINC			$ 956,859	$ (820,747)	$ 43,303	$ 719,055	$ 1,121,946	$ 1,334,701	$ (657,404)	$ (783,995)
Meter Allocation											
Number of Customers				36,425	30,980	3,306	4,361	1,014	67	3	-
Average Cost Per Service					533.02	533.02	856.57	3,892.10	11,360.03	18,296.78	
Meter Cost				26,773,352	16,513,078	1,762,177	3,735,500	3,946,585	761,122	54,890	-
Service Line Allocation											
Number of Customers				36,425	30,980	-	4,361	1,014	67	3	-
Average Cost Per Service					1,383.75	-	1,289.34	3,572.94	3,572.94	3,572.94	0
Service Cost				52,364,335	42,868,449	-	5,622,822	3,622,958	239,387	10,719	-
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				82,207	22,302	-	7,749	21,120	1,686	6,253	23,097
Transmission Plant				$ 82,135,229							
Specific Assignment				$ 36,192.40	$ -	$ -	$ -	$ -	$ -	$ 36,192.40	
Residual Transmission Plant		DEM03		82,099,036	$ 22,272,659	$ -	$ 7,738,805	$ 21,092,214	$ 1,683,972	$ 6,244,773	$ 23,066,613
Total Allocation of Transmission Plant				$ 82,135,229	$ 22,272,658.94	$ -	$ 7,738,805.23	$ 21,092,214.01	$ 1,683,971.61	$ 6,280,965.80	$ 23,066,613.02
Transmission Allocator	TDEM			1.000000	0.271170597	0	0.094220292	0.256798628	0.020502428	0.076471033	0.280837022
Transmission Demand Allocator				82,207	22,302	-	7,749	21,120	1,686	6,253	23,097
Transmission Plant				$ 7,748,257							
Specific Assignment				$ 36,192.40	$ -	$ -	$ -	$ -	$ -	$ 36,192.40	
Residual Transmission Plant		DEM03		7,712,065	$ 2,092,207	$ -	$ 726,953	$ 1,981,321	$ 158,186	$ 586,610	$ 2,166,788
Total Allocation of Transmission Plant				$ 7,748,257	$ 2,092,207.05	$ -	$ 726,953.30	$ 1,981,320.64	$ 158,185.75	$ 622,802.15	$ 2,166,788.02
Transmission Allocator	TDEMOM			1.000000	0.270022933	0	0.093821527	0.25571179	0.020415656	0.080379647	0.279648447

Exhibit WSS-4

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 68 Degree Days
<u>For Determination of Demand Allocation Factors</u>

	Total	Residential	Small Non Residential GS	Large Non Residential GS
Non-Temp Sensitive Load (per Day)	4,727	746	337	3,644
Temp Sensitive Load (per Degree Day)	683	317	109	257
Calculated Daily Requirements at -3 Degrees	51,171	22,302	7,749	21,120
Percentage of Total		43.58%	15.14%	41.27%

Allocation of Underground Storage

	Storage Withdrawals	Residential	Small Non Residential GS	Large Non Residential GS
Total Allocated Withdrawals Thru February 9th				
December	459,871	185,886	65,452	208,533
January	497,651	203,916	71,618	222,117
Feb. 1-9	154,735	62,909	22,127	69,699
Total	1,112,257	452,711	159,197	500,349
Balance of Working Gas Allocated on the Basis of -3 Degree Feb. 10 Design Day	1,788,743	779,593	270,875	738,275
Total Working Gas	2,901,000	1,232,304	430,072	1,238,624
Total Allocation Factor For Underground Storage	1.000000	0.424786	0.148250	0.426964

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)	746	337	3,644	0	4,727
Temperature Sensitive Load (per Degree Day)	317	109	257	0	683

		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	5,184	1,863	7,242	0	14,289	0	0	0	0
2	14	5,184	1,863	7,242	0	14,289	0	0	0	0
3	14	5,184	1,863	7,242	0	14,289	0	0	0	0
4	14	5,184	1,863	7,242	0	14,289	0	0	0	0
5	15	5,501	1,972	7,499	0	14,972	0	0	0	0
6	15	5,501	1,972	7,499	0	14,972	0	0	0	0
7	15	5,501	1,972	7,499	0	14,972	0	0	0	0
8	15	5,501	1,972	7,499	0	14,972	0	0	0	0
9	16	5,818	2,081	7,756	0	15,655	0	0	0	0
10	16	5,818	2,081	7,756	0	15,655	0	0	0	0
11	17	6,135	2,190	8,013	0	16,338	0	0	0	0
12	17	6,135	2,190	8,013	0	16,338	0	0	0	0
13	18	6,452	2,299	8,270	0	17,021	0	0	0	0
14	18	6,452	2,299	8,270	0	17,021	0	0	0	0
15	19	6,769	2,408	8,527	0	17,704	0	0	0	0
16	19	6,769	2,408	8,527	0	17,704	0	0	0	0
17	20	7,086	2,517	8,784	0	18,387	0	0	0	0
18	20	7,086	2,517	8,784	0	18,387	0	0	0	0
19	20	7,086	2,517	8,784	0	18,387	0	0	0	0
20	21	7,403	2,626	9,041	0	19,070	0	0	0	0
21	21	7,403	2,626	9,041	0	19,070	0	0	0	0
22	21	7,403	2,626	9,041	0	19,070	0	0	0	0
23	22	7,720	2,735	9,298	0	19,753	0	0	0	0
24	22	7,720	2,735	9,298	0	19,753	0	0	0	0
25	22	7,720	2,735	9,298	0	19,753	0	0	0	0
26	22	7,720	2,735	9,298	0	19,753	0	0	0	0
27	23	8,037	2,844	9,555	0	20,436	0	0	0	0
28	23	8,037	2,844	9,555	0	20,436	0	0	0	0
29	24	8,354	2,953	9,812	0	21,119	0	0	0	0
30	24	8,354	2,953	9,812	0	21,119	0	0	0	0
Total	561	200,217	71,259	253,497	0	524,973	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)	746	337	3,644	0	4,727
Temperature Sensitive Load (per Degree Day)	317	109	257	0	683

		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	25	8,671	3,062	10,069	0	21,802	13,649	5,428	1,917	6,304
2	25	8,671	3,062	10,069	0	21,802	12,537	4,986	1,761	5,790
3	26	8,988	3,171	10,326	0	22,485	12,556	5,019	1,771	5,766
4	26	8,988	3,171	10,326	0	22,485	13,466	5,383	1,899	6,184
5	26	8,988	3,171	10,326	0	22,485	13,859	5,540	1,954	6,365
6	26	8,988	3,171	10,326	0	22,485	13,994	5,594	1,974	6,427
7	26	8,988	3,171	10,326	0	22,485	14,387	5,751	2,029	6,607
8	26	8,988	3,171	10,326	0	22,485	14,388	5,751	2,029	6,608
9	27	9,305	3,280	10,583	0	23,168	14,390	5,780	2,037	6,573
10	27	9,305	3,280	10,583	0	23,168	14,391	5,780	2,037	6,574
11	27	9,305	3,280	10,583	0	23,168	13,950	5,603	1,975	6,372
12	28	9,622	3,389	10,840	0	23,851	14,342	5,786	2,038	6,518
13	28	9,622	3,389	10,840	0	23,851	14,343	5,786	2,038	6,519
14	28	9,622	3,389	10,840	0	23,851	14,735	5,944	2,094	6,697
15	29	9,939	3,498	11,097	0	24,534	14,735	5,969	2,101	6,665
16	29	9,939	3,498	11,097	0	24,534	14,753	5,976	2,103	6,673
17	29	9,939	3,498	11,097	0	24,534	14,753	5,976	2,103	6,673
18	29	9,939	3,498	11,097	0	24,534	15,144	6,135	2,159	6,850
19	30	10,256	3,607	11,354	0	25,217	15,144	6,159	2,166	6,819
20	30	10,256	3,607	11,354	0	25,217	15,535	6,318	2,222	6,995
21	30	10,256	3,607	11,354	0	25,217	15,483	6,297	2,215	6,971
22	30	10,256	3,607	11,354	0	25,217	15,483	6,297	2,215	6,971
23	30	10,256	3,607	11,354	0	25,217	15,874	6,456	2,271	7,147
24	30	10,256	3,607	11,354	0	25,217	15,874	6,456	2,271	7,147
25	30	10,256	3,607	11,354	0	25,217	15,874	6,456	2,271	7,147
26	30	10,256	3,607	11,354	0	25,217	16,007	6,510	2,290	7,207
27	31	10,573	3,716	11,611	0	25,900	16,007	6,535	2,297	7,176
28	31	10,573	3,716	11,611	0	25,900	16,007	6,535	2,297	7,176
29	31	10,573	3,716	11,611	0	25,900	16,069	6,560	2,306	7,204
30	31	10,573	3,716	11,611	0	25,900	16,069	6,560	2,306	7,204
31	31	10,573	3,716	11,611	0	25,900	16,069	6,560	2,306	7,204
Total	882	302,720	106,585	339,638	0	748,943	459,867	185,886	65,452	208,533

