FILED 11/1/2022
DOCUMENT NO. 10827-2022
FPSC - COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the matter of:

DOCKET NO. 20220067-GU

Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.
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VOLUME 3
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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ANDREW GILES FAY
COMMISSIONER GARY F. CLARK
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Wednesday, October 26, 2022

TIME: Commenced: 9:30 a.m.
Concluded: 4:15 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
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I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
12	As identified on the CEL		478
13-16	As identified on the CEL		533
17-20	As identified on the CEL		575
28-30	As identified on the CEL		392
123	MFRs with errata	357	
124	FPUC's response to Staff 9th Set of Interrogatories, No. 86B	568	

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

CHAIRMAN FAY: All right. Good morning, everyone. I will let everyone grab their seats, we will get started this morning. I do want to take up a few preliminary matters before we start with our first witness. So the first will be -- and I am going to help staff guide us with this a little bit, but the first will be taking up the comprehensive MFRs, the errata into the record.

So Mr. Sandy, I guess -- I think we are at 123, but essentially can we take that into the exhibit as a comprehensive exhibit item for everything, is that correct?

MR. SANDY: Yes, Mr. Chairman, that is correct.

And for the record, it would include an errata sheet that would have been filed on October 19th that pertains to all the MFRs. And I believe the utility is going to sponsor that exhibit.

CHAIRMAN FAY: Okay. Great.

And then the only question, I think, on that was I -- I saw -- I think it was -- is it for Ms. Parmer had an errata filed on September 14th.

So are they -- does that -- does that line up correctly, or was something also filed for her on the 14th, or October?

MS. KEATING: She had her own separate errata that was -- she had no other one than the one in September.

CHAIRMAN FAY: Okay. Great. So that would be included in that final version, Mr. Sandy?

MR. SANDY: Yes, Mr. Chairman.

CHAIRMAN FAY: Okay. Great.

Well, so seeing no objections, we will move that as 123, is that correct?

MR. SANDY: Yes, sir.

CHAIRMAN FAY: Okay. We will move that in no objections as 123.

(Whereupon, Exhibit No. 123 was marked for identification and received into evidence.)

CHAIRMAN FAY: All right. And then next, if we could take up any additional stipulations that may have been worked out since yesterday. What I would like to do is, Mr. Sandy, if you could provide us those stipulations. I want to make sure the parties have had the opportunity to look at that language, but then the Commission could go ahead and vote those out before we get to the first witness, would that be appropriate?

MR. SANDY: Mr. Chairman, I provided a draft to all the parties of the stipulations that they discussed it yesterday. I haven't gotten any feedback yet on whether they agree with my language or not. Once the language has been worked out, then presumably we could admit that as an exhibit into the record, but I would defer to -- and then it would have to be voted on --

CHAIRMAN FAY: Okay.

MR. SANDY: -- Mr. Chairman, but I would defer to the parties as to where they are at on that stipulation language.

CHAIRMAN FAY: Yeah. Let me -- I will start with FPUC and then OPC on it. Now, if there is not clarity as to the language or the stipulations, since they don't appear to stipulate to any witness testimony, it wouldn't necessarily alter what we are going to do today, so let's try not to get too bogged down in the commas or anything. If we feel that you are comfortable with them, just let us know.

MS. KEATING: I think that we are fine, but in all candor, Mr. Chairman, we haven't really had a chance to look at some of the language. If we could maybe have until the next break to take a look, and I know there were some early morning back and forth about the language particularly for one of the added issues -- issues that was added late.

CHAIRMAN FAY: Okay. Let's do that. Just --

MS. KEATING: So if that's all right.

CHAIRMAN FAY: That's fine. I just want to make clear for the record we are not -- none of the parties are sort of waiving their ability to question on any of those things that might be stipulated. The presumption is they are not in at this point, and then if we stipulate them later, that's correct perfectly fine.

Ms. Christensen, does that work for you?

MS. CHRISTENSEN: Yeah, I need a few minutes to go through the language and make sure it's worded the way that we need it to be. Thank you.

CHAIRMAN FAY: Okay. Great.

With that, Mr. Sandy, do we have any other preliminary matters before we start our first witness? Which I believe we would be calling Ms. Parmer this morning for FPUC.

MR. SANDY: As far as I know, Mr. Chairman, there are no further preliminary matters.

CHAIRMAN FAY: Okay. Great.

Ms. Keating or Mr. Munson, you are welcome to call your first witness.

MS. KEATING: Thank you, Mr. Chairman. FPUC calls Kelley Parmer to the stand.

Whereupon,

KELLEY PARMER

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MS. KEATING:

Q Good morning, Ms. Parmer.

A Good morning.

Q Would you please state your full name and business address for the record?

A Yes. Kelley Parmer. 500 Energy Lane, Suite 100, Dover, Delaware, 19901.

Q And by whom are you employed and in what capacity?

A Chesapeake Utilities, Assistant Vice-President Customer Care.

Q And did you cause to be prepared and filed in this proceeding 23 pages of direct testimony?

A Yes, I did.

Q Did you also cause to be prepared and filed an

errata sheet on September 14th?

A   Yes, I did.

Q   Do you have any additional changes or corrections to your direct testimony?

A   No, I do not.

MS. KEATING: Mr. Chairman, we would ask that the direct testimony of Ms. Parmer be entered into the record as though read.

CHAIRMAN FAY: Okay. Show that entered without objection.

(Whereupon, prefiled direct testimony of Kelley Parmer was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20220067-GU: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.

Prepared Direct Testimony of Kelley Parmer

Date of Filing: May 24, 2022

Q. Please state your name and business address.

A. My name is Kelley Parmer. My business address is 500 Energy Lane Suite 100 Dover, DE 19901.

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

A. I am employed by Chesapeake Utilities Corporation as the Assistant Vice President of Customer Care.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science degree in Business Management from the University of Maryland Global Campus. I have worked in the regulated gas and electric utility industry supporting customer service in various capacities for 21 years. I have been employed with Chesapeake Utilities for 6 years beginning my career here as a Director, Planning & Analysis, a role in which I was charged with creating procedures for forecasting & staffing, metric creation and tracking, and support of customer facing technologies such as the implementation of the Cisco phone system. In 2018, my responsibilities were expanded to include the contact center functions with particular focus on inbound contacts and walk-in offices in Delaware, Maryland, and Florida. In September 2020, I accepted the role of Assistant Vice President, Customer Care.

Prior to Chesapeake Utilities, I worked for Pepco Holdings, Inc. for 15 years. I began in a Customer Service Representative role in 2000 at the time of a billing system implementation failure. In this role, I provided over the phone and face to face support for all types of customer inquiries. After several years, I moved into a supervisory position overseeing a team of 12-16 agents. Then, I held a Senior Analyst role within the Workforce Management team supporting contact center forecasting and staffing, metric tracking and reporting, support of data requests from regulatory bodies, storm and crisis staffing, and contact center system administration. As of 2012, I held the role of Call Center Manager supporting the organization through a Systems, Applications, and Products billing system replacement. In this role, I was responsible for management of the contact centers, our energy conservation agents, and our vendor partners.

Q. Please describe your current responsibilities.

A. I am currently responsible for all customer care functions for Chesapeake Utilities Corporation's regulated subsidiaries, including for Florida Public Utilities Company. My areas of responsibility include, among other things, billing, credit and collections, contact centers, payment processing, as well as all associated support functions that impact the customer service experience of our customers.

Q. How will you refer to the Company?

A. For purposes of clarity and ease of reference, I'd like to explain how I will refer to the various Florida business entities under the Chesapeake Utilities Corporation umbrella. When referring to the Florida LDC business units as a whole; i.e., Florida Public Utilities Company (Natural Gas Division), Florida Public Utilities Company-

Fort Meade, Florida Public Utilities Company-Indiantown Division, and the Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas, I will refer to these entities jointly as "FPUC" or "the Company".

When referring to Chesapeake Utilities Corporation, the parent company, I will refer to it as the "CUC" or the "Corporation."

Q. Have you filed testimony before the Florida Public Service Commission in prior cases?

A. No.

Q. Have you previously provided testimony before other regulatory bodies?

A. No.

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

A. I will provide an overview of the Customer Care organizational changes that have occurred since the acquisition of FPUC by CUC. Next, I will discuss the improvements implemented by Customer Care to enhance the customer experience with our Local Distribution Companies ("LDCs") in Florida. Next, I will discuss the impacts of, and Customer Care's response to, the COVID-19 Pandemic ("COVID"). I will conclude by discussing new and enhanced customer programs being considered by Customer Care.

Q. Do you have any exhibits to which you will refer in your testimony?

A. Yes. With my testimony, I am providing the following Exhibit:

KP-1 - The Customer Care Communications Policy

KP-2 – The Red Flag Policy

Q. Are you sponsoring any Minimum Filing Requirements ("MFR")s in this case?

A. Yes. Attached is Exhibit KP-3 which reflects MFRs that I have co-sponsored.

Organizational Overview

Q. Please explain the reorganization of the Customer Care department you mentioned above.

A. CUC is always looking for ways to enhance the customer experience. Our most recent core initiative in this regard is the reorganization of our Customer Care division serving Florida, Delaware, and Maryland to drive process improvements and standardization.

For FPUC in particular, this represents a significant change in how Customer Care operates. Specifically, prior to its acquisition by CUC, FPUC operated somewhat like a "mom-and-pop" type business. For instance, Customer Care representatives were responsible for handling all aspects of customer service, while also holding significant administrative responsibilities for the office. Customer Care support existed in the West Palm Beach and Debary local offices driving resource inefficiency and a limited commonality in the level of service provided due to a lack of standardization. Throughout FPUC, there was no system that routed calls based on the customer need, provided any tracking or reporting, nor any on-hold capabilities. As a result, Customer Care did not have key metrics upon which they could determine current performance levels or make steps to improve. Even the most basic metric of number of calls received was not being tracked. In 2011, Customer Care was separated into three internal groups that would focus on the specific rolls of front office, back office, and collections. The front office focused on handling inbound contacts and supporting the business offices. The back office focused on billing functions including completion of service orders and system updates. The collections area focused on managing bad debt through a collections and write-off process. These efforts resulted in significant changes in the contact center to better distribute calls and workload among all of the customer service representatives, as well as to track service levels and overall performance. In the Back Office and Collections teams we were able to build expertise for the required competencies that helped to streamline and optimize processes.

Customer Experience Improvements

Q. Please describe the Company's commitment to customer service.

A. FPUC's dedication and commitment to delivery of quality customer service is paramount. With society's ever-increasing access to information, the Company has experienced a significant increase in its customers' expectations related to their overall experience with the Company. Customers care not only about the safety and reliability of the service they receive, but also about the quality of their interactions with the Company and Company employees, both on a day-to-day basis and when the need arises to contact us for support. As such, the Company has responded by making prudent investments in technology, as well as improvements to our processes, enabling us to analyze customer interactions and feedback, which is then incorporated into our continually evolving short and long-term strategies to improve all aspects of the customer experience, including call handling, website, communication, processes, and procedures. Our customer communication strategy has evolved to a more proactive approach, as well, in that we communicate pertinent information to customers regarding areas of interest, such as bill and process changes and storm preparedness, across multiple channels, such as email and social media.

Q. What types of Customer Care technology improvements has the Company made?

A. We have implemented several technologies to improve the customer's experience with payment options, when calling into our call center, and foundational technology to drive efficiencies with staffing models, interaction tracking, and productivity tracking.

Q. Please provide some specific examples of technology improvements that the Company has made in the customer service area.

A. In 2011, the Company purchased an Avaya phone system, which allowed Customer Care to begin tracking metrics. This technology enabled Customer Care to transition to a virtual call center. This meant that a Customer Service Representative working in our North Florida office could answer a call from a customer anywhere in Florida.

Concurrent to the Avaya system upgrade, the Company implemented a call recording solution by the name of Verint. This allowed FPUC to start measuring how effectively we were handling customer inquiries, which helped us gain another valuable insight into the customer experience, including specific pressure points.

Shortly after these implementations, we created a quality assurance department, which has now evolved over the past few years into a comprehensive VOC program, which I will discuss in more detail later in my testimony.

Q. Would you please elaborate on the benefit to the Company's customers related to the new telephony systems?

A. In 2017, FPUC implemented a new phone platform, Cisco, to replace our unsupported Avaya platform with newer and more robust technology. Cisco allowed us to leverage additional data points for contact center and individual performance to enable identification of process improvements and efficiencies as well as creation of customer options.

Another area the Company made improvements to was a redesign of our call flows. To accomplish this we engaged our customers in focus groups to interact with the call flows we had in place at that time and the new ones we proposed. We were able to record via video the feedback that they provided. This feedback was used to create the final call flows, which included reordering of options, recorded messages for commonly requested information, expedited connection to our payment processing platform, and additional options for direct connections to other departments within the organization. This new phone platform also enabled deployment of new workforce planning technology, updated call recording and quality monitoring system, virtual call technology, and deployment of dashboards to create additional visibility into customer service performance.

With the Cisco platform implementation, we were able to deploy several other technologies that have improved processes and helped us gain insight into how to improve our customer's experience. One of these technologies was a new workforce management system, which we used to track metrics, create capacity planning, and better match contact center resources to workload. We also upgraded the prior call recording and monitoring solution to a third party company, Eleveo, which not only provided similar call recording functionality with improved compliance regarding suppression of confidential personal information but also greatly enhanced our quality program through utilization of improved forms and ability to identify additional call details such as sentiment. We added wallboard functionality, which displays near real-time key performance metrics and the weather, and also has the ability to display critical messages through the use of a running banner. The wallboard functionality was available via a screen in every contact center, as well as a desktop application for those not in a local office. This application provided needed visibility so any real-time adjustments could be made to improve performance. Finally, this upgrade enabled the ability to add call back technology to improve our customers' experience with wait times.

Q. What other advancements has the Company made to support its customers?

A. Since the initial reorganization discussed above, the Company has continued to identify opportunities to improve the customer experience. For example, in the past two years, FPUC has focused on breaking down silos across the Customer Care business units by moving our labor resources under a single manager. This has allowed us to focus on expanding the resource pool and create a succession plan to help minimize the potential for business disruptions, and to identify additional opportunities for process improvements and synergies.

Q. What other steps has the Company taken to improve the customer experience?

A. In 2017, we began development of a program to deploy our Customer Care Representatives supporting incoming contacts to work remotely from their homes with our first agent being deployed in the early part of 2018. As a result of COVID, this remote deployment has been expanded to all Customer Care Representatives supporting incoming contacts and now also includes those Customer Care Analysts supporting billing, credit, and similar support functions. Having a remote workforce enables us to be more agile when responding to customer needs by creating an "on demand" staff to be used in special events such as storms, safety issues or other times when call volumes substantially increase. Furthermore, it expands our ability to recruit talent in other areas outside of the immediate office location.

Q. Has the Company made any other customer experience improvements?

A. Yes. In an effort to respond to increasing customer expectations over the last several years, FPUC has implemented several more key support functions. One such function is the Workforce Planning team created in 2016. This team works to align the Company's labor resources throughout the day to meet customer demand, tracks performance metrics, and creates short and long-term mitigation strategies that support customer facing software such as the call flows/options, call recording, and on-hold technology. The forecast methodology and data collected by the Workforce Planning team showed a need to add staff to improve response times and expand into other contact channels. Additionally, our Customer Experience team has been expanded to not only monitor agent performance, but to also analyze customer feedback and reactions to inform initiatives and strategy. Another key support function we have added is the addition of a training manager. This new role has enabled FPUC to create a robust new hire program and a refresher training program that is vital to attracting and retaining qualified agents.

Q. Would you please provide some detail on the three additional CSR positions being added to Schedule G2-19f?

A. These additional three CSR positions are critical in helping the Company continue to meet the increasing expectations of our customers, as well as the continued growth of the Company's system. We have prudently added these positions in 2022 in an effort to meet this ongoing demand in the Customer Service areas.

Quality of Service

Q. Please describe what steps the Company has taken to improve efficiency, quality, and effectiveness of interactions between Customer Care and customers?

A. Since the acquisition by CUC, we have dedicated resources to improving our effectiveness and level of quality for customer interactions extending beyond live interactions. CUC gained the ability to monitor and evaluate live calls in 2011. This was an important first step in creation of one of our most critical improvements, our Voice of the Customer ("VOC") program. The VOC program covers a wide variety of issues ranging from implementation of quality standards for call handling, customer feedback, and implementation of customer satisfaction tracking.

