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DEPARTMENT OF THE AIR FORCE
HEADQUARTERS AIR FORCE LEGAL OPERATIONS AGENCY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Rate Increase by	**)**	**Docket No. 20170179-GU**
Florida City Gas	**)**	**Filed: February 1, 2018**
	)	

February 1, 2018

Florida Public Service Commission
2540 Shumard Oak Blvd. Room 110
Tallahassee, FL 32399

Sir/Ma'am:

Enclosed for filing on behalf of Federal Executive Agencies ("FEA") are the Direct Testimony of Brian C. Collins and Direct Testimony and Exhibits of Christopher C. Walters.

Thank you for your assistance. If you should have any question about this filing, please do not hesitate to contact me.

Sincerely,

Attorneys for Federal Executive Agencies

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CERTIFICATE OF SERVICE
Docket No. 20170179-GU

I HEREBY CERTIFY that a true and correct copy of the foregoing Federal Executive Agencies' Direct Testimony of Brian C. Collins and Direct Testimony and exhibits of Christopher C. Walters has been furnished by electronic mail (e-mail) and/or U.S. Mail this 1st day of February 2018 to the following:

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA CITY GAS	))))	**DOCKET NO. 20170179-GU**

Direct Testimony of

Brian C. Collins

On behalf of

Federal Executive Agencies

February 1, 2018

BRUBAKER & ASSOCIATES, INC.

Project 10543

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA CITY GAS	**))))**	**DOCKET NO. 20170179-GU**

Table of Contents to the
Direct Testimony of Brian C. Collins

Page

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA CITY GAS	))))	**DOCKET NO. 20170179-GU**

Direct Testimony of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony addresses Florida City Gas's ("FCG" or "Company") class cost of service ("CCOS") study and the allocation of any allowed distribution rate increase to the Company's rate classes.

I have examined the testimony and exhibits presented by FCG in this proceeding with respect to class cost of service and class revenue allocation, and will comment on the propriety of its proposals and make certain recommendations.

I will also comment on and make certain recommendations regarding the Company's proposal to allocate interstate pipeline capacity costs to all FCG transportation customers. FCG's transportation customers do not receive their gas supply from FCG, but rather receive gas supply from a third party supplier that uses capacity on interstate gas pipelines to deliver gas supply to FCG's distribution system .

To the extent my testimony does not address any particular issue does not indicate tacit agreement with the Company's or another party's position on that issue.

Q PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are summarized as follows:

1. The CCOS study filed by FCG in this proceeding does not accurately reflect class cost causation. FCG's CCOS study allocates the costs of distribution mains to customer classes only on the basis of a demand component and not on the basis of both demand and customer components. Allocation of distribution mains costs on both a demand and customer basis better reflects cost causation.

2. The demand component of the Company's costs of distribution mains is allocated using the Peak and Average ("P&A") method which does not best reflect cost causation because it partially allocates those costs on a volumetric basis. The Company does not design its distribution system

on the basis of annual volumes, but rather on design day demand and the number of customers on its system.

3. The Company bases its class revenue allocation on its proposed CCOS study. Because the Company's CCOS study does not accurately reflect cost causation, I recommend an alternative allocation of any revenue increase to customers. Based on the level of increase requested, the impact on customers and recognizing the principle of gradualism, I have proposed an across-the-board increase for all customer classes. Based on the Company's claimed revenue deficiency, this would result in an increase of 29.3% for each rate class. To the extent the Florida Public Service Commission ("Commission") approves a different revenue increase for FCG, the percentage increase should be adjusted accordingly.

4. The Company should not purchase interstate pipeline capacity to ensure that <u>all</u> transportation customers receive gas supply in the event their respective third party suppliers fail to deliver gas supply. As a result, I recommend that the Company's proposal to allocate interstate pipeline capacity costs to all transportation customers be rejected at this time.

5. The Company should create a backup capacity service that allocates the costs of FCG purchased interstate pipeline capacity only to those FCG transportation customers (essential and non-essential) that require the Company to back up delivery of their gas supply from their respective third party gas suppliers to ensure firm delivery.

I. <u>Class Cost of Service and Rate Design Principles</u>

Q COULD YOU PLEASE EXPLAIN THE RATEMAKING PROCESS AND THE DESIGN OF RATES?

A The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and the extent to which an increase or decrease in revenues is necessary. Second, we must determine how any increase or decrease in revenues is to be distributed among the various customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within the class.

The guiding principle at each step should be cost of service. In the first step—determining revenue requirements—it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current rate levels exceed the utility's revenue requirement, a rate reduction is required. In short, rate revenues should equal actual cost of service. The same principle should apply in the second and third steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class, no more and no less. This may require a rate increase for some classes and a rate decrease for other classes. The standard tool for performing this exercise is a CCOS study, which shows the rates of return for each class of service. The goal is to modify rate levels so that each class of service provides approximately the same rate of return. Finally, in designing tariffs for individual classes, the goal should also be to align the rate design with the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing service to that customer.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATEMAKING PROCESS?

A The basic reasons for using cost of service as the primary factor in the ratemaking process are equity and stability. Cost of service ratemaking sends efficient price signals and encourages conservation.

Q PLEASE DISCUSS THE EQUITY CONSIDERATION.

A When rates are based on a CCOS study that is prepared using allocation methodologies that best reflect cost causation, each customer pays what it costs the utility to serve that customer, no more and no less. But when rates are not based on a reasonable CCOS study, then some customers are required to contribute disproportionately to the utility's revenues by subsidizing the service provided to other customers. This is inherently inequitable.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility associated with changes in numbers of customers and their usage patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, thereby reducing the utility's need to file for future rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of costs. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (*i.e.*, expected increases in overall revenue requirements) into changes in the rates charged to particular customer classes (and to customers within the classes). From the customer's perspective, this situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan.

Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?

A I am referring to the utility's "embedded" or actual accounting costs of rendering service; that is, those costs which are used by the Commission in establishing the utility's overall revenue requirement.

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A CCOS STUDY?

A The basic purpose of a CCOS study is to determine the costs that a utility incurs to provide service to different categories of customers. After the utility’s overall cost of service (or revenue requirement) is determined, a CCOS study is used, first, to allocate the cost of service between the utility’s jurisdictional and non-jurisdictional businesses, and then second, to allocate the jurisdictional cost of service among the utility’s jurisdictional customer classes.

A CCOS study shows the extent to which each customer class contributes to the total cost of the system. For example, when a class produces the same rate of return as the total system, it returns to the utility just enough revenues to cover the costs incurred in serving that class (including a reasonable authorized return on investment). If a class produces a rate of return below the system average, the revenues it provides for the utility are insufficient to cover all relevant costs. If, on the other hand, a class produces a rate of return above the average, then that class pays revenues sufficient to cover the costs attributable to it, and it also pays for part of the costs attributable to other classes that produce below-average rates of return. The CCOS study therefore is an important tool, because it shows the revenue requirement for each class along with the rate of return under current rates and any proposed rates.

Q WOULD YOU PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A CCOS STUDY?

A Yes. Cost of service is a basic and fundamental ingredient to proper ratemaking. In all CCOS studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the functionalization, classification, and allocation of costs. Functionalization is the determination and arrangement of costs according to major functions, such as production, storage, transmission and distribution. Classification involves identifying the nature of these costs according to whether the costs vary with the demand placed upon the system, the quantity of gas consumed, or the number of customers being served. Fixed costs are those costs that tend to remain constant over the short run irrespective of changes in output, and are generally considered to be demand-related. Fixed costs include those costs that are a function of the size of the utility's investment in facilities, and those costs that are necessary to keep the facilities "on line." Variable costs, on the other hand, are basically those costs that tend to vary with throughput (or usage), and are generally considered to be commodity-related. Customer-related costs are those costs that are most closely related to the number of customers served, rather than the demands placed upon the system or the quantity of gas consumed.

II. FCG's Proposed CCOS Study

Q HAVE YOU REVIEWED THE CCOS STUDY FILED BY FCG IN THIS PROCEEDING USED TO ESTABLISH RATES?

A Yes. I have reviewed the CCOS study filed by FCG in this proceeding that is sponsored by Company witness Daniel J. Nikolich.

According to Mr. Nikolich at page 29 of his testimony, the Company's filed CCOS study allocates capacity costs, including the costs of distribution mains, to FCG's customer classes based on the standard P&A method. This is opposed to a method that allocates a portion of distribution mains costs on a coincident design day demand basis and a portion on the basis of a customer component.

Based on my review of the Company's CCOS study, it appears that the Company fails to allocate any portion of distribution mains costs on a customer basis.

Q WHAT IS YOUR CONCLUSION WITH RESPECT TO THE COMPANY'S FILED CCOS STUDY?

A For the reasons discussed below, I conclude that the Company's CCOS study does not best reflect cost causation. As explained later in this testimony, the Company's CCOS study does not best reflect class cost causation because it uses the P&A method to allocate the cost of mains to customer classes and also fails to classify and allocate any distribution mains costs on a customer basis. Because of these flaws in the Company's CCOS study, the Company CCOS study should not be used to allocate costs to customer classes.

Q THOUGH THE COMPANY ALLOCATES CAPACITY COSTS ON THE P&A METHOD DOES IT RECOGNIZE THAT DESIGN DAY DEMAND REFLECTS COST CAUSATION?

A Yes, it does. According to Mr. Nikolich's testimony at page 18, he states that:

> Capacity costs are directly related to being able to meet the peak design or maximum demand requirements placed on the local distribution system by its customers. Capacity costs are incurred to

ensure that the system is ready to serve customers at peak design requirements levels.

The Company designs its distribution system to meet the design day demands of its customer classes as well as to connect all customers to its distribution system. To better reflect class cost causation, the Company should have classified its mains costs on both a demand and customer basis. The demand component should be allocated to classes based on the design day demands while the customer component should be allocated to classes based on the number of customers in each class.

Q SHOULD A CCOS STUDY PROPERLY REFLECT COST CAUSATION?

A Yes. In selecting a particular CCOS study methodology, the fundamental question is whether that methodology properly reflects cost causation. In other words, costs should be allocated to the utility's customer classes based on how the costs are incurred. The *Gas Distribution Rate Design Manual* published by the National Association of Regulatory Utility Commissioners ("NARUC") describes this principle as follows: "*Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those cost*s. This apportionment must be based on the fashion in which the utility's system, facilities and personnel operate to provide the service."[1]

The principal objective of any CCOS study is to allocate costs to a utility's customer classes in a manner that is as reasonably consistent as possible with the incurrence of those costs. This does not mean that the method chosen should result in a perfectly precise and accurate allocation of costs, because no such method exists. Invariably, some amount of judgment will be required. But the "primary goal"

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[1] NARUC *Gas Distribution Rate Design Manual* at 20 (emphasis added).

must always be to allocate costs in a way that best reflects cost causation, and in my view, the Company's CCOS study does not achieve that objective.

Q PLEASE EXPLAIN WHY THE COMPANY'S FILED STUDY DOES NOT BEST REFLECT COST CAUSATION.

A When a gas distribution utility installs new distribution mains to expand the capacity of its system, there are two factors that the utility must consider. First, the utility must design its system to ensure that it will be capable of meeting customers' demand on the system peak day (or "design day"). The expected demand on the system peak day is the key consideration. It dictates not only the need for an expansion, but also the proper size (in diameter) of the expanded distribution mains to be installed—and that, in turn, dictates the costs that the utility must incur. Thus, the costs incurred by the utility are a function of design day demand, because it is only when the distribution system is designed to meet the design day demand of the utility's rate classes that the utility is able to meet its firm customers' demands each and every day of the year.

Second, the utility must also design its system in such a way that all customers are physically connected to the system. While the diameter of the mains installed depends upon peak demand, the total length of the mains depends upon the number of customers being served. To illustrate, a much greater level of investment is needed to serve 10,000 customers with individual peak demands of 1 Mcf located at various geographical locations than what is needed to serve one customer with a demand of 10,000 Mcf at a single geographic location. Thus, the costs that a gas distribution utility incurs to provide service are driven by both peak day demand and the number of customers connected to the system.

FCG's filed study fails to allocate the costs of distribution mains to customer classes on the basis of both (1) each class's contribution to the total design day demand of the system and (2) the number of customers within each class. The Company's CCOS study does not properly allocate costs based on how they are incurred because it allocates distribution mains costs based on the P&A method, which is inconsistent with the cost-causation principle, and therefore, is not reasonable for the purpose of setting rates in this proceeding.

Q WHY DOES THE P&A METHOD FAIL TO BEST ALLOCATE CAPACITY COSTS BASED ON COST CAUSATION?

A Though the P&A method allocates a portion of distribution mains costs based on the design day demand of each customer class, it also allocates a portion of the costs based on each class's annual usage. Allocating capacity-related costs based on annual usage does not reflect cost causation and is not based on sound cost of service principles.

Q WHY DOES ALLOCATING A PORTION OF DISTRIBUTION MAINS COSTS ON AN ANNUAL USAGE BASIS NOT REFLECT SOUND COST OF SERVICE PRINCIPLES?

A As explained above, when a gas distribution utility is considering whether to expand the capacity of its distribution system, the key consideration is the expected demands of the customer classes on the peak day. The expected demands on the peak day dictate both the need for the expansion as well as the proper size of the expanded mains, and that in turn dictates the total cost of the project. The cost of the project is therefore a function of the peak day demand—and that cost is *the* *same* regardless of how much gas customers are expected to use throughout the year. For example, the cost is the same regardless of whether customers are expected to use gas consistently throughout the entire year, or during only part of the year (e.g., the winter months).

Q IN ADDITION TO THE FACT THAT IT DOES NOT REFLECT SOUND COST OF SERVICE PRINCIPLES, ARE THERE OTHER PROBLEMS WITH ALLOCATING COSTS ON THE BASIS OF ANNUAL USAGE?

A Yes. Allocating costs based on annual usage also is unfair to the customers that make more efficient use of the facilities. This is best illustrated with a simple example. Assume that Customer A uses 5 Mcf each and every day of the year (an annual total of 1,825 Mcf), and that Customer B, who is located directly across the street, uses 5 Mcf for 180 days of the year but nothing the rest of the year (an annual total of 900 Mcf). Assume further that the annualized investment cost of the main needed to serve these two customers is $300. The total annual usage of the two customers is 2,725 Mcf, of which approximately two-thirds is attributable to Customer A and approximately one-third to Customer B.

In order to serve these customers, the gas company must construct a main capable of delivering 10 Mcf of design day capacity on the peak day (Customer A's 5 Mcf plus Customer B's 5 Mcf). Because each customer uses one-half of the firm main capacity on the peak day, it seems reasonable that they should share equally in the cost. In fact, that is how the costs would be shared under a design day demand-based allocation.

The results would be quite different, however, if the distribution mains costs were allocated based on annual usage. In that situation, Customer A would be allocated \$200 (2/3 of the total \$300 cost) while Customer B would be allocated just \$100 (1/3 of the total \$300 cost) because it does not use its half of the facility for six months of the year. Thus, the fact that Customer A uses the facility efficiently every day of the year will cause Customer B to save money, but Customer B's less efficient use will cause Customer A to pay additional money. In fact, Customer A would likely be much better off if the gas company simply built a dedicated main with a capacity of 5 Mcf solely to serve Customer A's load. Similarly, Customer B would likely be worse off if it had to pay for its own dedicated main.

With proper cost allocation, both customers should be better off sharing a facility because there will be economies of scale resulting from the larger capacity main.

Q DOES ALLOCATING DISTRIBUTION MAINS COSTS BASED ON ANNUAL USAGE CREATE AN UNBALANCED ALLOCATION AMONG CUSTOMER CLASSES?

A Yes. In the example above, even though both Customer A and Customer B have the same design day demand, they effectively pay different costs of capacity per unit of design day demand when costs are allocated based on annual usage. The total capacity cost incurred by the gas distribution company is \$30 per Mcf of design day capacity (\$300/10 Mcf). However, the higher usage Customer A pays \$40 per Mcf of design day capacity (\$200/5 Mcf), while the lower usage Customer B pays \$20 per Mcf of design day capacity (\$100/5 Mcf). Thus, under an annual usage-based allocation, a customer that utilizes the distribution system more efficiently pays a premium for design day capacity (\$40/Mcf - \$20/Mcf = \$20/Mcf) above what a customer that uses the system less efficiently must pay. This occurs despite the fact that the two customers have equal rights to design day capacity on the system peak day and despite the fact that the average cost of design day capacity incurred by the utility is $30 per Mcf.

This simple example illustrates why it is unreasonable to allocate distribution mains costs on the basis of annual usage, when such costs are incurred to ensure adequate capacity for all customers that require firm service throughout the year.

Q IS ANNUAL USAGE A DESIGN CRITERION FOR A TYPICAL GAS DISTRIBUTION COMPANY FACILITY?

A No, it is not. To be sure, annual usage is certainly a factor that should be and is considered in allocating the variable cost of operating the gas system. However, annual usage does not determine the amount of system capacity that is necessary to provide firm (i.e., non-interruptible) service to every customer every day of the year. Rather, the actual physical size of the distribution mains, compressors, and related equipment is based on customers' contributions to the system design day demand. The system's capacity must be sized for design day demand, so that all firm customers can utilize their entitlement to that capacity to receive a firm, uninterrupted supply of gas every day of the year, including the day of the system peak demand.

Q IS THE COMPANY'S P&A BASED CCOS STUDY, WHICH PARTIALLY ALLOCATES THE COSTS OF DISTRIBUTION MAINS BASED ON ANNUAL USAGE, REASONABLE?

A No. The Company's CCOS study based on the P&A method fails to meet the cost of service principle of cost causation. As explained above, a typical gas utility (such as FCG) does not use annual usage to design its distribution facilities. Rather, it designs the distribution system based on its customers' contributions to the system's design day demand. Therefore, allocating the capacity-related costs associated with distribution mains (including both rate base and expenses) on the basis of annual usage is inappropriate, because it does not reflect how the costs are incurred by the Company. Such a cost allocation does not follow how the costs are actually incurred.

Q BUT DOESN'T THE COMPANY'S DISTRIBUTION SYSTEM ALLOW CUSTOMERS TO RECEIVE VOLUMES OF GAS THROUGHOUT THE YEAR?

A I do not dispute that, after the distribution system is designed and constructed to meet design day demand, customers use the system to receive volumes of gas throughout the year. However, if firm customers expect supply sufficient to meet their design day demand, then they should pay for adequate distribution capacity to allow gas to be delivered every day to meet their expected demands, including days with above-average demands. Otherwise, firm customers will not be allocated adequate capacity to deliver gas on days with above-average usage, which would be most cold days, and their service would be interrupted on all of those days.

It is the design day demand which drives the capacity-related cost incurred in order to design, construct, implement and maintain a distribution system that is adequate to provide firm service throughout the year, including the system peak day, to all customers that want firm service. Distribution systems are sized based on design day demands to ensure that firm gas supply can actually be delivered every single day of the year. Because cost causation is driven by design day demand, distribution-related costs should be allocated based on design day demand.

If the distribution system can meet the design day demand of its customers, it can meet the demand of its customers on every single day of the year. Daily needs must be met, but the only way to ensure that will happen is through a system that is designed to meet the design day demand.

Using annual usage to allocate capacity-related costs based on perceived benefits resulting from year-round use of the Company's distribution system is not based on cost-causative factors. There are no objective measures to define such benefits or determine the extent to which particular customers derive such benefits. In contrast, cost causation is based on the design and engineering of the distribution system and an understanding of the drivers that determine a utility's costs of such distribution system. The Company's CCOS study does not best represent the allocation of capacity-related costs on the Company's distribution system.