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)	746	337	3,644	0	4,727
Temperature Sensitive Load (per Degree Day)	317	109	257	0	683

		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	31	10,573	3,716	11,611	0	25,900	15,613	6,374	2,240	6,999
2	31	10,573	3,716	11,611	0	25,900	15,586	6,363	2,236	6,987
3	31	10,573	3,716	11,611	0	25,900	15,602	6,369	2,239	6,994
4	31	10,573	3,716	11,611	0	25,900	15,596	6,367	2,238	6,992
5	32	10,890	3,825	11,868	0	26,583	15,602	6,392	2,245	6,966
6	32	10,890	3,825	11,868	0	26,583	15,728	6,443	2,263	7,022
7	32	10,890	3,825	11,868	0	26,583	15,727	6,443	2,263	7,021
8	32	10,890	3,825	11,868	0	26,583	15,734	6,446	2,264	7,025
9	32	10,890	3,825	11,868	0	26,583	15,731	6,444	2,264	7,023
10	32	10,890	3,825	11,868	0	26,583	15,722	6,441	2,262	7,019
11	32	10,890	3,825	11,868	0	26,583	15,745	6,450	2,266	7,029
12	33	11,207	3,934	12,125	0	27,266	15,720	6,461	2,268	6,991
13	33	11,207	3,934	12,125	0	27,266	15,712	6,458	2,267	6,987
14	33	11,207	3,934	12,125	0	27,266	15,681	6,445	2,263	6,973
15	34	11,524	4,043	12,382	0	27,949	15,720	6,482	2,274	6,964
16	34	11,524	4,043	12,382	0	27,949	16,115	6,645	2,331	7,139
17	34	11,524	4,043	12,382	0	27,949	16,107	6,641	2,330	7,136
18	33	11,207	3,934	12,125	0	27,266	16,109	6,621	2,324	7,164
19	33	11,207	3,934	12,125	0	27,266	16,133	6,631	2,328	7,174
20	33	11,207	3,934	12,125	0	27,266	16,112	6,623	2,325	7,165
21	32	10,890	3,825	11,868	0	26,583	15,992	6,551	2,301	7,140
22	32	10,890	3,825	11,868	0	26,583	15,999	6,554	2,302	7,143
23	32	10,890	3,825	11,868	0	26,583	16,000	6,555	2,302	7,143
24	32	10,890	3,825	11,868	0	26,583	16,390	6,714	2,358	7,317
25	32	10,890	3,825	11,868	0	26,583	16,390	6,714	2,358	7,317
26	32	10,890	3,825	11,868	0	26,583	16,523	6,769	2,377	7,377
27	31	10,573	3,716	11,611	0	25,900	16,912	6,904	2,426	7,582
28	31	10,573	3,716	11,611	0	25,900	16,912	6,904	2,426	7,582
29	31	10,573	3,716	11,611	0	25,900	16,912	6,904	2,426	7,582
30	31	10,573	3,716	11,611	0	25,900	16,912	6,904	2,426	7,582
31	31	10,573	3,716	11,611	0	25,900	16,912	6,904	2,426	7,582
Total	995	338,541	118,902	368,679	0	826,122	497,654	203,916	71,618	222,117

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)	746	337	3,644	0	4,727
Temperature Sensitive Load (per Degree Day)	317	109	257	0	683

		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	31	10,573	3,716	11,611	0	25,900	16,348	6,674	2,346	7,329
2	30	10,256	3,607	11,354	0	25,217	16,321	6,638	2,335	7,349
3	30	10,256	3,607	11,354	0	25,217	15,952	6,488	2,282	7,182
4	30	10,256	3,607	11,354	0	25,217	15,560	6,328	2,226	7,006
5	30	10,256	3,607	11,354	0	25,217	15,180	6,174	2,171	6,835
6	30	10,256	3,607	11,354	0	25,217	15,306	6,225	2,189	6,891
7	30	10,256	3,607	11,354	0	25,217	15,305	6,225	2,189	6,891
8	30	10,256	3,607	11,354	0	25,217	14,926	6,070	2,135	6,720
9	29	9,939	3,498	11,097	0	24,534	14,923	6,045	2,128	6,750
10	29	9,939	3,498	11,097	0	24,534	14,914	6,042	2,126	6,746
Total	299	102,243	35,961	113,283	0	251,487	154,734	62,909	22,127	69,699

Exhibit WSS-5

Zero Intercept Analysis
Distribution Mains

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2022

Weighted Linear Regression Statistics

		Estimate	Standard Error
Size Coefficient ($ per Foot)		1.2282658	0.7530723
Zero Intercept ($ per Foot)		7.9727703	2.1847521
R-Square		0.9457323	

Plant Classification

Total Number of Units		8,705,759
Zero Intercept		7.9727703
Zero Intercept Cost	$	69,409,017
Total Cost of Sample	$	97,654,497
Percentage of Total		0.710761092
Percentage Classified as Customer-Related		71.08%
Percentage Classified as Demand-Related		28.92%

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2022

Description	Pipe Size		Cost of Plant	Quantity (Feet)	Unit Cost ($ per Foot)
Distribution Main Pipe, Under 2" Plastic	1.500	$	6,272,663	505,775	12.40208
Distribution Main Pipe, 2" Plastic	2.000	$	54,818,890	5,403,545	10.14499
Distribution Main Pipe, 3" Plastic	3.000	$	214,908	79,537	2.70199
Distribution Main Pipe, 4" Plastic	4.000	$	27,245,688	1,742,521	15.63579
Distribution Main Pipe, 6" Plastic	6.000	$	1,801,713	69,388	25.96577
Distribution Main Pipe, Under 2" Steel	1.500	$	197,690	42,719	4.62768
Distribution Main Pipe, 2" Steel	2.000	$	677,653	231,970	2.92130
Distribution Main Pipe, 3" Steel	3.000	$	113,819	23,367	4.87093
Distribution Main Pipe, 4" Steel	4.000	$	3,664,240	302,706	12.10495
Distribution Main Pipe, 6" Steel	6.000	$	1,985,802	218,670	9.08127
Distribution Main Pipe, 8" Steel	8.000	$	661,431	85,561	7.73052
Total		$	97,654,497.00	8,705,759	

Exhibit WSS-6

Cost Component for Residential Service

Delta Natural Gas Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended December 31, 2022

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	$ 35,166,573	$ 18,175,412	$ 53,341,985	$ 25,129,258	$78,471,243
(2)	Rate of Return	Proposed Overall ROR	7.44%	7.44%	7.44%	7.44%	7.44%
(3)	Return	(1) x (2)	$ 2,615,627	$ 1,351,855	$ 3,967,482	$ 1,869,069	$ 5,836,551
(4)	Interest Expenses	Exhibit 2 Pages 25 & 27	$ 647,272	$ 342,282	$ 989,554	$ 490,171	$ 1,479,725
(5)	Net Income	(3) - (4)	$ 1,968,355	$ 1,009,573	$ 2,977,928	$ 1,378,899	$ 4,356,827
(6)	Income Taxes		$ 447,570	$ 229,560	$ 677,130	$ 313,538	$ 990,668
(7)	Operation and Maintenance Expenses	Exhibit 2 Pages 9 & 11	$ 1,620,211	$ 1,934,348	$ 3,554,560	$ 2,915,168	$ 6,469,727
(8)	Depreciation Expenses	Exhibit 2 Pages 17 & 19	2,497,202	1,418,897	3,916,098	1,735,791	5,651,889
(9)	Other Taxes	Exhibit 2 Pages 21 & 23	954,639	504,820	1,459,460	722,936	2,182,396
(10)	Expense Adjustments	Exhibit 2 Page 29	-	-	-	-	-
(11)	Total Cost of Service	(3)+(6)+(7)+(8)+(9)+(10)	$ 8,135,250	$ 5,439,480	$ 13,574,729	$ 7,556,502	$21,131,231
(12)	Less: Misc Revenue	Exhibit 2 Page 29	14,239	9,521	23,759	13,226	36,985
(13)	Net Cost of Service	(11) - (12)	$ 8,121,011	$ 5,429,959	$ 13,550,970	$ 7,543,276	$21,094,246
(14)	Billing Units	Exhibit 2 Page 35	30,465	30,465	30,465	1,386,493	
(15)	Unit Costs	(13) / (14)	$22.21/Cust/Mo	$14.85/Cust/Mo	$37.07/Cust/Mo	$5.4405/Mcf	

Exhibit WSS-7

Depreciation Study

The Prime Group LLC

2021 Depreciation Study

Delta Natural Gas Company

May 2021

William Steven Seelye
Managing Partner
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 depreciation filed depreciation studies in Case Nos. 2004-00067, 2007-00089 and 2010-00116 using 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 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 32 counties in the central and eastern part of Kentucky.