As mentioned, our customers' expectations and the method in which they interact with us continue to evolve. As a result, in 2017 we expanded our quality program to a VOC program. Under the VOC program, we now analyze a customer's interaction with us across all touchpoints. We established transactional surveys to measure customer sentiment, customer satisfaction, net promoter score, and to capture unstructured feedback. Net promoter score is a customer loyalty and satisfaction measure taken from asking customers how likely they are to recommend a company and/or service. The VOC program also captures feedback received across social media channels, escalated complaints, call observations, and any other feedback mechanisms.

The program then aggregates all data on a monthly basis to produce an analysis of successes and opportunities. The Customer Experience team produces actionable recommendations that are then reviewed for short and/or long-term strategy initiatives, as well as level of investment. This analysis has driven several improvements within customer service, among them adoption of a best-in-class call strategy, improvement of our payment options, reduction of payment fees, and implementation of call back functionality. This analysis is also a key reason for our consideration of a new Customer Information System ("CIS").

Q. Please explain how the VOC aids the development of quality standards for Customer Service.

A. Our VOC program collects customer and employee feedback across all channels. Our Customer Experience team analyzes the information along with best practices to develop our quality standards. The quality standards for those in Customer Care help evaluate both soft skills, such as tone and professionalism, as well as hard skills related to processing requests completely and accurately.

Q. Would you please provide some examples of how these enhancements have been successful?

A. As a result of our VOC program, we continue to adjust our Customer Care strategy to meet evolving customer expectations and implement industry best practices. The program began with refining our call quality standards with an added focus on enhancing our coaching program. This program has been improved since its initial implementation to now capture and measure data from multiple touchpoints, such as surveys, social media, call monitoring, emails, website inquiries, and escalated complaints. With this data, an analysis can be performed to include a root cause analysis that helps inform organizational strategies and objectives. As mentioned, the consideration of an upgrade to our billing and payment system is a direct result of the feedback we have received. We heard that customers struggled to use the current system and they were unhappy with the level of fees being assessed. As of January 2022, we were able to reduce the fees making a check payment free if they set up an account online, while also reducing the one-time payment costs for using a check by 31%. Some customers also told us that they would still like to receive a paper bill when setting up an online account so we gave back that option. In addition, during our busy season that occurs between October to April, customers did not want to wait in queue, so we implemented a call back technology that allows them to keep their place in line without staying on the line. They receive a call back when an agent becomes available.

We have also leveraged this feedback to greatly enhance our communications during a severe weather event. We proactively share storm preparation information, as well as key resources in the community. Our social media platforms are utilized more than ever as we heard that customers first went to these channels to get valuable information. In addition to social media, our website has gone through a few redesigns to ensure ease of use from any device by making all sites mobile friendly We have found that these platforms are the most customer-friendly, proactive means of keeping our customers informed.

Q. Has the Company been able to measure improvement in customer communication resulting from these enhancements?

A. Yes. Even with increased customer expectations, the Company has been successful at lowering the number of complaints. Based on 2013 total complaints of 23 across all of our Florida LDCs, we have shown a consistent annual reduction of 35% or better. Over the past nine years, the Company has not received any formal complaint for FPUC – Indiantown Division, and our FPUC - Fort Meade Division has only experienced one formal complaint over the past nine years.

Self Service Functionality

Q. Please discuss the benefit to the Company's customers resulting from implementation of third party payment options.

A. Several enhancements to our payment platform have been made over the past ten years with the most recent functionality being implemented in January 2022. The payment platform enhancements have focused on ease of customer use and access to billing and payment information to provide customers a self-service option. One of these enhancements was the implementation of an electronic billing platform, EZ-Billing, which has been received well by customers. EZ-Billing allows customers quicker access to their bill, payment options such as auto pay, and to receive their bill electronically providing an eco-friendlier option. The improvements implemented in January of this year will provide additional payment options and notifications, such as text messaging and payment via text. This update provided a no-fee option for automatic check payments when the customer sets up their account online. The improvement maintained the one-time payment option using EZ-Pay, at a reduced fee. Our retail payment network has also been extended which offers customers an option to pay their bills without a fee when visiting at local merchants. These new partners include businesses, such as Walmart, as well as smaller entities.

Q. Have your customers embraced these new options?

A. Customers have embraced the EZ-Billing option. Customers tend to prefer either the online payment option or mailing their payment directly to FPUC, as evidenced by an enrollment rate of 48.7% for our Florida customers.

<u>Customer Communications</u>

Q. How has the Company improved Company-to-customer communications?

A. FPUC's overall communication programs and methods are constantly evolving to meet changing needs and to utilize additional contact channels. Customer Care collaborates with the Company's Strategic Communications team deploying a comprehensive communication policy, which is included with my testimony as Exhibit KP-1, to help with continued improvement. The methods by which we keep the lines of communication open with our customers continues to broaden from traditional telephone and email to the utilization of social media and our website to provide a variety of options that fit our customer's preferred method of communication. Particular focus has been given to the utilization of our website to include banners for immediate and important information, leveraging our telephone system to share mass messages, and posting of FAQs to our website and social media channels to help with customer questions. Furthermore, we implemented the ability to deploy outbound call campaigns to reach customers that may be impacted in a specific area. We constantly review our social media pages to respond to customer inquiries but to also measure sentiment and effectiveness of communication. This has enabled us to identify when more communication may be required and the level of specificity. During adverse weather, we have been able to communicate with individuals and communities through our social media channel to offer and deploy support where appropriate.

Q. Does the Company have a process to communicate directly with individual customers when necessary, such as in an outage situation?

A. Yes. While natural gas systems are not prone to service outages, special care is taken to communicate and provide additional channels of communication during weather events. These process enhancements include a personal outreach to hospitals and nursing care facilities in the event of an extended outage.

Q. What steps has the Company taken to protect customer data given the Company's use of a broader range of communications channels?

A. The Company has updated its internal policies and audits to protect customer data in a broader range of situations. I have included our "Red Flag" policy as Exhibit KP-2 in my testimony. When we upgraded our call recording system, we implemented pause and resume technology to stop recording when customers provide us personally identifiable information during the payment process. The automation identifies when the agent is entering the fields where we would ask for credit card or banking information and pauses the recording. The automation then recognizes when the payment process is completed and automatically resumes the recording.

When customers utilize our payment platform, it provides a multitude of features to protect their information. Some examples of this are:

- When a customer is asked to create an account profile with a unique username and password. As part of the sign in protection, they are provided numerous security questions and must choose three to provide the answers. One of the three questions may be present upon signing in, or when adding, changing, or deleting information from their profile.
- As part of the verification process, the customer will need to check the box "I'm not a robot". This security measure will ask them to verify by clicking on pictures containing specific items. The customer will continue to click on appropriate pictures until the item no longer appears in any picture.
- Customers can also create a Sign-In Seal feature, which provides the security of having the customer know they are on the official site. The seal is unique to the customer and is only shown when accessing the official site.

- In this application, customers' account numbers as well as payment information are masked showing only the last 4 digits only.

Within our customer information system, enhancements were made to mask the social security number so only the last four digits are shown. In addition, a customer service representative can enter the customer's full social security number or driver's license or opt to use only the last four digits based on the customer's preference. The numbers are automatically masked upon entering. We also implemented procedures in case the customer is not comfortable in providing their social security number.

In addition to these measures, FPUC completes identity theft training every year for all employees who come into contact with personally identifiable information. This training confirms procedures for proper identification of a customer and procedures for handling sensitive information. FPUC is also an active member of the Utilities United Against Scams ("UUAS"). Each of the participating members have resources available in the event of a potential scam whereby our customers are the target of scammers and securing ill-gotten payments. This organization has been successful in shutting down a number of scam operations.

Q. Could you please elaborate on the technologies that are used to protect customer personal identifiable information?

A. As will be discussed in more detail by Company witness Gadgil, CUC uses a variety of technology and processes to protect systems containing customer Personal Identifiable Information. Some of those technologies and processes include:

- Advanced Endpoint Detection & Response Protection across the enterprise

- Data Loss Prevention
- Policies around data handling and protection
- A Third Party Risk Program focused on vendor vetting, selection and risk ranking, ensuring CUC's partners don't raise our risk profile
- A mature Vulnerability Management program, utilizing National Institute of Standards and Technology "NIST" approved scanners, which perform weekly scans to identify any new vulnerabilities. NIST is a non-regulated federal agency that develops and publicizes security compliance standards that are mandated under the Federal Information Security Management Act and other regulations.

COVID-19 Pandemic Response

Q. Would you please summarize the impact to customers related to the COVID-19 Pandemic?

A. Customer impacts from the COVID-19 Pandemic have been, and still are, significant. In response to the economic challenges for our customers, the Company took several proactive measures to help customers through this unprecedented time. FPUC initiated outreach to customers to ease their concerns regarding bill payments and potential service interruptions. In May 2020, the Company proactively suspended disconnects for non-payment and instituted flexible, extended payment plan options. We leveraged existing relationships with support agencies, such as Our Lady Star of the Sea Catholic Church and established new relationships in order to connect customers with financial support. These programs were communicated through multiple channels to reach as many customers as possible. These include the website, bill inserts, special mailings, social media, email blasts, and updates via our toll-free number.

Q. Please describe how the Customer Care department responded to the COVID-19 pandemic to protect the Company's customers.

A. During the pandemic, the Company immediately deployed several measures to help customers deal with the financial strain. As mentioned, we suspended all collection activity to include collection notices, calls, and disconnections. We extended long term payment plans to help mitigate large bills. FPUC partnered with local agencies to connect customers with financial support. Our retail payment network was expanded during the COVID-19 pandemic to provide additional options to all customers even those without access to the internet. We continued to accept payments via mail, online, drop boxes and through our customer service number 24-hours-a-day, seven days a week.

Furthermore, in an effort to protect both its employees and our customers, FPUC suspended customer walk-in services as of April 2020. With the uncertainty in how long COVID would continue, and with the increased payment channels provided, the Company made the very difficult decision to close its walk-in centers permanently in October 2021. The customers have been understanding and accepting of these changes.

Q. What other channels were leveraged to enhance communications with the Company's customers?

A. The additional communication channels that were leveraged include targeted mailings, bill inserts, bill messages, website, social media, email blasts, recording messaging on our customer service number, outbound campaigns, and communication with local agencies such as Catholic Charities.

New & Enhanced Customer Programs

Q. What other program enhancements has the Company implemented to improve the customer experience?

A. In addition to the technology and process improvements mentioned, several additional key improvements are underway that will not only enhance the customer experience but will also create additional options for customers. For example, in late 1st quarter of 2022, the contact center deployed a best-in-class contact center platform called Five9. The Five9 platform provides operational flexibility through ease of updates to our call flow options and messaging for inbound contacts. We will gain the functionality of communicating via chat and text. The platform gives us the ability to blend contacts and deliver to the appropriately skilled agent via a single dashboard that will drive efficiencies and provide insight into customer communication channel preference and channel effectiveness. We will also be able to integrate support of social media inquiries to complete a view of the customer's journey. Not only will we gain functionality of implementing contact channels but will also gain functionality in securing additional customer feedback regarding reasons for the inquiry to identify opportunities to reduce the need for customer contact. We will leverage the scripted options within the application to further strengthen our emergency call handling. These would include safety messaging and key questions relative to gas emergencies.

In addition to this functionality, we will integrate our virtual call back, workforce management system, call recording, quality systems, and performance dashboards into this single program. This reduces risks of vendor management and provides a more holistic view of the contact center performance leveraging additional data points to collect information and analyze to validate our initiatives and strategy.

Q. Are there any other processes you want to mention?

A. Yes. By 2nd quarter 2022, the Company plans to implement lockbox functionality for mailed payments. Previously, these payments were all mailed to our Maryland office where they were processed manually. The new functionality will automate the payment processing function and should reduce overall processing time.

Q. Are there any other significant enhancements you want to mention?

A. Yes. The Company is currently evaluating the potential to implement a new billing system that will consolidate the two existing platforms that are at the end of their life expectancy into one more streamlined system. The new billing system will offer enhancements to our ability to see a consolidated view in order to better assist the customer. The system will reduce many of our manual processes to now automate completion. Our current systems lack certain functionality that more modern billing systems provide, such as consolidated customer information, ability to send customer statements and information automatically, ability to capture customer preferences, automated service order processing, automated exception reporting and alerts, and ability to see a holistic view of a customer with multiple accounts to name a few.

Q. Is the new billing system mentioned above being requested in this docket?

A. No. We do not anticipate its implementation prior to the Company's projected test year for this proceeding.

Q. Would you please summarize your testimony?

A. As evidenced throughout my testimony, a lot of work and focus has been placed on improving the customer experience. We are committed to continuing to meet our customer expectations through making prudent investments in technology, providing options for completing transactions with us, opening additional channels of communication to conduct business, and continuing to expand our Voice of the Customer program. The prudent investments made thus far in modernizing our phone system and supporting technologies have transformed the way we do business over the past 10+ years. We have set a good foundation that we can build on to continue to meet, and hopefully exceed, customer expectations while controlling costs. We will do this through securing systems that enable us to provide options for the customer to conduct business with us that does not require customer service representative intervention. The utilization of our recently secured contact center platform will allow us to communicate with customers differently enabling for customers to communicate with us in their preferred method. Finally, expanding our Voice of the Customer program by increasing our survey pool and means in which we seek feedback will help us to gather more information on the customer's wants and needs. That feedback will be leveraged to inform both our short-term and long-term strategy.

Q . Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.	DOCKET NO. 20220067-GU FILED: September 14, 2022

FLORIDA PUBLIC UTILITIES COMPANY'S
ERRATA SHEET TO THE DIRECT TESTIMONY OF KELLEY PARMER

Florida Public Utilities Company ("FPUC") hereby submits this Errata Sheet to correct the Direct Testimony of its witness Kelley Parmer, originally filed on May 24, 2022:

Page and Line Number	Correction
Page 13, Line 10	Replace “Based on” with “Comparing each year to” Change “23” to “22”
Page 13, Line 11	After “shown,” change “a” to “an”, replace “consistent annual” with “average” and change “35%” to “31%” After the percent (%), insert “from 2013 through 2021” Delete “or”
Page 13, Line 12	Delete “better” before the period.

Respectfully submitted this 14th day of September, 2022,

By: */s/Beth Keating*

Beth Keating
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Attorneys for Florida Public Utilities Company

BY MS. KEATING:

Q Ms. Parmer, did you also cause to be prepared and filed Exhibits KP-1 through 3?

A Yes, I did.

MS. KEATING: Mr. Chairman, I believe those are already marked as Exhibits 28 through 30 on staff's Comprehensive Exhibit List.

CHAIRMAN FAY: Yep.

BY MS. KEATING:

Q Ms. Parmer, did you prepare a summary of your testimony?

A Yes, I did.

Q Would you please go ahead and present that?

A Absolutely.

Good morning, Mr. Chairman and Commissioners. I appreciate the time to meet with you today.

The purpose of my direct testimony is to explain how Chesapeake has evolved the Florida Public Utilities' customer experience since the acquisition.

10 plus years ago, Florida Public Utilities was largely operating its independent offices right across the footprint. Chesapeake began investing in the evolution of the customer experience through a phone platform and a quality system. This transformed the way we do business at a foundational level, and also helped

to transform us into the virtual customer service organization that we are today. Additionally, the investment in the quality program helped to begin our journey of building A Voice to the Customer Program.

While we have come a long way, we still have a long way to go to become a world-class customer organization. This rate relief will help to ensure that we can continue to build upon the foundation that we have focused on over the past decade.

This concludes the summary of my testimony. Again, I appreciate the time to meet with you today.

Q Thank you, Ms. Parmer.

MS. KEATING: Mr. Chairman, the witness is tendered for cross.

CHAIRMAN FAY: Okay. Great. Thank you.

Ms. Christensen, you are recognized. Oh, Ms. Christensen, just real quick. Do you have a general idea, I am going to try to plan for scheduling for the parties and the witnesses as to your questioning on let's say Parmer, and then we will go back to --

MS. CHRISTENSEN: Moul?

CHAIRMAN FAY: Mr. Moul, yeah.

MS. CHRISTENSEN: Probably -- I mean, I only have, like, a handful of questions for Ms. Parmer.

CHAIRMAN FAY: Okay.

MS. CHRISTENSEN: But probably 30 minutes or 30 to 50 minutes worth on Moul, if that depending on how he responds.

CHAIRMAN FAY: Okay. Great.

And just for the parties and witnesses, the plan would be to -- we will go to some point break for lunch and then work through this afternoon. It looks like we probably will get through this afternoon. If we are anywhere dose to that, we will run a little bit longer today just to close out and probably try to get travel cost and witnesses back home if we are able to do so.

So with that, Ms. Christensen, you are recognized. Go ahead.

MS. CHRISTENSEN: Thank you.