Q PLEASE SUMMARIZE WHY THE ALLOCATION OF DISTRIBUTION MAINS COSTS ON BOTH A DEMAND AND CUSTOMER BASIS MORE ACCURATELY REFLECTS COST CAUSATION AS COMPARED TO AN ALLOCATION OF MAINS COSTS BASED PARTIALLY ON ANNUAL USAGE.

A As previously discussed, a gas distribution company designs its distribution mains to meet the firm coincident demands of its rate classes on the system design day. The company also designs its distribution mains in such a way that all customers are connected to the system. The company does not design its system to meet the total annual volumes of gas sold to its rate classes. It is only when the distribution mains system is designed to meet the design day demand of the company's rate classes that the company is able to deliver gas each and every day of the year to meet its customers' demands. Therefore, the company incurs the costs of these facilities to meet class coincident design day demands and to connect all customers to the distribution mains system. Allocating the costs of these facilities on a coincident design day demand basis and on a customer basis reflects how the costs are incurred and, as a result, more accurately reflects cost causation than allocating costs on an annual usage basis. As a result, the Company's CCOS study does not best reflect class cost causation on the FCG distribution system.

III. <u>Distribution of Gas Revenue Increase to Classes</u>

Q HAVE YOU REVIEWED FCG'S PROPOSAL FOR DISTRIBUTING ITS REQUESTED REVENUE INCREASE TO CLASSES?

A Yes. The Company's proposed revenue allocation to customer classes is shown on Schedule H-1, pages 4 and 5. The Company essentially bases its class revenue allocation on the results of its CCOS study.

Q UNDER THE COMPANY'S CLASS REVENUE ALLOCATION BASED ON ITS CCOS STUDY, DO CERTAIN CLASSES RECEIVE LARGE INCREASES RELATIVE TO THE SYSTEM AVERAGE INCREASE?

A Yes. For example, the GS-120K rate class would receive an increase of 101.2%, which is nearly 3.5 times the system average increase of 29.3%. Because this is a large usage class, the Company's CCOS study, which partially allocates distribution mains costs on a volumetric basis using the P&A method, combined with the Company's failure to classify and allocate any portion of its distribution mains costs on a customer basis, likely over allocates costs to these large customers.

If the Company's class revenue allocation was based on a CCOS study that better reflects cost causation, one which allocated mains costs on both a coincident design day demand basis and on a customer basis, this rate class would very likely see a revenue increase closer in line with the system average increase.

Q DO YOU AGREE WITH THE COMPANY'S PROPOSED CLASS REVENUE ALLOCATION?

A No. Because FCG's CCOS study does not accurately reflect class cost causation, I recommend that the Company's class revenue allocation be distributed to classes on an equal percent basis. Because the Company's CCOS study produces class allocation results that aren't reliable, an equal percentage increase to all classes is equitable in this case.

Based on the Company's claimed revenue deficiency, this would result in an increase of 29.3% to each rate class. To the extent the Commission approves a different revenue increase for FCG, the percentage increase should be adjusted accordingly.

IV. FCG's Interstate Capacity Cost Allocation Proposal

Q HAVE YOU REVIEWED FCG'S PROPOSED INTERSTATE PIPELINE CAPACITY COST ALLOCATION?

A Yes. The Company's proposal is described in the direct testimony of FCG witness Mr. Gregory Becker.

Q WHAT IS THE COMPANY'S PROPOSAL?

A The Company proposes to allocate the cost of interstate pipeline capacity it purchases to both sales and transportation customers (both essential and non-essential).

Specifically, the Company proposes to purchase enough interstate pipeline capacity to transport not only the gas supply demand of its sales customers, but also that of its transportation customers, to its distribution system.

FCG is apparently concerned that if it does not purchase interstate pipeline capacity for <u>all</u> transportation customers, it will not have enough interstate pipeline capacity to deliver gas supply for its sales customers, as well as for transportation customers who may convert from transportation only service to FCG sales service with little notice. FCG is also concerned it will have inadequate interstate pipeline capacity necessary to deliver gas supply for those transportation customers whose third party suppliers are unable to provide gas supply on days of peak demand because of inadequate firm capacity reserved on interstate pipelines by those third party suppliers.

FCG would essentially purchase enough interstate pipeline capacity to ensure gas supply delivery for <u>all</u> of its transportation customers to FCG's distribution system, even though FCG does not have the obligation to do so because transportation customers have gas supply procured on their behalf by third party suppliers who arrange for delivery of that gas on an interstate gas pipeline to FCG's distribution system.

Q WHY DOES THE COMPANY INCUR CAPACITY COSTS ON AN INTERSTATE PIPELINE?

A The Company reserves capacity on an interstate pipeline in order to deliver enough gas supply to its distribution system for delivery to its sales customers. Transportation customers do not purchase gas supply from FCG. Therefore, FCG's transportation customers rely on third party suppliers to procure the necessary capacity over an interstate pipeline to allow for the delivery of gas supply of transportation customers to FCG's distribution system.

Q DOES THE COMPANY RECOGNIZE THAT IT DOES NOT HAVE THE OBLIGATION TO PROVIDE TRANSPORTATION CUSTOMERS WITH GAS SUPPLY?

A Yes. Both its current and proposed tariffs state the following in the Transportation - Special Conditions, Section E:

> In the event that Customer's Third Party Supplier fails to deliver gas on behalf of its Customers, the Company may, in its sole discretion, provide replacement gas supplies. The Company shall have no obligation to provide natural gas supplies to Customers that contract for gas supply from a TPS.

The Company also indicates that the third party supplier is responsible for making arrangements for transporting gas from its source to FCG's interconnection with the delivering pipeline supplier.

Q DOES THE COMPANY HAVE PENALTIES IN ITS TARIFFS THAT APPLIED TO TRANSPORTATION CUSTOMERS THAT FAIL TO DELIVER GAS SUPPLY TO MEET THEIR NEEDS?

A Yes The Company can apply daily nomination penalties to third party suppliers as well as charge third party suppliers for all pipeline imbalance and charges for failure to deliver confirmed quantities of gas.

The Company also has the discretion to reduce or completely curtail deliveries to transportation customers.

Q DOES THE COMPANY HAVE SOLID EVIDENCE THAT THIRD PARTY SUPPLIERS WILL BE UNABLE TO DELIVER GAS SUPPLY TO TRANSPORTATION CUSTOMERS DUE TO A LACK OF FIRM INTERSTATE PIPELINE CAPACITY?

A No. FCG indicates in its response to Citizens Interrogatory No. 160, that it is unable to verify the specific transportation arrangements of its transportation customers with their third party suppliers.

Based on the Company's proposal to allocate interstate pipeline capacity costs to all transportation customers regardless of their contract arrangements with third party suppliers, it appears that the Company has assumed that transportation customers have not performed the necessary due diligence to ensure that their third party suppliers will deliver firm gas supply to the FCG distribution system.

Q DOES THE COMPANY'S PROPOSAL TO ALLOCATE INTERSTATE PIPELINE CAPACITY COSTS TO ALL TRANSPORTATION CUSTOMERS RECOGNIZE THAT SOME TRANSPORTATION CUSTOMERS MAY HAVE BACKUP GAS SUPPLY?

A No. It appears that the Company's proposal does not recognize the possibility that some transportation customers may choose interruptible gas supply. The Company's proposal does not recognize the interruptible nature of some customers and whether they can turn on alternative gas supply equipment or whether they can simply curtail or reduce their gas supply demands on days when interstate pipeline capacity is in short supply.

Q COULD TRANSPORTATION CUSTOMERS END UP PAYING MORE FOR CAPACITY THAN THEY REQUIRE UNDER THE COMPANY'S PROPOSAL?

A Yes. If a transportation customer pays for firm delivery of its gas supply from a third party supplier, and also pays for interstate pipeline capacity from FCG, it will very likely overpay for the firm delivery of its gas supply and could very well pay for interstate pipeline capacity it does not need.

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that FCG's proposal as designed be rejected at this time.

I am not opposed to ensuring that transportation customers receive the gas supply they require, but the Company should allocate the costs of purchased interstate capacity only to those customers who actually cause the Company to incur those costs.

For example, FCG could create a standby or backup service in its tariff where the costs of interstate pipeline capacity costs for transportation customers are paid for only by those customers who may not have backup supply or have concerns that their third party supplier is unable to deliver all of its firm gas supply needs. FCG should not incur costs for all transportation customers without determining that all customers actually need the backup service.

Transportation customers should only pay for the services they require. This would apply to both essential and non-essential transportation customers.

FCG should acquire interstate pipeline capacity necessary to meet sales customers and only those transportation customers that need gas supply delivery backup from FCG. FCG should not indiscriminately buy transportation capacity to meet the needs of all transportation customers without determining whether customers actually need the service. To do so otherwise could cause excessive charges to transportation customers.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the Delaware Public Service Commission, the Florida Public Service Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm has participated in more than 700 regulatory proceeding in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE AND APPROVAL OF DEPRECIATION STUDY BY FLORIDA CITY GAS	))))))	**DOCKET NO. 20170179-GU**

Direct Testimony and Exhibits of

Christopher C. Walters

On behalf of

Federal Executive Agencies

February 1, 2018

BRUBAKER & ASSOCIATES, INC.

Project 10543

Table of Contents to the
Direct Testimony of Christopher C. Walters

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE AND APPROVAL OF DEPRECIATION STUDY BY FLORIDA CITY GAS	))))))	**DOCKET NO. 20170179-GU**

Direct Testimony of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony will address the current market cost of equity and the overall rate of return used to set rates in this proceeding for Florida City Gas ("FCG").

I. SUMMARY

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS ON RATE OF RETURN.

A I recommend the Florida Public Service Commission ("Commission") award a return on common equity of 9.3%, which within my recommended range of 9.00% to 9.60%. My recommended return on equity results in a ratemaking rate of return of 5.57% and an investor-capital rate of return of 6.71%, as shown on my Exhibit CCW-1. My recommended return on equity will fairly compensate the Company for its current market cost of common equity, and it will mitigate the Company's claimed revenue deficiency in this proceeding while providing a return that fairly balances the interests of customers and shareholders.

I also respond to FCG witness Dr. James Vander Weide's return on equity results in the range of 9.4% to 11.0%, with a recommended point estimate of 11.25%.[1]

II. RATE OF RETURN

Q PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A In this section of my testimony, I will explain the analysis I performed to determine the reasonable rate of return in this proceeding and present the results of my analysis. I begin my estimate of a fair return on equity by reviewing the authorized

[1] Vander Weide Direct at 53 and 55.

returns approved by the regulatory commissions in various jurisdictions, the market assessment of the regulated utility industry investment risk, credit standing, the outlook for the utility industry since the passage of the Tax Cuts and Jobs Act of 2017 (the "Tax Act"), and stock price performance. I used this information to get a sense of the market's perception of the risk characteristics of regulated utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to FCG's utility operations.

As described below, I find the credit rating outlook of the industry to be strong, supportive of the industry's financial integrity and access to capital. Further, regulated utilities' stocks have exhibited strong price performance over the last several years, which is evidence of utility access to capital.

Based on this review of credit outlooks and stock price performance, I conclude that the market continues to embrace the regulated utility industry as a safe-haven investment and views utility equity and debt investments as low-risk securities.

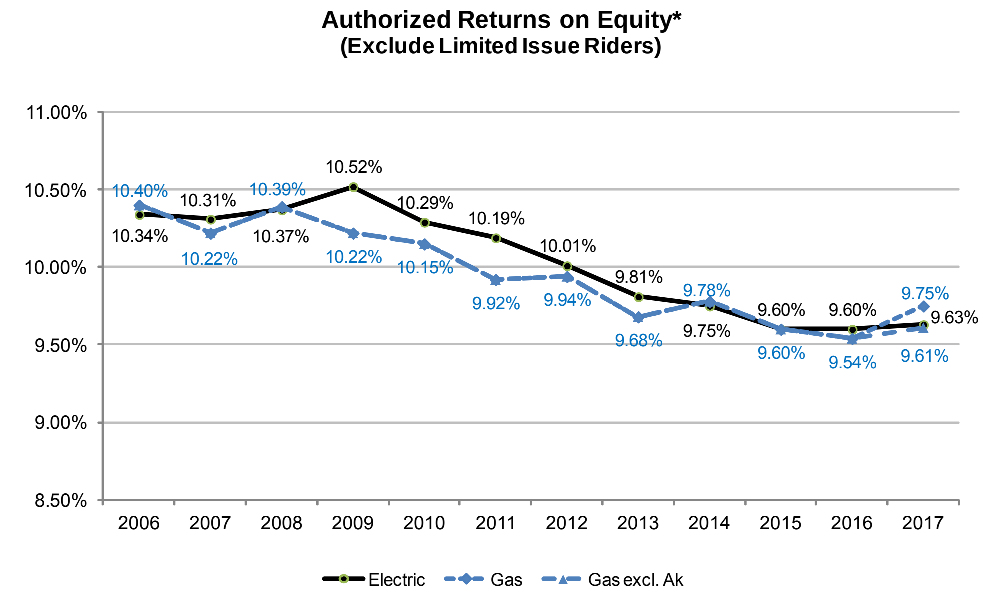
I also reviewed the projected changes in interest rates over the rate effective period, along with the Federal Reserve's monetary policy impacts that could affect cost of capital, interest rates and a fair return on equity in this proceeding. This information is used to assess whether or not current capital market costs are reasonable estimates of the capital market costs that will prevail during the period that rates determined in this proceeding will be in effect.

II.A. Industry Authorized Returns on Equity, Access to Capital, And Credit Strength

Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED RETURNS ON EQUITY FOR REGULATED UTILITIES, UTILITIES' CREDIT STANDING, AND UTILITIES' ACCESS TO CAPITAL USED TO FUND INFRASTRUCTURE INVESTMENT.

A Authorized returns on equity for both electric and gas utilities have been steadily declining over the last ten years, as illustrated in Figure 1 below. Many recent authorized returns on equity for electric and gas utilities have declined downward to about 9.50%.

FIGURE 1



Source and Note:
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions -- January - September 2017, October 26, 2017 at pages 5 and 6.
* Electric Returns exclude Limited Issue Riders.
* RRA excludes the Alaska NSTAR decision from its calculations.

While the declines in authorized returns on equity are public knowledge and align with declining capital market costs, utilities have been able to maintain a stable outlook and have been able to attract large amounts of capital at low cost to fund very large capital programs.

Q HAVE CREDIT RATING AGENCIES COMMENTED ON THE DECLINING TREND IN AUTHORIZED RETURNS ON EQUITY?

A Yes. Credit rating agencies have recognized the declining trend in authorized returns. Specifically, Moody's states:

> **Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles**
>
> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE).[2]

Further, in a report, Standard & Poor's ("S&P") states:

> **2. Earned returns will remain in line with authorized returns**
>
> Authorized returns on equity granted by U.S. utility regulators in rate cases this year have been steady at about <u>9.5%</u>. Utilities have been adept at earning at or very near those authorized returns in today's economic and fiscal environment. A slowly recovering economy, natural gas and electric prices coming down and then stabilizing at fairly low levels, and the same experience with interest rates have led to a perfect "non-storm" for utility ratepayers and regulators, with utilities benefitting alongside those important constituencies. Utilities have largely used this protracted period of favorable circumstances to consolidate and institutionalize the regulatory practices that support earnings and cash flow stability.[3]

---

[2] *Moody's Investors Service*, "US Regulated Utilities: Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.
[3] *Standard & Poor's Ratings Services*: "Corporate Industry Credit Research: Industry Top Trends 2016, Utilities," December 9, 2015, at 23, emphasis added.

Q PLEASE DESCRIBE THE RATINGS ACTIVITY THAT CREDIT RATING AGENCIES HAVE TAKEN WITH RESPECT TO THE REGULATED UTILITY INDUSTRY DURING THE PERIOD OF DECLINING RETURNS ON EQUITY.

A The credit rating changes for the electric and gas utility industry reflect a significant strengthening of the industry credit outlook.

The natural gas utility industry credit rating changes are shown in Table 1 below. The gas industry changes in credit ratings are similar to the electric utilities. In 2009, 42% of the gas industry had a credit rating in the BBB category, but by the end of 2016, 66% of gas utilities' credit ratings improved to A- or above.

TABLE 1

S&P Ratings by Category
Natural Gas Utilities
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017*
A or higher	57%	57%	50%	50%	38%	33%	33%	44%	56%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%
BBB+	14%	14%	38%	38%	13%	22%	33%	33%	33%
BBB	14%	14%	0%	0%	0%	0%	0%	0%	0%
BBB-	14%	14%	13%	13%	13%	11%	0%	0%	0%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

* As of August 30, 2017.
Source: S&P CAPITAL IQ, downloaded 6/20/2017 and 8/30/2017.
Note: Subsidiary rating is used if parent not rated.

Moody's has commented on the improved credit standing of regulated utility companies in its publication "Regulation Remains a Credit Supportive Ratings Driver Two Years After Sector-Wide Upgrades." Moody's stated as follows:

> **Summary**
>
> In January and February 2014, we upgraded the ratings of 147 US regulated electric and gas utility debt issuers as part of a sector-wide rating action that reflected our more favorable view of the relative credit supportiveness of US utility regulation. Factors supporting this view include better cost-recovery provisions, reduced regulatory lag,

> and generally fair and open relationships between utilities and their state regulators.[4]

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT INFRASTRUCTURE CAPITAL PROGRAMS?

A Yes. In its October 23, 2017 Capital Expenditure Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several comments about utility capital investments:

> • Projected 2017 capital expenditures for the 53 gas and electric utilities in the RRA universe has stayed steady at about $117.5 billion, which would be an all-time high for the sector.
>
> • CapEx projections for the longer term increased modestly from our previous analysis in March 2017, rising to $111.8 billion for 2018 and $102.4 billion for 2019, as companies' plans for future projects solidified and new opportunities arose.
>
> The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation and implement new technologies. We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future.
>
> * * *
>
> From a natural gas perspective, many utilities are participating in the sizable and ongoing expansion of the nation's gas midstream network. In addition, replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety.
>
> * * *
>
> For gas utilities, the CapEx/OCF ratio has fluctuated far more substantially than for electric utilities. Gas utilities saw large swings in the ratio from 2000 through 2012, with a peak of 1.5x in 2000 and a low of 0.7 in 2009. Since reaching 1.4x in 2012, the ratio appears to have stabilized somewhat, although 2015 was slightly lower at 1.0x,

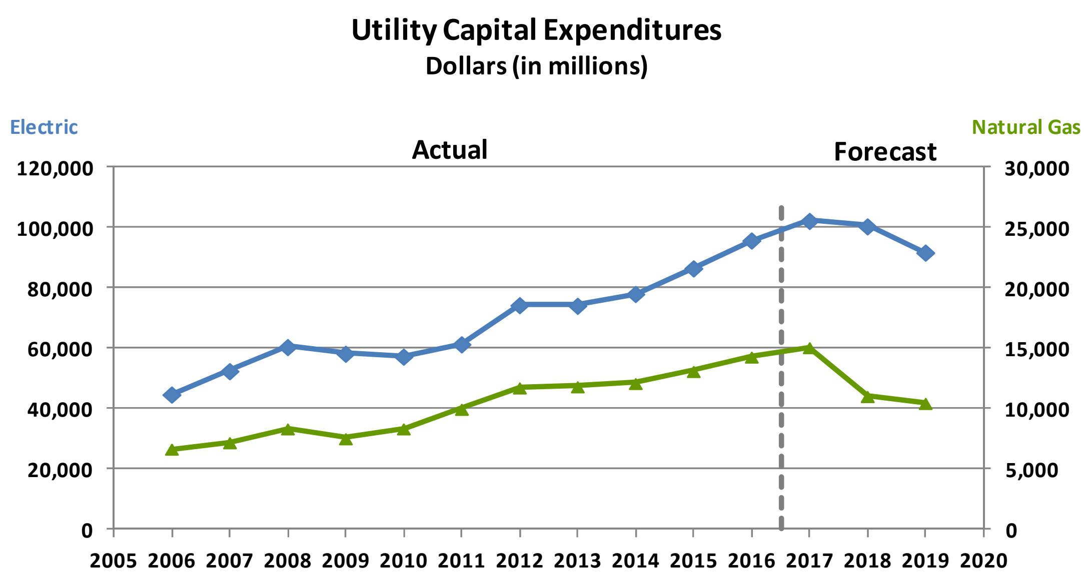
---

[4] *Moody's Investor Service*: "U.S. Regulated Utilities: Regulation Remains a Credit Supportive Ratings Driver Two Years After Sector-Wide Upgrades," November 6, 2015, emphasis added.