Description of Life Methodology

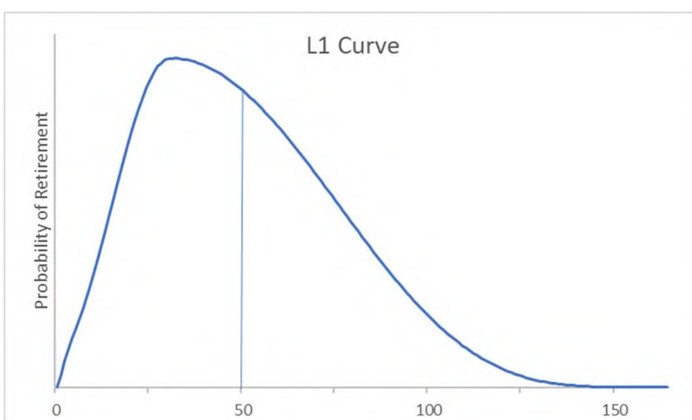
The purpose of performing a depreciation study is to ensure that the depreciation expenses recorded by the utility and included in cost of service represent a reasonably accurate and systematic measurement of the annual accrual levels necessary to distribute plant costs, less salvage and removal, over 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 2014, 2017, and 2020. 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.

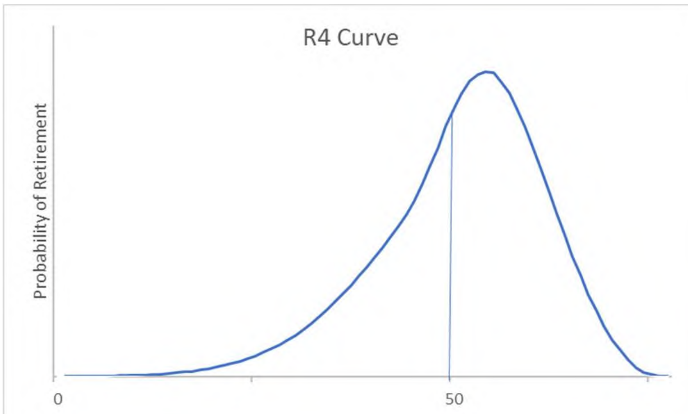
The original Iowa State publications identified four classes of survivor curves: (i) Left-Model Curves ("L" curves), (ii) Right-Model Curves ("R" curves), (iii) Symmetrical Curves ("S" curves), and (iv) Origin Model Curves ("O" curves).

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:



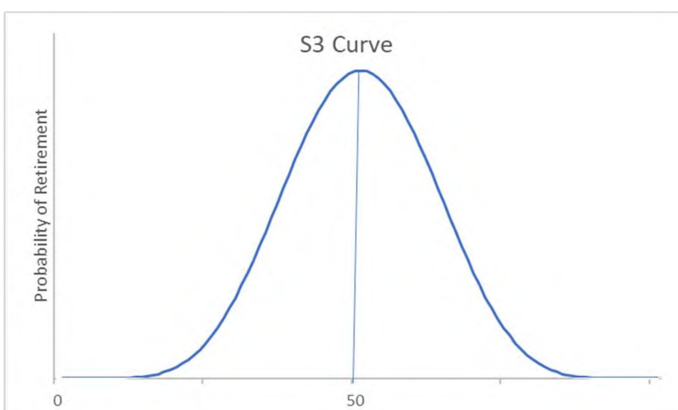
A characteristic of the "L" class of survivor curves is that while a high percentage of the property is retired prior to the average service life, the longer the property has been in service the less likely it is to fail, as illustrated by the long tail of the probability density curve on the right.

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:

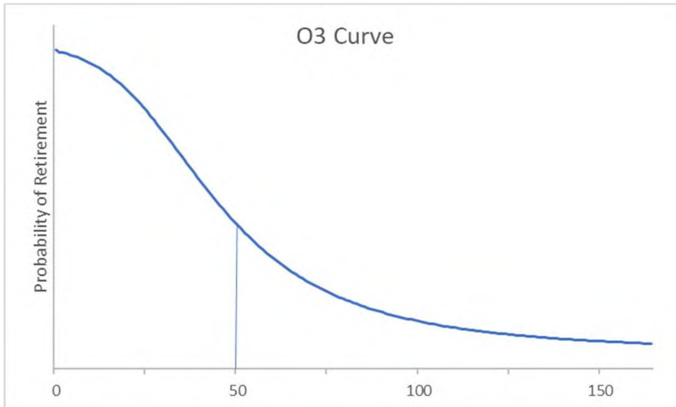


A characteristic of the “R” class of survivor curves is that most of the property is retired after the average service life. However, the longer the property has been in service the more likely it is to fail, as illustrated by the short tail of the probability density curve on the right.

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:

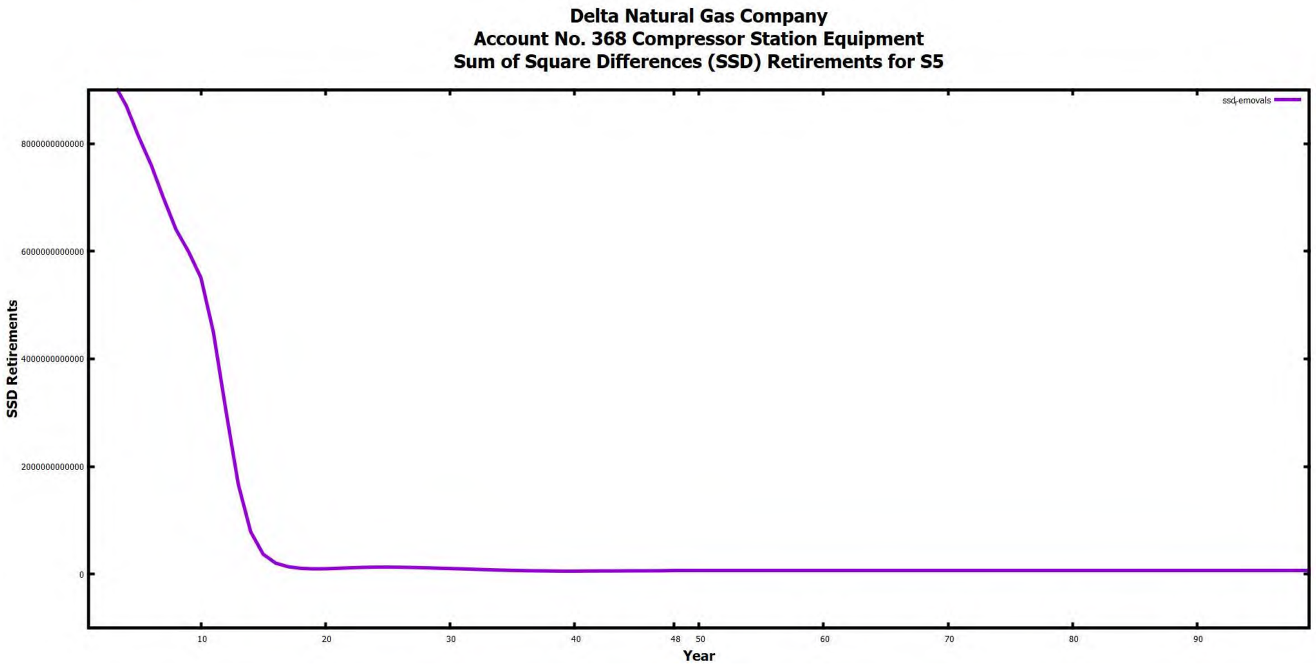


In addition to the curves identified in the Iowa State publications, so-called “half curves” were also utilized in the SPR analysis. Half curves are simple averages between two curves within the same class of Iowa Curves. For example, The S1.5 curve represents the simple average of an S1 and S2 curve.

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 48 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, 20 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 20 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 20-year period and the most recent five and ten years. Comparison of the 5-year average net salvage percentages to the 10- and 20-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 2019, which reflects the data utilized in Delta's 2009 Depreciation Study updated to include the 2010 to 2020 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 53 years. The R5 curve with an ASL of 53 years results in a remaining life of 32.82 years. Using a negative net salvage of zero for this account results in a depreciation rate of 3.05%, which is a slight reduction from the current depreciation rate of 3.11%.

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 L1 curve is recommended using an ASL of 49 years.

The L1 curve with an ASL of 49 years results in a remaining life of 34.9 years. With a negative net salvage of -11%, the depreciation rate is 3.18%, which is the same as the current depreciation rate.

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 45.1 years. Using a negative net salvage of -15% for this account results in a depreciation rate of 3.10%, which is a slight reduction from the current depreciation rate of 3.11%.

For Account 381 – Meters, Delta's records included plant additions dating back to 1940. Account 381 was analyzed using the SPR model. Based on the SPR analysis, the O2 curve is recommended using an ASL of 46 years. The O2 curve with an ASL of 46 years results in a remaining life of 35 years. Using a negative net salvage of zero for this account results in a depreciation rate of 2.86%, which is a slight reduction from the current depreciation rate of 2.90%.