EXAMINATION

BY MS. CHRISTENSEN:

Q And good morning, Ms. Parmer.

A Good morning.

Q I just have a few questions for you, and I am going to start at page 10 of your direct testimony. And looking at your testimony regarding the quality of service.

A You said page nine?

Q Page 10.
A Page 10. Okay. I am there.
Q Okay. And this is regarding the quality of service. You would agree that FPUC put in an automated phone system since 2011 right after it was acquired by the Chesapeake Corporation, is that correct?
A That's correct.
Q Okay. And since that time, you have changed to the program and added features to your call response system, is that accurate?
A Yes. That's correct.
Q And with the implementation of the new billing and payment -- and with that, you implemented a new billing and payment system as well, is that correct?
A We implemented a payment system, but that's really been enhanced from what it was. That relationship was longstanding with COBRA. We have not implemented a new billing system.
Q Okay. So with those additions, would it be a fair characterization of your testimony to say that some customers struggled with the use of the current system?
A Absolutely. With any automated system, you have customers who struggle to use them. Our goal is to try to work with them, listen to feedback to ensure they don't as much as possible.

Q And would it also be fair to say that you testified that some of the customers were not happy with the fees being assessed?
A Absolutely. The fees were higher historically before an upgrade January of this year.
Q Okay. And I think you said, and maybe you just said in your response, that you were able to reduce those fees with on-line payment options, is that correct?
A We were able to reduce the fees the same way they make payments today, via the phone system, through an upgrade.
Q Okay. And then you also, I think, testified that FPUC implemented a callback feature, is that correct?
A Yes. That's correct.
Q Okay. Would you agree that these features are kind of industry standards?
A Excuse me, could you repeat that?
Q For customer service type of interactions in today's environment, that this is kind of standard practice for a lot of businesses in dealing with customers particularly, would you agree that's kind of used?
A I would agree that an automated system tends

to be standard practice, but not a callback.

Q Okay. All right. I have no further questions, thank you, Ms. Parmer.

CHAIRMAN FAY: Okay. Great. Thank you. Mr. Moyle.

MR. MOYLE: Thank you, I just have a couple of questions.

EXAMINATION

BY MR. MOYLE:

Q I looked in your testimony and you talked about some call centers that had in DeBary and West Palm Beach --

A Yes.

Q -- and it seems those weren't working very well, is that right?

A No. That's not correct. All those call centers exist, but they are all remote. We are a 100-percent remote organization post COVID. So those same people exist in those locations, they are just home-based.

Q Okay. So the employees are still in West Palm and DeBary, but they are not coming into an office?

A Yes. That's correct.

Q Okay. Thank you.

MR. MOYLE: That was it. Thank you.

CHAIRMAN FAY: Thank you, Mr. Moyle.
Staff?
MR. SANDY: No cross-examination, Mr. Chair.
CHAIRMAN FAY: Okay. Commissioners?
All right. Redirect?
MS. KEATING: No redirect.
CHAIRMAN FAY: All right. With that, Ms. Keating, we would move Exhibits 28, 29 and 30 into the record without objection.
MS. KEATING: Thank you.
(Whereupon, Exhibit Nos. 28-30 were received into evidence.)
CHAIRMAN FAY: All right. And, Ms. Keating, would you like your witness excused?
MS. KEATING: Yes, Mr. Chairman.
CHAIRMAN FAY: All right. Ms. Parmer, thank you.
THE WITNESS: Thank you.
(Witness excused.)
CHAIRMAN FAY: All right. Ms. Keating, whenever you are ready, you can call your next witness. Go ahead.
MS. KEATING: Mr. Chairman, FPUC would call Paul Moul to the stand.
CHAIRMAN FAY: Ms. Christensen, we have one

additional exhibit from you, is that correct?
MS. CHRISTENSEN: I believe -- well, I think since staff passed out the exhibit that I would have, which would be the deposition transcript, I can just use staff's.
CHAIRMAN FAY: Okay. Great.
MS. CHRISTENSEN: If I need it.
CHAIRMAN FAY: Okay.
Whereupon,
PAUL MOUL
was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:
EXAMINATION
BY MS. KEATING:
Q Good morning, Mr. Moul.
A Good morning.
Q Would you please state your name and business address for the record?
CHAIRMAN FAY: Mr. Moul, is your mic on? Just make sure the button in front of you -- you should see the green light in front of you. There you go.
THE WITNESS: Now I am set. Thank you.
My name is Paul Moul. My last name is spelled M-O-U-L, and the way I pronounce it it rhymes with

owl.

BY MS. KEATING:

Q Would you please state your business address for the record?

A Yes, my business address is 251 Hopkins Road, Haddonfield, New Jersey, 08033.

Q And by whom are you employed?

A I am sorry?

Q By whom are you employed?

A I am an independent financial and regulatory consultant.

Q And on whose behalf are you appearing in this proceeding?

A I am here today on behalf of Florida Public Utilities and its affiliates.

Q And did you cause to be prepared and filed in this proceeding 52 pages of direct testimony?

A I did.

Q And do you have any changes or corrections to that testimony?

A There are none that I am aware of at this time.

MS. KEATING: Mr. Chairman, we would ask that Mr. Moul's direct testimony be inserted into the record as though read.

CHAIRMAN FAY: Okay. Show it entered.

(Whereupon, prefiled direct testimony of Paul Moul was inserted.)

FLORIDA PUBLIC UTILITIES COMPANY
DIRECT TESTIMONY OF
PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return that the Florida Public Service Commission ("FPSC" or the "Commission") should recognize in the determination of the revenues that Florida Public Utilities Company ("FPUC") and the Florida natural gas division (i.e., Central Florida Gas or "CFG") of Chesapeake Utilities Corporation ("CUC" or the Parent Company) should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data set forth in Exhibit No. PRM-1, which is a thirty (30) page document that is divided into Schedules 1 through 15. My testimony is based upon my firsthand knowledge of FPUC and CUC consisting of information obtained from meetings with FPUC's management as well as both Parent Company and Company-specific data, which is widely disseminated within the financial community. For purposes of clarity, I will refer to the consolidated entity consisting of FPUC, CFG, FPUC-Indiantown Division, and FPUC-Fort Meade together as "Company."

Q. BASED UPON YOUR ANALYSIS, WHAT IS YOUR CONCLUSION CONCERNING THE APPROPRIATE RATE OF RETURN FOR THE COMPANY IN THIS CASE?

A. Based upon my analysis of the Company, it is my opinion that the rate of return on common equity should be set within the range of 10.75% to 11.75%. My cost of equity determination should be viewed in the context of the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. As shown on page 1 of Schedule 1, I have presented the weighted average cost of capital for the Company, which is calculated for the test year ending December 31, 2023. I should note that the Company has made adjustments to my overall rate of return recommendation to include deferred income taxes as zero-cost capital because these items are not treated as rate base deductions in Florida. My recommended range of the rate of return and return on equity range are shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	39.44%	3.46%	1.36%
Short-Term Debt	5.51%	3.30%	0.18%
Common Equity	55.05%	10.75%	5.92%
Total	100.00%		7.46%

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	39.44%	3.46%	1.36%
Short-Term Debt	5.51%	3.30%	0.18%
Common Equity	55.05%	11.75%	6.47%
Total	100.00%		8.01%

From this range, I recommend that the Company's proposed rates be set to include a 7.73% overall rate of return that contains an 11.25% cost of equity. Those returns are shown on page 1 of Schedule 1 of Exhibit No. PRM-1. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. WHAT BACKGROUND INFORMATION HAVE YOU CONSIDERED IN REACHING A CONCLUSION CONCERNING THE COMPANY'S COST OF CAPITAL?

A. The Company provides natural gas distribution service to approximately 90,000 customers in twenty-one counties throughout Florida. For the year 2021, the Company's gas throughput (combined sales and transportation) was represented by approximately 5% to residential customers, 14% to commercial customers, 74% to industrial customers, and 7% to other customers. It is noteworthy that the major percentage of the Company's throughput is represented by industrial sales. However, these customers represent less than 3% of the Company's entire customer base. This means that the energy needs of a few customers can have a significant impact on the Company's operations.

The Company obtains its natural gas supply through connections with the six interstate pipelines and purchase agreements with gas commodity suppliers. The Company is a wholly-owned subsidiary of CUC. CUC provides the Company with all of its investor required capital -- both debt and equity.

Q. HOW HAVE YOU DETERMINED THE COST OF COMMON EQUITY IN THIS CASE?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a gas distribution utility, such as the Company. In this regard, I have considered four (4) well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), the Comparable Earnings ("CE") approach. The results of my analysis of these well-recognized analyses indicates that the Company's rate of return on common equity should be in the range of 10.75% to 11.75%.

Q. IS THE MARKET IMPACT OF THE COVID-19 PANDEMIC REFLECTED IN YOUR ANALYSIS OF THE COST OF EQUITY FOR THE COMPANY?

A. Yes. My cost of equity analysis reflects the impact of the COVID-19 Pandemic ("Pandemic"). These events had a significant impact on the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the Pandemic, which ended a record-setting, 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. Recently, renewed economic growth has produced inflation levels higher than have been seen in four decades. Indeed, in February 2022, the rate of inflation spiked upward to 7.9%, the highest in forty-years, due to Pandemic-related supply side issues, strong consumer demand, and tight labor markets. Supply shortages have also significantly impacted the consumer sector of the economy. Energy prices have increased as well, with the commodity cost of natural gas moving up. While short-term interest rates remain at historically low levels, longer term interest rates began to rise in February 2021. At present, short-term interest rates are poised to increase after the FOMC ends its bond buying program. The FOMC has indicated that several increases in the Fed Funds rate will likely occur in 2022 and 2023. The first of these increases occurred on March 16, 2022, when the Fed Funds rate was increased by 0.25%. Recently, the yield on ten-year Treasury notes reached 2.00% for the first time since mid-2019. Over the course of the Pandemic, stock prices rebounded and reached a new high in reaction to renewed economic growth. While there has been a pullback in overall market prices in early 2022, commonly known as a market correction, it followed a stellar market performance in 2021 i.e., a 26.89% annual price appreciation. I have considered these events as they impact the inputs that I used in the various models of the cost of equity.

Q. IN YOUR OPINION, WHAT FACTORS SHOULD THE COMMISSION CONSIDER WHEN DETERMINING THE COMPANY'S COST OF CAPITAL IN THIS PROCEEDING?

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

Q. HOW HAVE YOU MEASURED THE COST OF EQUITY IN THIS CASE?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of eight (8) gas companies. The companies are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. PLEASE EXPLAIN THE SELECTION PROCESS USED TO ASSEMBLE THE GAS GROUP?

A. I began with all of the gas utilities contained in the Value Line Investment Survey, which consists of ten companies. Value Line is an investment advisory service that is a widely-used source in public utility rate cases. I eliminated two companies from the Value Line group. UGI Corporation was removed due to its large international presence as well as the relative proportion of its regulated businesses

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

to the overall company. UGI Corporation's portfolio consists of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and electric generation. Of the total business, UGI Corporation generated 14% of its revenues and 10% of its earnings from the regulated utilities for the twelve months ended September 30, 2021. Further, only 29% of UGI's assets are devoted to regulated businesses (as of September 30, 2021). I also removed South Jersey Industries from the Gas Group because it entered into an agreement to be acquired by a private equity investor. The remaining eight companies in the Gas Group are identified on page 2 of Schedule 3.

Q. HOW HAVE YOU PERFORMED YOUR COST OF EQUITY ANALYSIS WITH THE MARKET DATA FOR THE GAS GROUP?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized. In other words, employing group average data, rather than individual company analysis, minimizes the effect of extraneous influences on the market data for an individual company.

Q. PLEASE SUMMARIZE YOUR COST OF EQUITY ANALYSIS.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table sets forth the results that are summarized on page 2 of Schedule 1 using each of these approaches.

	Excluding Flotation Costs	Including Flotation Costs [1]
DCF	11.65%	11.82%
RP	10.75%	10.92%
CAPM	14.41%	14.58%
CE	12.05%	12.05%

The average of all methods is 12.22%, excluding flotation costs, and 12.34%, including flotation costs. The median values are 11.85%, excluding flotation costs and 11.94% including flotation costs. From these measures, I recommend a cost of equity of 10.75% to 11.75%. The low end of my range is based on the Risk Premium approach excluding flotation costs. The upper end of my range is represented by median return of 11.85%, excluding flotation cost, and rounded down to the nearest quarter percentage point. The midpoint of the range is 11.25% and is near the average of the DCF and Risk Premium approaches, excluding flotation costs. My recommendation in this case is represented by the 11.25% midpoint cost of equity. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements.

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

To obtain new capital and retain existing capital, the rate of return on common equity for FPUC must be high enough to recognize the risks and uncertainties of its business and the requirements of the capital markets.

NATURAL GAS RISK FACTORS

Q. WHAT FACTORS CURRENTLY AFFECT THE BUSINESS RISK OF NATURAL GAS UTILITIES?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Presently, supply side issues and inflationary pressures are adversely impacting the business risk of natural gas utilities and other companies. Today, they operate in a complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers. The gas distribution industry also faces the risk associated with increased availability of renewable energy sources, expanded emphasis on energy efficiency, and potential initiatives directed toward decarbonization as a national energy policy.

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

Q. PLEASE DISCUSS SOME OF THE OPERATIONAL RISKS FACED BY THE COMPANY?

A. Risks that affect the Company's operations relate to adequate delivery capability, counterparty risk and risks related to cyber-security. For many of the Company's customers, they obtain their natural gas directly from third-party marketers. The Company is also faced with counterparty risk should suppliers fail to perform their obligations, especially with regard to hedging obligations. In addition, the handling of natural gas is attended with safety considerations. Finally, cyber-attacks have increased risks to gas delivery systems, elevating the need for enhanced cyber-security systems to protect gas customers and companies from attack by foreign enemies and domestic terrorists.

The natural gas business also faces significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory. Propane and fuel oil have an advantage because they are subject to minimal regulatory constraints when conducting their marketing activities.

Q. HOW DOES THE COMPANY'S THROUGHPUT TO LARGE VOLUME CUSTOMERS AFFECT ITS RISK PROFILE?

A. CUC's risk profile is significantly influenced by natural gas delivered to industrial customers. Indeed, CUC's industrial customers represent 74% of the total throughput. Deliveries to these customers are usually thought to be of higher risk than sales to other customers. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from the competitors noted above, as well as other competing natural gas service providers. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory.

Q. WHAT RISKS ARE ASSOCIATED WITH THE COMPANY'S INFRASTRUCTURE?

A. The Company must maintain and replace, where appropriate, its aging infrastructure and is in the process of doing so across its service territory. To maintain safe and reliable service to existing customers, the Company must invest in these infrastructure upgrades.

The continuing cost of upgrading, replacing and expanding CUC's infrastructure is expected keep the level of construction expenditures at heightened levels. Over the next five years, CUC's total capital expenditures for all its divisions and subsidiaries are expected to be approximately $798.618 million. These expenditures will represent an approximate 45% ($798.618 million ÷ $1,744.878 million) increase in its net utility plant from the level at December 31, 2021. For the Company, capital expenditures in Florida are expected to be $193.983 million for the next five-years. There is the potential for actual spending to exceed these levels. At the forecasted level, this represents 47% ($193.983 million ÷ $415.807 million) of net utility plant at December 31, 2021. As noted previously, a fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital necessary to meet its capital needs on an ongoing basis. The need for infrastructure replacement is prevalent throughout the natural gas industry. CUC must compete for capital with other natural gas companies in other states, as well as other utilities and non-regulated companies. To successfully compete, it must have a fair rate of return on invested capital.

Q. HOW SHOULD THE COMMISSION RESPOND TO THE ISSUES FACING THE NATURAL GAS UTILITIES AND, IN PARTICULAR, THE COMPANY?

A. The Commission should recognize and take into account the competitive environment, as well as the business and physical risks inherent in providing natural gas service to end use customers, in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital during a period of significant, continuous investments in its infrastructure.

FUNDAMENTAL RISK ANALYSIS

Q. IS IT NECESSARY TO CONDUCT A FUNDAMENTAL RISK ANALYSIS TO PROVIDE A FRAMEWORK FOR A DETERMINATION OF A UTILITY'S COST OF EQUITY?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I compared the CUC to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group. CUC is used here, rather than the Company, because CUC obtains and allocates capital to its divisions and subsidiaries.

Q. WHAT ARE THE COMPONENTS OF THE S&P PUBLIC UTILITIES?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. WHAT COMPANIES COMPRISE THE GAS GROUP?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., Southwest Gas Holdings, and Spire, Inc.