> before jumping up again to 1.3x in 2016, and dipping down to 1.1x in the first half of 2017.[5]

Indeed, historical versus projected outlooks for the electric and gas industries' capital investments are shown in Figure 2 below. As shown in this graph, gas industry investment outlooks are expected to be considerably higher in the forecast (2017-2019), relative to the last ten-year historical period. As noted by S&P Global Market Intelligence, capital investment is exceeding internal sources of funds to the gas utilities, requiring them to seek external capital to fund capital investments.

FIGURE 2



Source: *S&P Global Market Intelligence, Financial Focus*, Capital Expenditure Update, October 23, 2017, Page 7

As shown in Figure 2 above, the capital investments for the electric utility industry are significantly higher than the capital investments for the gas industry but they follow the same trend over the historical and forecasted period.

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[5] S&P Global Market Intelligence, RRA Financial Focus: "Utility Capital Expenditures: 2017 CapEx projections hold steady, 2018 and 2019 edge up," October 23, 2017, at 1 and 4.

Q IS THERE EVIDENCE OF ROBUST VALUATIONS OF GAS UTILITY SECURITIES?

A Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit CCW-2, the historical valuation of the gas utilities followed by *Value Line*, based on a price-to-earnings ("P/E") ratio, price-to-cash flow ("P/CF") ratio, and market price-to-book value ("M/B") ratio, indicates utility security valuations today are very strong and robust relative to the last 11 years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

Q HOW SHOULD THE COMMISSION USE THIS MARKET INFORMATION IN ASSESSING A FAIR RETURN FOR FCG?

A Market evidence is quite clear that capital market costs are near historically low levels. Authorized returns on equity have fallen to the mid 9.0% area; utilities continue to have access to large amounts of external capital to fund large capital programs; and utilities' investment grade credit standings are mostly stable. The Commission should carefully weigh all this important observable market evidence in assessing a fair return on equity for FCG.

<u>II.B. Regulated Utility Industry Market Outlook</u>

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A Regulated utilities' credit ratings have improved over the last few years and the outlook has been labeled "Stable" by credit rating agencies. Credit analysts have also observed that utilities have strong access to capital at attractive pricing (i.e., low capital costs), which has supported very large capital programs.

S&P recently published a report titled "Corporate Industry Credit Research: Industry Top Trends 2017, Utilities." In that report, S&P noted the following:

> – **Ratings Outlook**: <u>Rating trends across regulated utilities remain mostly stable supported by stable regulatory oversight</u>, slow but steady demand for utility services, and tempered by aggressive capital spending that will keep credit metrics from improving. Emerging new political trends in historically stable regions like Europe and the U.S. may have far-reaching effect on utilities over time, but S&P Global Ratings sees little immediate influence from those factors in 2017. Sovereign rating developments can influence utility ratings in some countries and we expect them to vary in different parts of the globe.
>
> * * *
>
> – **Assumptions:** <u>Sales growth at most utilities is closely tied to the general economic outlook in its service territory,</u> which can vary considerably from utility to utility. We project solid regulatory support for utility earnings and cash flow, with the occasional exception due to specific political or policy issues at the local level. Capital spending will continue to be elevated in most areas, with substantial infrastructure needs.
>
> * * *
>
> – **Industry Trends:** The <u>utility industry in most regions is stable</u>, consistent with our general ratings outlook and the nature of the essential products and services utilities sell.[6]

Similarly, Fitch states:

> **Stable Financial Performance:** <u>The stable financial performance of Utilities, Power & Gas (UPG) issuers continues to support a sound credit profile</u> for the sector, with 93% of the UPG portfolio carrying investment-grade ratings as of June 30, 2015, including 65% in the 'BBB' rating category. Second-quarter 2015 LTM [Long-Term Maturity] leverage metrics remained relatively unchanged year over year (YOY) while interest coverage metrics modestly improved. Fitch

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[6] *Standard & Poor's Global Ratings*: "Industry Top Trends 2017, Utilities," February 16, 2017, at 1, emphasis added.

> Ratings expects this trend to broadly sustain for the remainder of 2015, driven by positive recurring factors.[7]

Moody's recent comments on the U.S. Utility Sector state as follows:

> **2017 Outlook - <u>Timely Cost-Recovery Drives Stable Outlook</u>**
>
> <u>Our outlook for the US regulated utilities industry is stable.</u> This outlook reflects our expectations for the fundamental business conditions in the industry over the next 12 to 18 months.
>
> **A credit-supportive regulatory environment is the main driver of our stable outlook.** Our stable outlook for the US regulated utility industry is based on our expectation that utilities will continue to recover costs in a timely manner and maintain stable cash flows.[8]

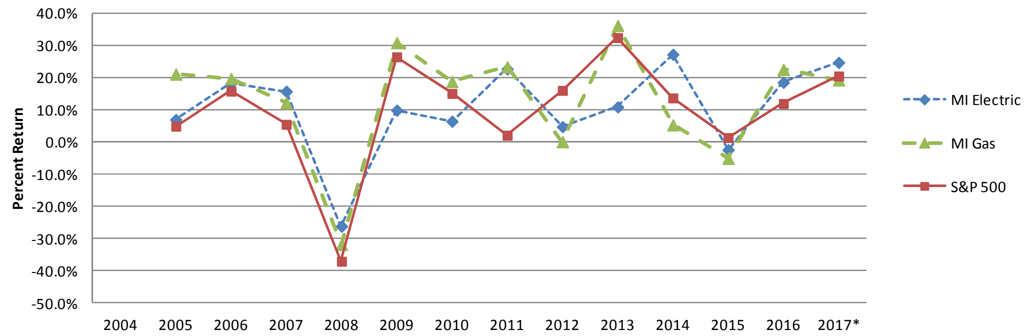
Q PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A As shown in Figure 3 below, S&P Global Market Intelligence ("MI") has recorded utility stock price performance compared to the market. The industry's stock performance data from 2004 through the second quarter of 2017 shows that the MI Electric and Gas Company Indexes have largely outperformed the market through downturns and recoveries. This relatively stable price performance for utilities supports my conclusion that utility stock investments are regarded by market participants as moderate- to low-risk investments.

[7] *Fitch Ratings*: "U.S. Utilities, Power & Gas Data comparator," September 21, 2015, at 1 and 7, emphasis added.
[8] *Moody's Investors Service*: "Regulated Utilities - US: 2017 Outlook – Timely Cost-Recovery Drives Stable Outlook," November 4, 2016, at 1, emphasis added.

FIGURE 3

Index Comparison



Source: S&P GLobal Market Intelligence.
*Data through November 2017

Q HAS THE PASSAGE OF THE TAX ACT IMPACTED THE INDUSTRY OUTLOOK FROM THE CREDIT RATING AGENCIES?

A The Tax Act is too new for the ratings agencies to spell out a cohesive and definitive outlook for the regulated utilities industry. Based on recent reports, the outlooks appear to be mixed from “Stable” or “Negative” over the short-term, to “Positive” over the long-term. While the overall impact on the industry is uncertain at this time, one thing is certain that all three agencies seem to agree on is that the impact resulting from the Tax Act is going to vary widely across the industry between parent holding companies and their operating utility subsidiaries on a case-by-case basis. For example, in a recent report S&P stated the following:

> **Ratings Outlook:**
> <u>Rating trends across regulated utilities in North America remain mostly stable supported by stable regulatory oversight</u>, mostly flat demand for utility services, but tempered by aggressive capital spending and tax reform considerations in the U.S. that will keep credit metrics from improving and weaken some entities <u>depending on individual tax situations</u> and regulatory/management responses. Emerging new technological and regulatory trends in historically stable Canada and the U.S. may have far-reaching effect on utilities over time, but we see limited influence from those factors in 2018.
>
> **Industry Trends:**

> The utility sector in the U.S. and Canada is stable with some modest downside ratings exposure, consistent with our general ratings outlook and the nature of the essential products and services utilities sell. Tax reform in the U.S. has emerged as a more urgent issue and could on a case-by-case basis result in downgrades. However, the industry as a whole is well positioned to withstand mild shocks, and we see steady growth and stable credit quality overall.[9]

Similarly, Fitch had the following to say:

> The Tax Cuts and Jobs Act signed into law on Dec. 22, 2017 has negative credit implications for U.S. regulated utilities and utility holding companies over the short-to-medium term, according to Fitch Ratings. A reduction in customer bills to reflect lower federal income taxes and return of excess accumulated deferred income taxes is expected to lower revenues and funds from operations (FFO) across the sector. Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative rating actions for those issuers that have limited headroom to absorb the leverage creep.
>
> State regulators have begun to examine the impact of tax reform on the regulated utilities in their state. While most state regulators will seek to provide some sort of rate relief to customers, they may be open to a negotiated outcome that also preserves the creditworthiness of the utilities. Management actions to defend their credit profiles are also important in assessing the future rating trajectory of an issuer. Overall, Fitch expects rating actions to be limited and on a case by case basis. Holding companies are more vulnerable given the elevated leverage profile for many driven by past debt funded acquisitions.
>
> Over a longer-term perspective, Fitch views tax reform as modestly positive for utilities. The sector retained the deductibility of interest expense, which would have otherwise significantly impacted cost of capital for this capital intensive sector. The exemption from 100% capex expensing is also welcome news for the sector, which has seen years of bonus depreciation reduce rate base leading to lower earnings. Finally, the reduction in federal income taxes lowers cost of service to customers, providing utilities headroom to increase rates for capital investments.[10]

Finally, Moody's had the following to say:

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[9] S&P Global Ratings, "Industry Top Trends 2018: North America Regulated Utilities", January 25, 2018 at 1. (emphasis added)

[10] FitchRatings, "Fitch: Tax Reform Creates Near-term Credit Pressure for U.S. Utilities", January 24, 2018. (emphasis added)

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.
>
> <u>The change in outlook to negative from stable for the 24 companies affected in this rating action primarily reflects the incremental cash flow shortfall caused by tax reform on projected financial metrics that were already weak, or were expected to become weak, given the existing rating for those companies.</u> The negative outlook also considers the uncertainty over the timing of any regulatory actions or other changes to corporate finance polices made to offset the financial impact.
>
> <u>The vast majority of US regulated utilities, however, continue to maintain stable rating outlooks. We do not expect the cash flow reduction associated with tax reform to materially impact their credit profiles because sufficient cushion exists within projected financial metrics for their current ratings.</u> Nonetheless, further actions could occur on a company specific basis.[11]

<u>II.C. FEDERAL RESERVE AND MARKET CAPITAL COSTS OUTLOOK</u>

Q HAVE YOU CONSIDERED CONSENSUS MARKET OUTLOOKS FOR CHANGES IN INTEREST RATES IN FORMING YOUR RECOMMENDED RETURN ON EQUITY IN THIS CASE?

A Yes. The outlook for changes in interest rates, inflation, and GDP growth have been impacted by expectations that the Federal Reserve Bank Open Market Committee ("FOMC") will raise short-term interest rates. Consensus economists are expecting continued increases in the Federal Funds Rate as the FOMC continues to normalize interest rates in response to the strengthening of the U.S. economy.

[11] *Moody's Investors Service*, "Rating Action: Moody's changes outlooks on 25 us regulated utilities primarily impacted by tax reform", January 19, 2018. (emphasis added)

This is evident from a comparison of current and forecasted changes in the Federal Funds Rate, as shown in Table 2 below. However, while the Federal Funds Rate is expected to increase over the next several years, consensus economists are not projecting significant increases in long-term interest rates. This is also illustrated in Table 2 below.

TABLE 2

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	2Q 2017	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q 2019
Federal Funds Rate									
Aug-17	**0.9**	1.2	1.3	1.5	1.6	1.8	2.0		
Sep-17	**0.9**	1.2	1.3	1.5	1.6	1.8	2.0		
Oct-17		1.2	1.2	1.4	1.6	1.8	2.0	2.2	
Nov-17		**1.2**	1.2	1.4	1.6	1.8	2.0	2.1	
Dec-17		**1.2**	1.2	1.4	1.6	1.8	2.0	2.2	
Jan-18			1.2	1.5	1.7	1.9	2.0	2.2	2.4
T-Bond, 30 yr.									
Aug-17	**2.9**	3.0	3.1	3.3	3.4	3.6	3.7		
Sep-17	**2.9**	2.9	3.1	3.2	3.4	3.5	3.6		
Oct-17		2.8	2.9	3.1	3.3	3.4	3.5	3.6	
Nov-17		**2.8**	3.0	3.1	3.3	3.4	3.5	3.6	
Dec-17		**2.8**	2.9	3.1	3.3	3.4	3.5	3.6	
Jan-18			2.8	3.0	3.1	3.3	3.4	3.5	3.6
GDP Price Index									
Aug-17	**1.0**	1.7	2.0	2.1	2.1	2.1	2.2		
Sep-17	**1.0**	1.7	2.0	2.1	2.0	2.1	2.1		
Oct-17		1.7	2.0	1.9	1.9	2.1	2.1	2.2	
Nov-17		**2.2**	2.0	1.9	2.0	2.1	2.1	2.2	
Dec-17		**2.2**	2.2	2.0	1.9	2.1	2.1	2.2	
Jan-18			2.2	2.0	1.9	2.0	2.1	2.2	2.0

Source and Note:
Blue Chip Financial Forecasts, August 2017 through January 2018.
Actual Yields in Bold

I note that the five increases in the Federal Funds Rate experienced over the last few years have not caused comparable changes in outlooks for changes in long-term interest rates. This is illustrated on my Exhibit CCW-3. As shown on that schedule, the actions taken by the FOMC to increase the Federal Funds Rate have simply flattened the yield curve, and have not resulted in an equal increase in long-term interest rates. This is significant because cost of common equity is impacted by long-term interest rates, not short-term interest rates. As a result, the recent increases in the Federal Funds Rate, and the expectation of continued increases in the Federal Funds Rate, have not, and are not expected to, significantly impact long-term interest rates.

The Federal Reserve has also recently implemented a strategy to begin to unwind its balance sheet position in long-term securities toward the end of this year. The Federal Reserve built up approximately $4.7 trillion of Treasury and mortgage-backed security holdings as part of a quantitative easing ("QE") program that spanned 2008 to 2014. During this QE program, the Federal Reserve procured long-term securities in an effort to support the Federal Reserve's monetary policy, mitigate long-term interest rates, and to support a recovering economy.

There has been concern that if the Federal Reserve starts to unwind this balance sheet position, it will cause an increase in long-term interest rates. However, the Federal Reserve announced that when it does unwind its balance sheet position, it will do so in small increments so as to not have a significant impact on long-term interest rates.[12]

For these reasons, the Federal Reserve actions on short-term interest rates have not resulted in matched increases in long-term interest rates. Further, the Federal Reserve's proposed plan for unwinding its balance sheet position is not expected to have a significant impact on long-term interest rates. All this indicates

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[12] Board of Governors of the Federal Reserve System, Press Release, "Federal Reserve Issues FOMC Statement," June 14, 2017.

that the Federal Reserve's monetary policy changes related to a strengthening economy have not and are not expected to increase long-term interest rates. Further, this outlook is reflected in consensus economists' forecasts of long-term interest rates, which indicate a relatively low capital market cost period for at least the intermediate period.

II.D. FCG'S Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF FCG.

A The market's assessment of FCG's investment risk is best described by credit rating analysts' reports. However, because FCG is not a rated entity, the best proxy for understanding the risks of FCG is the rating agencies' assessments of FCG's immediate parent company, Southern Company Gas ("SCG"). SCG's current corporate bond rating from S&P is A-.[13] SCG's outlook from S&P is "Negative" as a result of concerns at SCG's and FCG's ultimate parent company, Southern Company related to, among other things, the uncertainty surrounding the construction of the Vogtle Nuclear station.

Specifically, S&P states:

> **Ratings Action**
>
> On Aug. 4, 2017, S&P Global Ratings affirmed its ratings, including the 'A-' issuer credit ratings, on Southern Co. and its subsidiaries Alabama Power Co., Georgia Power Co., Gulf Power Co., and Southern Co. Gas. We also affirmed our 'BBB+' issuer credit ratings on Southern Co.'s subsidiaries Mississippi Power Co. and Southern Power Co. The outlook remains negative.
>
> **Rationale**

[13] S&P Global Market Intelligence.

> The negative outlook on Southern and its subsidiaries reflects the potential for lower ratings if the company proceeds with the Vogtle nuclear construction project in a manner that further increases business risk while its financial profile remains in its current weakened state.
>
> * * *
>
> Southern's financial profile has weakened mostly due to the largely debt-financed acquisition of AGL Resources Inc. The 2016 acquisition bolstered Southern's business risk profile but left the company with no cushion at the current rating level.
>
> * * *
>
> Southern Co. Gas' (formerly AGL Resources Inc.) regulated gas distribution operations are sufficiently large to somewhat de-emphasize, but not offset, the impact of Southern's non-utility operations, mainly Southern Power. While we expect that Southern Power will grow at a robust pace, we expect that its contribution to Southern's credit profile will remain consistently below 20% of the total.
>
> * * *
>
> **Outlook**
>
> The negative outlook on Southern Co. and its subsidiaries reflects the heightened potential for lower ratings if the company's financial profile remains weakened while it takes on additional risk in completing the construction of its new nuclear units without full assurance of cost recovery.[14]

II.E. FCG’s Proposed Capital Structure

Q WHAT IS THE COMPANY’S PROPOSED CAPITAL STRUCTURE?

A FCG witness Mr. Michael Morley sponsors the Company’s proposed capital structure, which is shown below in Table 3. The proposed capital structure is for the forecasted test year ending December 31, 2018.

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[14] *S&P Global Ratings RatingsDirect*: “Research Update: Southern Co. And Subsidiaries Outlook Still Negative Pending Vogtle Decision; Ratings Affirmed,” August 4, 2017, at 2-4.

TABLE 3

FCG's Proposed Investor-Supplied Capital Structure

Description	Weight
Long-Term Debt	46.69%
Short-Term Debt	6.41%
Common Equity	46.90%
Total Regulatory Capital Structure	100.00%

Source: MFR Schedule G-3, page 2.

Q DO YOU HAVE ANY COMMENTS ON THE COMPANY'S CAPITAL STRUCTURE?

A The Company's requested investor-supplied capital structure, including short-term debt, is relatively consistent with the capital structures of my proxy group and the industry. I conclude that this capital structure is reasonable for FCG.

II.G. Return on Equity

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works

& Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

These decisions identify the general financial and economic standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE FCG'S COST OF COMMON EQUITY.

A I have used several models based on financial theory to estimate FCG's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; and (4) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities with investment risk similar to FCG.

II.H. Risk Proxy Group

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP TO ESTIMATE FCG'S CURRENT MARKET COST OF EQUITY.