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 28 years. Using a negative net salvage of -12 for this account results in a depreciation rate of 4.0%, which is the same as the current depreciation rate.

For Account 383 – House Regulators, Delta's records included plant additions dating back to 1940. 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 24.5 years. Using a net salvage of 3% for this account results in a depreciation rate of 3.96%, which is a slight reduction from the current depreciation rate of 4.13%.

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 37.9 years. Using a net salvage of zero for this account results in a depreciation rate of 2.64%, which is a slight reduction from the current depreciation rate of 2.15%.

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 53 years. The S3 curve with an ASL of 53 years results in a remaining life of 35.5 years. Using a negative net salvage of -2.3% for this account results in a depreciation rate of 2.88%, which is an increase from the current depreciation rate of 2.35%.

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 48 years. The S5 curve with an ASL of 48 years results in a remaining life of 31.6 years. Using a negative net salvage of -1% for this account results in a depreciation rate of 3.20%, which is a slight reduction from the current depreciation rate of 3.26%.

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 44 years. The S5 curve with an ASL of 44 years results in a remaining life of 30.0 years. Using a negative net salvage of -5% for this account results in a depreciation rate of 3.50%, which is a slight decrease from the current depreciation rate of 3.53%.

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	R3	S3	43	53	42.5	35.5		-2.3	2.35%	2.88%
368	COMPRESSOR STATTION EQUIPMENT	S4	S5	36	48	30.7	31.6		-1	3.26%	3.20%
369	MEASURING & REG STAT EQUIPMENT	S3	L2	39	44	28.3	30.0		-5	3.53%	3.50%
376	DISTRIBUTION MAINS	R3	R5	37	53	31.8	32.82	1	0	3.11%	3.05%
378	MEAS & REG STAT - GENERAL	R1	L1	36	49	31.4	34.9		-11	3.18%	3.18%
380	SERVICES	R1	L0	40	53	30.3	45.1		-40	3.11%	3.10%
381	METERS	S1	O2	46	46	35	35	0	0	2.90%	2.86%
382	METER & REGULATOR INSTALLATION	S1	S0	40	43	25.5	28	-1.75	-12	4.00%	4.00%
383	HOUSE REGULATORS	S6	S3	28	43	24.15	24.5	0.25	3	4.13%	3.96%
385	INDUSTRIAL METER SETS	R1	L0	52	49	46.3	37.9	0.32		2.15%	2.64%

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	2.35%	2.88%
368	COMPRESSOR STATTION EQUIPMENT	3.26%	3.20%
369	MEASURING & REG STAT EQUIPMENT	3.53%	3.50%
376	DISTRIBUTION MAINS	3.11%	3.05%
378	MEAS & REG STAT - GENERAL	3.18%	3.18%
380	SERVICES	3.11%	3.10%
381	METERS	2.90%	2.86%
382	METER & REGULATOR INSTALLATION	4.00%	4.00%
383	HOUSE REGULATORS	4.13%	3.96%
385	INDUSTRIAL METER SETS	2.15%	2.64%

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

		Survivor Curve		Average Srervice Life (ASL)		Remaining Life		Net Salvage		Depreciation Rates	
Account	Description	Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	Current	Recommended
367	TRANSMISSION MAINS	R3	S3	43	53	42.5	35.5		-2.3	2.35%	2.88%
368	COMPRESSOR STATION EQUIPMENT	S4	S5	36	48	30.7	31.6		-1	3.26%	3.20%
369	MEASURING & REG STAT EQUIPMENT	S3	L2	39	44	28.3	30.0		-5	3.53%	3.50%
376	DISTRIBUTION MAINS	R3	R5	37	53	31.8	32.82	1	0	3.11%	3.05%
378	MEAS & REG STAT - GENERAL	R1	L1	36	49	31.4	34.9		-11	3.18%	3.18%
380	SERVICES	R1	L0	40	53	30.3	45.1		-40	3.11%	3.10%
381	METERS	S1	O2	46	46	35	35	0	0	2.90%	2.86%
382	METER & REGULATOR INSTALLATION	S1	S0	40	43	25.5	28	-1.75	-12	4.00%	4.00%
383	HOUSE REGULATORS	S6	S3	28	43	24.15	24.5	0.25	3	4.13%	3.96%
385	INDUSTRIAL METER SETS	R1	L0	52	49	46.3	37.9	0.32		2.15%	2.64%

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	2.35%	2.88%	-0.53%
368	COMPRESSOR STATION EQUIPMENT	3.26%	3.20%	0.06%
369	MEASURING & REG STAT EQUIPMENT	3.53%	3.50%	0.03%
376	DISTRIBUTION MAINS	3.11%	3.05%	0.06%
378	MEAS & REG STAT - GENERAL	3.18%	3.18%	0.00%
380	SERVICES	3.11%	3.10%	0.01%
381	METERS	2.90%	2.86%	0.04%
382	METER & REGULATOR INSTALLATION	4.00%	4.00%	0.00%
383	HOUSE REGULATORS	4.13%	3.96%	0.17%
385	INDUSTRIAL METER SETS	2.15%	2.64%	-0.49%

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 = 53

Year	Additions	Actual Retirements	Balance	Simmulated 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	1016210	-0	1
1961	0	0	1016211	1	1016209	-1	2
1962	11049	0	1027260	2	1027257	-2	3
1963	5069	0	1032329	3	1032323	-3	6
1964	43691	0	1076020	6	1076008	-6	12
1965	401158	2041	1475137	10	1477156	2031	-2019
1966	185675	3161	1657651	15	1662816	3146	-5165
1967	42318	253	1699716	25	1705109	228	-5393
1968	570758	857	2269617	38	2275829	819	-6212
1969	10242	0	2279859	59	2286012	-59	-6153
1970	30291	0	2310150	90	2316213	-90	-6063
1971	390160	2034	2698276	126	2706247	1908	-7971
1972	220046	1507	2916815	185	2926108	1322	-9293
1973	20159	16495	2920479	260	2946007	16235	-25528
1974	155219	1027	3074671	356	3100870	671	-26199
1975	1038377	2117	4110931	488	4138759	1629	-27828
1976	667139	20496	4757574	650	4805248	19846	-47674
1977	32582	3803	4786353	850	4836979	2953	-50626
1978	351269	0	5137622	1118	5187130	-1118	-49508

Delta Natural Gas Company
Account 367 -- Transmission Mains

Simulated Retirements for Iowa Curve S3 with ASL = 53

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1979	157163	49379	5245406	1436	5342858	47943	-97452
1980	637037	55435	5827008	1809	5978086	53626	-151078
1981	94865	6555	5915318	2297	6070654	4258	-155336
1982	67797	0	5983115	2852	6135600	-2852	-152485
1983	100369	1955	6081529	3497	6232472	-1542	-150943
1984	124371	4268	6201632	4313	6352530	-45	-150898
1985	920732	68009	7054355	5189	7268073	62820	-213718
1986	679514	6010	7727859	6241	7941346	-231	-213487
1987	367787	37158	8058488	7498	8301634	29660	-243146
1988	407419	25639	8440268	8825	8700228	16814	-259960
1989	1575177	91099	9924346	10436	10264969	80663	-340623
1990	375466	55172	10244640	12229	10628206	42943	-383566
1991	590206	26277	10808569	14180	11204232	12097	-395663
1992	770645	69983	11509231	16485	11958392	53498	-449161
1993	1311531	10603	12810159	18918	13251005	-8315	-440846
1994	2015785	149281	14676663	21677	15245112	127604	-568449
1995	2576777	192503	17060937	24762	17797128	167741	-736191
1996	2231947	299672	18993212	28006	20001069	271666	-1007857
1997	983281	16271	19960222	31681	20952668	-15410	-992446
1998	1073527	22418	21011331	35624	21990571	-13206	-979240
1999	4791367	11535	25791163	39867	26742071	-28332	-950908
2000	1951563	56873	27685853	44491	28649142	12382	-963289
2001	710776	131121	28265508	49409	29310509	81712	-1045001
2002	3267445	0	31532953	54747	32523207	-54747	-990254
2003	4131461	71705	35592709	60384	36594284	11321	-1001575
2004	1726918	197446	37122181	66423	38254779	131023	-1132598
2005	639279	281	37761179	72881	38821177	-72600	-1059998
2006	3695479	9636	41447022	79661	42436995	-70025	-989973