Q. IS KNOWLEDGE OF A UTILITY'S BOND RATING AN IMPORTANT FACTOR IN ASSESSING ITS RISK AND COST OF CAPITAL?

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

Q. HOW DO THE CREDIT QUALITY RATINGS COMPARE FOR THE COMPANY, THE GAS GROUP, AND THE S&P PUBLIC UTILITIES?

A. There is no public rating on the debt of CUC. The long-term debt of CUC carries a designation of "2b" from the National Association of Insurance Commissioners ("NAIC"), which represents investment grade debt and is equivalent to the Baa/BBB ratings by Standard & Poor's Corporation ("S&P") and Moody's Investors Service ("Moody's") -- both national recognized credit rating agencies. Presently, the average corporate credit rating ("CCR") for the Gas Group is A- from S&P and the Long Term ("LT") issuer rating in A3 from Moody's. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The bond ratings for the companies in the Gas Group are displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average Long Term ("LT") issuer credit quality rating credit quality rating is A3 by Moody's and BBB+ by S&P, as shown on page 3 of Schedule 4. The credit quality rating for CUC is slightly lower than the Gas Group, largely reflecting the larger short-term debt balances the Company has maintained historically as it has undertaken various multi-year projects. The Company's strategy is to align the permanent financing with the in-service dates of the large projects to ensure that permanent financing matches recovery of capital costs. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. HOW DO THE FINANCIAL DATA COMPARE FOR THE COMPANY, THE GAS GROUP, AND THE S&P PUBLIC UTILITIES?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period from 2017-2021. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, CUC is much smaller than the average size of the Gas Group, and very much smaller than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for CUC and the Gas Group as compared to the S&P Public Utilities.

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

The five-year average price-earnings ("P-E") multiple was fairly similar for CUC, the Gas Group and the S&P Public Utilities. The five-year average dividend yield was lowest for CUC, followed by the Gas Group and the S&P Public Utilities, which had the highest dividend yield. The five-year average market-to-book ratio was highest for CUC, while the market-to-book rates was somewhat lower for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a

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

company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). A firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 60.1% for CUC, 50.5% for the Gas Group, and 41.0% for the S&P Public Utilities. CUC's common equity ratio was higher than the Gas Group, thereby indicating increased balance sheet strength and lower financial risk.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.044 (0.5% ÷ 11.4%) for CUC, 0.106 (1.0% ÷ 9.4%) for the Gas Group, and 0.051 (0.5% ÷ 9.9%) for the S&P Public Utilities. The variability of CUC's rates of return was somewhat close to the S&P Public Utilities and lower than the Gas Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[4] The five-year average operating ratios were 80.9% for CUC, 82.9% for the Gas Group, and 79.8% for the S&P Public Utilities. CUC's operating ratios were close to the Gas Group, and the S&P Public Utilities, which indicates similarity of risk.

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

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 5.78 times for CUC, 4.29 times for the Gas Group, and 2.97 times for the S&P Public Utilities. The interest coverages were higher for CUC as compared to the Gas Group, thereby indicating lower credit risk for lenders.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. During the pandemic, there was further pressure on cash flows due to the suspension of collection activities and the moratorium against service disconnections for nonpayment. Quality of earnings has not been a significant concern for CUC, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 64.0% for CUC, 56.9% for the Gas Group, and 66.0% for the S&P Public Utilities. In each instance, there is a compelling need for external capital from investors in order to fund capital expenditure requirements. A reasonable return is necessary in order to attract that capital.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[5] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.80 for CUC, 0.86 as the average for the Gas Group (see page 2 of Schedule 3) and 0.90 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. PLEASE SUMMARIZE YOUR RISK EVALUATION.

A. The investment risk of CUC parallels that of the Gas Group in certain respects. CUC has lower risk as shown by its lower beta, historically higher common equity ratio, its lower variability of earnings, and its higher interest coverages, but its operating ratio, quality of earnings and internally generated funds factors are comparable to those of the Gas Group. The Company's overall risk is higher than the Gas Group due to its smaller size. In addition, the higher levels of short-term debt and the absence of a formal credit rating could also impact the overall risk

[5] Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

profile, although the Company has successfully managed these while accessing competitively priced capital.

Q. BASED ON YOUR ANALYSIS, DOES THE GAS GROUP PROVIDE A REASONABLE BASIS TO MEASURE THE COMPANY'S COST OF EQUITY FOR THIS CASE?

A. Yes. On balance, the risk factors average out, indicating that the cost of equity for the Gas Group provides a reasonable basis for measuring the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. PLEASE EXPLAIN THE SELECTION OF CAPITAL STRUCTURE RATIOS FOR THE COMPANY.

A. CUC provides all the permanent capital, both debt and equity, for all its divisions and subsidiaries, e.g., FPUC. For this case, CUC's capital structure ratios have been employed for rate of return purposes.

Q. DOES SCHEDULE 5 PROVIDE THE CAPITALIZATION AND CAPITAL STRUCTURE RATIOS YOU HAVE CONSIDERED?

A. Yes. Schedule 5 presents the CUC's actual capitalization and related capital structure ratios at December 31, 2021 and projected at the December 31, 2022 and December 31, 2023.

Q. WHAT FINANCING ARRANGEMENTS ARE CURRENTLY IN PLACE FOR CUC?

A. CUC presently has "shelf" agreements with Prudential and MetLife. These agreements expire in April 2023 and May 2023, respectively. The original amounts of these agreements have previously been partially drawn upon. The remaining borrowing capacity is $150 million and $100 million, respectively. It is currently projected that CUC will issue $80 million under these agreements on December 1, 2022. The interest rate and terms of payment will be determined at the time of issuance. The proceeds received from the issuances of these shelf notes will be used to reduce short-term borrowings under the revolver and/or to fund capital expenditures.

Q. HAVE YOU MADE ADJUSTMENTS TO THE CUC CAPITAL STRUCTURE RATIOS FOR RATESETTING PURPOSES?

A. Yes. I have eliminated accumulated other comprehensive income (OCI") and the debt associated with Marlin subsidiary equipment financing that is secured by the associated equipment. The Marlin equipment financing provides no source of funds available to other divisions of CUC or to the Company and therefore, is eliminated from the capital structure for this case.

Q. PLEASE EXPLAIN THE JUSTIFICATION FOR REMOVING THE ACCUMULATED OCI?

A. The accumulated OCI must be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and commodity contracts cash flow hedges. None of the accounting entries that affect accumulated OCI have anything to do with financing the rate base of the Company (i.e., they do not generate or consume any cash). A MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. As such, MPL arises from changes in stock market values and interest rates, which impacts the value of the trust fund assets, as well as the present value of the pension benefit obligation. Due to the uncertainty associated with OCI, it should be excluded from the common equity.

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE ADOPTED FOR RATE OF RETURN PURPOSES IN THIS PROCEEDING?

A. Since rate-setting is prospective, the rate of return should consider conditions that will exist during the period of time the proposed rates will be effective. I, therefore, propose the test year-end capital structure ratios of 39.44% long-term debt 5.51% short-term debt, and 55.05% common equity. These ratios are appropriate because CUC provides all investor-provided capital to the Company. As such, the Commission should establish new rates using these ratios. Adjustments for deferred income taxes would be required for applications to the rate base.

COST OF SENIOR CAPITAL

Q. WHAT COST RATE HAVE YOU ASSIGNED TO THE DEBT PORTION OF THE COMPANY'S CAPITAL STRUCTURE?

A. The determination of the cost of debt is essentially an arithmetic exercise. This is due to the fact that CUC has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, the actual embedded cost of long-term debt was 3.58% at December 31, 2021. The embedded cost of long-term debt is expected to be 3.46% at December 31, 2023, as shown on page 3 of Schedule 6. The details leading to the development of the individual effective cost rates for each series of long-term debt are shown on page 3 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates to the present value of the interest and principal payments with the net proceeds of the bond. That is to say, the effective cost rate is the internal rate of return ("IRR") that equates the present value of all future interest and principal payments with the net proceeds of the bond.

For this analysis, I adopted the 3.46% embedded cost of long-term debt for rate of return purposes, because the 3.46% long-term debt cost rate is directly associated to the amount of long-term debt shown on Schedule 5 and provides the basis for the 39.44% long-term debt ratio.

Q. THE COMPANY HAS FORECAST NEW ISSUES OF LONG-TERM DEBT FOR CUC IN DECEMBER 2022. IS THE RATE OF INTEREST ON THE NEW LONG-TERM DEBT FINANCING REASONABLE?

A. Yes. For the December 2022 new issue by CUC, the Company has forecast a rate of 4.00%. The Company is proposing a fifteen-year term for its proposed new issues of long-term debt. This rate is reasonable based upon the forecast contained in the Blue Chip Financial Forecasts, which I will describe below. Blue Chip provides a consensus forecast of future interest rates. According to Blue Chip, the consensus yield on thirty-year Treasury bonds is forecast to be 2.7% for the fourth quarter of 2022 (see page 2 of Schedule 14). Adding to that yield the interest rate spread of 1.25% related to A-rated public utility bonds that I will describe below, the Blue Chip derived yield would be 3.95% (i.e., 2.7% + 1.25%). Since the

Company's NAIC rating is" 2a," a higher rate would be required for this proposed issue. Hence, 4.00% is reasonable.

Q. WHAT COST RATE FOR SHORT-TERM DEBT HAS BEEN PROPOSED IN THIS CASE?

A. The forecast interest rate for short-term debt would be 3.30%. This is derived based on the forecasted general trend toward higher short-term debt interest rates. The forecast London Interbank Offered Rate ("LIBOR") rate is 2.4179%. The resulting cost rate for CUC's short-term borrowings is: LIBOR forecast of 2.4179% + spread of 0.7000% over the LIBOR rate + $180,000 commitment fee, which represents 0.09% of the unused portion of the $200 million of the borrowing capacity.

Therefore, the forecasted interest rate for short-term debt would be 3.30% (2.4179% + 0.7000% + 0.1821%), which reflects the 0.70% margin that the Company is required to pay under its short-term credit facility that exceeds LIBOR plus the commitment fee on unused borrowings.

COST OF EQUITY – GENERAL APPROACH

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE COST OF EQUITY FOR THE COMPANY.

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

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the company. It is for this reason that I have used more than one method to measure the CUC's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity in the range of 10.75% to 11.75% for the CUC and FPUC.

DISCOUNTED CASH FLOW

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on Schedule 1, page 2, for the Gas Group. Excluding flotation costs, the DCF return is 11.65% with the leverage adjustment and 10.20% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below. Flotation costs add 0.17% to the returns noted above.

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

Q. WHAT IS THE DIVIDEND YIELD COMPONENT OF A DCF ANALYSIS?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended February 2022, the monthly dividend yields

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

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

For the twelve months ended February 2022, the average dividend yield was 3.22% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.33% and 3.16%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.33% for the Gas Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different, but generally-accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7.[7] This adjustment adds twelve basis points to the six-month average historical yield, thus producing the 3.45% adjusted dividend yield for the Gas Group.

[7] These adjustments are the 1/2 growth approach, the discrete approach, and the quarterly approach. Under the 1/2 growth approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0) results in this third DCF formulation.

Q. WHAT FACTORS INFLUENCE INVESTORS' GROWTH EXPECTATIONS?

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

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

Q. HOW DID YOU DETERMINE AN APPROPRIATE GROWTH RATE?

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

Q. WHAT DATA FOR THE GAS GROUP HAVE YOU CONSIDERED IN YOUR GROWTH RATE ANALYSIS?

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. I used the historical growth rates from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

Q. IS A FIVE-YEAR INVESTMENT HORIZON ASSOCIATED WITH THE ANALYSTS' FORECASTS CONSISTENT WITH THE TRADITIONAL DCF MODEL?

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

Q. WHAT ARE THE ANALYSTS' FORECASTS OF FUTURE GROWTH THAT YOU CONSIDERED?

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

Q. WHAT ARE THE PROJECTED GROWTH RATES PUBLISHED BY THE SOURCES YOU DISCUSSED?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (4.83%), Zacks (6.00%), and Value Line (7.44%).

Q. ARE CERTAIN GROWTH RATE FORECASTS ENTITLED TO GREATER WEIGHT IN DEVELOPING A GROWTH RATE FOR USE IN THE DCF MODEL?

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

Q. WHAT GROWTH RATE DO YOU USE IN YOUR DCF MODEL?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 4.83% to 7.44%. DCF growth rates should not, however, be established by mathematical formulation, and I have not done so.

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

In my opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. ARE THE DIVIDEND YIELD AND GROWTH COMPONENTS OF THE DCF ADEQUATE TO ACCURATELY DEPICT THE RATE OF RETURN ON COMMON EQUITY WHEN IT IS USED TO CALCULATE A UTILITY'S WEIGHTED AVERAGE OVERALL COST OF CAPITAL?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 40.89% long-term debt, 0.45% preferred stock, and 58.66% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. WHAT IS A LEVERAGE ADJUSTMENT?

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

Q. WHY IS A LEVERAGE ADJUSTMENT NECESSARY?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations, using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[9] provide a return of 7.70% when applicable to a capital structure with 100% common equity.

Q. ARE THERE SPECIFIC FACTORS THAT INFLUENCE MARKET-TO-BOOK RATIOS THAT DETERMINE WHETHER THE LEVERAGE ADJUSTMENT SHOULD BE MADE?

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

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common

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

for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins.

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

Q. IS THE LEVERAGE ADJUSTMENT THAT YOU PROPOSE DESIGNED TO TRANSFORM THE MARKET RETURN INTO ONE THAT IS DESIGNED TO PRODUCE A PARTICULAR MARKET-TO-BOOK RATIO?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P+g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.70%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.88% to compensate investors for the risk of a 51.27% debt ratio and 0.07% for a 1.73% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 11.65% (7.70% + 3.88% + 0.07%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.45% dividend yield, the 6.75% growth rate, and 1.45% for the leverage adjustment in order to arrive at the same 11.65% (3.45% + 6.75% + 1.45%) return. I know of no means to mathematically solve for the 1.45% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.45% adjustment is merely a convenient way to compare the 11.65% return computed using the Modigliani & Miller[10] formulas to the 10.20% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF shown on Schedule 1, page 2) based on a market-value capital structure. A 10.20% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case,

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[10] Franco Modigliani and Merton H. Miller, The Cost of Capital, Corporation Finance, and the Theory of Investments, American Economic Review, June 1958, at 261-297. Franco Modigliani and Merton H. Miller, Taxes and the Cost of Capital: A Correction, American Economic Review, June 1963, at 433-443.

lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. PLEASE PROVIDE THE DCF RETURN BASED UPON YOUR PRECEDING DISCUSSION OF DIVIDEND YIELD, GROWTH, AND LEVERAGE.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs (flot.), as shown on Schedule 11. In developing the flotation cost adjustment factor, I reduced the 3.9% issuance and selling expenses shown on Schedule 11 to 1.5%. I did this because I applied the adjustment factor (i.e., 1.000 + 0.015) to the entire DCF return, rather than to just the dividend yield component. The resulting DCF cost rate is 11.82%, computed as follows:

	D_1/P_0	+	*g*	+	*lev.*	=	*k*	x	*flot.*	=	*K*
Gas Group	3.45%	+	6.75%	+	1.45%	=	11.65%	x	1.015	=	11.82%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.17% (11.82% - 11.65%) to the rate of return on common equity for the Gas Group. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. PLEASE DESCRIBE YOUR USE OF THE RISK PREMIUM APPROACH TO DETERMINE THE COST OF EQUITY.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium in order to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule 1, page 2. That result is 10.75%, excluding flotation costs.

Q. WHAT LONG-TERM PUBLIC UTILITY DEBT COST RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSIS?

A. In my opinion, and as I will explain in more detail further in my testimony, a 4.00% yield represents a reasonable estimate of the prospective yield on long-term, A-rated public utility bonds.

Q. WHAT HISTORICAL DATA ARE SHOWN BY THE MOODY'S DATA?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 12, page 1. For the twelve months ended

February 2022, the average monthly yield on Moody's index of A-rated public utility bonds was 3.20%. For the six- and three-month periods ended February 2022, the yields were 3.20% and 3.38%, respectively. During the twelve months ended February 2022, the range of the yields on A-rated public utility bonds was 2.95% to 3.68%. Page 2 of Schedule 12 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 12, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.10% on a twelve-month average basis, 1.18% on a six-month average basis, and 1.31% on a three-month average basis. With these data, 1.25% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. WHAT FORECASTS OF INTEREST RATES HAVE YOU CONSIDERED IN YOUR ANALYSIS?