A My natural gas utility proxy group is largely the same as the proxy group relied on by FCG's witness, Dr. Vander Weide, with three exceptions. I have excluded South Jersey Industries because it has announced that on October 16, 2017, it reached a definitive agreement to acquire Elizabethtown Gas and Elkton Gas. This announcement had a noticeable impact on the Company's stock price. Also, I excluded Chesapeake Utilities Corporation and UGI Corp. because they are not rated by S&P or Moody's. My proxy group is shown on my Exhibit CCW-4.

I would also note that Dr. Vander Weide appears to have used two different comparable groups in his analyses without explanation. For example, his CAPM analysis proxy group had ten gas utilities. However, his DCF study excluded Southwest Gas. My proxy group includes Southwest Gas.

Q WHY IS IT APPROPRIATE TO EXCLUDE COMPANIES WHICH ARE INVOLVED IN MERGER AND ACQUISITION ("M&A") ACTIVITY FROM THE PROXY GROUP?

A M&A activity can distort the market factors used in DCF and risk premium studies. M&A activity can have impacts on stock prices, growth outlooks, and relative volatility in historical stock prices if the market was anticipating or expecting the M&A activity prior to it actually being announced. This distortion in the market data thus impacts the reliability of the DCF and risk premium estimates for a company involved in M&A.

Moreover, companies generally enter into M&A in order to produce greater shareholder value by combining companies. The enhanced shareholder value normally could not be realized had the two companies not combined.

When companies announce an M&A, the public assesses the proposed merger and develops outlooks on the value of the two companies after the combination based on expected synergies or other value adds created by the M&A.

As a result, the stock value before the merger is completed may not reflect the forward-looking earnings and dividend payments for the company absent the merger or on a stand-alone basis. Therefore, an accurate DCF return estimate on companies involved in M&A activities cannot be produced because their stock prices do not reflect the stand-alone investment characteristics of the companies. Rather, the stock price more likely reflects the shareholder enhancement produced by the proposed transaction. For these reasons, it is appropriate to remove companies involved in M&A activity from a proxy group used to estimate a fair return on equity for a utility.

Q WHY IS IT APPROPRIATE TO EXCLUDE UTILITIES THAT DO NOT HAVE A BOND RATING FROM S&P AND MOODY'S?

A Credit rating agencies undertake a detailed assessment of the business and financial risk in awarding a bond rating. This bond rating is available to public capital market participants, and is a generally independent assessment of the investment risk of the subject company. While a bond rating generally assesses the credit strength of the company, it is useful in determining the predictability and strength of the company's cash flows to meet its financial obligations including cash needed to meet common equity shareholders' investment return outlooks. For these reasons, credit ratings from S&P's and Moody's are information that is available to the investment community to assess the overall investment risk of the underlying company.

Because Chesapeake Utilities and UGI do not have a bond rating from S&P or Moody's, it is not possible to determine whether or not the credit rating agencies have found that its investment risk is reasonably similar to that of FCG or any of the other proxy group companies. Because the information was not available to determine that they are reasonably comparable in investment risk to FCG, they were excluded from the proxy group.

II.I. Discounted Cash Flow Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \;....\; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return otherwise known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on January 5, 2018. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used the most recently paid quarterly dividend as reported in *Value Line*.[15] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors'

[15] *The Value Line Investment Survey*, December 1, 2017.

consensus about what the dividend, or earnings growth rate, will be and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[16] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices more so than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL, and Reuters. All such projections were available on January 9, 2017, as reported online.

Each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

[16] *See, e.g.,* David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

Q WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A The growth rates I used in my DCF analysis are shown in Exhibit CCW-5. The average growth rate for my proxy group is 5.66%.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit CCW-6, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 8.36% and 8.08%, respectively.

Q DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term sustainable growth rate of 5.66%. The three- to five-year growth rates are higher than my estimate of a maximum long-term sustainable growth rate of 4.20%, which I discuss later in this testimony. For this reason, caution should be exercised when determining an appropriate DCF result.

Q HOW DID YOU ESTIMATE A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A A long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Hence, the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Financial Forecasts* projects that over the next five and ten years, the U.S. nominal GDP will grow approximately 4.20%. These GDP growth projections reflect a real growth outlook of

2.0% and an inflation outlook of 2.1% going forward. As such, the average growth rate over the next ten years is approximately 4.20%, which is a reasonable proxy of long-term sustainable growth.[17]

In my multi-stage growth DCF analysis, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Hence, recognizing the long-term GDP growth rate as a maximum sustainable growth is logical, and is generally consistent with academic and economic practitioner accepted practices.

II.J. Sustainable Growth DCF

Q PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit CCW-7. These dividend payout ratios and earnings retention ratios can be used to develop a

[17] *Blue Chip Financial Forecasts,* December 1, 2017, at 14.

sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on FCG's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit CCW-8, the average sustainable growth rate for the proxy group using this internal growth rate model is 6.21%.

Q DO YOU HAVE ANY COMMENTS CONCERNING YOUR SUSTAINABLE GROWTH RATE?

A Yes. As shown on my Exhibit CCW-8, page 1, the internal growth by reinvesting retained earnings is about 4.30%. This growth rate is reasonably consistent with a long-term sustainable growth. However, after reflecting sales of additional shares, the sustainable growth rate is increased from 4.30% up to 6.21%. Further, this sustainable growth rate is subject to an obvious outlier. Specifically, Atmos internal growth rate 5.80% but its sustainable growth rate is almost doubled. In light of this outlier, it would be appropriate to use the median growth rate, which better reflects the central tendency of my proxy group's sustainable growth rates. The median growth rate is 5.66%.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit CCW-9. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.91% and 8.36%, respectively.

II.K. Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. My first constant growth DCF is based on consensus analysts' growth rate projections so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on this constant growth DCF model is that it cannot reflect a rational expectation that a period of high or low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A Analyst-projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which in turn accelerates earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because rate base growth will slow and the utility has limited human and capital resources available to expand its construction program. Therefore, the three- to five-year growth rate projection could be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in the discussion of my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge on the maximum sustainable long-term growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth. Sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed utility sales growth tracks the U.S. GDP growth, albeit at a lower level, as shown in Exhibit CCW-10. Utility sales growth has lagged behind GDP growth for more than a decade. Therefore, the U.S. GDP nominal growth rate is a conservative (i.e., generous to the utility) proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at</u>

> <u>about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[18]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[19]

Q IS THERE ANY ACTUAL INVESTMENT HISTORY THAT SUPPORTS THE THEORY THAT THE CAPITAL APPRECIATION FOR STOCK INVESTMENTS WILL NOT EXCEED THE NOMINAL GROWTH OF THE U.S. GDP?

A Yes. This is evidenced by a comparison of the compound annual growth of the U.S. GDP compared to the geometric growth of the U.S. stock market. Morningstar measures the historical geometric growth of the U.S. stock market over the period 1926-2016 to be approximately 5.8%.[20] During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.4%.[21]

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[18] *"Fundamentals of Financial Management*," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298, emphasis added.
[19] *Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook* at 51 and 52.
[20] *Duff & Phelps, 2017 SBBI Yearbook* at 6-17.
[21] U.S. Bureau of Economic Analysis, February 28, 2017.

As such, the compound geometric growth of the U.S. nominal GDP has been higher but comparable to the nominal growth of the U.S. stock market capital appreciation. This historical relationship indicates the U.S. GDP growth outlook is a conservative estimate of the long-term sustainable growth of U.S. stock investments.

Q HOW DID YOU DETERMINE A SUSTAINABLE LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OUTLOOK OF THE MARKET?

A I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip Financial Forecasts* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP and are likely the most influential on investors' expectations of future growth outlooks. The consensus economists' published GDP growth rate outlook is 4.20% over the next five to ten years.[22]

Therefore, I propose to use the consensus economists' projected five- and ten-year average GDP consensus growth rates of 4.20%, as published by *Blue Chip Financial Forecasts*, as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts* projections provide real GDP growth projections of 2.0% and GDP inflation of 2.1%[23] over the five-year and ten-year projection periods. These consensus GDP growth forecasts represent the most likely views of market participants because they are based on published consensus economist projections.

[22] *Blue Chip Financial Forecasts*, December 1, 2017, at 14.
[23] *Id.*

Q DID YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these sources corroborate my consensus analysts' projections, as shown below in Table 4.

TABLE 4

GDP Forecasts

Source	Term	Real GDP	Inflation	Nominal GDP
Blue Chip Financial Forecasts	5-10 Yrs	2.0%	2.1%	4.2%
EIA - Annual Earnings Outlook	29 Yrs	2.0%	2.1%	4.2%
Congressional Budget Office	6 Yrs	1.9%	2.0%	4.0%
Moody's Analytics	25 Yrs	2.0%	1.8%	3.8%
Social Security Administration	49 Yrs			4.4%
The Economist Intelligence Unit	25 Yrs	1.7%	1.9%	3.6%

The EIA, in its *Annual Energy Outlook,* projects real GDP out until 2050. In its 2017 Annual Report, the EIA projects real GDP through 2050 to be 2.0% and a long-term GDP price inflation projection of 2.1%. The EIA data supports a long-term nominal GDP growth outlook of 4.2%.[24]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth to be 1.9% during the next 6 years with a GDP price inflation outlook of 2.0%. The CBO 6-year outlook for nominal GDP based on this projection is 4.0%.[25]

Moody's Analytics also makes long-term economic projections. In its recent 25-year outlook, Moody's Analytics is projecting real GDP growth of 2.0% with GDP

[24] DOE/EIA Annual Energy Outlook 2017 With Projections to 2050, downloaded March 1, 2017.
[25] *CBO: The Budget and Economic Outlook: 2017 to 2027*, January 2017, downloaded March 1, 2017.

inflation of 1.8%. Based on these projections, Moody's is projecting nominal GDP growth of 3.8% over the next 25 years.[26]

The Social Security Administration ("SSA") makes long-term economic projections out to 2095. The SSA's nominal GDP projection, under its intermediate cost scenario of 49 years, is 4.4%.[27]

The Economist Intelligence Unit, a division of *The Economist* and a third-party data provider to SNL, makes a long-term economic projection out to 2050. The Economist Intelligence Unit is projecting real GDP growth of 1.7% with an inflation rate of 1.9% out to 2050. The real GDP growth projection is in line with the consensus economists. The long-term nominal GDP projection based on these outlooks is approximately 3.6%.[28]

The real GDP and nominal GDP growth projections made by these independent sources support the use of the consensus economists' five-year and ten-year projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage growth covers the first five years, consistent with the term of the analyst growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions

[26] www.economy.com, *Moody's Analytics Forecast*, January 24, 2018.
[27] www.ssa.gov, "2017 OASDI Trustees Report," Table VI.G4, downloaded July 20, 2017.
[28] *SNL Financial, Economist Intelligence Unit*, downloaded on March 1, 2017.

the growth rate from the first stage to the third stage using a linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.20% long-term sustainable growth rate based on the consensus economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A As shown in Exhibit CCW-11, the average and median DCF returns on equity for my proxy group using the 13-week average stock price are 7.11% and 7.18%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The results from my DCF analyses are summarized in Table 5 below:

TABLE 5

Summary of DCF Results

Description	Proxy Group Average	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	8.36%	8.08%
Constant Growth DCF Model (Sustainable Growth)	8.91%	8.36%
Multi-Stage Growth DCF Model	7.11%	7.18%

I conclude that my DCF studies support a return on equity of 8.70%. I consider the results of all my studies, along with my assessment of the inputs and results as described above. In addition to the aforementioned, I also exercised judgment within my results due to uncertainty revolving around the net impact of the Tax Act. Based on this assessment, I find a return on equity based on the DCF methodology of 8.70% is appropriate.

II.L. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period January 1986 through third quarter 2017. The common equity required returns were based on regulatory commission-authorized returns for gas utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period January 1986 through third quarter 2017 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit CCW-12, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit CCW-13, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.41%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I incorporated five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit CCW-13, the five-year rolling average risk premium over Treasury bonds ranged from 4.17% to 6.68%, while the ten-year rolling average risk premium ranged from 4.30% to 6.44%.

As shown on my Exhibit CCW-14, the average indicated equity risk premium over contemporary Moody's utility bond yields was 4.04%. The five-year and ten-year rolling average risk premiums ranged from 2.80% to 5.52% and 3.11% to 5.09%, respectively.

Q DO YOU BELIEVE THAT THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES IS APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Yes. The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data.

Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, some studies, such as Duff & Phelps referred to later in this testimony, have recommended that use of "actual achieved investment return data" in a risk premium study should be based on long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term, abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual investment returns, and, thus, need not encompass a very long historical time period.

Q BASED ON THESE DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE FCG'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit CCW-15, where I show the yield spread between utility bonds and Treasury bonds over the last 38 years. As shown in this schedule, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.51% and 1.95%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities for 2017 are 1.13% and 1.52%, respectively. The current average "A" rated utility bond yield spread over Treasury bond yields is now lower than the 38-year average spread. The current "Baa" rated utility bond yield spread over Treasury bond yields is lower than the 38-year average spread.

The current 13-week average "A" rated utility bond yield is 3.83% and compares to the current Treasury bond yield of 2.80%, as shown in Exhibit CCW-16. This current utility to Treasury bond yield spread of 1.03% is lower than the 38-year average spread for "A" rated utility bonds of 1.51%. The current spread for the "Baa" rated utility bond yield to Treasury bond yield of 1.37% is also lower than the 38-year average spread of 1.95%.

These utility bond yield to Treasury bond yield spreads are evidence that the market perception of utility risk is about average relative to this historical time period and demonstrate that utilities continue to have strong access to capital in the current market.

Q HOW DID YOU DETERMINE WHAT A REASONABLE RISK PREMIUM IS IN THE CURRENT MARKET?

A I observed the spread of Treasury securities relative to public utility bonds and corporate bonds in gauging whether or not the risk premium in current market prices is stable relative to the past. What this observation of market evidence clearly demonstrates is that the valuations in the current market place an above average risk premium on securities that have greater risk.

This market evidence is summarized below in Table 6, which shows the utility bond yield spreads over Treasury bond yields on average for the period 1980 through September 2017, and the corporate bond yield spreads for Aaa corporates and Baa corporates.

TABLE 6

Comparison of Yield Spreads Over Treasury Bonds

Description	Utility A	Utility Baa	Corporate Aaa	Corporate Baa
Average Historical Spread	1.51%	1.95%	0.84%	1.93%
2016 Spread	1.33%	2.08%	1.07%	2.12%
2017 Spread	1.13%	1.52%	0.88%	1.58%
13-Week Spread	1.03%	1.37%		

Sources: Exhibit CCW-15 & CCW-16.

The observable yield spreads shown in the table above illustrate that securities of greater risk have recently had average risk premiums relative to the long-term historical average risk premium. Specifically, A-rated utility bonds to Treasuries, a relatively low-risk investment, have a yield spread in 2017 that has been lower than, though comparable to that of, its long-term historical yield spread. This is an indication that low risk investments like A-rated utility bonds have premium values relative to minimal risk Treasury securities.

Only recently have Baa-rated utility bond yield spreads gone below the 38-year average of 1.95%. For example, in 2016, the Baa-rated yield spread averaged 2.08%, which is approximately 13 basis points above the long-term average of 1.95%, shown in Exhibit CCW-15. While the higher risk Baa utility and corporate bond yields currently have a below-average yield spread of 40 basis points (1.52% vs. 1.95%), there appears to be more volatility in the spread. The higher risk Baa utility bond yields do not have the same premium valuations as their lower risk A-rated utility bond yields, and thus the yield spread for greater risk investments is wider than lower risk investments.

This illustrates that securities with greater risk, such as Baa-rated bonds versus A-rated bonds, have recently commanded above average risk premium spreads in the marketplace. Utility equity securities are greater risk than Baa utility bonds. Because greater risk securities appear to support an above-average risk premium relative to historical averages, this would support an above-average risk premium in measuring a fair return on equity for a utility stock or equity security.

Q WHAT IS YOUR RECOMMENDED RETURN FOR FCG BASED ON YOUR RISK PREMIUM STUDY?

A To be conservative, I am recommending more weight to the high-end risk premium estimates than the low-end. I state this because of the relatively low level of interest rates now but relative upward movements of utility yields more recently. Exercising judgment and caution may be warranted at this time due to the speculated impacts of the Tax Act. For these reasons, I propose weighted average risk premium estimate based on applying 75% weight to my high-end risk premium estimates and 25% to the low-end. Applying these weights, the risk premium for Treasury bond yields would be approximately 6.1%,[29] which is considerably higher than the 31-year average risk premium of 5.41% and reasonably reflective of the 3.6% projected Treasury bond yield. A Treasury bond risk premium of 6.1% and projected Treasury bond yield of 3.6% produce a risk premium estimate of 9.7%.

Similarly, applying these weights to the utility risk premium indicates a risk premium of 4.9%.[30] This risk premium is above the 31-year historical average risk premium of 4.04%. This risk premium in combination with the current observable Baa utility bond yield of 4.17%, rounded to 4.20%, produces an estimated return on equity of 9.1%.

Based on this methodology, my Treasury bond risk premium and my utility bond risk premium indicate a return in the range of 9.1% to 9.70%, with a midpoint of 9.40%. Due to uncertainty surrounding the impact on utilities as a result of various factors including the Federal Reserve's monetary policy, a strengthening economy, and the Tax Act, I recommend a risk premium return above the midpoint of the range. In my judgment, a return of 9.6% is a conservative, yet reasonable, risk premium return estimate at this time.

[29] (4.17% * 25%) + (6.68% * 75%) = 6.05%, rounded to 6.1%.
[30] (2.80% * 30%) + (5.52% * 70%) = 4.84%, rounded to 4.9%.

II.M. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are non-systematic risks. In a broad sense, systematic risks are market risks and non-systematic risks are business risks. The CAPM theory suggests the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, FCG's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A Currently, as published in the *Blue Chip Financial Forecasts*, the consensus economists have projected the 30-year Treasury bond yield to be 3.60%.[31] I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.60% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic market risks. Consequently, for companies with betas less than 1.0,

[31] *Blue Chip Financial Forecasts*, January 1, 2018, at 2.

using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit CCW-17, the proxy group average *Value Line* beta estimate is 0.71.

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A I derived two market risk premium estimates: a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Duff & Phelps' *2017 SBBI Yearbook* estimates the historical arithmetic average inflation-adjusted market return over the period 1926 to 2016 as 8.9%.[32] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.2%.[33] Using these estimates, the expected market return is approximately 11.30%.[34] The market risk premium then is the difference between the 11.30% expected market return and my 3.60% risk-free rate estimate, or approximately 7.70%.

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[32] *Duff & Phelps, 2017 SBBI Yearbook* at 6-18.
[33] *Blue Chip Financial Forecasts*, January 1, 2018 at 2.
[34] $\{ [(1 + 0.089) * (1 + 0.022)] – 1 \} * 100$.

My historical estimate of the market risk premium was also calculated by using data provided by Duff & Phelps in its *2017 SBBI Yearbook*. Over the period 1926 through 2016, the Duff & Phelps study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.0%[35] and the total return on long-term Treasury bonds was 6.0%.[36] The indicated market risk premium is 6.0% (12.0% - 6.0% = 6.0%).

Q HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY DUFF & PHELPS?

A The Duff & Phelps analysis indicates a market risk premium falls somewhere in the range of 5.5% to 6.9%. My market risk premium falls in the range of 6.0% to 7.7%. My average market risk premium of approximately 6.9% is at the high-end of the Duff & Phelps range.

Q HOW DOES DUFF & PHELPS MEASURE A MARKET RISK PREMIUM?