Delta Natural Gas Company
Account 367 -- Transmission Mains

Simulated Retirements for Iowa Curve S3 with ASL = 53

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2007	23029	413654	41056396	86984	42373040	326671	-1316644
2008	422077	30824	41447649	94652	42700465	-63828	-1252816
2009	584129	16882	42014896	102856	43181739	-85974	-1166842
2010	132196	10519	42136573	111611	43202323	-101092	-1065751
2011	171642	5091	42303123	120779	43253186	-115688	-950063
2012	125059	31477	42396705	130776	43247469	-99299	-850764
2013	82313	827	42478191	141313	43188468	-140487	-710277
2014	414762	10678	42882274	152501	43450729	-141822	-568455
2015	1738289	4801	44615762	164793	45024225	-159992	-408463
2016	252006	34975	44832793	177687	45098544	-142712	-265751
2017	218446	28149	45023090	191674	45125316	-163525	-102226
2018	951614	39298	45935407	206889	45870041	-167591	65366
2019	659733	5126	46590014	222948	46306827	-217822	283187
2020	243108	28574	46804548	240504	46309431	-211930	495118

Account No. 367 -- Transmission Mains
Iowa Curve: S3 ASL: 53 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 Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

367 -- Transmission Mains

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	822,238,974	1,071,064	0.1%	-	24,441	(24,441)	-2.3%

Five Year Average Net Salvage	-15.6%
Ten Year Average Net Salvage	-12.9%
Current Net Salvage	0.0%
Recommend Net Salvage	-2.3%

Account 368 – Compressor Station Equipment

Delta Natural Gas Company
Account 368 -- Compressor Station Equipment

Simulated Retirements for Iowa Curve S5   with ASL = 48

Year	Additions	Actual Retirements	Balance	Simmulated 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	1203298	24684	-101734
1988	-9661	0	1091903	0	1193636	-0	-101733

Delta Natural Gas Company
Account 368 -- Compressor Station Equipment

Simulated Retirements for Iowa Curve S5 with ASL = 48

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1989	11796	6000	1097699	1	1205431	5999	-107732
1990	0	0	1097699	3	1205428	-3	-107729
1991	190334	0	1288033	7	1395755	-7	-107722
1992	12181	0	1300214	15	1407921	-15	-107707
1993	-2	0	1300212	32	1407888	-32	-107676
1994	-32363	0	1267849	63	1375462	-63	-107613
1995	0	0	1267849	111	1375351	-111	-107502
1996	0	0	1267849	206	1375145	-206	-107296
1997	0	0	1267849	363	1374782	-363	-106933
1998	8440	0	1276289	549	1382673	-549	-106384
1999	519600	0	1795889	922	1901351	-922	-105462
2000	26345	0	1822234	1315	1926381	-1315	-104147
2001	-415000	0	1407234	1913	1509469	-1913	-102235
2002	6074	0	1413308	2706	1512837	-2706	-99529
2003	443449	0	1856757	3544	1952742	-3544	-95985
2004	17735	221236	1653256	4704	1965773	216532	-312517
2005	1622	0	1654878	5893	1961501	-5893	-306623
2006	827361	22421	2459817	7200	2781662	15222	-321845
2007	2407136	0	4866954	8622	5180176	-8622	-313223
2008	155458	0	5022412	9978	5325656	-9978	-303244
2009	2475742	0	7498154	11219	7790179	-11219	-292025
2010	82891	459	7580586	12522	7860547	-12063	-279962
2011	0	0	7580586	13336	7847211	-13336	-266626
2012	0	0	7580586	14233	7832978	-14233	-252393
2013	1163388	0	8743973	14764	8981602	-14764	-237629
2014	69288	0	8813261	15030	9035860	-15030	-222599
2015	58683	4500	8867443	15409	9079133	-10909	-211690
2016	-130880	64061	8672502	15404	8932849	48657	-260347

Delta Natural Gas Company
Account 368 -- Compressor Station Equipment

Simulated Retirements for Iowa Curve S5   with ASL = 48

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2017	34360	0	8706862	15672	8951537	-15672	-244675
2018	40170	32636	8714395	16170	8975537	16466	-261141
2019	176316	95759	8794952	16614	9135238	79145	-340286
2020	12021	11476	8795497	18045	9129214	-6569	-333717

Account No. 368 -- Transmission Compressor Stations
Iowa Curve: S5 ASL: 48 Years

Delta Natural Gas Company
Account No. 368 Compressor Station Equipment
Sum of Square Differences (SSD) Retirements for S5

Delta Natural Gas Company
Account Investment Summary

368 -- Compressor Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

368 -- Compressor Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	120,683,413	452,549	0.4%	-	4,435	(4,435)	-1.0%

Five Year Average Net Salvage	-0.4%
Ten Year Average Net Salvage	-0.4%
Current Net Salvage	0%
Recommend Net Salvage	-1%

Account 369 – Measuring & Reg Station Equipment

Delta Natural Gas Company
Account 369 -- Meas & Reg Station Equipment

Simulated Retirements for Iowa Curve L2 with ASL = 44

Year	Additions	Actual Retirements	Balance	Simmulated 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	0	3425	-0	0
1956	3317	0	6742	1	6741	-1	1
1957	1730	0	8472	1	8470	-1	2
1958	4222	0	12694	2	12690	-2	4
1959	11640	0	24334	4	24326	-4	8
1960	36436	0	60770	7	60756	-7	14
1961	2350	0	63120	12	63094	-12	26
1962	143	360	62903	18	63219	342	-316
1963	1590	321	64172	31	64777	290	-605
1964	2469	486	66155	50	67196	436	-1041
1965	11196	4853	72498	71	78321	4782	-5823
1966	12600	43	85055	94	90827	-51	-5772
1967	6054	450	90659	122	96759	328	-6100
1968	5943	84	96518	153	102549	-69	-6031
1969	18946	1420	114044	190	121304	1230	-7260
1970	4457	0	118501	232	125529	-232	-7028
1971	22690	0	141191	278	147941	-278	-6750
1972	1848	0	143039	331	149458	-331	-6419
1973	11003	0	154042	390	160071	-390	-6029
1974	21450	339	175153	457	181065	-118	-5912
1975	68977	2071	242059	534	249508	1537	-7449
1976	25972	620	267411	627	274853	-7	-7442
1977	5860	662	272609	730	279983	-68	-7374
1978	2125	1040	273694	861	281247	179	-7553

Delta Natural Gas Company
Account 369 -- Meas & Reg Station Equipment

Simulated Retirements for Iowa Curve L2 with ASL = 44

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1979	11949	0	285643	1009	292187	-1009	-6544
1980	4539	0	290182	1175	295552	-1175	-5370
1981	2096	0	292278	1351	296297	-1351	-4019
1982	2119	0	294397	1540	296876	-1540	-2479
1983	11231	0	305628	1743	306364	-1743	-736
1984	93670	2350	396948	1955	398079	395	-1131
1985	40669	1654	435963	2178	436570	-524	-607
1986	4156	0	440119	2409	438317	-2409	1802
1987	1551	0	441670	2657	437211	-2657	4459
1988	14728	1210	455188	2925	449015	-1715	6173
1989	88465	5909	537744	3204	534276	2705	3468
1990	36020	0	573764	3494	566802	-3494	6962
1991	39795	0	613559	3803	602795	-3803	10764
1992	43190	0	656749	4135	641850	-4135	14899
1993	44138	3756	697131	4503	681485	-747	15646
1994	37008	0	734139	4889	713604	-4889	20535
1995	11055	23312	721882	5298	719361	18014	2521
1996	19636	0	741518	5723	733274	-5723	8244
1997	138952	0	880470	6164	866062	-6164	14408
1998	198341	0	1078811	6612	1057790	-6612	21021
1999	526196	3327	1601680	7076	1576911	-3749	24769
2000	185729	15619	1771790	7580	1755060	8039	16730
2001	84508	20741	1835557	8124	1831444	12617	4113
2002	184938	3080	2017415	8764	2007618	-5684	9797
2003	78872	0	2096287	9510	2076980	-9510	19307
2004	146005	0	2242292	10312	2212674	-10312	29619
2005	261710	25999	2478004	11187	2463197	14812	14807
2006	211113	26574	2662543	12160	2662150	14414	393

Delta Natural Gas Company
Account 369 -- Meas & Reg Station Equipment

Simulated Retirements for Iowa Curve L2   with ASL = 44

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
2007	409207	0	3071750	13220	3058137	-13220	13613
2008	103098	0	3174847	14389	3146845	-14389	28002
2009	207408	1934	3380321	15666	3338587	-13732	41734
2010	-115981	3000	3261340	17074	3205531	-14074	55809
2011	109283	0	3370623	18572	3296242	-18572	74380
2012	138950	16522	3493051	20188	3415005	-3665	78046
2013	97467	16000	3574518	21858	3490615	-5858	83903
2014	394151	6095	3962575	23648	3861118	-17554	101457
2015	55084	33007	3984652	25612	3890590	7395	94062
2016	135806	0	4120458	27716	3998679	-27716	121778
2017	43935	0	4164393	30079	4012536	-30079	151858
2018	12824	390249	3786969	32619	3992741	357629	-205772
2019	49414	0	3836383	35330	4006825	-35330	-170441
2020	809562	46923	4599023	38198	4778189	8725	-179166