A. I have determined the prospective yield on A-rated public utility debt by using the <u>Blue Chip Financial Forecasts</u> ("<u>Blue Chip</u>") along with the spread in the yields that I describe below. <u>Blue Chip</u> is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, <u>Blue Chip</u> stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on March 1, 2022, and a yield spread of 1.25%, derived from historical data.

Q. HOW HAVE YOU USED THESE DATA TO PROJECT THE YIELD ON A-RATED PUBLIC UTILITY BONDS FOR THE PURPOSE OF YOUR RISK PREMIUM ANALYSES?

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

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2022	First	3.2%	3.9%	2.2%	1.25%	3.45%
2022	Second	3.4%	4.2%	2.5%	1.25%	3.75%
2022	Third	3.7%	4.4%	2.6%	1.25%	3.85%
2022	Fourth	3.9%	4.6%	2.7%	1.25%	3.95%
2023	First	4.0%	4.8%	2.9%	1.25%	4.15%
2023	Second	4.1%	4.9%	3.0%	1.25%	4.25%

Q. ARE THERE ADDITIONAL FORECASTS OF INTEREST RATES THAT EXTEND BEYOND THOSE SHOWN ABOVE?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2021, publication Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2022-2026	4.40%	5.20%	3.40%
2027-2031	4.90%	5.70%	3.80%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 4.00% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions. Recent FOMC pronouncements have moved the forecasts of interest rates to higher levels.

Q. WHAT EQUITY RISK PREMIUM HAVE YOU DETERMINED FOR PUBLIC UTILITIES?

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

Common Equity Risk Premiums	
Low Interest Rates	6.81%
Average Across All Interest Rates	5.93%
High Interest Rates	5.05%

Based on my analysis of the historical data, the equity risk premium was 6.81% when the marginal cost of long-term government bonds was low (i.e., 2.80%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 5.05%. Over the entire spectrum of interest rates, the equity risk premium was 5.93% when the average government bond yield was 4.92%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums (i.e., 6.81%) associated with low interest rates (i.e., 2.80%).

Q. WHAT COMMON EQUITY COST RATE DID YOU DETERMINE BASED ON YOUR RISK PREMIUM ANALYSIS?

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

	i	+	***RP***	=	***k***	+	***flot.***	=	***K***
Gas Group	4.00%	+	6.75%	=	10.75%	+	0.17%	=	10.92%

CAPITAL ASSET PRICING MODEL

Q. HOW IS THE CAPM USED TO MEASURE THE COST OF EQUITY?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 14.41%, excluding flotation costs, for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 12.57% (14.41% - (0.18 x 10.23%)). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. WHAT BETAS HAVE YOU CONSIDERED IN THE CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.86 for the Gas Group.

Q. DID YOU USE THE VALUE LINE BETAS IN THE CAPM DETERMINED COST OF EQUITY?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[11] as follows:

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

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above

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

and the capital structure ratios measured at market value, the beta would become 0.55 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.04 for the book value capital structure of the Gas Group.

Q. WHAT RISK-FREE RATE HAVE YOU USED IN THE CAPM?

A. As shown on page 1 of Schedule 14, I provided the historical yields on Treasury notes and bonds. For the twelve months ended February 2022, the average yield on 30-year Treasury bonds was 2.09%. For the six- and three-months ended February 2022, the yields on 30-year Treasury bonds were 2.02% and 2.07%, respectively. During the twelve months ended February 2022, the range of the yields on 30-year Treasury bonds was 1.85% to 2.34%. The low yields that existed during 2020 can be traced to extraordinary events associated with the Covid-19 Pandemic that jolted the capital markets. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the FOMC acted to address these disruptions. The FOMC continued to support the money and capital markets during the recovery from the Pandemic. A transition is now taking place that will prospectively produce higher interest rates as the Pandemic nears its end and the FOMC ends it quantitative easing. That program ended in March 2022 and a Fed Funds rate increase of 0.25% occurred at that time. While interest rates have moved up generally, there has been a ”flight” to safety in Treasury obligations due to geopolitical turmoil in Europe. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2023 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by a 5.9% increase in Social Security payments announced on October 13, 2021, which is the largest one-year increase in nearly four decades. The Fed Funds rate is expected to continue to increase from very low levels that existed during the Covid-19 Pandemic. Higher interest rates clearly point to higher capital costs prospectively.

As shown on page 2 of Schedule 14, forecasts published by Blue Chip on March 1, 2022, indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.2% to 3.0% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.4% from 2023 through 2027 and 3.8% from 2028 to 2032. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 2.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. WHAT MARKET PREMIUM HAVE YOU USED IN THE CAPM?

A. As shown in the lower panel of data presented on Schedule 14, page 2, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 13, page 1. On that schedule, the market return was 12.09% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.80% when interest rates were low. As such, I carried over to Schedule 14, page 2, the average large common stock returns of 12.09% and the average yield on long-term government bonds of 2.80%. The resulting market premium is 9.29% (12.09% - 2.80%) based on historical data, as shown on Schedule 14, page 2. As also shown on Schedule 14, page 2, I calculated the forecast returns, which show a 13.91% total market return. With this forecast, I calculated a market premium of 11.16% (13.91% - 2.75%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 10.23% (11.16% + 9.29% = 20.45% ÷ 2).

Q. ARE THERE ADJUSTMENTS TO THE CAPM THAT ARE NECESSARY TO FULLY REFLECT THE RATE OF RETURN ON COMMON EQUITY?

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

Q. WHAT DOES YOUR CAPM ANALYSIS SHOW?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 1.04 for the Gas Group, the 10.23% market premium, the 1.02% size adjustment, and the flotation cost adjustment, the following result is indicated.

	Rf	+	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	=	***k***	+	***flot.***	=	***K***
Gas Group	2.75%	+	1.04	x (	10.23%	) +	1.02%	=	14.41%	+	0.17%	=	14.58%

<u>COMPARABLE EARNINGS APPROACH</u>

Q. WHAT IS THE COMPARABLE EARNINGS APPROACH?

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

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

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

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

Q. DID YOU COMPARE THE RESULTS OF YOUR DCF AND CAPM ANALYSES TO THE RESULTS INDICATED BY A COMPARABLE EARNINGS APPROACH?

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

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on Schedule 15, page 2, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. WHAT DATA DID YOU CONSIDER IN YOUR COMPARABLE EARNINGS ANALYSIS?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 11.5% using only the returns that were less than 20%, as shown on Schedule 15, page 2. The average forecasted rate of return as published by Value Line is 12.6% also using values less than 20%, as provided on Schedule 15, page 2. Using the average of these data, my Comparable Earnings result is 12.05%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S COST OF COMMON EQUITY?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.75% to 11.75% for FPUC and the Florida division of CUC. It is essential that the Commission consider a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize a 10.75% to 11.75% rate of return on common equity so that it can compete in the capital markets and retain reasonable credit quality.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

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

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

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

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

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

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

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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

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

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

BY MS. KEATING:

Q And, Mr. Moul, did you also cause to be prepared and filed Exhibit PRM-1?

A Yes, I did.

Q Do you have any changes to that exhibit?

A There are no changes that I am aware of at this time.

MS. KEATING: Mr. Chairman, I believe Mr. Moul's exhibit has already been marked on the Comprehensive Exhibit List as No. 12.

CHAIRMAN FAY: Yes.

MS. KEATING: Okay.

BY MS. KEATING:

Q Mr. Moul, did you prepare a summary of your testimony?

A I did.

Q Would you please go ahead and present that?

A Yes.

Good morning, Chairman and Commissioners. My name is Paul Moul, and I am here today to provide the Commission with evidence of cost of capital for Florida Public Utilities and its affiliates. As you know, the cost of equity is only one of the components of the company's overall rate of return, which is made up of both debt and equity. The cost of equity represents the return that is necessary to a attract investors and maintain the company's credit.

Unlike many items that comprise the company's cost to serve its customers, the cost of equity involves the application of considerable judgment. Due to the judgment involved in this analysis, I have used a variety of financial models to estimate investor return requirements, including the discounted cash flow model, the risk premium approach, the capital asset pricing model and the comparable earnings approach.

I have used these models to system estimate the returns needed to attract and retain investors to the company because the cost of equity is not directly observable from the sort of financial and stock market information that you would normally find in the morning newspaper or on the internet.

While these models seem to be very precise, the fact is that they use simplifying assumptions to describe investor behavior. This may be one reason why many commissions tend to consider multiple models in setting the cost of equity.

It is worth pointing out that the DCF model is particularly susceptible to producing results that can be counterintuitive. To base the costing of equity on DCF alone would lead -- or could lead to a perverse outcome.

In my analysis, I have used a proxy group of eight natural gas utilities that have stock that is traded to measure the company's cost of equity. Traded stock prices are necessary to apply the four models of the cost of equity that I noted previously.

I used the results of the equity models to arrive at a range of 10.75 percent to 11.75 percent as the cost of equity for the company, which is undoubtedly understated because the company's return is affected by its relatively small size. The proxy group companies that I had were very much larger than the company here.

For capital structure ratio purposes, I employed the ratios of CUC, Chesapeake Utilities Corporation, because it is the source of the investor provided capital for the company and because those ratios are reasonable. My determination in this regard is confirmed by the common equity ratio of my proxy group companies, hence the company's 55.05 common equity ratio is within the range and is region.

And I thank the Commission for this opportunity to present my evidence of the cost of equity for the company.

Q Thank you, Mr. Moul.

MS. KEATING: Mr. Chairman, the witness is tendered for cross.

CHAIRMAN FAY: Thank you.

Ms. Christensen, whenever you are ready.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning -- good morning, Mr. Moul.

A Good morning.

Q Do you have a copy of your direct testimony in front of you?

A I do.

Q Okay. And just one quick question. In creating your DCF and other models that you used to forecast what you thought was an appropriate ROE, you chose the proxy group, correct?

A Yes. They spun the criteria I set forth in my testimony.

Q Okay. And you chose that proxy group to be application reasonable representation for CUC for the purposes of forecasting ROE, correct?

A I did.

Q Okay. Let me turn your attention to page eight of your direct testimony.

A I have that.

Q Okay. Great.

On page eight of your direct testimony, you

summarize the results of the cost of equity models that you used in this case, is that correct?

A Yes.

Q Okay. And those models include the DCF model, Risk Premium model, the CAPM model and the Comparative Earnings model, both with and without floatation costs, is that correct?

A Yes. I call that last one comparable earnings.

Q Okay. And on lines 14 and 15, you state that you are recommending 11.25 percent ROE based on the midpoint cost of equity, is that right?

A Yes. That value is the midpoint of my range.

Q Okay. So is it true that the results of each of the cost of equity models you conducted have -- are having an impact on your overall ROE recommendation?

A Oh, that's true. I considered the results of each of the four models in coming up with my range.

Q Okay. Do you have an idea of what the national average of awarded ROEs for gas companies is in the U.S. currently?

A I have not looked at that recently. That was not part of my analysis. My analysis based -- is based upon the investor required returns and not returns established in other jurisdictions and other gas rate cases.

Q Okay. But do you recall discussing that the national average awarded ROE for gas utilities in the United States currently is 9.33 percent?

A That is a number that was discussed during my deposition based upon an RRA report. I don't believe that the Commission should place any weight on that because of the infirmities associated with that particular tabulation. The problem with that tabulation is --

Q I --

A I am sorry. I sort of strayed there.

Q Yeah.

I just want to know -- so am I -- based on your response, you agree that that number of 9.33 percent, based on the RRA report, was discussed as part of your deposition as -- and represented as the national average awarded ROE for gas utilities in the United States, correct?

A Yes. But we don't know how many --

Q Okay.

A -- returns were in that tabulation, nor do -- was it discussed which jurisdictions were considered there.

Q Okay. Would you agree that the results of

your cost of equity models are notably higher than the national average of awarded ROEs for gas utilities as presented in the RRA report of 9.33 percent?

A Oh, I clearly agree that my analysis shows that investors require a higher return than what's shown in that RRA report, because that RRA report is not a report that is representative of what investors require in the gas business today.

Q But you are aware that the RRA report is a compilation essentially of what ROEs have been awarded to gas companies throughout the United States, correct?

A Yes. It's backward looking, and what we are doing here is setting the rate of return for the test period that is forward-looking. So we have a disconnect between the RRA report and what we are trying to do here today to come up with a reasonable return that investors require.

Q Let me turn your attention to page 25 of your direct testimony. And in this section of your testimony, you are discussing your DCF results and your analysis, correct?

A Yes. That's what I report there.

Q And you have included a floatation cost and a leverage adjustment to your DCF results, is that correct?

A I did. And I showed my results with and without those adjustments.

Q Okay. And with both those -- these adders, the flotation cost and the leverage adjustment, your DCF result is 11.82 percent, correct? And that you can find on -- if you look to page eight, if you need to confirm that number.

A You have confused me here. I thought we were on page 25.

Q We are on page 25, but if I can turn your attention back to page eight if you need to confirm that number for yourself.

A 11.82 with all of those adjustments on page 25 I give you the results -- well, actually page 24 and 5 -- 25 without those adjustments.

Q Okay. And if you remove the .17 percent floatation adder, your DCF results in an 11.65 percent, is that correct?

A Correct.

Q And without either the floatation adder or the leverage adder, your DCF result would be 10.2 percent, is that correct?

A Correct.

Q And you would agree that the 10.2 percent DCF result that you would have without either the floatation

or the leverage adders is closer to the national average of awarded ROEs for natural gas companies of 9.33 percent?

A Well, it's -- it's the lowest of the numbers that we just talked about, and it's closer to the -- to the return that we discussed in an earlier question. Sure, I agree with that.

Q Okay. Looking at your Risk Premium model, your result without the floatation cost is 10.75 percent, is that correct?

A Yes.

Q And isn't it true that most risk premium models use the 30-year treasury bond interest rate instead of the A rated public utility forecasted rate in their analysis of risk premium?

A No, I don't agree with that, because what you are describing is the risk-free rate we used in the CAPM, which is a separate model -- an additional model. The risk premium is based upon A rated public utility bond yields.

Q Well, let's go forward and look at your CAPM model results.

According to your CAPM, the cost of equity for FPUC is 14.41 percent, is that correct?

A Yes. That includes the leverage adjustment and a size adjustment. Correct.

Q Right. But that excludes floatation costs?

A Correct.

Q And just for the sake of comparison at this point, do you recall that Mr. Garrett's CAPM cost of equity estimate was 7.9 percent?

A I will have to go back and check that, but that sounds about right.

Q Okay. Now, am I correct that there are three main inputs to the CAPM, which are the risk-free rate, beta and the equity risk premium?

A Yes, those are the basic Sharpe-Litner components of the CAPM. We talked a second ago about additional factors that should be considered, such as leverage and size. But those -- those are the key inputs that you just described.

Q And is it also true that increasing any of these inputs will have an increasing affect on the CAPM results?

A Sure, I agree with that. And a decrease would work the other way. Sure.

Q And you show those inputs into your CAPM model on page 48 of your direct testimony, is that correct? I will give you a second to get there.

A I do.

Q Okay. Regarding -- I am going to look at two of the inputs, specifically the beta and the equity risk premium.

Regarding the beta -- excuse me -- beta, you state the average beta for the proxy group, according to Value Line, is 0.86 percent. And if you need a reference, that's page 44, line a five of your direct testimony, correct?

A Yes, that's correct. That's the beginning point of the analysis before the leverage adjustment. I agree with that.

Q Okay. And now, is it also correct that the market beta is equal to zero?

A 1.00, correct.

Q In other words, if we essentially average the beta of all stocks in the U.S. in the equity markets, it would equal abate a of 1.0?

A Well, I guess you can look at it that way. I don't look at it that way. The beta of 1.00 is the beta for stocks that move in the same magnitude as the market as a whole. That's the way I look at it. But I -- I -- I guess you could look at it the way you described.

Q Okay. And would you agree that it is generally correct that a higher beta means the stock is riskier in the terms of the market risk?

A Yes. When looking solely at systematic risk, the only thing beta does is measure systematic risk for a particular company. How your stock behaves relative to the rest of the market. And that's -- that's a very narrow, specific measure of risk, and they call it systematic risk. Everything else is unsystematic risk, which is the business risk of the company, its capital structure, all those company specific risks are not reflected in the beta.

Q Okay. But I think -- I think you have answered my question, maybe gone a little bit farther than the question was.

And generally speaking, a higher market risk would equate to a higher cost of equity, is that a fair statement?

A Correct. Under the CAPM, looking solely at systematic risk, I agree with that.

Q So by Value Line publishing an average beta of only 0.86 percent for the proxy group, Value Line is essentially saying that the proxy group is less risky than the overall market, which has a beta of point -- or 1.0, correct?