A Duff & Phelps makes several estimates of a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2016 as well as normalized data. Using this data, Duff & Phelps estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Duff & Phelps claims the income return is the only true risk-free rate associated with Treasury bonds and is

[35] *Duff & Phelps, 2017 SBBI Yearbook* at 6-17.
[36] *Id.*

the best approximation of a truly risk-free rate.[37] I disagree with this assessment from Duff & Phelps because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Duff & Phelps' conclusion to show the reasonableness of my market risk premium estimates.

Duff & Phelps' range is based on several methodologies. First, Duff & Phelps estimates a market risk premium of 6.9% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments over the 1926-2016 period.

Second, Duff & Phelps updated the Ibbotson & Chen supply-side model, which found that the 6.9% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period, primarily over the last 30 years. Duff & Phelps believes this abnormal P/E expansion is not sustainable.[38] Therefore, Duff & Phelps adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Duff & Phelps published a long-horizon supply-side market risk premium of 5.97%.[39]

Finally, Duff & Phelps develops its own recommended equity, or market risk premium by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this

[37] *Duff & Phelps, 2017 Valuation Handbook* at 3-32.
[38] *Id.* at 3-36.
[39] *Id.*

methodology, and utilizing a "normalized" risk-free rate of 3.5%, Duff & Phelps concludes the current expected, or forward-looking, market risk premium is 5.5%, implying an expected return on the market of 9.0%.[40]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit CCW-18 using the CAPM equation above, based on my prospective market risk premium of 7.7% and my low market risk premium of 6.0%, a risk-free rate of 3.6%, and a beta of 0.71, my CAPM analysis produces return estimates of 9.10% and 7.89%, respectively. Based on my assessment of risk premiums in the market, as discussed above, I will place primary reliance on my high-end CAPM return estimate rounded to 9.10%.

II.N. Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR FCG?

A Based on my analyses, I estimate FCG's current market cost of equity to be 9.3%.

TABLE 7

Return on Common Equity Summary

Description	Results
DCF	8.70%
Risk Premium	9.60%
CAPM	9.10%

[40] *Id.* at 3-48.

My recommended return on common equity of 9.3% is within my estimated range of 9.0% to 9.60%. As shown in Table 7 above, the high-end of my estimated range is based on my risk premium result, while the low-end of my recommended range is approximately the average of my DCF and CAPM results.

My return on equity estimates reflect observable market evidence, account for uncertainty revolving the impact on utilities as a result of the Tax Act, the impact of Federal Reserve policies on current and expected capital market costs, an assessment of the current risk premium built into current market securities, a general assessment of the current investment risk characteristics of the utility industry, and the market's demand for utility securities.

III. RESPONSE TO DR. VANDER WEIDE

Q WHAT RETURN ON COMMON EQUITY IS FCG PROPOSING FOR THIS PROCEEDING?

A Dr. Vander Weide, who sponsors FCG's return on equity recommendation, proposes a return on equity of 10.3% for his proxy group and adjusts this result to account for FCG's additional financial risk when compared to the market value capital structures of his proxy companies. His adjusted recommendation is 11.25%, which is the same return on equity this Commission awarded FCG in its last rate case in 2004.[41] For his proxy group, Dr. Vander Weide recommends a range of 9.40% to 11.00%.[42] This range is based on: (1) a constant growth DCF analysis, (2) an ex post and ex ante risk premium analysis; and (3) a historical and a DCF-based CAPM study. In addition to his financial risk adjustment, Dr. Vander Weide also considered flotation costs in making his determination.

[41] Direct Testimony of Dr. Vander Weide at 53.
[42] *Id*.

Q HOW DID DR. VANDER WEIDE ARRIVE AT HIS ESTIMATED RETURN ON EQUITY AND POINT ESTIMATE OF 10.3% FOR HIS PROXY COMPANIES?

A Dr. Vander Weide relied on market-based models to estimate the current market cost of equity for his proxy group companies. As shown below in Table 8, which summarizes the results Dr. Vander Weide offers at page 51 of his testimony, Dr. Vander Weide relied on a constant growth DCF study, risk premium methodologies, and capital asset pricing model studies.

TABLE 8

Dr. Vander Weide Proxy Company Results

Model	Proxy Company[1] (1)	Corrected (3)
Constant Growth DCF	9.4%	9.0%
Ex Ante Risk Premium	11.0%	9.6%
Ex Post Risk Premium	10.2%	9.6%
CAPM Historical	10.0%	8.7%
CAPM DCF	10.7%	9.3%
Proxy Group Average	10.3%	
Recommended Range	9.4% - 11.0%	9.0% - 9.6%
ATWACC Adder	0.95%	9.3%
Recommended ROE	11.25%	

As shown in Table 8 above under Column 1, Dr. Vander Weide's analyses produced a return on equity in the range of 9.4% to 11.0%. The average of his results range is 10.3%. As shown under Column 2, Dr. Vander Weide proposes a 1.7% financial risk adder. His calculation is based on the after-tax weighted average cost of capital ("ATWACC") methodology in an attempt to account for the difference in financial risk between FCG's book value capital structure and the proxy group's historical average market value capital structure. The combination of the average result for Column 1 and the ATWACC adder in Column 2 supports the Company's requested return on equity of 12.0%. However, Dr. Vander Weide recommends, and FCG requests, a return on equity of 11.25%. Dr. Vander Weide attempts to further qualify his recommendation by stating that his recommended return on equity of 11.25% produces the approximate average rate of return being requested by natural gas utilities in 2017.

III.A. ATWACC Adder

Q HOW DID DR. VANDER WEIDE PRODUCE THE ATWACC ADDER OF 170 BASIS POINTS SHOWN IN TABLE 8 ABOVE?

A This adder was developed on his Exhibit No.___(JVW-1), Schedule 11. On that schedule, Dr. Vander Weide produces an.

He then relied on the 10-year average market value capital structure of *The Value Line Investment Survey* ("*Value Line*") Natural Gas Utility Industry. As shown in the top portion of his Schedule 11, he produces an ATWACC of 7.04% for the *Value Line* Natural Gas utilities at a 10.3% return on equity.

Next, Dr. Vander Weide relies on the long-term sources of capital proposed by FCG in this proceeding to determine its rate of return. Dr. Vander Weide found that for FCG to earn the same ATWACC as the Natural Utility industry (7.04%) at a 10.3% return on equity, FCG needs to earn an 12.0% return on equity. To be conservative, Dr. Vander Weide limits his recommendation to 11.25%.

Q IS DR. VANDER WEIDE'S ESTIMATED RETURN ON EQUITY OF 11.25% FOR FCG REASONABLE?

A No. Dr. Vander Weide's proposed ATWACC adjustment should be rejected. He has not provided an accurate comparison of the capital structure weights for the Natural Gas Utility Industry followed by *Value Line* and FCG. Specifically, Dr. Vander Weide relies on a 58% common equity for the 10-year average *Value Line* Natural Gas utilities on his Schedule 11.

Q DO YOU HAVE OTHER CONCERNS WITH DR. VANDER WEIDE'S PROPOSED ATWACC METHODOLOGY?

A Yes. This methodology simply is flawed and produces an unjust result for FCG. Dr. Vander Weide's adjustment is actually more of a market-to-book ratio adjustment rather than a financial risk adjustment. Essentially, he is estimating the return on equity on a market value capital structure that needs to be applied to a book value capital structure in order to support his recommended return on equity based on market value capital structure weight. Stated differently, this is a market-to-book ratio adjustment to the estimated return on common equity. A market-to-book ratio adjustment is designed to maintain a targeted market value of the stock, rather than to ensure that utility investors are fairly compensated for making investment in utility plant and equipment. The concept is fundamentally flawed and imbalanced.

Additionally, this methodology is not commonly relied on in determining utility returns on equity. In the United States, regulated utility authorized returns on equity are almost uniformly set based on book-value capital structures. As I have explained in detail above, these authorized returns have not been a deterrent for investors supplying capital to utilities. Utility investors are largely institutional investors that are well informed and manage very diversified portfolios. As can be seen in our proxy group's dividend yields, and other valuation metrics provided in my Exhibit CCW-2, utility capital costs have been, and continue to be, very low.

III.B. Vander Weide's DCF

Q PLEASE DESCRIBE DR. VANDER WEIDE'S DCF ANALYSIS.

A Dr. Vander Weide relied on a quarterly compounded DCF study, with an adjustment to the proxy group stock price of 5% to reflect flotation cost adjustments. Based on this study, Dr. Vander Weide estimates a DCF return for his proxy group of 9.4%.[43] This 9.4% DCF return is the approximate midpoint of two different averages Dr. Vander Weide calculated: (1) a simple average of 9.1%; and (2) a market capitalization weighted average of 9.6%. Dr. Vander Weide's DCF results are based on a proxy group average growth rate of 6.3% and an adjusted dividend yield of approximately 2.8%.

Q DO YOU TAKE ISSUE WITH DR. VANDER WEIDE'S DCF ANALYSES?

A Yes. I have several issues concerning his DCF analyses. First, Dr. Vander Weide's DCF estimate of 9.4% is overstated by his unorthodox use of market capitalization weighted average. I am not aware of this methodology being explicitly relied on in any jurisdiction. The most common measures of central tendency in determining results are the simple average or median.

Second, Dr. Vander Weide adjusted his dividend yield calculation by reducing the stock price by 5%. This adjustment reflected the estimated cost of issuing stock to the public or flotation cost expense. As outlined below, this flotation cost

[43] Vander Weide Direct Testimony at 26 and Exhibit No. ___(JVW-1)..

adjustment is not a known and measurable cost for FCG, and it overstates FCG's revenue requirement because it allows for recovery of an expense which Dr. Vander Weide has failed to prove was actually incurred by FCG, and therefore is not appropriately included in the development of its cost of service.

Finally, Dr. Vander Weide's model overstates a fair return on equity for FCG because it reflects quarterly compounding of dividends.

While I have several concerns with Dr. Vander Weide's DCF results, I will limit my concerns to his adjustment for flotation costs and reject his use of market capitalization weighting to calculate an average result in an effort to limit issues in this proceeding.

III.B.1. Flotation Costs

Q PLEASE DESCRIBE DR. VANDER WEIDE'S PROPOSED FLOTATION COST ADJUSTMENT.

A Dr. Vander Weide proposes a flotation cost adjustment by comparing the difference in his DCF return by making an adjustment to the stock price versus no adjustment. Dr. Vander Weide proposes to calculate the expected dividend yield by dividing the expected dividend by 95% of the average stock price, or a 5 percentage point reduction to the stock price, as a measure of flotation cost. Dr. Vander Weide observes that studies outlining flotation costs indicate that utilities generally incur a cost of 5% of the share price in issuing stock to the public. This flotation cost is in the form of direct expenses for issuing stock to the public, and pricing pressure when selling new stock.

Dr. Vander Weide estimates this 5% flotation cost by reviewing academic studies of flotation cost for utility companies, and reviewing actual issuances of other companies.[44]

Q IS DR. VANDER WEIDE'S FLOTATION COST ADJUSTMENT TO FCG'S RETURN ON EQUITY REASONABLE?

A No. I do not dispute that flotation costs would be appropriate if it was based on FCG's actual cost of issuing stock to the public. However, Dr. Vander Weide's flotation cost is not based on known and measurable costs for FCG, because it is not based on FCG's actual costs. Instead, Dr. Vander Weide's flotation cost adjustment reflects economic studies of other utility companies that have actually sold stock to the public. In his proposed flotation cost adjustment, Dr. Vander Weide failed to recognize that FCG does not incur costs associated with selling stock to the public. Including a public flotation cost adjustment to a fair return on equity will produce an excessive rate of return to FCG unless the adjustment is shown to be reasonably compensatory for actual flotation cost expenses. Dr. Vander Weide's proposed adjustment, again, is not based on this important balanced consideration in determining a fair return on equity for FCG.

Q IS IT REASONABLE TO ASSUME, AS DR. VANDER WEIDE HAS, THAT FCG HAS ACTUALLY INCURRED FLOTATION COSTS?

A No. FCG would only incur flotation costs if it has sold stock to the public, for the purpose of using the proceeds to invest in FCG infrastructure. FCG stock is not market traded. Rather, it is held by its publicly traded parent company, Southern

[44] Vander Weide Direct Testimony at 31-32 and Appendix 3.

Company. FCG's common equity capital is produced from several sources including retained earnings, and equity contributions from its parent company. FCG's retained earnings do not cause FCG to incur flotation costs. FCG's parent company equity contributions can be funded from many sources. If its parent company makes equity contributions with internal funds, or issues debt capital to fund equity contributions in the utility, then the parent company would not incur stock issuance flotation costs.

Only in the event where stock is sold to the public by the parent company, and the parent company allocates all or a portion of the stock sale costs to the utility, would there be a flotation cost incurred by FCG.

Q IN THE EVENT A PARENT COMPANY DID ISSUE STOCK TO THE PUBLIC AND DID INCUR FLOTATION COSTS, WOULD SUCH EXPENSES BE VERIFIABLE AND AUDITABLE BY THE UTILITY?

A Yes. If a parent company issued stock to the public to make equity contributions to the utility company, and the affiliate agreement with the parent company allows for transferring these costs to the utility, then the actual flotation costs could be audited by the Commission, determined to be legitimate and reasonable, and could then be included in the utility's cost of service. Unfortunately, Dr. Vander Weide has not provided proof of any <u>actual</u> flotation costs incurred by FCG, or properly allocated to FCG by its parent company. Therefore, because it is not known and measurable, this cost should not be included in its cost of service.

Q HOW WOULD DR. VANDER WEIDE'S DCF MODEL BE CHANGED IF IT IS CORRECTED TO REMOVE THE UNJUSTIFIED FLOTATION COST ADJUSTMENT AND IGNORING THE MARKET CAPITALIZATION WEIGHTED AVERAGE?

A Rejecting Dr. Vander Weide's flotation cost adjustment and market capitalization weighting methodology would effectively reduce his average DCF result of 9.4% to approximately 9.0%.

III.C. Vander Weide Ex Ante Risk Premium

Q PLEASE DESCRIBE DR. VANDER WEIDE'S EX ANTE RISK PREMIUM METHODOLOGY.

A Dr. Vander Weide estimated a DCF return on a proxy group of natural gas companies relative to the utility bond yield with a rating of "A." He performed this analysis for a period from June 1998 through June 2017. Dr. Vander Weide then performs a regression analysis to develop his risk premium estimate of 5.2% for this historical period based on prospective DCF return estimates relative to bond yields. (Appendix 4, pages 2-3)

To this estimated market risk premium of 5.2%, he added a projected "A" rated utility bond yield of 5.8%. He then concluded that this produced a return on common equity of 11.0%. (Vander Weide Direct Testimony at Appendix 4, page 3).

Q HOW DID DR. VANDER WEIDE PROJECT AN "A" UTILITY BOND YIELD?

A Dr. Vander Weide projects an A-rated utility bond yield of 6.2% using two methods. First, he uses the *Value Line* projected AAA corporate bond yield of 5.5% and the average yield spread between an A utility bond yield and an AAA corporate bond yield of 26 basis points. This produces an A utility bond yield projection of 5.76%.

Second, Dr. Vander Weide considered the Energy Information Administration ("EIA") forecast of an AA rated utility bond yield of 5.71%. He then adds the current spread between AA bond yields and A utility bond yields of approximately 12 basis points to the EIA forecasted AA utility bond yield of 5.71%. Collectively, this produces an average forecasted A-rated utility bond yield of 5.83%.

His recommended projected A utility bond yield is the average of these two projections, 5.8% ((5.76% + 5.83%)/2).[45]

Q PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VANDER WEIDE'S EX ANTE RISK PREMIUM ANALYSIS.

A I believe Dr. Vander Weide's estimated equity risk premium from his ex ante risk premium study represents an unreasonable risk premium return estimate.

Dr. Vander Weide's projected "A"-rated utility bond yield of 5.8% is approximately 200 basis points above current observable "A"-rated utility bond yields of 3.83% over the 13-week period ending January 5, 2018. (Exhibit CCW-16). Indeed, it is approximately 185 basis points higher than the highest "A"-rated utility bond yield experienced during that 13-week period. More importantly, Dr. Vander Weide's projection of an "A"-rated utility bond yield has not been shown to be reasonably consistent with any market participant's outlook on the cost of utility capital during the period rates determined in this proceeding will be in effect. As such, Dr. Vander Weide's utility bond yield projection overstates current observable utility bond yields, has no basis, and has been shown to have no relationship to

[45] Direct Testimony at 37-38.

market participants' outlook over the next two to three years. Rather, the *Value Line* projection and the Energy Information Administration ("EIA") projections used by Dr. Vander Weide reflect projected outlooks for capital market costs that are many years out into the future, ranging 10 years in the future. These projected interest rates do not reflect consensus for the current market, and do not reflect outlooks for capital costs applicable to the period rates determined in this case are likely to be in effect.

For these reasons, Dr. Vander Weide's ex-ante risk premium should be rejected. A more reasonable cost of equity estimate based on the risk premium method is 9.6% as I have developed and discussed above.

III.D. Vander Weide Ex Post Risk Premium

Q PLEASE DESCRIBE DR. VANDER WEIDE'S EX POST RISK PREMIUM METHODOLOGY.

A In Dr. Vander Weide's ex post risk premium methodology, he made two comparisons of the historical realized return on a stock index relative to estimated annual return for an "A" rated utility bond. His first risk premium study compared the total annual realized return on the S&P 500 versus the annual return on an A-rated utility bond index over the period 1937-2017. This produced a realized annual arithmetic average risk premium of 4.62%.[46] Second, Dr. Vander Weide compared the actual achieved annual return on an S&P utility stock index versus the annual total return on an A-rated utility bond. This produced an arithmetic average annual equity risk premium of 4.0%.[47]

Based on this analysis, Dr. Vander Weide estimates an equity risk premium in the range of 4.0% (based on S&P Utilities) to 4.6% (based on yield S&P 500). He

[46] Vander Weide Direct at 39.
[47] *Id.* at 40.

then applies this estimated equity risk premium to his projected "A" rated utility bond yield of 5.8% to produce an estimated equity risk premium in the range of 9.8% to 10.4% with a midpoint of 10.1%. (Vander Weide Direct Testimony at 41). He then adds 14 basis points for flotation costs, resulting in an estimate of 10.2%.

Q DO YOU BELIEVE THAT DR. VANDER WEIDE'S EX POST RISK PREMIUM RECOMMENDATION IS REASONABLE?

A No, I reject it for several reasons. First, as discussed earlier, his projected "A" rated utility bond yield of 5.8% substantially exceeds current observable utility bond yields of 3.83%.

Second, Dr. Vander Weide's development of an equity risk premium based on the S&P 500 does not reasonably reflect the risk-return relationship investors would require for an investment in FCG or other lower-risk regulated natural gas utilities. Therefore, this is simply not a reasonable methodology to estimate a fair return on equity for FCG.

For the reasons outlined above, I reject Dr. Vander Weide's flotation cost adjustment for FCG because he has not shown this as a legitimate cost of service item for FCG, and therefore represents an adjustment which is not known and measurable.

III.E. Vander Weide CAPM

Q PLEASE DESCRIBE DR. VANDER WEIDE'S CAPM STUDIES.

A Dr. Vander Weide performed a historical CAPM study based on a market risk premium of 6.9%, a projected risk-free rate of 4.2%, and beta estimate of 0.74. This study produced a return on equity estimate of 9.5%, which includes a 0.14% adjustment for flotation costs. (Vander Weide Direct Testimony at 45).