Account No. 369 -- Transmission Measurement Reg Station Equipment
Iowa Curve: L2 ASL: 44 Years

Delta Natural Gas Company
Account No. 369 -- Meas Reg Station Equipment
Sum of Square Differences (SSD) Retirements for L2
ssd_removals
SSD Retirements
800000000000
700000000000
600000000000
500000000000
400000000000
300000000000
200000000000
100000000000
10
20
30
40
44
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 Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

369 -- Measuring Regulating Station Equipment

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	65,113,000	590,124	0.9%	5,848	89,553	(83,704)	-14.2%

Five Year Average Net Salvage	-12.3%
Ten Year Average Net Salvage	-12.2%
Current Net Salvage	0%
Recommend Net Salvage	-5%

Account 376 – Distribution Mains

Delta Natural Gas Company
Account 376 -- Distribution Mains

Simulated Retirements for Iowa Curve R5 with ASL = 53

Year	Additions	Actual Retirements	Balance	Simmulated 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	1	1134825	-1	1
1963	86884	9832	1211878	2	1221707	9830	-9829
1964	89514	5084	1296308	3	1311218	5081	-14910
1965	123728	7814	1412222	5	1434941	7809	-22719
1966	135264	5133	1542353	10	1570195	5123	-27842
1967	317430	7612	1852171	17	1887608	7595	-35437

Delta Natural Gas Company
Account 376 -- Distribution Mains

Simulated Retirements for Iowa Curve R5   with ASL = 53

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	182038	13540	2020669	24	2069622	13516	-48953
1969	582335	11971	2591033	39	2651919	11932	-60886
1970	1455571	8116	4038488	57	4107433	8059	-68945
1971	1074050	109721	5002817	77	5181406	109644	-178589
1972	324850	26975	5300692	113	5506143	26862	-205451
1973	448840	12035	5737497	151	5954832	11884	-217335
1974	294232	42315	5989414	206	6248858	42109	-259444
1975	409344	47820	6350938	281	6657921	47539	-306983
1976	201118	19238	6532818	363	6858676	18875	-325858
1977	215318	19383	6728753	483	7073511	18900	-344758
1978	316671	46128	6999296	624	7389558	45504	-390262
1979	723822	90065	7633053	796	8112585	89269	-479532
1980	646465	46371	8233147	1031	8758019	45340	-524872
1981	1960024	104484	10088687	1290	10716753	103194	-628066
1982	1666448	145027	11610108	1631	12381569	143396	-771461
1983	1579871	121613	13068366	2052	13959388	119561	-891022
1984	1436971	129563	14375774	2524	15393836	127039	-1018062
1985	1581605	169907	15787472	3125	16972315	166782	-1184843
1986	1813432	202979	17397925	3820	18781928	199159	-1384003
1987	1928903	131752	19195076	4630	20706201	127122	-1511125
1988	2394747	75173	21514650	5585	23095363	69588	-1580713
1989	823954	67192	22271412	6687	23912630	60505	-1641218
1990	2593632	212392	24652652	7960	26498302	204432	-1845650
1991	3006462	91401	27567713	9401	29495363	82000	-1927650
1992	2091957	89533	29570137	11080	31576240	78453	-2006103
1993	2514631	63196	32021572	12936	34077935	50260	-2056363
1994	2265544	73474	34213642	15074	36328405	58400	-2114763
1995	3168792	105369	37277065	17497	39479700	87872	-2202635

Delta Natural Gas Company
Account 376 -- Distribution Mains

Simulated Retirements for Iowa Curve R5   with ASL = 53

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	2615832	143644	39749253	20164	42075369	123480	-2326116
1997	2773515	145370	42377398	23264	44825620	122106	-2448222
1998	4460035	338435	46498998	26652	49259002	311783	-2760004
1999	3293998	67788	49725208	30480	52522521	37308	-2797313
2000	3187950	248859	52664299	34754	55675717	214105	-3011418
2001	1640935	59039	54246195	39482	57277170	19557	-3030975
2002	1118712	111651	55253256	44785	58351098	66866	-3097841
2003	1493803	52274	56694785	50493	59794408	1781	-3099622
2004	1920768	156346	58459207	56983	61658193	99363	-3198985
2005	1752060	80120	60131148	64055	63346198	16065	-3215051
2006	1344632	52646	61423134	71641	64619189	-18995	-3196055
2007	1100003	220944	62302193	80301	65638891	140643	-3336698
2008	2211046	270986	64242253	89655	67760282	181331	-3518029
2009	1821352	88858	65974747	99827	69481807	-10969	-3507060
2010	1943240	92785	67825201	111669	71313378	-18884	-3488176
2011	1390833	227609	68988425	124638	72579572	102971	-3591147
2012	2501565	175151	71314839	139271	74941866	35880	-3627027
2013	2340376	118585	73536630	156651	77125591	-38067	-3588960
2014	1979981	153030	75363581	175602	78929969	-22572	-3566388
2015	1653150	146963	76869767	197321	80385798	-50357	-3516031
2016	1942210	113560	78698417	222253	82105755	-108693	-3407338
2017	2619977	201584	81116811	249159	84476574	-47575	-3359763
2018	3893676	241302	84769185	279403	88090847	-38101	-3321662
2019	7341094	221885	91888393	312959	95118982	-91074	-3230589
2020	6084618	318513	97654497	348589	100855010	-30076	-3200513


Account No. 376 -- Distribution Mains
Iowa Curve: R5 ASL: 53 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
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0
20
40
60
80
100

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 Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

376 -- Distribution Mains

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	##########	3,103,833	0.2%	-	332,501	(332,501)	-10.7%

Five Year Average Net Salvage	-18.8%
Ten Year Average Net Salvage	-17.3%
Previous	1%
Recommend Net Salvage	0%

Account 378 – Measurement & Reg Station

Delta Natural Gas Company
Account 378 --Measurement & Regulator Stations

Simulated Retirements for Iowa Curve L1 with ASL = 49

Year	Additions	Actual Retirements	Balance	Simmulated 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	109	-0	1
1944	0	0	110	0	109	-0	1
1945	0	0	110	0	109	-0	1
1946	0	0	110	0	109	-0	1
1947	0	0	110	0	108	-0	2
1948	260	0	370	0	368	-0	2
1949	97	0	467	1	464	-1	3
1950	202	0	669	1	665	-1	4
1951	535	0	1204	2	1198	-2	6
1952	904	0	2108	3	2100	-3	8
1953	789	0	2897	4	2884	-4	13
1954	38	0	2935	6	2917	-6	18
1955	5199	0	8134	7	8109	-7	25
1956	3855	0	11989	15	11948	-15	41
1957	1094	0	13083	22	13020	-22	63
1958	0	0	13083	28	12992	-28	91
1959	12372	0	25455	33	25330	-33	125
1960	0	0	25455	56	25274	-56	181
1961	0	0	25455	64	25210	-64	245
1962	321	198	25578	76	25455	122	123
1963	0	0	25578	88	25367	-88	211
1964	608	0	26186	102	25873	-102	313
1965	881	131	26936	116	26638	15	298
1966	5272	156	32052	132	31777	24	275
1967	0	0	32052	156	31622	-156	430

Delta Natural Gas Company
Account 378 --Measurement & Regulator Stations

Simulated Retirements for Iowa Curve L1 with ASL = 49

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	317	845	31524	172	31766	673	-242
1969	281	0	31805	192	31855	-192	-50
1970	23330	0	55135	212	54973	-212	162
1971	24948	0	80083	264	79656	-264	427
1972	13981	136	93928	321	93316	-185	612
1973	3975	632	97271	374	96917	258	354
1974	5207	594	101884	421	101703	173	181
1975	6244	929	107199	475	107472	454	-273
1976	3610	2518	108291	534	110549	1984	-2258
1977	8552	171	116672	592	118509	-421	-1837
1978	7190	797	123065	662	125037	135	-1972
1979	9000	0	132065	732	133304	-732	-1239
1980	41132	575	172622	811	173625	-236	-1003
1981	51901	1879	222644	938	224588	941	-1944
1982	13595	819	235420	1087	237096	-268	-1676
1983	20919	447	255892	1204	256811	-757	-919
1984	16759	0	272651	1348	272223	-1348	428
1985	12417	0	285068	1494	283146	-1494	1922
1986	37728	3248	319548	1645	319230	1603	318
1987	54661	700	373509	1839	372051	-1139	1458
1988	57764	6061	425212	2069	427746	3992	-2534
1989	84602	4564	505250	2324	510024	2240	-4774
1990	52015	9780	547485	2641	559398	7139	-11913
1991	44062	2750	588797	2944	600516	-194	-11719
1992	36700	15670	609827	3272	633943	12398	-24116
1993	49956	13127	646656	3614	680286	9513	-33630
1994	44296	9493	681459	4000	720582	5493	-39123
1995	101062	32084	750437	4398	817246	27686	-66809