A Yes. Again, this is strictly solely based on systematic risk. All the rest of the risks that a particular company are faced with are not captured by that measure.

Q Okay. But you reject the Value Line betas, and instead, use a considerably higher beta of 1.04, isn't that correct?

A Well, if I heard your question correctly, I would say that I disagree with that. I did not reject the Value Line beta. What I did, I took the Value Line beta and made a leverage adjustment using a modified formula. I didn't reject the Value Line beta, I used it and modified it.

Q Okay. So you didn't use the Value Line determined beta as it was stated in Value Line. You essentially created -- you leveraged it, and in leveraging it, you increased the beta, correct?

A I agree with that.

Q And increasing the beta, essentially what you are doing is increasing the risk profile of the company, correct?

A No. What I am trying to do is to align the beta with the capital structure we used to set rates.

Q Okay.

A All I did was take the Value Line beta and align it with the methodology we used to calculate it the weighted average cost of capital in a rate case. That's all did I.

Q Okay. So -- but you did not use the beta that was set for the proxy companies by Value Line, correct?

A That's correct, because that beta is not properly aligned with the capital structure we used to set rates in this proceeding.

Q Would you agree that the risk premium -- well, I am going to talk about your Risk Premium model right now. Would you agree that the equity risk premium is -- or I am sorry, let me back that up. Now I am going to focus on the equity risk premium input into the CAPM model.

Would you agree that the equity risk premium is an essential input into the CAPM?

A I guess we are having -- we are struggling with terminology here.

If we are still -- if we are still talking about the CAPM, I would refer to what I believe we are discussing here as the market premium. It's the market risk premium. It's what the market requires over and above the risk-free rate of return.

Q All else held constant, a higher equity risk premium estimate would result in a higher cost of equity estimate produced by the CAPM, you would agree with that?

A I do.

Q And you used an equity risk premium of 10.23 percent in your CAPM, is that correct?

A Yes, but let's stick with my terminology, if we could. I call that the market risk premium.

Q And in the formula, what do those symbols represent? Is that considered an equity risk premium in the model?

A Well, the way I express the market risk premium is RM minus RF, which is the return on the market less the risk-free rate of return.

Q Okay. Let's ask -- for sake of comparison, do you recall Mr. Garrett used an equity risk premium of 5.6 percent?

A I believe that's probably the right number. I could go back and check that, but it sounds right.

Q Okay. As part of your equity risk premium estimate, did you consider the results published by reputable analysts such as Duff & Phelps?

A No.

Q Do you recall from Mr. Garrett's testimony that Duff & Phelps recently published an equity risk premium estimate of only 5.5 percent?

A I could accept that subject to check. I have not looked at that publication. I couldn't say.

Q Okay. Is it fair to say that you are asking

the Commission to accept an equity risk premium estimate that's nearly twice as high as the one published by Duff & Phelps?

A What I am asking the Commission to do is base the determination of the cost of equity on what investors expect or require, which, in my analysis, is based upon an independent objective measure of the market risk premium. I did not rely on third-party estimates like what you are describing. I am basing my recommendation based upon an objective market-based approach, not results that somebody else published.

Q Okay. So you are not relying on a third party independent published result, is that what you are saying?

A No. I don't -- I don't think that's the proper way to apply the Capital Asset Pricing model. It's to utilize inputs that investors rely upon to develop their expectations.

Q Okay. As part of your risk -- or your equity risk premium analysis, did you consider any expert surveys?

A No.

Q Do you recall that Mr. Garrett's testimony did the IESE Business School conducted an expert survey that reported an average equities risk premium of only 5.6

percent?

A I think I remember that number; but for reasons I have just explained, that we should not be relying upon other studies where we don't know how they were conducted, the reliability of the results, and whether investors themselves rely upon those outcomes.

Q All right. So is it your opinion that experts who responded to the IESE expert survey have estimated an equity risk premium that's several hundred basis points lower than what the Commission should accept?

A I think the Commission should reject that approach because we do not know whether investors themselves rely upon those types of outcomes. It's -- those studies --

Q Okay.

A -- in my view, are obscure studies that are not widely relied upon by investors.

Q Okay. So let me ask you this: If the Commission accepted your equity risk premium recommendation of 10.23 percent, which equity risk premium estimates are investors more likely to rely on? The one published by Duff & Phelps, the one reported in the expert surveys, or a result adopted by the Commission that is nearly twice as high?

A What was my third choice? I am sorry.

Q The third choice was a result adopted by a commission that is twice as high as the otherwise published equity risk premiums?

A Well, I would urge the Commission to rely upon information that we know investors actually use. And the first two that you gave me, they are suspect. We don't know that investors use that information at all.

Q So you are saying they publish those results for no reason?

A Well, they are -- they are published for academic reasons, but we don't know that investors are using those results.

MS. CHRISTENSEN: I have no further questions.

CHAIRMAN FAY: Okay. Thank you.

Mr. Moyle?

MR. MOYLE: No questions.

CHAIRMAN FAY: Okay. Staff?

MR. SANDY: Yes, Mr. Chairman, I have a few questions.

EXAMINATION

BY MR. SANDY:

Q Good morning, Mr. Moul, how are you?

A Excellent. How are you?

Q I am doing very well. Thank you.

I would like to talk to you about your

leverage adjustment, or your proposed leverage adjustment in this rate case.

As a general principle, you would agree that as financial risk decreases, a return on equity would not increase?

A That's correct. Not only would not increase, it would go down as well. The return would go down with the reduction in the financial risk.

Q Okay. And the leverage adjustment that you are proposing in this particular rate case -- this rate case, actually increases ROE, is that right?

A It does, because the financial risk associated with the capital structure we used to set rates has more financial risk.

Q Okay. When evaluating a utility's credit risk, do rating agencies usually rely on a book value of the utility or market value?

A I would say they look at book values.

Q Okay. And on page 34 of your testimony, you state that your leverage adjustment is developed through precise mathematical calculations using well-recognized analytical procedures that are widely accepted in the financial literature, would you agree with me there?

A I do.

Q Okay. The literature in question, does any of

that have to do with regulated gas utilities?

A It was not derived specifically for regulated gas utilities. I would agree with that. It applies to any and all companies regardless of whether they are regulated or not.

Q Okay. Your answer, as I heard it, seemed a little broad, so let me just reask my question so I can make sure we are on the same page.

In regards to your proposed leverage adjustment, do any of the widely accepted financial literature that you cite reference regulated utilities?

A Not specifically. No.

Q Okay. Are you familiar with whether the Florida Public Service Commission utilizes leverage adjustments as the one you proposed in this rate case on regulated gas utilities?

A My understanding is the Commission uses leverage adjustments all the time. They do so in the water utility industry, where they have a formula that adjusts the return based upon the leverage a particular utility has. So the Commission has -- and they have been doing this for years -- has a very long history of making adjustments to the ROE for leverage variations.

Q Okay. Let me just underline my question, though. My question was specifically for regulated gas

utilities.

A   Oh, gas utilities. I am sorry. I misheard you.

Q   That's okay.

Ultimately, in regards specifically to regulated gas utilities, you would agree that the Commission does not utilize leverage adjustments as the one you have proposed in this rate case?

A   Well, the answer to your question is I really don't know, because I don't think the Commission has set an ROE for a gas utility for a very long time. I just don't know the answer to that.

Q   You don't know or you are not aware of any instances where the leverage adjustment has been used?

A   I would say both. I neither know or am aware. But I don't know that the Commission has addressed this issue for a gas utility in my memory.

Q   Okay. Are you aware of whether the Public Service Commission utilizes market capitalization in its analysis?

A   I do -- I do not believe they do that.

Q   Okay. Are you familiar with what original cost ratemaking is?

A   I am.

Q   Okay. Are you aware of whether the Commission

utilizes original cost in its analysis instead of market valuation?

A As a generalization, yes, but I was -- I have been sitting in the room now for a day, and I hear a lot of talk about acquisition adjustments, and that -- I don't know how that fits within the original cost regulation.

Q So if I understand your answer correctly, the answer is, yes, we utilize original cost analysis in lieu of market capitalization?

A Yes. You do use book values rather than market values in the determination, say, for instance, of the rate base. But I do think that you do make adjustments to that.

Q Okay.

A If I heard testimony of other witnesses in the room yesterday, I think you make other adjustments.

Q Okay. And in terms of the adjustment you are proposing with this leverage adjustment, in essence, this adds approximately 145 basis points on the return on common equity, is that right?

A Yes.

Q Okay. And if we could put some hard numbers on this. Assuming that 100 basis points in this proceeding equals out to about 2.3 million, which is a

little bit of back-of-the-envelope math, I will admit, is it fair too say that your leverage adjustments adds something to the tune of about three-and-a-half million on the ROE?

A I can accept that subject to check. I haven't done that math.

Q I completely understand.

And isn't it ultimately your contention, then, that your adjustment of the 145 basis points would be unnecessary ultimately in this proceeding if the Commission utilized market capitalization in lieu of original cost valuation?

A I agree with that.

Q Okay. Wouldn't a market capitalization analysis potentially result in a windfall of gains or losses for the shareholders of the utility if the Commission went that route?

A I don't think I would use that terminology. I mean, what it would do is align the returns with investor expectations, because they are the ones that determine what the capitalization is based on market values.

I mean, you buy and sell stocks and market value. You don't buy and cell stocks at book value. Well, I mean, you could if book value equaled market price, but investors buy securities based on market values, not book values.

Q A utility's stock price is -- may fluctuate with the markets due to factors other than the financial fundamentals of the company, you would agree with me there?

A I agree with that.

Q It may be things such as irrational exuberance?

A I agree with that too.

Q There may be market manipulation at play?

A Well, I don't know about market manipu -- I can't say it -- market manipulation.

Q Sure.

A That's a tough one.

Q I understand.

A Certainly the market today is being significantly impacted by program trading. There is lots of algorithms out there that are causing the market to go up, down, whatever it's doing, based upon computer programs. I wouldn't call that mani -- I can't say it, manipulation, but certainly there is other things going on. Sure.

MR. SANDY: Okay. No further questions at this time, Mr. Chairman.

CHAIRMAN FAY: Okay. Great. Thank you, Mr. Sandy.

MR. SANDY: Yes, sir.

CHAIRMAN FAY: Commissioners?

Commissioner Clark, you are recognized.

COMMISSIONER CLARK: Thank you, Mr. Chairman. Thank you, Mr. Moul. I promise you my line of questioning will be a little simpler than that you have heard so far today.

Just an observation I would like for you to comment on in regards to your recommendation on ROE. The recent movements in the market, the economy, the stock market, interest rates, how has that affected the recommendation you are making? And let me caveat that with, had we been in for this rate case 12 months ago under different market conditions, how would that have affected the ROE that you are recommending?

THE WITNESS: Well, if we had filed this earlier, the recommendation probably would have been lower. And if we were filing it today, it would be higher, because interest rates have moved up quite dramatically this year.

So a lot of my evidence here, I think, ran through February. And we were just at the -- at the very threshold of the increases that the FOMC, the fed, has implemented, which is driven up interest rates. So we have a -- we have but a very small part of the increase in the cost of capital reflected in this particular recommendation.

In response to your question, if we had filed earlier, it would have been lower. If we were filing today or next month, or whenever, it would have been higher.

COMMISSIONER CLARK: And that just kind of plays along with Ms. Christensen -- Ms. Christensen's line of questioning regarding the studies that have been -- that are published about what the average ROEs are. In your opinion, what time period would the current published studies cover?

THE WITNESS: Oh, all those studies are based upon analysis -- I haven't looked at the studies. My questions is the studies probably ran through 2020 or 2021, at best.

My approach looks at requirements -- well, today, I mean, back in February, when I put this thing together. So my approach is much more contemporaneous with what's going on in the market. Those studies are applicable to past periods, which may or may not reflect today's fundamentals.

COMMISSIONER CLARK: Thank you, sir.

CHAIRMAN FAY: Great. Thank you, Commissioner Clark.

Let's see, next redirect?

MS. KEATING: No redirect, Mr. Chairman.

CHAIRMAN FAY: Okay. And I believe we have Exhibit 12 to enter into the record for Mr. Moul without objection.

MS. KEATING: Thank you.

CHAIRMAN FAY: Show that entered.

(Whereupon, Exhibit No. 12 was received into evidence.)

CHAIRMAN FAY: And I do believe Mr. Moul is coming back for rebuttal.

MS. KEATING: That's correct.

CHAIRMAN FAY: Excuse your witness for now?

MS. KEATING: Yes, Mr. Chairman.

CHAIRMAN FAY: All right. Mr. Moul, we will see you back for rebuttal.

THE WITNESS: Thank you.

CHAIRMAN FAY: Ms. Keating, you are welcome to call your next witness.

MR. MUNSON: At this time, Mr. Chairman, FPUC calls Mike Reno, please.

Whereupon,

MICHAEL RENO

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. MUNSON:

Q Good morning, Mr. Reno. How are you?
A I am good. Thank you.
Q Good.
Can you please state your full name for the record?
A Michael Reno.
Q And who do you work for and what do you do there?
A I am a managing director with Ernst & Young's National Energy Practice.
Q And on whose behalf are you appearing in this proceeding?
A I am here on behalf of Florida Public Utilities.
Q And can you please provide your business address for the record, please?
A Yes. My address is 1101 New York Avenue NW, Washington, DC, 20005.

Q Very good.

And did you have 14 pages of direct testimony filed in this case?

A I did.

Q And did you have any exhibits in this case?

A I do not.

Q Do you have any changes to your testimony in this case, Mr. Reno?

A I do not.

MR. MUNSON: Mr. Chairman, at this time, we would move Witness Reno's direct testimony into the record as if read.

CHAIRMAN FAY: Okay. Show that entered.

(Whereupon, prefiled direct testimony of Michael Reno was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA PUBLIC UTILITIES COMPANY

Docket No. 20220067-GU

Direct Testimony

of

Michael J. Reno,
Ernst & Young, LLP

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Michael Reno. I am a managing director in Ernst & Young LLP's National Energy Practice. My business address is 1101 New York Avenue, NW, Washington, District of Columbia, 20005-4213.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Florida Public Utilities Company.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I graduated from Kansas State University in 1987 with a Bachelor of Science degree in Business Administration, with an emphasis in accounting, and a Master of Science in 1988, with an emphasis in accounting. After completion of my Master of Science in Accounting, I joined Deloitte Tax LLP, formerly Deloitte Haskins & Sells. In 2012, I joined Ernst & Young LLP as an executive director in the National Energy Practice. I am a Certified Public Accountant, licensed in the District of Columbia and in the Commonwealth of Virginia. I have practiced public accounting for over 32 years. In my practice, I provide tax services to regulated water, electric and gas utilities. I regularly assist clients with tax planning, support and explain tax reporting positions, and perform tax return reviews. My experience includes providing advice on accounting for income taxes and performing tax provision reviews. I also regularly consult with companies regarding tax accounting and its impact on the rate setting process as well as compliance with the normalization rules. Additionally, I am a frequent speaker at industry seminars and conferences on the topic of tax accounting for rate-regulated utilities. I have spoken at the Edison Electric Institute tax committee meetings and the American Gas Association tax committee meetings in addition to other industry meetings.

Q. HAVE YOU TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes, I have testified on tax, tax accounting and regulatory tax matters before the Florida Public Service Commission, New Jersey Board of Public Utilities, the California Public Utilities Commission, the Connecticut Public Utilities Regulatory Authority, Michigan Public Service Commission, and the Federal Energy Regulatory Commission.

II. <u>PURPOSE OF TESTIMONY</u>

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

A. The purpose of my testimony is to explain how the accumulated deferred income tax ("ADIT") balances included as a component of Florida Public Utilities' capital structure for the purposes of its general rate case filing comply with the normalization method of accounting as defined in Internal Revenue Code "IRC" 168(i)(9). I will also provide support for the calculation of income tax expense included as a component of Florida Public Utilities Company's cost of service.

III. THE NORMALIZATION METHOD OF ACCOUNTING

Q. CAN YOU PLEASE PROVIDE BACKGROUND ON WHAT TRIGGERS AN ADIT BALANCE ON THE BOOKS AND RECORDS OF A REGULATED COMPANY?

A. ADIT arises from timing differences between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes. Generally, ADIT represents the accumulation of deferred tax liabilities recorded on the balance sheet that captures the tax amount attributable to temporary differences, driven by the different income recognition requirements for tax reporting purposes and for financial statement or book accounting purposes.