However, Dr. Vander Weide states that this method understates the cost of equity by comparing the realized S&P utility index risk premium of 5.47% to that of the S&P 500 index risk premium of 6.08%. The realized S&P Utility risk premium is approximately 90%, or 0.90, of the S&P 500 risk premium. Dr. Vander Weide asserts that the average utility beta of 0.735 would understate the cost of equity compared to the 0.90 realized difference in risk premiums. Based on this analysis, Dr. Vander Weide proposes to use a beta estimate of 0.90 with his 4.2% risk-free rate and 6.9% market risk premium. This produces a return on equity estimate of 10.6%, including his flotation cost adjustment of 14 basis points. The average of these two methods for his historical CAPM is 10.0% ((9.5% + 10.6%) ÷ 2 = 10.0%).

Dr. Vander Weide also performed a DCF-based CAPM study, where he estimated the market risk premium using a DCF return on the S&P 500. Based on that study, Dr. Vander Weide estimated a market risk premium of 7.7% (Schedule 9). Using this market risk premium, his risk-free rate of 4.2%, and beta estimate of 0.74, produced a CAPM return estimate of 10.0% including a 14 basis point flotation cost adder. (Vander Weide Direct Testimony at 52).

Again, Dr. Vander Weide observed that the measured beta may not accurately represent the utility's betas going forward. As such, based on a relationship between the historical return on the market and historical return on the S&P Utility Stock Index, he adjusted the *Value Line* beta of 0.74 up to 0.90. Using this alternative beta, a risk-free rate of 4.2%, a market risk premium of 7.7%, and a 14 basis point flotation cost adder, he estimates a current market cost of equity of

11.3%. The average of these two methods for his DCF-based CAPM is 10.7% ((10.0% + 11.3%) ÷ 2 = 10.7%).

Dr. Vander Weide then concludes that his CAPM analyses indicate a return in the range of 10.0% to 10.7%.[48]

Q DO YOU HAVE ANY CONCERNS WITH DR. VANDER WEIDE'S HISTORICAL CAPM RETURN ESTIMATE?

A Yes. His CAPM return estimate of 9.5% based on a *Value Line* measured beta is overstated because of his inclusion of a flotation cost allowance of 14 basis points. That return produces a CAPM return estimate of 9.40% excluding his flotation cost adder. As explained above, Dr. Vander Weide has not justified FCG's actual cost of issuing stock to the public, and therefore his flotation cost adjustment is not known and measurable and should be excluded from his cost study.

Second, his historical CAPM return estimate based on an adjustment to the *Value Line* beta is inappropriate and should be rejected. The *Value Line* beta of 0.74 for his proxy group has already been adjusted. An additional adjustment to his proxy group's beta is unwarranted.

Specifically, *Value Line* adjusts the raw beta estimate for a long-term tendency to converge toward a market beta of 1. For raw beta estimates less than 1, *Value Line*'s beta adjustment process will increase the beta estimate closer to 1. For raw beta estimates greater than 1, *Value Line*'s beta adjustment process will decrease the beta estimate closer to 1. Dr. Vander Weide's proposal to adjust a *Value Line* <u>adjusted</u> beta has no academic support, no sound theoretical basis, and

[48] Vander Weide Direct at 53.

accomplishes nothing but to inflate a reasonable estimate of FCG's current market cost of equity.

Q HOW DID DR. VANDER WEIDE DERIVE HIS RISK-FREE RATE OF 4.20%?

A He derived a forecasted yield of a Treasury bond rate based on data he gathered from *Value Line*, EIA and other sources. Specifically, he relies on a *Value Line* forecasted 10-year Treasury note of 4.0% and adds a spread of 35 basis points to produce his estimated forecasted yield on a long-term Treasury bond of around 4.35%.

He uses an EIA forecasted 10-year Treasury bond yield of 3.75%, and adds the 35 basis point spread to produce a forecasted long-term Treasury bond yield of 4.1%.

His point estimate of 4.20% is the midpoint of his forecast using these *Value Line* and EIA projected 10-year Treasury bond yields (4.1% to 4.35%).

Q IS DR. VANDER WEIDE'S PROJECTION OF A RISK-FREE RATE REASONABLE?

A No. He has not shown that his projected Treasury bond yields reflect current capital market participants' outlooks, and therefore are not a general assessment of independent market analysts' assessment of FCG's market cost of capital. A more balanced methodology would be to use *The Blue Chip Financial Forecasts*' consensus economists' projected Treasury bond rates. This is a source I used as an independent assessment of what market participants believe Treasury bond rates will be over the period in which rates will be in effect. Based on that assessment, a Treasury bond rate of 3.6% is appropriate.

Q HOW WOULD DR. VANDER WEIDE'S CAPM STUDIES CHANGE IF *THE BLUE CHIP FINANCIAL FORECASTS*' PROJECTED TREASURY BOND RATE OF 3.6% WAS USED, AND THE *VALUE LINE* PROXY GROUP BETA IS NOT ADJUSTED?

A Using a risk-free rate projection of 3.6%, a beta estimate of 0.74, and market risk premium of 6.9% indicates a CAPM return estimate of 8.7%. If his DCF-based market risk premium estimate of 7.7% is used to reflect the low level of Treasury bond yields reflecting the market's premiums paid for low-risk securities, the CAPM return estimate would be 9.3%. Hence, this reasonable estimate of a CAPM return estimate would indicate a return in the range of 8.7% to 9.3%.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Christopher C. Walters

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Southern Illinois University Edwardsville in 2008 where I received a Bachelor of Science Degree in Business Economics and Finance. I graduated with a Master of Business Administration Degree from Lindenwood University in 2011.

In January 2009, I accepted the position Financial Representative with American General Finance and was quickly promoted to Senior Assistant Manager. In this position I was responsible for assisting in the management of daily operations of the branch, analyzing and reporting on the performance of the branch to upper management, performing credit analyses for consumers and small businesses, as well as assisting home buyers obtain mortgage financing.

In January 2011, I accepted the position of Analyst with BAI. As an Analyst, I performed detailed analysis, research, and general project support on regulatory and competitive procurement projects. In July 2013, I was promoted to the position of Consultant. As a Consultant, I have performed detailed technical analyses and research to support regulatory projects including expert testimony, and briefing assistance covering various regulatory issues. At BAI, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory filing tasks have included measuring the cost of capital, capital structure evaluations, assessing financial integrity, merger and acquisition related issues, risk management related issues, depreciation rate studies, other revenue requirement issues and wholesale market and retail regulated power price forecasts. Since 2011, I have been working with BAI witnesses on utility rate of return filings. Specifically, I have assisted BAI witnesses in analyzing rate of return studies, drafting discovery requests and analyzing responses, drafting rate of return testimony and exhibits and assisting with the review of the briefs.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony before state regulatory commissions including: Arkansas, Delaware, Kansas, Kentucky, Michigan, Minnesota, Ohio and Oklahoma. I have also filed an affidavit before the Federal Energy Regulatory Commission ("FERC").

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

Florida City Gas

Rate of Return

Line	Description	Amount[1]	Weight	Cost[1,2]	Weighted Cost
	Ratemaking Capital Structure				
1	Common Equity	$ 115,745,170	38.7%	9.30%	3.60%
2	Long-Term Debt	$ 115,217,944	38.5%	4.66%	1.80%
3	Short-Term Debt	$ 15,814,600	5.3%	2.64%	0.14%
4	Customer Deposits	$ 3,888,281	1.3%	2.73%	0.04%
5	Deferred Taxes	$ 48,612,155	16.2%	0.00%	0.00%
6	Total Capitalization	$ 299,278,150	100.0%		5.57%
	Investor-Supplied Capital Structure				
7	Common Equity	$ 115,745,170	46.9%	9.30%	4.36%
8	Long-Term Debt	$ 115,217,944	46.7%	4.66%	2.18%
9	Short-Term Debt	$ 15,814,600	6.4%	2.64%	0.17%
10	Total Investor Capital	$ 246,777,714	100.0%		6.71%

Sources:
[1] MFR Schedule G-3, page 2.
[2] Direct testimony at 2.

Florida City Gas

Natural Gas Utilities
(Valuation Metrics)

		Price to Earnings (P/E) Ratio [1]												
Line	Company	12-Year Average	2017 [2]	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Atmos Energy	16.09	23.80	20.80	17.50	16.09	15.87	15.93	14.36	13.21	12.54	13.59	15.87	13.52
2	Chesapeake Utilities	17.20	28.00	21.77	19.15	17.70	15.62	14.81	14.16	12.21	14.20	14.15	16.72	17.85
3	New Jersey Resources	16.91	23.80	21.25	16.61	11.73	15.98	16.83	16.76	14.98	14.93	12.27	21.61	16.13
4	NiSource Inc.	20.33	24.90	23.18	37.34	22.74	18.89	17.87	19.36	15.33	14.34	12.07	18.82	19.16
5	Northwest Nat. Gas	20.20	28.80	26.92	23.69	20.69	19.38	21.08	19.02	16.97	15.17	18.08	16.74	15.85
6	ONE Gas Inc.	21.26	24.70	22.74	19.79	17.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	17.88	25.90	21.71	17.95	18.03	18.90	16.94	18.48	16.81	14.96	15.90	17.18	11.86
8	Southwest Gas	17.29	22.50	21.64	19.35	17.86	15.76	15.00	15.69	13.97	12.20	20.27	17.26	15.94
9	Spire Inc.	16.22	20.70	19.61	16.49	19.80	21.25	14.46	13.05	13.74	13.39	14.31	14.19	13.60
10	UGI Corp.	15.20	19.20	19.33	17.71	15.81	15.44	16.38	15.03	10.86	10.30	13.30	15.14	13.97
11	WGL Holdings Inc.	16.64	24.60	20.05	16.99	15.15	18.25	15.27	16.97	15.11	12.58	13.66	15.60	15.46
12	Average	17.41	24.26	21.73	20.23	17.58	17.53	16.46	16.29	14.32	13.46	14.76	16.91	15.33
13	Median	17.17	24.60	21.64	17.95	17.83	17.11	16.15	16.22	14.48	13.80	13.91	16.73	15.66

		Market Price to Cash Flow (MP/CF) Ratio [1]												
Line	Company	12-Year Average	2017 [2/a]	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
14	Atmos Energy	7.97	12.39	11.36	9.30	8.79	7.72	7.02	6.87	6.15	5.76	6.48	7.44	6.36
15	Chesapeake Utilities	9.25	14.97	12.06	10.16	9.25	8.12	7.46	7.35	6.36	9.48	7.88	8.58	9.40
16	New Jersey Resources	11.85	14.76	13.94	11.71	8.95	11.29	12.29	12.71	11.32	11.34	9.15	13.76	11.01
17	NiSource Inc.	7.54	10.10	8.56	10.38	10.56	8.71	7.81	6.81	5.09	4.06	4.87	6.69	6.87
18	Northwest Nat. Gas	9.25	11.58	11.57	9.46	8.84	8.61	9.48	9.08	8.94	8.26	8.75	8.54	7.83
19	ONE Gas Inc.	10.07	11.84	11.10	9.19	8.16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	South Jersey Inds.	10.95	14.54	10.88	10.70	10.57	11.57	10.95	11.98	10.78	9.57	10.38	11.23	8.32
21	Southwest Gas	5.88	8.78	7.41	6.56	6.35	5.94	5.55	5.60	4.91	3.84	4.89	5.42	5.28
22	Spire Inc.	9.57	10.85	10.32	8.47	12.03	13.76	8.80	8.08	8.12	8.58	8.95	8.46	8.46
23	UGI Corp.	7.50	10.39	9.02	8.47	7.49	6.55	6.30	7.51	6.02	5.74	7.11	7.92	7.48
24	WGL Holdings Inc.	9.19	13.15	11.36	9.59	8.46	9.83	9.03	9.52	8.34	7.17	7.68	8.39	7.81
25	Average	8.89	12.12	10.69	9.45	9.04	9.21	8.47	8.55	7.60	7.38	7.62	8.64	7.88
26	Median	8.75	11.84	11.10	9.46	8.84	8.66	8.31	7.80	7.24	7.71	7.78	8.42	7.82

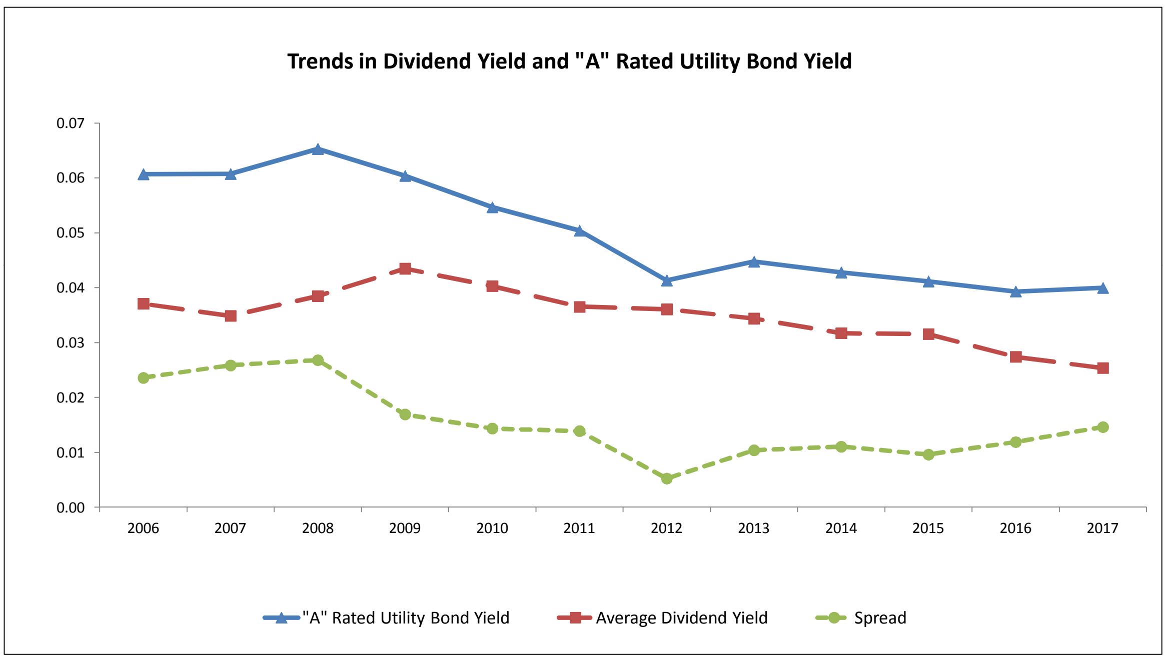
		Market Price to Book Value (MP/BV) Ratio [1]												
Line	Company	12-Year Average	2017 [2/b]	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
27	Atmos Energy	1.48	2.22	2.11	1.72	1.55	1.39	1.28	1.30	1.18	1.05	1.20	1.40	1.34
28	Chesapeake Utilities	1.86	2.53	2.28	2.19	2.12	1.83	1.66	1.61	1.40	1.37	1.64	1.84	1.85
29	New Jersey Resources	2.22	2.75	2.52	2.28	2.13	2.05	2.33	2.31	2.09	2.16	1.92	2.17	2.01
30	NiSource Inc.	1.40	2.05	1.84	1.95	1.94	1.58	1.37	1.15	0.92	0.69	0.94	1.16	1.19
31	Northwest Nat. Gas	1.78	2.09	1.92	1.63	1.59	1.56	1.72	1.70	1.78	1.73	1.96	2.05	1.69
32	ONE Gas Inc.	1.47	1.88	1.67	1.26	1.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	South Jersey Inds.	2.12	2.19	1.79	1.77	2.07	2.27	2.21	2.59	2.38	1.95	2.08	2.21	1.93
34	Southwest Gas	1.53	2.13	1.96	1.68	1.68	1.61	1.51	1.43	1.24	0.97	1.20	1.46	1.46
35	Spire Inc.	1.55	1.72	1.64	1.44	1.33	1.34	1.51	1.46	1.39	1.68	1.71	1.66	1.71
36	UGI Corp.	1.99	2.71	2.41	2.29	1.97	1.69	1.45	1.75	1.55	1.66	2.01	2.16	2.21
37	WGL Holdings Inc.	1.82	2.73	2.45	2.15	1.69	1.71	1.66	1.63	1.50	1.45	1.59	1.64	1.59
38	Average	1.76	2.27	2.05	1.85	1.74	1.70	1.67	1.69	1.54	1.47	1.62	1.78	1.70
39	Median	1.72	2.19	1.96	1.77	1.69	1.65	1.58	1.62	1.45	1.56	1.67	1.75	1.70

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 21, 2017.
[2] The Value Line Investment Survey, December 1, 2017.
Notes:
[a] Based on the average of the high and low price for 2017 and the projected 2017 Cash Flow per share, published in The Value Line Investment Survey, December 1, 2017.
[b] Based on the average of the high and low price for 2017 and the projected 2017 Book Value per share, published in The Value Line Investment Survey, December 1, 2017.

Florida City Gas

Natural Gas Utilities
(Valuation Metrics)

		Dividend Yield[1]												
Line	**Company**	**12-Year Average (1)**	**2017 [2/a] (2)**	**2016 (3)**	**2015 (4)**	**2014 (5)**	**2013 (6)**	**2012 (7)**	**2011 (8)**	**2010 (9)**	**2009 (10)**	**2008 (11)**	**2007 (12)**	**2006 (13)**
1	Atmos Energy	3.84%	2.20%	2.39%	2.88%	3.11%	3.53%	4.13%	4.19%	4.70%	5.34%	4.78%	4.16%	4.66%
2	Chesapeake Utilities	3.10%	1.74%	1.91%	2.18%	2.44%	2.87%	3.25%	3.36%	3.91%	4.09%	4.10%	3.62%	3.76%
3	New Jersey Resources	3.27%	2.63%	2.86%	3.14%	3.50%	3.71%	3.38%	3.33%	3.69%	3.46%	3.35%	3.02%	3.19%
4	NiSource Inc.	4.25%	2.83%	2.76%	3.53%	2.69%	3.30%	3.84%	4.53%	5.66%	7.64%	5.69%	4.29%	4.21%
5	Northwest Nat. Gas	3.65%	3.01%	3.28%	4.01%	4.14%	4.22%	3.83%	3.85%	3.63%	3.73%	3.27%	3.12%	3.73%
6	ONE Gas Inc.	2.43%	2.41%	2.32%	2.71%	2.28%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	South Jersey Inds.	3.23%	3.15%	3.64%	3.95%	3.40%	3.14%	3.22%	2.81%	3.00%	3.43%	3.08%	2.81%	3.15%
8	Southwest Gas	2.87%	2.49%	2.62%	2.87%	2.72%	2.69%	2.75%	2.78%	3.15%	4.01%	3.19%	2.56%	2.60%
9	Spire Inc.	3.92%	2.96%	3.08%	3.53%	3.78%	3.96%	4.11%	4.31%	4.70%	3.91%	3.94%	4.43%	4.34%
10	UGI Corp.	2.89%	1.98%	2.35%	2.50%	2.61%	3.01%	3.68%	3.30%	3.48%	3.23%	2.85%	2.69%	2.96%
11	WGL Holdings Inc.	3.91%	2.52%	2.94%	3.41%	4.24%	3.94%	3.89%	4.06%	4.37%	4.62%	4.22%	4.19%	4.48%
12	**Average**	**3.48%**	**2.54%**	**2.74%**	**3.16%**	**3.17%**	**3.44%**	**3.61%**	**3.65%**	**4.03%**	**4.35%**	**3.85%**	**3.49%**	**3.71%**
13	Median	3.40%	2.52%	2.76%	3.14%	3.11%	3.42%	3.75%	3.60%	3.80%	3.96%	3.65%	3.37%	3.75%
14	**"A" Rated Utility Bond Yield[3]**	**5.01%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
15	**Spread**	**1.53%**	**1.46%**	**1.19%**	**0.96%**	**1.11%**	**1.04%**	**0.52%**	**1.39%**	**1.43%**	**1.69%**	**2.68%**	**2.59%**	**2.36%**



Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 21, 2017.
[2] The Value Line Investment Survey, December 1, 2017.
[3] www.moodys.com, Bond Yields and Key Indicators, through December 27, 2017.
Notes:
[a] Based on the average of the high and low price for 2017 and the projected 2017 Dividends Declared per share, published in The Value Line Investment Survey, December 1, 2017.