Delta Natural Gas Company
Account 378 --Measurement & Regulator Stations

Simulated Retirements for Iowa Curve L1 with ASL = 49

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	58206	6552	802091	4904	870548	1648	-68457
1997	116218	11878	906431	5381	981385	6497	-74954
1998	62585	3424	965592	5981	1037989	-2557	-72397
1999	133573	5574	1093591	6541	1165021	-967	-71430
2000	8746	5017	1097320	7249	1166517	-2232	-69197
2001	27018	1727	1122611	7819	1185716	-6092	-63105
2002	14796	0	1137407	8473	1192039	-8473	-54632
2003	132610	17455	1252562	9114	1315535	8341	-62973
2004	59940	27748	1284754	9941	1365534	17807	-80780
2005	117525	63211	1339068	10690	1472369	52522	-133301
2006	21873	4571	1356370	11570	1482672	-6999	-126302
2007	0	11456	1344914	12347	1470325	-891	-125412
2008	48697	10839	1382772	13130	1505892	-2291	-123120
2009	14183	200	1396755	13980	1506095	-13780	-109340
2010	209969	5886	1600838	14782	1701281	-8896	-100444
2011	184982	18834	1766985	15862	1870401	2972	-103416
2012	98827	4837	1860975	16913	1952315	-12076	-91340
2013	9495	1247	1869223	17929	1943882	-16682	-74659
2014	128519	2009	1995734	18855	2053547	-16846	-57813
2015	74727	4825	2065636	19963	2108310	-15138	-42675
2016	16268	1925	2079978	20991	2103588	-19065	-23610
2017	2773	6043	2076709	21965	2084396	-15922	-7687
2018	44965	12768	2108906	22932	2106429	-10164	2477
2019	68280	6217	2170969	23932	2150777	-17715	20192
2020	28512	318513	2194334	24952	2154338	293562	39996

Account No. 378 -- Measurement Reg Station Equipment
Iowa Curve: L ASL: 49 Years


Delta Natural Gas Company
Account 378 --Measurement Regulator Stations
Sum of Square Differences (SSD) Retirements for L1
ssd_removals
SSD Retirements
240000000000
220000000000
200000000000
180000000000
160000000000
140000000000
120000000000
100000000000
80000000000
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 Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

378 -- Measuring Regulating Equipment - General

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	33,407,499	206,946	0.6%	-	64,416	(64,416)	-31.1%

Five Year Average Net Salvage	-19.8%
Ten Year Average Net Salvage	-25.4%
Current Net Salvage	0%
Recommend Net Salvage	-11%

Account 380 – Services

Delta Natural Gas Company
Account 380 -- Services

Simulated Retirements for Iowa Curve L0 with ASL = 53

Year	Additions	Actual Retirements	Balance	Simmulated 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	Simmulated 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

Account No. 380 -- Services
Iowa Curve: L0 ASL: 53 Years

Delta Natural Gas Company
Account 380 --Services
Sum of Square Differences (SSD) Retirements for L0

Delta Natural Gas Company
Account Investment Summary

Account 380 -- Services

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	301,572,391	2,985,174	1.0%	-	4,834,117	(4,834,117)	-161.9%

Five Year Average Net Salvage	-155.3%
Ten Year Average Net Salvage	-177.4%
Current Net Salvage	0%
Recommend Net Salvage	-40%

Account 381 – Meters

Delta Natural Gas Company
Account 381 -- Meters

Simulated Retirements for Iowa Curve O2 with ASL = 46

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1940	1300	0	1300	0	1300	0	0
1941	0	0	1300	16	1284	-16	16
1942	0	0	1300	16	1268	-16	32
1943	0	0	1300	16	1252	-16	48
1944	0	0	1300	16	1236	-16	64
1945	0	0	1300	16	1221	-16	79
1946	0	0	1300	16	1205	-16	95
1947	1361	0	2661	16	2550	-16	111
1948	7200	0	9861	33	9717	-33	144
1949	12983	0	22844	120	22580	-120	264
1950	11515	0	34359	279	33816	-279	543
1951	8282	0	42641	420	41678	-420	963
1952	25195	0	67836	521	66353	-521	1483
1953	4329	0	72165	829	69853	-829	2312
1954	6163	0	78328	882	75135	-882	3193
1955	14171	0	92499	957	88348	-957	4151
1956	29813	0	122312	1130	117031	-1130	5281
1957	15293	0	137605	1494	130830	-1494	6775
1958	17188	0	154793	1681	146336	-1681	8457
1959	19856	0	174649	1892	164301	-1892	10348
1960	21145	0	195794	2134	183312	-2134	12482
1961	24843	0	220637	2393	205762	-2393	14875
1962	14485	0	235122	2696	217551	-2696	17571
1963	31894	2480	264536	2874	246571	-394	17965
1964	18103	1822	280817	3263	261411	-1441	19406
1965	23944	259	304502	3485	281870	-3226	22632
1966	20427	51	324878	3778	298519	-3727	26359
1967	36960	123	361715	4027	331452	-3904	30263

Delta Natural Gas Company
Account 381 -- Meters

Simulated Retirements for Iowa Curve O2   with ASL = 46

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1968	44180	722	405173	4479	371153	-3757	34020
1969	61872	527	466518	5019	428006	-4492	38512
1970	219572	286	685804	5775	641804	-5489	44000
1971	210607	399	896012	8456	843955	-8057	52057
1972	91736	545	987203	11028	924663	-10483	62540
1973	91823	36	1078990	12150	1004336	-12114	74654
1974	58878	82	1137786	13274	1049941	-13192	87845
1975	78982	61	1216707	13995	1114928	-13934	101779
1976	48111	274	1264544	14961	1148078	-14687	116466
1977	66317	144	1330717	15550	1198844	-15406	131873
1978	67406	441	1397682	16362	1249888	-15921	147794
1979	53560	1416	1449826	17186	1286262	-15770	163564
1980	69898	185265	1334459	17841	1338319	167424	-3860
1981	92069	6704	1419824	18696	1411692	-11992	8132
1982	195244	15730	1599338	19821	1587115	-4091	12223
1983	125587	12072	1712853	22206	1690497	-10134	22356
1984	147259	28342	1831770	23740	1814016	4602	17754
1985	82296	11883	1902183	25540	1870772	-13657	31411
1986	81339	15181	1968341	26546	1925564	-11365	42777
1987	122066	13487	2076920	27541	2020089	-14054	56831
1988	216913	10148	2283685	29033	2207969	-18885	75716
1989	86154	8015	2361824	31682	2262442	-23667	99382
1990	195258	7947	2549135	32734	2424965	-24787	124170
1991	142091	6556	2684670	35119	2531937	-28563	152733
1992	111792	7596	2788866	36854	2606875	-29258	181991
1993	281873	5117	3065622	38219	2850530	-33102	215092
1994	239405	6513	3298514	41659	3048276	-35146	250238
1995	297778	10650	3585642	44580	3301474	-33930	284168

Delta Natural Gas Company
Account 381 -- Meters

Simulated Retirements for Iowa Curve O2   with ASL = 46

Year	Additions	Actual Retirements	Balance	Simmulated Retirements	Sim Balance	Difference in Retirements	Difference in Plant Balance
1996	1004419	15643	4574418	48213	4257679	-32570	316739
1997	94368	21641	4647145	60472	4291575	-38831	355570
1998	828613	21341	5454417	61622	5058566	-40281	395851
1999	221392	7875	5667934	71737	5208221	-63862	459713
2000	203319	19071	5852182	74436	5337104	-55365	515078
2001	408435	15242	6245375	76914	5668626	-61672	576749
2002	577828	211869	6611334	81892	6164562	129977	446772
2003	1828445	13068	8426711	88931	7904076	-75863	522635
2004	92829	10023	8509517	111238	7885667	-101215	623850
2005	215473	14168	8710822	112354	7988786	-98186	722036
2006	225642	18888	8917576	114973	8099455	-96085	818122
2007	317640	84505	9150711	117701	8299393	-33196	851318
2008	149376	31448	9268640	121547	8327223	-90099	941417
2009	82941	48653	9302928	123331	8286834	-74678	1016094
2010	76612	167164	9212376	124295	8239151	42870	973225
2011	94499	108364	9198511	125174	8208476	-16810	990035
2012	67662	62399	9203775	126260	8149878	-63861	1053896
2013	112817	59191	9257401	127012	8135683	-67821	1121718
2014	165281	427804	8994878	128301	8172663	299503	822215
2015	150933	90567	9055244	130222	8193374	-39655	861869
2016	620069	64615	9610698	131953	8681491	-67338	929207
2017	545644	1143633	9012709	139402	9087733	1004231	-75024
2018	555428	303708	9264429	145925	9497236	157783	-232807
2019	364430	312877	9315982	152560	9709107	160317	-393125
2020	400538	366700	9349821	156844	9952801	209855	-602980