Q. WHY DOES CONGRESS REQUIRE A PUBLIC UTILITY TO USE THE NORMALIZATION METHOD OF ACCOUNTING?

A. In 1954, Congress enacted a new tax law that provided for accelerated depreciation. The primary motive behind the introduction of accelerated depreciation was to provide a permanent investment incentive to business taxpayers. Because federal income tax expense is included in a utility's cost of service for ratemaking purposes, some regulatory agencies reduced the federal tax expense included in cost of service to reflect the reduction in a utility's tax liability caused by accelerated depreciation, i.e., some regulators "flowed through" the tax benefit associated with accelerated depreciation to ratepayers. As a result, the accelerated depreciation became a massive federal utility subsidy to ratepayers as opposed to an investment incentive for the utility. Moreover, the flow through of the benefits of accelerated depreciation to ratepayers resulted in a loss of federal income tax revenues because the flow-through reduced utility profits. To ensure that accelerated depreciation achieved its stated purpose, Congress enacted the normalization rules in 1969, which permit a utility to claim accelerated depreciation only if the utility complies with the normalization rules.

Q. DOES CONGRESS MANDATE THE USE OF THE NORMALIZATION METHOD OF ACCOUNTING?

A. Yes, IRC Sec. 168(f)(2) provides that "public utility property" does not qualify for accelerated depreciation if the taxpayer does not use a "normalization method of accounting." IRC Sec. 168(i)(10) defines "public utility property" as including property used predominantly in the trade or business of the furnishing or sale of gas through a local distribution system, and the transportation of gas by pipeline if a public utility commission or other similar body establishes the rates for such furnishing or sale. Therefore, while the Internal Revenue Code does not mandate any particular rate treatment, it does limit the ability to use accelerated depreciation unless the utility uses the normalization method of accounting.

Q. CAN YOU DEFINE THE NORMALIZATION METHOD OF ACCOUNTING?

A. Yes, IRC Sec. 168(i)(9) defines the general requirements a taxpayer must meet to be considered as using the normalization method of accounting. First, the taxpayer must use (i) the same method of depreciation to compute both its tax expense and its depreciation expense to establish its cost of service for ratemaking purposes and to reflect operating results in its regulated books of accounting, and (ii) a recovery period that is no shorter than the useful life is used in determining depreciation for ratemaking purposes. Second, the difference between the actual tax expense computed using tax depreciation and the tax expense determined for ratemaking purposes must be reflected in a deferred tax reserve. Third, in determining the rate of return of a public utility, the public utility commission may not exclude from the rate base an amount that exceeds the addition to the deferred tax reserve for the period used in determining the tax expense for ratemaking purposes. Fourth, the utility may not use an "inconsistent" procedure or adjustment. A procedure or adjustment is "inconsistent" if it employs an estimate or projection with respect to a utility's (i) tax expense, (ii) depreciation expense, or (iii) reserve for deferred taxes, unless such estimate or projection is also used with respect to the other two items and rate base. If a taxpayer fails to satisfy any one of these requirements, it ceases to qualify for accelerated depreciation, and must compute depreciation using the straight-line method over the asset's regulatory life.

Q. HOW DOES THE NORMALIZATION METHOD OF ACCOUNTING APPLY IN THE RATEMAKING CONTEXT?

A. A utility's federal income tax expense is an element of the utility's cost of service. The first requirement of the normalization rules requires the utility to calculate the federal income tax expense included in its cost of service using the same method of depreciation it uses for financial statement purposes, i.e. straight-line depreciation.

The difference between the utility's actual federal income tax expense and the federal income tax expense included in its cost of service related to the use of accelerated depreciation for federal income tax purposes is tracked in a deferred income tax reserve account, commonly referred to as an ADIT account. Typically, the use of accelerated depreciation results in a deferred income tax expense and a corresponding deferred income tax liability, i.e., the current federal income tax payable is less than the total federal income tax expense included in cost of service, which includes both current and deferred income taxes. The deferred tax expense associated with accelerated depreciation is equivalent to an interest free-loan from the Internal Revenue Service. Because a utility is not permitted to earn a rate of return on cost-free capital, the deferred tax liability reduces the utility's rate base or is included as zero-cost capital within the capital structure.

Q. DOES THE IRS REQUIRE THE USE OF A SPECIFIC METHOD UNDER THE NORMALIZATION RULES TO DETERMINE THE ADIT BALANCE THAT SHOULD BE EXCLUDED FROM RATE BASE?

Treasury Reg. Sec. 1.167-1(h)(6)(ii) provides the procedure for determining the amount of the reserve for deferred taxes to be excluded from rate base (i.e.., as no-cost capital). Section 1.167(l)-1(h)(6)(ii) provides if, in determining depreciation for ratemaking tax expense, a period (the "test period") is used which is part historical and part future, then the amount of the reserve account for this period is the amount of the reserve at the end of the historical portion of the period and a pro rata amount of any projected increase to be credited to the account during the future portion of the period.

The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period. This is generally referred to as "the proration formula" or the "proration methodology."

IV. THE APPLICATION OF THE PRORATION ADJUSTMENT TO FLORIDA PUBLIC UTILITIES COMPANY'S ADIT BALANCES FOR THE PURPOSES OF CALCULATING ITS RATE BASE

Q. CAN YOU DESCRIBE THE NATURE OF FLORIDA PUBLIC UTILITIES COMPANY'S ADIT BALANCES?

A. As mentioned previously, timing differences between the recognition of items of income or expense for tax purposes versus financial statement accounting purposes results in either a deferred tax asset or a deferred tax liability balance. Accelerated or bonus depreciation is the most common example of a temporary difference that generates a deferred tax liability. When accelerated depreciation is claimed by a taxpayer, the depreciation expense deduction during the beginning of the assets useful life is much larger than it is for financial statement reporting purposes. Because the recognition of this expense is only an issue of timing and not amount, this difference will eventually reverse over the course of the asset's useful life, and the deferred tax liability will be reduced accordingly. Alternatively, there are also instances where an expense is recognized for financial statement or book reporting purposes but is not fully allowed as a deduction for income tax purposes, resulting in a deferred tax asset. The requirement that overhead expenses be capitalized to items of inventory and deducted as a cost of goods sold once inventory is sold or consumed for income tax purposes but not for financial statement reporting provides an example of a timing difference that results in a deferred tax asset.

Florida Public Utilities Company's largest deferred income tax expense item is attributable to what is referred to as "state decoupling." This occurs when a state does not conform to certain federal tax provisions, and net income used to calculate the state income tax differs from both the income reported for financial statement purposes and the income reported for federal tax purposes as a result. The other primary driver of Florida Public Utilities Company's ADIT balance is the temporary difference, or deferred income tax expense, stemming from its recognition of tax depreciation versus depreciation expense for financial statement accounting purposes. MFR Schedule C-24 provides a complete listing of the deferred income tax expense items recognized by Florida Public Utilities Company during the historical base year. Each of these items contributes to the ADIT balances included on MFR Schedule B-18.

Q. WERE THERE ANY ADJUSTMENTS TO THE HISTORIC TEST PERIOD AMOUNTS TO ARRIVE AT THE PROJECTED TEST PERIOD AMOUNTS INCLUDED IN FLORIDA PUBLIC UTILITIES COMPANY'S ADIT BALANCES?

A. MFR Schedule C-24 provides the detail related to the historic base year deferred tax expense total, listing each item that contributes to the total timing difference between net income for book purposes and net income for tax purposes. MFR Schedule G-2 provides the same for the historic base year +1 (i.e. year ending 12/31/2022) and the projected test year (i.e. year ending 12/31/2023). As reflected in these schedules, the timing differences are consistent in amount from the historic base year through the projected test year for each item, with the exception of the depreciation timing difference, included on each of the schedules under Line 3, and the "Deferred Only Adjustment" reflected on Line 28. The amount attributable to both of these timing differences is appropriately updated in the future and projected test periods based on the information reasonably available at the time of this rate case filing.

Q. CAN YOU DESCRIBE THE NATURE OF THESE ADJUSTMENTS, AND HOW THE AMOUNTS WERE DETERMINED?

A. The adjustment to the timing difference stemming from accelerated depreciation for both the historic base year +1 and the projected test year is driven by projected depreciation on existing assets for both book and tax purposes and estimates related to planned or expected purchases and anticipated retirements during each of these periods. Using this information, Florida Public Utilities Company's calculated the total projected tax and book depreciation for the projected and future periods and included the difference in the deferred tax expense total for each year accordingly, as reflected on MFR Schedule G-2.

Outside of the adjustment related to accelerated depreciation, the "Deferred Only Adjustment" included MFR Schedule G-2, Line 28 was also updated for the future test periods. This deferred tax expense item includes the yearly amortization of the deferred tax liability recorded as part of the Florida Public Utilities Company acquisition adjustment in accordance with Florida Public Service Commission Order No. PSC-12-0010-PAA-GU, and the deferred tax expense associated with the amortization of both the protected excess ADIT (i.e. subject to the normalization rules and properly amortized using the average rate of assumption method) and the unprotected excess ADIT resulting from the statutory rate change enacted as part of the federal Tax Cuts and Jobs Act ("TCJA"). Because these totals for the future test periods are known at the time of this rate case filing, they are properly adjusted to reflect the projected deferred tax expense totals for the future test periods.

Q. HOW DOES THE PRORATION REQUIREMENT IMPACT FLORIDA PUBLIC UTILITIES COMPANY'S CAPITAL STRUCTURE FOR THE PROJECTED TEST PERIODS?

A. Florida Public Utilities Company calculated the proration requirement for the test year ending 12/31/2023, and then compared the prorated ADIT balances to the 13-month average ADIT balances per book. The result in both cases was a weighted average cost of capital totaling 6.43%. Because the proration adjustment did not yield a change to Florida Public Utilities' capital structure, it was not included in the MFR schedules as part of this rate case filing.

V. <u>THE CALCULATION OF INCOME TAX EXPENSE INCLUDED IN FLORIDA PUBLIC UTILITIES COMPANY'S COST OF SERVICE</u>

Q. HOW DID FLORIDA PUBLIC UTILITIES COMPANY CALCULATE THE PROJECTED INCOME TAX EXPENSE?

A. Florida Public Utilities Company used the historical timing differences between the recognition of items of income or expense for book purposes and tax purposes to estimate the timing differences for the projected test years. The projected net income before income taxes and interest expense, less the interest expense calculated on the cost of capital projections, adjusted for the anticipated timing differences was multiplied by the effective tax rate to arrive at the total current tax expense.

Q. HOW WAS THE EFFECTIVE TAX RATE USED TO CALCULATE PROJECTED INCOME TAX EXPENSE DETERMINED?

A. Florida Public Utilities Company uses an effective tax rate of 25.35%, which accounts for both the applicable federal and state tax rates, which are 21% and 5.5%, respectively. MFR Schedule G-2 provides specific details related to the calculation of both state and federal income tax expense for the projected periods.

Q. WERE THERE ANY ADJUSTMENTS INCLUDED IN THE TAX EXPENSE CALCULATION FOR PERMANENT DIFFERENCES BETWEEN BOOK INCOME AND TAX INCOME?

A. As detailed on MFR Schedule C-23, Florida Public Utilities Company adjusted its federal taxable income for the historic base year ending 12/31/2021, the historic base year +1 ending 12/31/2022, and the projected test year ending 12/31/2023 to account for book expense items that are not deductible for tax purposes, otherwise known as permanent differences. These permanent items were consistent across each of the three periods.

Q. WERE ANY OTHER ADJUSTMENTS INCLUDED IN THE TAX EXPENSE CALCULATION?

A. Yes. As part of the TCJA, the corporate income tax rate was reduced from 34% to 21%. Because the ADIT reserves, which represent a future obligation to pay a future tax liability, are determined and recorded based on the tax rate in effect at the time the reserve balance is generated, the tax rate reduction resulted in the ADIT balances being overstated by 13%. This excess ADIT resulting from the corporate tax rate decrease can be broken out into two categories, protected and unprotected. “Protected” excess ADIT stems from accelerated depreciation deferred tax balances, and the application of the prescribed normalization method to reduce and return the excess ADIT back to customers when computing cost of service for ratemaking purposes is required. Alternatively, unprotected excess ADIT is not required to be normalized, and can be amortized over any period sanctioned by the applicable regulators.

As it relates to the protected portion of excess ADIT, the normalization method of accounting requires the use of the average rate of assumption method (“ARAM”) in order to reduce the excess tax reserves in computing the cost of service for ratemaking purposes. Under ARAM, the excess ADIT related to public utility property will be amortized over the remaining life of the property at a rate that follows the reversal of the deferred tax.

The unprotected portion of Florida Public Utilities Company's excess ADIT is properly amortized over a period of ten years, as approved by the Florida Public Service Commission in Final Order No. PSC-2019-0076-FOF-GU, issued February 25, 2019, in Docket No. 20180051-GU (Florida Public Utilities Company – Indiantown and Florida Public Utilities Company – Fort Meade are separate divisions of FPUC. Docket Nos. 20180052-GU, 20180053-GU and 20180054-GU were opened to address the tax impacts affecting FPUC – Indiantown, FPUC – Fort Meade, and Chesapeake, respectively).

Schedule MFR C-18 provides detail related to the historic base year amortization of the protected and unprotected portions of Florida Public Utilities Company's excess ADIT stemming from the statutory change in tax rates. This amortization expense is accounted for in Florida Public Utilities Company's pretax income and returned to customers accordingly utilizing the average rate of assumption method for the protected portion, and the 10-year period, consistent with the Florida Public Service Commission's Final Order referenced above, for the unprotected portion.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BY MR. MUNSON:

Q Mr. Reno, are you prepared to present a summary of your testimony?

A I am.

Q Please proceed.

A Good morning, Mr. Chairman and Commissioners. Thank you for the opportunity to address you today.

The purpose of my direct testimony is twofold. First is to explain how FPUC's calculation of accumulated deferred income taxes included as a component of cost of capital complies with the tax normalization rules; and second, explaining how FPUC's calculation of income tax expense included as an element of cost of service is appropriate.

This concludes my summary.

MR. MUNSON: Mr. Chair, at this time, we tender Mr. Reno for cross-examination.

CHAIRMAN FAY: Great. Thank you, Mr. Munson.

Mr. Rehwinkel, you are recognized.

MR. REHWINKEL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. REHWINKEL:

Q Good morning, Mr. Reno.

A Good morning.

Q I just have, I think, a couple of questions

for you.

Are you responsible for preparing the tax return for CUC and its subsidiaries?

A I personally am not.

Q Do you -- are you involved in it, is your firm?

A Yes, Ernst & Young does.

Q And you are here as a representative of Ernst & Young?

A I am.

Q Okay. Can you tell me what impacts related to, is it the Inflation Reduction Act, the tax change that was implemented in August of 2022, have been reflected in the company's filing?

A The Inflation Reduction Act was effective, right, or enacted in August. Most of the provisions are effective starting in 2023. It included, you know, both health care as well as some tax provisions, I believe. And I haven't done the thorough analysis yet. I don't believe any of the changes to the law impacted Florida Public Utilities Company taxes. Most of it related to energy tax credits for renewable energy, as well as tax raisers related to a corporate alternative minimum tax that I think earlier witnesses referenced having a threshold that Chesapeake Utilities doesn't yet meet to be imposed on it.

Q Okay. So given that its impact is prospective beginning 1/1/2023, which is the test year, to the base best of your knowledge, there are no impacts that would affect the income tax expense included in the filing, is that correct?

A That's my understanding.

Q That you. Those are all the questions I have. Thank you, Mr. Reno.

CHAIRMAN FAY: Thank you.

Mr. Moyle?

MR. MOYLE: No questions.

CHAIRMAN FAY: Okay. Staff?

MR. SANDY: No questions.

CHAIRMAN FAY: Okay. Commissioners?

All right. Any redirect, Mr. Munson?

MR. MUNSON: No redirect, Mr. Chair. Thank you.

CHAIRMAN FAY: Okay. We have no exhibits.

Let's see, and with that, Mr. Munson, would you like your witness excused for now?

MR. MUNSON: Yes, Mr. Chairman.

CHAIRMAN FAY: All right. Mr. Reno, you are excused for now. We will have you back for rebuttal.

THE WITNESS: Thank you.

CHAIRMAN FAY: Thank you.

I was saying Ms. Keating, but, Mr. Munson, are you calling the next witness?

MR. MUNSON: Yes, please.

CHAIRMAN FAY: All right.

MR. MUNSON: At this time, we call Ms. Pat Lee.

Whereupon,

PATRICIA LEE

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. MUNSON:

Q Good morning, Ms. Lee. Can you please state your full name for the record?

A My name is Patricia Lee.

Q And who do you work for and what's your job?

A I am a consultant working on behalf of Florida Public Utilities.

Q And do you have a business address you can provide for the record, please?

A Yes, 116 SE Villas Court, Apartment C, Tallahassee, Florida, 32303.