Florida City Gas

Natural Gas Utilities
(Valuation Metrics)

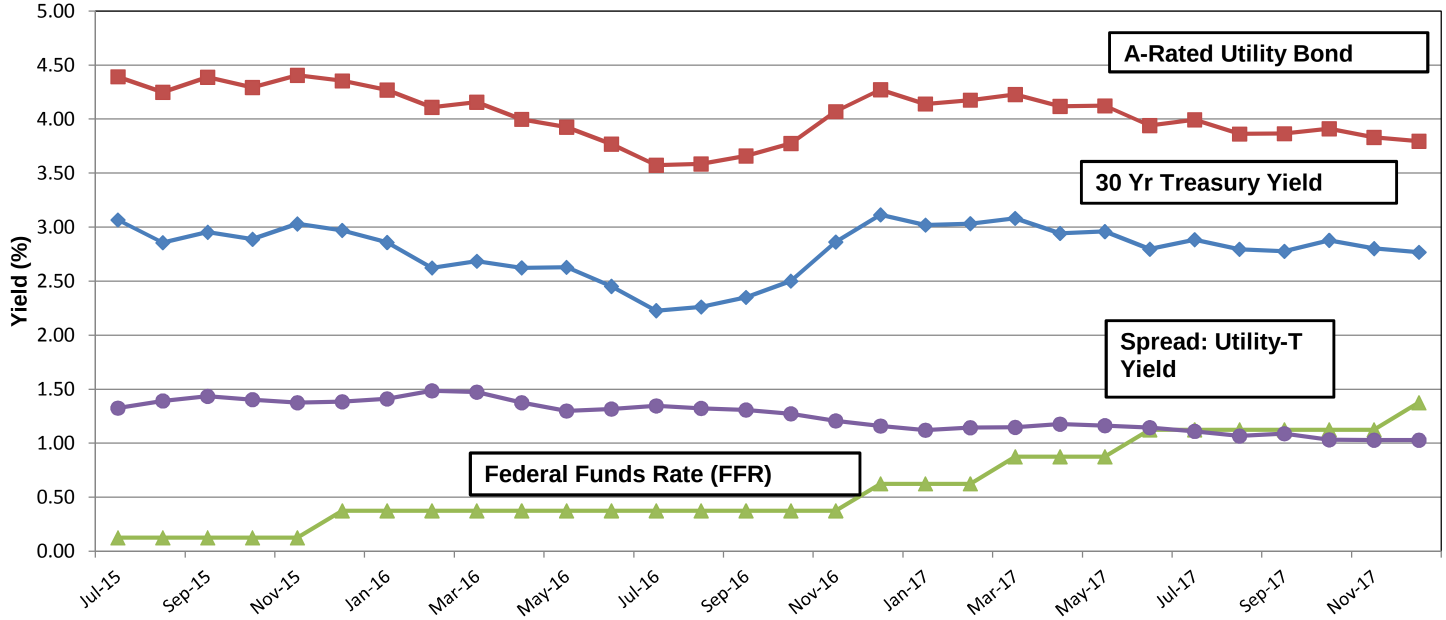
		Cash Flow / Capital Spending		
Line	**Company**	**2017** **(1)**	**2018** **(2)**	**3 - 5 yr Projection** **(3)**
1	Atmos Energy	0.59x	0.59x	0.59x
2	Chesapeake Utilities	0.46x	0.50x	0.64x
3	New Jersey Resources	1.19x	1.23x	1.27x
4	NiSource Inc.	0.54x	0.60x	0.62x
5	Northwest Nat. Gas	0.87x	0.80x	0.96x
6	ONE Gas Inc.	0.89x	0.93x	1.12x
7	South Jersey Inds.	0.71x	0.71x	0.63x
8	Southwest Gas	0.84x	0.89x	0.96x
9	Spire Inc.	0.92x	1.00x	1.15x
10	UGI Corp.	1.45x	1.54x	1.66x
11	WGL Holdings Inc.	0.54x	0.57x	0.56x
12	Average	0.82x	0.85x	0.92x
13	Median	0.84x	0.80x	0.96x

Sources:
The Value Line Investment Survey Investment Analyzer Software, downloaded on November 7, 2017.

Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

Florida City Gas

Timeline of Federal Funds Rate Increases



Fed FFR Actions:

December 2015	0.25	→	0.50
December 2016	0.50	→	0.75
March 2017	0.75	→	1.00
June 2017	1.00	→	1.25
December 2017	1.25	→	1.50

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

Florida City Gas

Proxy Group

		Credit Ratings[1]		Common Equity Ratios	
Line	**Company**	**S&P**	**Moody's**	**MI[1]**	**Value Line[2]**
		(1)	**(2)**	**(3)**	**(4)**
1	Atmos Energy Corporation	A	A2	51.4%	61.3%
2	New Jersey Resources Corporation[3]	A	Aa2	48.5%	52.3%
3	NiSource Inc.	BBB+	Baa2	34.0%	40.2%
4	Northwest Natural Gas Company	A+	A3	52.4%	55.6%
5	ONE Gas, Inc.	A	A2	58.5%	61.3%
6	Southwest Gas Holdings, Inc.	BBB+	Baa1	50.7%	51.8%
7	Spire Inc.	A-	Baa2	41.7%	49.1%
8	**Average**	**A-**	**A3**	**48.2%**	**53.1%**
9	**Florida City Gas**			**46.9%[4]**	
10	**Southern Company Gas**	**A-[5]**			

Sources:
[1] S&P Global Market Intelligence, Downloaded on January 24, 2018.
[2] *The Value Line Investment Survey* , December 1, 2017.
[3] New Jersey Resources Corporation is not rated. Ratings shown are for New Jersey Natural Gas Co., a wholly owned operating subsidiary of New Jersey Resources Corp.
[4] Vander Weide direct at 6.
[5] *S&P RatingsDirect,* "Research Update: Southern Co. And Subsidiaries Outlook Still Negative Pending Vogtle Decision; Ratings Affirmed," August 4, 2017.

Florida City Gas

Consensus Analysts' Growth Rates

		Zacks		MI		Reuters		Average of
Line	Company	Estimated Growth %[1]	Number of Estimates	Estimated Growth %[2]	Number of Estimates	Estimated Growth %[3]	Number of Estimates	Growth Rates
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Atmos Energy Corporation	7.00%	N/A	7.00%	1	6.50%	1	6.83%
2	New Jersey Resources Corporation3	6.00%	N/A	6.00%	1	N/A	N/A	6.00%
3	NiSource Inc.	5.90%	N/A	6.74%	4	7.70%	3	6.78%
4	Northwest Natural Gas Company	4.50%	N/A	4.67%	3	N/A	N/A	4.59%
5	ONE Gas, Inc.	5.80%	N/A	5.40%	1	6.00%	1	5.73%
6	Southwest Gas Holdings, Inc.	5.90%	N/A	4.00%	1	N/A	N/A	4.95%
7	Spire Inc.	5.00%	N/A	4.75%	2	4.52%	2	4.76%
8	**Average**	**5.73%**	**N/A**	**5.51%**	**2**	**6.18%**	**2**	**5.66%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on January 9, 2018.
[2] S&P Global Market Intelligence, https://platform.mi.spglobal.com, downloaded on January 9, 2018.
[3] Reuters, http://www.reuters.com/, downloaded on January 9, 2018.

Florida City Gas

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$87.98	6.83%	$1.94	2.36%	9.19%
2	New Jersey Resources Corporation3	$42.74	6.00%	$1.09	2.71%	8.71%
3	NiSource Inc.	$26.54	6.78%	$0.70	2.82%	9.60%
4	Northwest Natural Gas Company	$65.01	4.59%	$1.89	3.04%	7.63%
5	ONE Gas, Inc.	$75.73	5.73%	$1.68	2.35%	8.08%
6	Southwest Gas Holdings, Inc.	$81.27	4.95%	$1.98	2.56%	7.51%
7	Spire Inc.	$77.47	4.76%	$2.25	3.04%	7.80%
8	**Average**	**$65.25**	**5.66%**	**$1.65**	**2.70%**	**8.36%**
9	**Median**					**8.08%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on January 9, 2017.
[2] Exhibit CCW-5.
[3] *The Value Line Investment Survey* , December 1, 2017.

Florida City Gas

Payout Ratios

		Dividends Per Share		Earnings Per Share		Payout Ratio	
Line	**Company**	**2016**	**Projected**	**2016**	**Projected**	**2016**	**Projected**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
1	Atmos Energy Corporation	$1.68	$2.30	$3.38	$4.50	49.70%	51.11%
2	New Jersey Resources Corporation3	$0.98	$1.12	$1.61	$2.05	60.87%	54.63%
3	NiSource Inc.	$0.64	$1.20	$1.01	$1.50	63.37%	80.00%
4	Northwest Natural Gas Company	$1.87	$2.00	$2.12	$3.15	88.21%	63.49%
5	ONE Gas, Inc.	$1.40	$2.45	$2.65	$4.00	52.83%	61.25%
6	Southwest Gas Holdings, Inc.	$1.80	$2.50	$3.18	$4.80	56.60%	52.08%
7	Spire Inc.	$1.96	$2.50	$3.24	$4.65	60.49%	53.76%
8	**Average**	**$1.48**	**$2.01**	**$2.46**	**$3.52**	**61.73%**	**59.48%**

Source:
The Value Line Investment Survey , December 1, 2017.

Florida City Gas

Sustainable Growth Rate

		3 to 5 Year Projections										Sustainable
Line	Company	Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Growth Rate (11)
1	Atmos Energy Corporation	$2.30	$4.50	$38.50	2.93%	11.69%	1.01	11.86%	51.11%	48.89%	5.80%	10.58%
2	New Jersey Resources Corporation3	$1.12	$2.05	$17.85	5.62%	11.48%	1.03	11.80%	54.63%	45.37%	5.35%	5.66%
3	NiSource Inc.	$1.20	$1.50	$13.60	1.54%	11.03%	1.01	11.11%	80.00%	20.00%	2.22%	4.00%
4	Northwest Natural Gas Company	$2.00	$3.15	$32.25	1.65%	9.77%	1.01	9.85%	63.49%	36.51%	3.60%	4.71%
5	ONE Gas, Inc.	$2.45	$4.00	$41.45	2.79%	9.65%	1.01	9.78%	61.25%	38.75%	3.79%	4.91%
6	Southwest Gas Holdings, Inc.	$2.50	$4.80	$50.00	7.38%	9.60%	1.04	9.94%	52.08%	47.92%	4.76%	7.19%
7	Spire Inc.	$2.50	$4.65	$48.30	4.52%	9.63%	1.02	9.84%	53.76%	46.24%	4.55%	6.39%
8	**Average**	**$2.01**	**$3.52**	**$34.56**	**3.78%**	**10.41%**	**1.02**	**10.60%**	**59.48%**	**40.52%**	**4.30%**	**6.21%**
9	**Median**										**4.55%**	**5.66%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey* , December 1, 2017.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Florida City Gas

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1]	2016 Book Value Per Share[2]	Market to Book Ratio	Common Shares Outstanding (in Millions)[2] 2016	3-5 Years	Growth	S Factor[3]	V Factor[4]	S * V
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Atmos Energy Corporation	$87.98	$33.32	2.64	103.93	120.00	2.92%	7.70%	62.13%	4.79%
2	New Jersey Resources Corporation3	$42.74	$13.58	3.15	85.88	86.50	0.14%	0.45%	68.23%	0.31%
3	NiSource Inc.	$26.54	$12.60	2.11	323.16	350.00	1.61%	3.39%	52.52%	1.78%
4	Northwest Natural Gas Company	$65.01	$29.71	2.19	28.63	30.00	0.94%	2.06%	54.30%	1.12%
5	ONE Gas, Inc.	$75.73	$36.12	2.10	52.28	55.00	1.02%	2.14%	52.31%	1.12%
6	Southwest Gas Holdings, Inc.	$81.27	$35.03	2.32	47.48	52.00	1.84%	4.26%	56.90%	2.42%
7	Spire Inc.	$77.47	$38.73	2.00	45.65	50.00	1.84%	3.67%	50.01%	1.84%
8	**Average**	**$65.25**	**$28.44**	**2.36**	**98.14**	**106.21**	**1.47%**	**3.38%**	**56.63%**	**1.91%**

Sources and Notes:
[1] S&P Global Market Intelligence, Downloaded on January 9, 2017.
[2] *The Value Line Investment Survey* , December 1, 2017.
[3] Expected Growth in the Number of Shares, Column (3) * Column (6).
[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

Florida City Gas

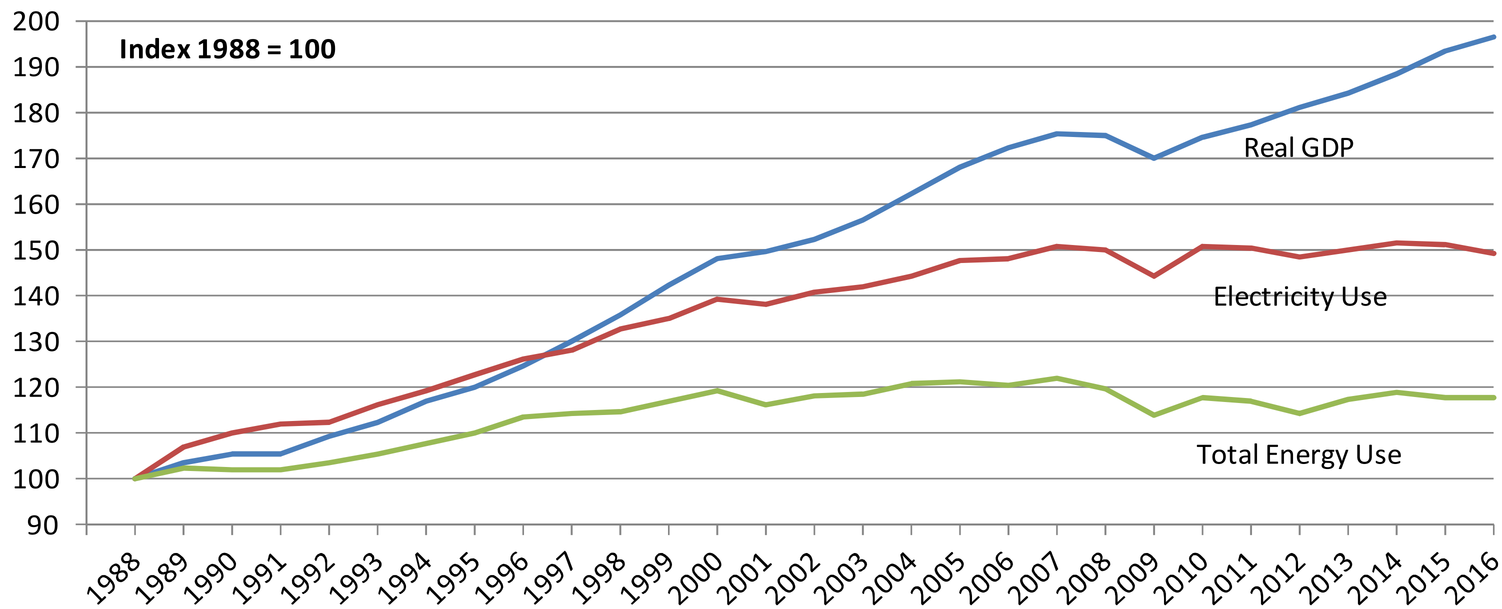
Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$87.98	10.58%	$1.94	2.44%	13.02%
2	New Jersey Resources Corporation3	$42.74	5.66%	$1.09	2.70%	8.36%
3	NiSource Inc.	$26.54	4.00%	$0.70	2.74%	6.75%
4	Northwest Natural Gas Company	$65.01	4.71%	$1.89	3.04%	7.76%
5	ONE Gas, Inc.	$75.73	4.91%	$1.68	2.33%	7.24%
6	Southwest Gas Holdings, Inc.	$81.27	7.19%	$1.98	2.61%	9.80%
7	Spire Inc.	$77.47	6.39%	$2.25	3.09%	9.48%
8	**Average**	**$65.25**	**6.21%**	**$1.65**	**2.71%**	**8.91%**
9	**Median**					**8.36%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on January 9, 2017.
[2] Exhibit CCW-8, page 1.
[3] *The Value Line Investment Survey*, December 1, 2017.

Florida City Gas

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Energy Information Administration
Federal Reserve Bank of St. Louis

Florida City Gas

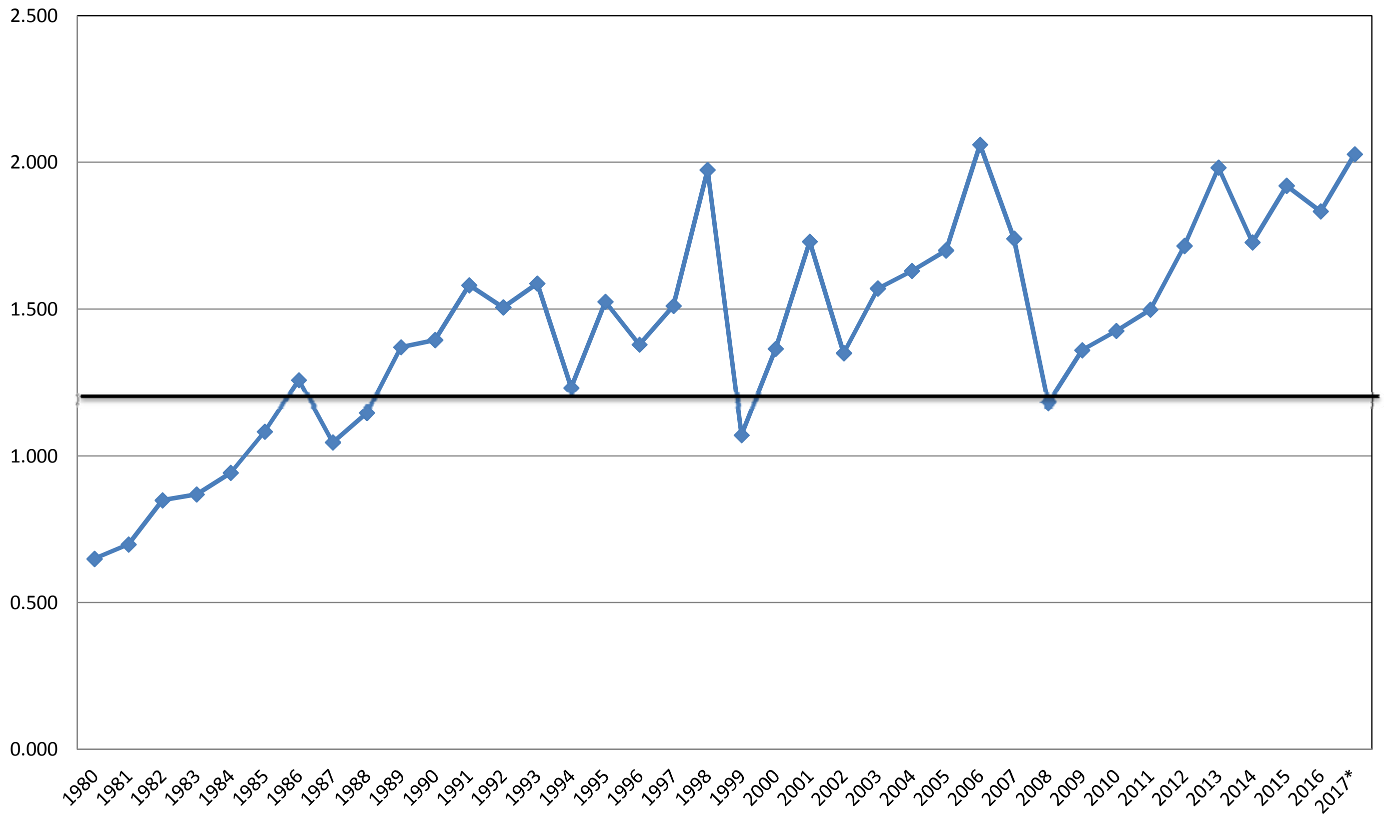
Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1]	Annualized Dividend[2]	First Stage Growth[3]	Second Stage Growth Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth[4]	Multi-Stage Growth DCF
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Atmos Energy Corporation	$87.98	$1.94	6.83%	6.39%	5.96%	5.52%	5.08%	4.64%	4.20%	6.91%
2	New Jersey Resources Corporation3	$42.74	$1.09	6.00%	5.70%	5.40%	5.10%	4.80%	4.50%	4.20%	7.18%
3	NiSource Inc.	$26.54	$0.70	6.78%	6.35%	5.92%	5.49%	5.06%	4.63%	4.20%	7.44%
4	Northwest Natural Gas Company	$65.01	$1.89	4.59%	4.52%	4.46%	4.39%	4.33%	4.26%	4.20%	7.30%
5	ONE Gas, Inc.	$75.73	$1.68	5.73%	5.48%	5.22%	4.97%	4.71%	4.46%	4.20%	6.74%
6	Southwest Gas Holdings, Inc.	$81.27	$1.98	4.95%	4.83%	4.70%	4.58%	4.45%	4.33%	4.20%	6.85%
7	Spire Inc.	$77.47	$2.25	4.76%	4.66%	4.57%	4.48%	4.39%	4.29%	4.20%	7.33%
8	**Average**	**$65.25**	**$1.65**	**5.66%**	**5.42%**	**5.18%**	**4.93%**	**4.69%**	**4.44%**	**4.20%**	**7.11%**
9	**Median**										**7.18%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on January 9, 2017.
[2] *The Value Line Investment Survey*, December 1, 2017.
[3] Exhibit CCW-5.
[4] *Blue Chip Financial Forecasts*, December 1, 2017 at 14.