Account No. 381 -- Meters
Iowa Curve: O2 ASL: 46 Years

Delta Natural Gas Company
Account 381 -- Meters
Sum of Square Differences (SSD) Retirements for O2

Delta Natural Gas Company
Account Investment Summary

Account 381 -- Meters

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

Account 381 -- Meters

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	176,619,437	3,554,885	2.0%	6,894	-	6,894	0.2%

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	Simmulated 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	Simmulated 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	Simmulated 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

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

Delta Natural Gas Company
Account Investment Summary

382 -- Meter Regulator Installation

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

382 -- Meter Regulator Installation

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	65,238,934	759,401	1.2%	13,015	999,060	(986,045)	-129.8%

Five Year Average Net Salvage	-107.4%
Ten Year Average Net Salvage	-136.6%
Current Net Salvage	-1.75%
Recommend Net Salvage	-12%

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	Simmulated 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	Simmulated 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	Simmulated 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

Account No. 383 -- House Regulators
Iowa Curve: S3 ASL: 43 Years

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 Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

Account 383 -- House Regulators

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	70,015,237	434,500	0.6%	10,731	-	10,731	2.5%

Five Year Average Net Salvage	3.7%
Ten Year Average Net Salvage	2.1%
Current Net Salvage	25%
Recommend Net Salvage	3%

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	Simmulated 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	Simmulated 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	Simmulated 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

Account No. 385 -- Industrial Meter Sets
Iowa Curve: L0 ASL: 49 Years

Delta Natural Gas Company
Account 385 -- Industrial Meter Sets
Sum of Square Differences (SSD) Retirements for L0

Delta Natural Gas Company
Account Investment Summary

Account 385 -- Industrial Meter Sets

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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
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

Delta Natural Gas Company
Account Investment Summary

Account 385 -- Industrial Meter Sets

Ending June	Balance Beginning	Transfer	Additions	Retirements	Balance Beginning
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

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%
Total	31,375,892	385,685	1.2%	1,051	39,232	(38,181)	-9.9%

Five Year Average Net Salvage	-10.5%
Ten Year Average Net Salvage	-9.7%
Current Net Salvage	0.32%
Recommend Net Salvage	0%

Exhibit WSS-8

Summary of Current and Proposed Depreciation Rates

Delta Natural Gas Company
Analysis of Depreciation Rates

Account	Description	Depreciation Rates		Change in
		Current	Recommended	Rate
367	TRANSMISSION MAINS	2.35%	2.88%	-0.53%
368	COMPRESSOR STATION EQUIPMENT	3.26%	3.20%	0.06%
369	MEASURING & REG STAT EQUIPMENT	3.53%	3.50%	0.03%
376	DISTRIBUTION MAINS	3.11%	3.05%	0.06%
378	MEAS & REG STAT - GENERAL	3.18%	3.18%	0.00%
380	SERVICES	3.11%	3.10%	0.01%
381	METERS	2.90%	2.86%	0.04%
382	METER & REGULATOR INSTALLATION	4.00%	4.00%	0.00%
383	HOUSE REGULATORS	4.13%	3.96%	0.17%
385	INDUSTRIAL METER SETS	2.15%	2.64%	-0.49%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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	)))))	**CASE NO. 2021-00185**

TESTIMONY OF
ANDREA SCHROEDER
CONTROLLER
DELTA NATURAL GAS COMPANY, INC.

Filed: May 28, 2021

Background

Q. Please state your name and business address.

A. My name is Andrea Schroeder. 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 oversee the daily accounting operations and help guide Delta's strategic financial decisions.

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

A. I began working at Delta as Controller at the beginning of May 2021.

Q. By whom were you employed prior to Delta?

A. I was employed by Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") in various roles from 2008 to 2021. Most recently, I was the Manager of Civic Affairs and was responsible for managing the franchise process across LG&E's and KU's service territories, building strategic relationships with community leaders and local elected officials, and ensuring compliance with government agency rules and regulations. I also worked as a Rate & Regulatory Analyst before being promoted to Manager of Civic Affairs. Prior to LG&E and KU, I worked at the Kentucky Public Service Commission from 2001 to 2008, first as a Public Utility Financial Analyst and then as Executive Advisor to the Chairman. Prior to LG&E and KU, I worked as a Financial Analyst at Thornton Oil and as the Director of Finance and Administration at Kentucky Retail Federation.

Q. Please briefly describe your educational experience.

A. I attended Sullivan University from 1991 to 1992, receiving an Associate's degree in marketing. I then attended Kentucky State University from 1995 to 1997 and earned a Bachelor's degree in accounting and business/management.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to present certain schedules required by 807 KAR 5:001 Section 16 filed with Delta's application and (2) to discuss Delta's plan to merge the books and records of Delta and Peoples Gas Kentucky LLC ("PKY").

<u>Filing Requirements</u>

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 16(7)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	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 (5) through (10), (13) through (17).	Tabs 26 to 31, 34 to 38
807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports	Tab 39
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	Tab 45

	immediately prior to base period, each month of base period, and subsequent months, as available.	
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(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)(h)	Computation of gross revenue conversion factor for forecasted period.	Tab 61
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

Q. Please describe Tab 17 of the Filing Requirements.

A. Tab 17 provides Delta's and PKY's annual and monthly budgets for 2020 and 2021, as well as the combined companies' annual and monthly budgets for 2020, 2021, and 2022.

Q. Please explain Filing Requirement Tab 29.

A. Tab 29 shows Delta's mix of gas supply for the years 2021 through 2024. The total pipeline purchases increase by a small amount each year.

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

A. Tab 30 shows that the forecasted number of employees for the years 2021 through 2024 stays constant at 162 employees per year. This number is based on 153 full-time employees at Delta, plus 9 employees from PKY that closely support Delta's operations. The forecast assumes Delta is fully staffed and does not count any part-time employees.

Q. Can you explain what Tab 31 shows?

A. Yes. Tab 31 presents Delta's labor cost changes for the years 2021 through 2024. Delta has calculated a 4.5% increase in total wages over the previous year for 2022 and a 3.0% increase in total wages over previous year amounts for 2023 and 2024. Delta has no collective bargaining agreements.

Q. Please explain Filing Requirement Tab 35.

A. Tab 35 shows the forecasted changes in numbers of customers by class. Delta projects the number of customers to remain the same in each of its four customer classes – residential, commercial, industrial, and farm tap – through 2024.

Q. Please describe Tab 36.

A. Tab 36 provides Delta's gas sales volume forecasts in cubic feet for 2022, 2023, and 2024. This shows Delta forecasts gas sales to remain flat over the next three years across all rate classes.

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 SAP 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 September 2019 through April 2021.

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 parties and outings, and employee gift expenses for the base period and forecasted period for both Delta and PKY. The schedule also notes the amounts that are booked below the line and not proposed to be recovered in rates.

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.

Q. Is Delta providing comparative financial data and earnings measures in Tab 64?

A. Yes. Tab 64 provides Delta's comparative financial data and earnings measures for the ten most recent years, the base period, and the forecast period. Delta is also providing the financial data and earnings measures for PKY since 2013, which is when PKY was formed.

Q. Are you sponsoring other filing requirements that you have not described in detail in your testimony?

A. Yes, I am sponsoring each of the filing requirements shown in the table in my testimony. 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.

Merging Operations of Delta and PKY

Q. Did Delta recently acquire PKY?

A. Yes. In April 2021, ownership of PKY, a farm tap affiliate of Delta's owned by PNG Companies, LLC, was transferred to Delta. As described further in Mr. Brown's testimony, Delta is in the process of merging the operations of PKY into Delta and once complete, PKY's corporate entity will be dissolved.

Q. Please describe how the records of PKY and Delta are presented in this case.

A. Certainly. For the forecasted test period, all PKY and Delta information is combined. The historical information provided differs because PKY was previously a farm tap affiliate and was not regulated in the same manner as Delta. To the extent that historical records for PKY exist, Delta is providing those to further augment Delta's rate application. In certain instances, no such historical records exist.

Q. Are the books and records of Delta and PKY currently kept separately?

A. Yes.

Q. Does Delta intend to merge the books and records of Delta and PKY when PKY is dissolved?

A. Yes. When the merger of Delta and PKY's operations is complete and PKY's corporate entity is dissolved, PKY's books and records will no longer be separate. Delta intends to keep one set of books and records and file one annual report to the Commission that includes PKY's operations when PKY is dissolved.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

The undersigned, **Andrea Schroeder**, being duly sworn, deposes and says she is Controller of Delta Natural Gas Company, Inc., that she 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 her information, knowledge, and belief.

Andrea Schroeder
ANDREA SCHROEDER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of May, 2021.

Emily P. Bennett (SEAL)
Notary Public

Emily P. Bennett
Notary Public, ID KYNP8460
State at Large, Kentucky
My Commission Expires on June 20, 2024

My Commission Expires:
6/20/24