Florida City Gas

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2017: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports, October 27, November 17, December 1, and December 15, 2017.

Florida City Gas

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Gas Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	7.80%	5.66%		
2	1987	12.74%	8.58%	4.16%		
3	1988	12.85%	8.96%	3.89%		
4	1989	12.88%	8.45%	4.43%		
5	1990	12.67%	8.61%	4.06%	4.44%	
6	1991	12.46%	8.14%	4.32%	4.17%	
7	1992	12.01%	7.67%	4.34%	4.21%	
8	1993	11.35%	6.60%	4.75%	4.38%	
9	1994	11.35%	7.37%	3.98%	4.29%	
10	1995	11.43%	6.88%	4.55%	4.39%	4.42%
11	1996	11.19%	6.70%	4.49%	4.42%	4.30%
12	1997	11.29%	6.61%	4.68%	4.49%	4.35%
13	1998	11.51%	5.58%	5.93%	4.73%	4.55%
14	1999	10.66%	5.87%	4.79%	4.89%	4.59%
15	2000	11.39%	5.94%	5.45%	5.07%	4.73%
16	2001	10.95%	5.49%	5.46%	5.26%	4.84%
17	2002	11.03%	5.43%	5.60%	5.45%	4.97%
18	2003	10.99%	4.96%	6.03%	5.47%	5.10%
19	2004	10.59%	5.05%	5.54%	5.62%	5.25%
20	2005	10.46%	4.65%	5.81%	5.69%	5.38%
21	2006	10.40%	4.90%	5.50%	5.70%	5.48%
22	2007	10.22%	4.83%	5.39%	5.66%	5.55%
23	2008	10.39%	4.28%	6.11%	5.67%	5.57%
24	2009	10.22%	4.07%	6.15%	5.79%	5.70%
25	2010	10.15%	4.25%	5.90%	5.81%	5.75%
26	2011	9.92%	3.91%	6.01%	5.91%	5.80%
27	2012	9.94%	2.92%	7.02%	6.24%	5.95%
28	2013	9.68%	3.45%	6.23%	6.26%	5.97%
29	2014	9.78%	3.34%	6.44%	6.32%	6.06%
30	2015	9.60%	2.84%	6.76%	6.49%	6.15%
31	2016	9.54%	2.60%	6.94%	6.68%	6.29%
32	2017 [3]	9.75%	2.92%	6.83%	6.64%	6.44%
33	**Average**	**11.03%**	**5.61%**	**5.41%**	**5.36%**	**5.36%**
34	**Minimum**				**4.17%**	**4.30%**
35	**Maximum**				**6.68%**	**6.44%**

Sources:
[1] *Regulatory Research Associates, Inc* ., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3. *S&P Global Market Intelligence* , RRA Regulatory Focus, Major Rate Case Decisions, January-September 2017, October 26, 2017, p. 5.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.
[3] Data includes January - September 2017.

Florida City Gas

Equity Risk Premium - Utility Bond

Line	Year	Authorized Gas Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	9.58%	3.88%		
2	1987	12.74%	10.10%	2.64%		
3	1988	12.85%	10.49%	2.36%		
4	1989	12.88%	9.77%	3.11%		
5	1990	12.67%	9.86%	2.81%	2.96%	
6	1991	12.46%	9.36%	3.10%	2.80%	
7	1992	12.01%	8.69%	3.32%	2.94%	
8	1993	11.35%	7.59%	3.76%	3.22%	
9	1994	11.35%	8.31%	3.04%	3.21%	
10	1995	11.43%	7.89%	3.54%	3.35%	3.16%
11	1996	11.19%	7.75%	3.44%	3.42%	3.11%
12	1997	11.29%	7.60%	3.69%	3.49%	3.22%
13	1998	11.51%	7.04%	4.47%	3.64%	3.43%
14	1999	10.66%	7.62%	3.04%	3.64%	3.42%
15	2000	11.39%	8.24%	3.15%	3.56%	3.45%
16	2001	10.95%	7.76%	3.19%	3.51%	3.46%
17	2002	11.03%	7.37%	3.66%	3.50%	3.50%
18	2003	10.99%	6.58%	4.41%	3.49%	3.56%
19	2004	10.59%	6.16%	4.43%	3.77%	3.70%
20	2005	10.46%	5.65%	4.81%	4.10%	3.83%
21	2006	10.40%	6.07%	4.33%	4.33%	3.92%
22	2007	10.22%	6.07%	4.15%	4.43%	3.96%
23	2008	10.39%	6.53%	3.86%	4.32%	3.90%
24	2009	10.22%	6.04%	4.18%	4.27%	4.02%
25	2010	10.15%	5.47%	4.68%	4.24%	4.17%
26	2011	9.92%	5.04%	4.88%	4.35%	4.34%
27	2012	9.94%	4.13%	5.81%	4.68%	4.55%
28	2013	9.68%	4.48%	5.20%	4.95%	4.63%
29	2014	9.78%	4.28%	5.50%	5.22%	4.74%
30	2015	9.60%	4.12%	5.48%	5.38%	4.81%
31	2016	9.54%	3.93%	5.61%	5.52%	4.94%
32	2017 [3]	9.75%	4.05%	5.70%	5.50%	5.09%
33	**Average**	**11.03%**	**6.99%**	**4.04%**	**3.99%**	**3.95%**
34	**Minimum**				**2.80%**	**3.11%**
35	**Maximum**				**5.52%**	**5.09%**

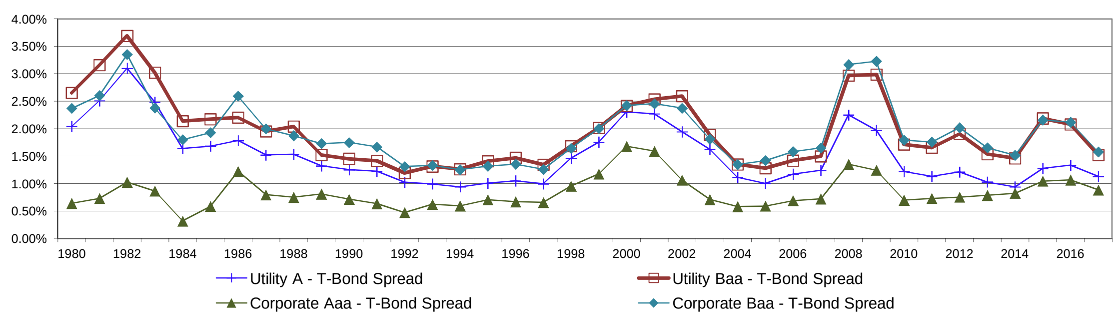
Sources:
[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January-September 2017, October 26, 2017, p. 5.
[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yieldsfor the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields from 2010-2017 were obtained from http://credittrends.moodys.com/.
[3] Data includes January - September 2017.

Florida City Gas

Bond Yield Spreads

Line	Year	T-Bond Yield[1] (1)	Public Utility Bond A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Corporate Bond Aaa[3] (6)	Baa[3] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Utility to Corporate Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.90%	6.07%	6.32%	1.17%	1.42%	5.59%	6.48%	0.69%	1.58%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.47%	5.96%	1.22%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017[4]	2.92%	4.05%	4.44%	1.13%	1.52%	3.80%	4.50%	0.88%	1.58%	-0.06%	0.25%
39	**Average**	**6.62%**	**8.13%**	**8.57%**	**1.51%**	**1.95%**	**7.46%**	**8.55%**	**0.84%**	**1.93%**	**0.01%**	**0.67%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2017 were obtained from http://credittrends.moodys.com/.
[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2017 were obtained from http://credittrends.moodys.com/.
[4] Data includes January - September 2017.

Florida City Gas

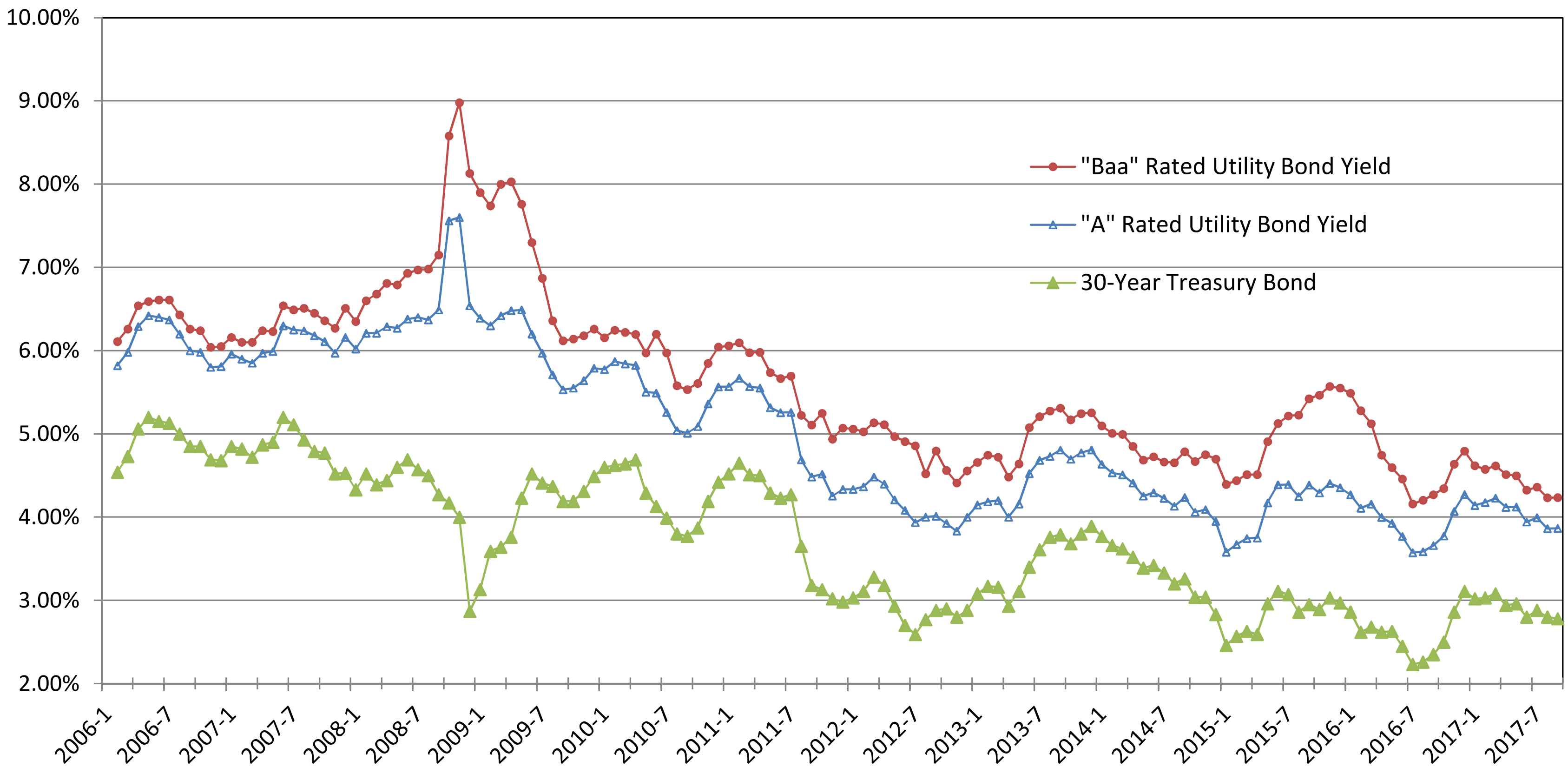
Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	01/05/18	2.81%	3.82%	4.15%
2	12/28/17	2.75%	3.77%	4.11%
3	12/22/17	2.83%	3.85%	4.19%
4	12/15/17	2.68%	3.72%	4.06%
5	12/08/17	2.77%	3.81%	4.16%
6	12/01/17	2.76%	3.80%	4.15%
7	11/24/17	2.76%	3.81%	4.15%
8	11/17/17	2.78%	3.83%	4.17%
9	11/09/17	2.81%	3.83%	4.15%
10	11/03/17	2.82%	3.83%	4.15%
11	10/27/17	2.93%	3.94%	4.28%
12	10/20/17	2.89%	3.91%	4.26%
13	10/13/17	2.81%	3.85%	4.19%
14	**Average**	**2.80%**	**3.83%**	**4.17%**
15	**Spread To Treasury**		**1.03%**	**1.37%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Florida City Gas

Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

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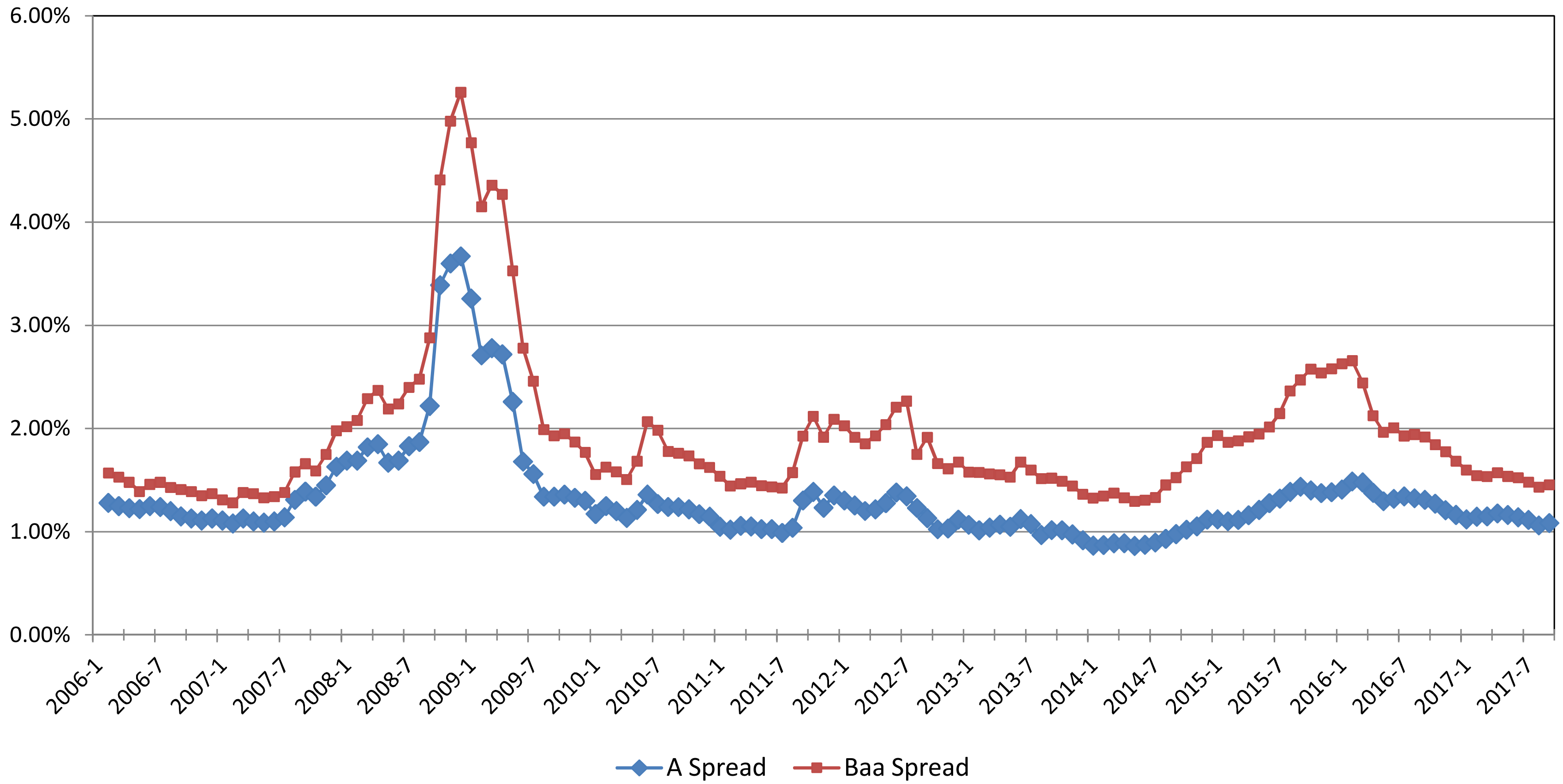
Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Florida City Gas

Value Line Beta

Line	Company	Beta
1	Atmos Energy Corporation	0.70
2	New Jersey Resources Corporation3	0.80
3	NiSource Inc.	0.60
4	Northwest Natural Gas Company	0.70
5	ONE Gas, Inc.	0.70
6	Southwest Gas Holdings, Inc.	0.80
7	Spire Inc.	0.70
8	**Average**	**0.71**

Source:
The Value Line Investment Survey,
December 1, 2017.

Florida City Gas

CAPM Return

Line	Description	High Market Risk Premium (1)	Low Market Risk Premium (2)
1	Risk-Free Rate[1]	3.60%	3.60%
2	Risk Premium[2]	7.70%	6.00%
3	Beta[3]	0.71	0.71
4	**CAPM**	**9.10%**	**7.89%**

Sources:
[1] *Blue Chip Financial Forecasts*, January 1, 2018, at 2.
[2] *Duff & Phelps, 2017 SBBI Yearbook* at 6-17 and 6-18, and *Duff & Phelps, 2017 Valuation Handbook* at 3-36 and 3-48.
[3] Exhibit CCW-17.