Q And did you have 24 pages of direct testimony in a filing September 9th filed in this case?

A I did.

Q And did you sponsor Exhibits PSL-1 through PSL-4, including those corrections filed on September 9th in this case?

A I am sorry, you will repeat that?

Q Sure. Did you -- let me do it this way. Did you sponsor Exhibits PSL-1 through PSL-4?

A I did. But going back to your first about how many pages in my testimony, I think there were 25 pages.

Q Okay. Thank you for that.

Do you have any changes to your testimony or exhibits?

A No, sir.

MR. MUNSON: At this time, Mr. Chair, we move Witness Lee's direct testimony into the record as if read. And also note that the previously identified exhibits have been marked as Nos. 13 through 16 in the staff's Comprehensive Exhibit List.

CHAIRMAN FAY: Okay. Great. Show that testimony entered.

(Whereupon, prefiled direct testimony of Patricia Lee was inserted.)

Before the Florida Public Service Commission

Docket No. 20220067-GU: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.

Prepared Revised Direct Testimony of Patricia Lee

Date of Refiling: September 9, 2022

I. POSITION, QUALIFICATIONS, AND PURPOSE

Q. Please state your name and business address.

A. My name is Patricia Lee. My address is 116 SE Villas Court, Unit C, Tallahassee, Florida 32303.

On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of Florida Public Utilities Company ("FPUC" or "Company").

Q. Please state your prior work experience and responsibilities.

A. I was employed as a high school mathematics teacher from 1971-1974, when I began working in the area of statistical analysis for the State of Florida. I joined the Florida Public Service Commission ("FPSC" or "Commission") staff in 1978. While my position changed over the years, my areas of primary focus were depreciation and capital recovery. I also reviewed and analyzed cost studies for the purpose of determining unbundled network element prices and universal service cost levels, as well as for the purpose of determining the appropriate nuclear decommissioning and fossil dismantlement annual accrual levels. In that regard, I was responsible for depreciation issues and other issues such as determining the appropriate cost model inputs. I retired in 2011 after over 30 years of service. I began working for BCRI Inc., d/b/a BCRI Valuation Services[1] in 2012 where I represented consumer advocate groups and Industrial Power Users in hydro and electric and jet fuel company depreciation filings. I prepared FPUC's 2015 and 2019 electric depreciation studies as well as the 2019 consolidated gas company depreciation study.

Q. What is your educational background?

A. I have a BS in mathematics from Appalachian State University in Boone, North Carolina.

Q. Please describe your other professional activities.

A. I am a member of the Society of Depreciation Professionals ("SDP"), an organization that has established national standards for depreciation professionals. I previously served as President of the SDP and was an instructor at several annual meetings concerning depreciation accounting. On behalf of the FPSC, I participated as a faculty member of the National Association of Regulatory Utility Commissioners ("NARUC") Annual Regulatory Studies Program and also for the SDP in the area of depreciation accounting. I was also a member of the NARUC Staff Subcommittee on Depreciation and Technology. In this regard, I co-authored the NARUC 1996 Public Utility Depreciation Practices manual and three NARUC papers that addressed the impact of depreciation on infrastructure development, economic depreciation, and stranded investment. Two of these papers were published in the 1996-1997 and 1998 SDP Journals.

Q. Have you previously testified before any state and/or international regulatory commissions?

[1] BCRI is a consulting and research company founded in 1998 by Stephen Barreca. The company specializes in assessing technological change and appraising utility property.

A. Yes, I have proffered testimony in proceedings before the Alberta Utilities Commission, the Public Utilities Board of Manitoba, the Newfoundland Labrador Board of Commissioners, the British Columbia Utilities Commission, and the FPSC. My Curriculum Vitae as well as a list of proceedings I was either assigned, or in which I presented testimony is found in Exhibit PSL-1.

Q. Have you been accepted as an expert in Depreciation in any previous proceedings?

A. Yes, on multiple occasions.

Q. What was your responsibility and participation in the conduct of the 2023 Depreciation Rate Study (the "Study") for Florida Public Utilities Company?

A. I was responsible for and participated in all aspects of the work performed resulting in the recommendations contained in the depreciation study narrative and workbook in Revised Exhibit PSL-2.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to discuss and support the 2023 Study conducted for FPUC's consolidated natural gas divisions distribution, and general depreciable plant assets based on plant and reserve balances estimated as of January 1, 2023.

Q. Are you sponsoring any exhibits?

A. Yes. Attached to my testimony are Exhibits PSL-1, Revised PSL-2, PSL-3, and Revised PSL-4. Exhibit PSL-1 is my Curriculum Vitae, Revised Exhibit PSL-2 is the Depreciation Study and workbook, Exhibit PSL-3 is a Life Table example, and Revised Exhibit PSL-4 illustrates the recommended depreciation rates for the mains and services accounts with and without reserve allocations. To the best of my knowledge, the information contained in these exhibits is true and correct.

II. TESTIMONY STRUCTURE, DEPRECIATION DEFINITION, STUDY PURPOSE, AND STUDY CONCLUSIONS

Q. How is your direct testimony structured?

A. My direct testimony has five sections. Sections II and II are introductory.

Section III, I explain how the depreciation Study conforms to the depreciation study requirements of Rule 25-7.045, Florida Administrative Code ("F.A.C."), and provide context for the 2023 FPUC Depreciation Study.

Section IV addresses the determination of depreciation rates, including identifying the formula used in the remaining life rate design. This section also explains and fully discusses each component of the depreciation rate that is supported by the Study.

Section V discusses the change in annual depreciation expenses based on my proposed resultant depreciation rates and amortizations.

Q. What is the basic purpose of depreciation?

A. The purpose of depreciation is to systematically spread the recovery of prudently invested capital over the period the plant items represented by that capital are providing service to the public. Depreciation is an expense of doing business. Ideally, the timing of the expenses matches the timing of the active period of service.

Depreciation rates are prescribed on the basis of estimates of the equipment's expected rate of loss in value due to known causes, including wear and tear, obsolescence, and changes in demand. Depreciation expense is part of a company's revenue requirement, and the accumulated depreciation (depreciation reserve) is a deduction from rate base.

Q. Please generally describe the purpose of the Study.

A. The basic purpose of the depreciation Study is to attain the proper depreciation expenses and accumulated reserve level for FPUC's gas distribution and general plant accounts. The prime concerns in developing depreciation rates for each account are remaining life, net salvage, and reserve level.

Rule 25-7.045(4)(a), Florida Administrative Code, requires regulated gas companies to file comprehensive depreciation studies at least once every five years from the last submitted study unless otherwise directed by the Commission. Plant and reserve activity for FPUC since the last depreciation study, indicate a need to revise life and salvage values and resultant remaining life depreciation rates. This Study also affords the opportunity to review the recovery position (depreciation reserve) for any imbalances and corrections through reserve allocations or amortization that may be needed.

Q. Based on the Study, what conclusions do you reach?

A. I conclude that:

- FPUC's current approved life and salvage parameters should be revised as set forth in the workbook on Revised Exhibit PSL-2, Schs. A and B, which are sponsored by me.
- A 5-year amortization of the reserve imbalance associated with the Commission approved amortized general plant accounts shown in the workbook on Revised Exhibit PSL-2, Sch. E, is recommended. The amortization results in an annual expense increase of $288,819.

- The recommended rates and amortizations for each account applied to estimated plant balances and depreciation reserve balances as of January 1, 2023, result in a decrease in an annual depreciation expense of approximately $1.5 million shown on Schedule C in the workbook, Revised Exhibit PSL-2. This amount was determined by comparing the annual depreciation expenses calculated using current-approved depreciation rates with those calculated using the proposed depreciation rates.

III. FPUC'S DEPRECIATION STUDY

Q. What does the FPSC Rule 25-7.045, Florida Administrative Code, require a depreciation study include?

A. The Commission's depreciation rule requires the following information be included in a depreciation study:

- An effective date for new depreciation rates and/or recovery schedules. If the proposed effective date coincides with the expected date for new revenues initiated through a rate proceeding, the depreciation study must be submitted no later than the filing of the Minimum Filing Requirements.
- A comparison of the current and proposed depreciation components for each account. The components include average service life, age, curve shape, net salvage, and average remaining life.
- A comparison of current and proposed depreciation rates and expenses identifying the proposed date for implementing the proposed rates. Additionally, plant

balances, reserve balances, remaining lives, and net salvage percentages are required in this comparison.

- Each recovery and amortization schedule.
- A comparison of the book reserve to the calculated theoretical reserve based on proposed rates and components for each account.
- A general narrative describing the service environment of the company and the factors necessitating a revision in depreciation rates.
- An explanation and justification for each account under study defining the specific factors that justify the proposed life and salvage components and rates. A discussion of any proposed reserve transfers to correct reserve imbalances. Any statistical or mathematical methods of analysis or calculation used in the depreciation rate design should be included.
- All calculations, analysis, and numerical basic data used in the depreciation rate design for each account. This should include plant activity and reserve activity for each year since the last submitted study. Where available, retirement data should be aged.
- The mortality and salvage data used in developing proposed depreciation rates for each account must agree with the booked activity. Unusual transactions not included in life or salvage studies should be specifically enumerated and explained.
- Calculations of the proposed depreciation rates should be made using both the whole life and remaining life techniques.

Q. Does the 2023 Depreciation Study contain the information and data required by the Commission's depreciation rule?

A. Yes, it does. The narrative and workbook in Revised Exhibit PSL-2 contain all the information and data required.

Q. Did the Company provide any specific information for conducting the Study?

A. Yes, the Company provided the following information:

- Aged retirements for each year since the last depreciation study (2018-2022);
- Plant and reserve summaries for each year since the last depreciation study;
- 2022 projected additions and retirements;
- 2022 projected plant balances;
- 2022 projected monthly depreciation expenses:
- Net salvage for 2018 through projected 2022;
- 2022 aged motor vehicle listing;
- Projected 2022 average age calculations; and
- Prior year reserve adjustments to be recorded in 2022.

Q. What date of implementation is recommended for the revised depreciation rates?

A. A January 1, 2023, implementation date is recommended for the revised depreciation rates and amortization schedules set forth in the Study. This date coincides with the expected date for new revenues in the forthcoming rate case filing. All data have been estimated[2] to reflect the recommended date as required by Rule 25-7.045, Florida Administrative Code.

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[2] Estimated plant balances include actual plant balances as of December 31, 2021, and Company planning and budgeting for 2022.

Q. Does the Study provide a general narrative describing FPUC's service environment and factors necessitating the need to revise current approved depreciation rates?

A. Yes, Revised Exhibit PSL-2, pages 1-2, contain a general narrative discussing the need to revise depreciation rates.

Q. Does the Study provide an explanation and justification for any and all proposed changes in life or salvage and any proposed reserve amortization?

A. Yes, Exhibit Revised PSL-2, pages 3-25, contain an account-by-account explanation and justification for the recommended life and salvage factors and pages 25-26 provide an explanation and justification for recommended general plant reserve deficiency amortization.

Q. What property is included in the depreciation Study?

A. There are two functional groups of depreciable property that are analyzed in the study: (1) Distribution Plant, and (2) General Plant. Distribution plant primarily consists of lines and associated facilities used to distribute gas to FPUC customers. General Plant property is plant (such as office buildings) used to support the overall Company operations.

Q. Please describe your depreciation study approach.

A. The components required in the remaining life rate design are average service life, age, curve shape, average remaining life, net salvage, and reserve. The depreciation study approach I used in determining these components is similar to that used in each FPUC depreciation study for the last 20+ years. The aged retirement data and the average age distributions of the surviving investments along with lives of other Florida gas companies were used to determine if a revision to the average service life underlying the currently approved average remaining life for each account is needed.

For many FPUC accounts, the retirement rate[3] since the last depreciation study (2018-2022) has averaged less than one percent. This level of activity makes the results of any statistical analysis meaningless for developing life expectations. For this reason, reliance on industry averages is necessary. I have used the range of average service lives underlying the currently prescribed average remaining lives for Florida companies in determining an appropriate average service life for FPUC.[4] Florida companies have more similar operating and regulatory environments among them than they do with gas companies in other states. Additionally, they are subject to similar weather and environmental conditions than companies in other states.

Q. **How was the average age of the surviving investment for each account determined?**

A. The calculation of the average age of the surviving investments as of January 1, 2023, is shown in the workbook on Revised Exhibit PSL-2, Schs. L and M.

Sch. M shows the computation of the average age as of January 1, 2023, for each account except motor vehicles. The source for the age and cost basis of each vintage is FPUC's Continuing Property Record System. Sch. L identifies each motor vehicle in service as of December 31, 2022, the placement year, the original cost, and the age of the vehicle to which the average age is calculated.

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[3] Retirement rate = retirements/exposures = [retirements during the year/(end of year plant balance + retirements)] x 100.

[4] Prescribed average remaining lives for Florida gas companies have been vetted and approved by the Commission. The underlying average service lives provide a zone for reasonableness where there is a lack of retirement experience.

The age of each vehicle on Sch. L and each vintage of Sch. M is determined by subtracting the placement or install year from the as-of-date minus a half year. The as-of-date for these schedules is 2023. The reduction by a half year is called the half-year convention and assumes that the additions were made throughout the year so that, on average, they came into service about mid-year.[5] For example, the age of investments surviving from 2014 would have an age of 8.5 years as of January 1, 2023. The average age for each account is the direct weighting of the vintage age with the original vintage cost. The average age as of January 1, 2022, is then used with the 2022 estimated additions and retirements to arrive at the January 1, 2023, average age shown on Schs. L and M.

Q. What is a survivor curve?

A. A survivor or mortality curve is a graphical picture of the amount of property surviving at each age through the life of the property group. The graph plots the percent surviving on the y-axis and the age on the x-axis. The survivor curve depicts the expected retirement pattern of plant in an account over time. Iowa Curves are types of survivor curves developed to describe the life characteristics of utility property. They are the descriptive and accepted representation of retirements of utility property and consist of 34 retirement distributions. Survivor curves were not generated by statistical analysis for any account in the Study. Rather, the Iowa Curve underlying the currently prescribed average remaining life was reviewed to determine if it is still appropriate based on the average age and average retirement rate.

[5] The half-year convention is a common accounting convention adopted to obtain consistent statistics. Frank K. Wolf and W. Chester Fitch, *Depreciation Systems*, Iowa State University Press, 1992, p. 22.

In this Study, the "Proposed" curve shapes shown in the workbook on Revised Exhibit PSL-2, Sch. 1, are primarily based on those underlying the current FPSC approved average remaining lives and have basically remained unchanged since 2006. The curve shape for each account was reviewed and any modifications proposed are based on actual retirement experience since the previous depreciation study and the current average age. If the proportion surviving at the current age implies more or less retirements than those experienced since the last review, a change in curve shape is not necessarily proposed if the curve is considered indicative of future expectations. Instead, the situation is usually monitored and if a pattern continues into the next depreciation study, it may warrant investigation and new analysis. For most of the accounts, FPUC has no planned near-term retirements that could affect the curve shape, but the continued lack of retirements does indicate longer lives.

Q. How is a survivor curve used in this Study?

A. The average service life, Iowa Curve, and average age are used to develop the average remaining life of the account.

IV. DETERMINATION OF THE DEPRECIATION RATES

Q. How were your recommended depreciation rates determined?

A. The depreciation rates are calculated using the remaining life technique in Rule 25-6.045(1)(e), Florida Administrative Code.

$$\text{Remaining Life Rate} = \frac{100\% - \text{Reserve\%} - \text{Average Future Net Salvage\%}}{\text{Average Remaining Life (in Years)}}$$

The numerator of the formula represents the amount remaining to be recovered for each account (plant investment[6] less reserve less any net salvage) and the denominator represents the current estimate of the number of years left in which to recover (average remaining life) the investment.

Q. What portion of the formula used to derive depreciation rates is supported by the Depreciation Rate Study?

A. I describe in more depth below how the Study determines each component of the formula, as well as the Study results for each component, but the formula components supported by the Study are:

Reserve: The depreciation reserve was provided by FPUC with estimated plant and reserve balances estimated at January 1, 2023. The reserve percent is derived by dividing the reserve balance by the plant balance for each account.

Net Salvage: The Study supports the overall net salvage percent for each Distribution and non-amortizable General Plant account. Net salvage is the realized gross salvage less the costs to remove the retired asset. The percentages are calculated by dividing the net salvage costs, as supported by the Study, by the original cost of the retired assets.

Remaining Life: The Study supports the remaining life calculation by determining the appropriate average service life, curve shape, and average age for each account.

Resulting Depreciation Rates and Expenses: The Study calculates the depreciation rates; the annual expenses are calculated by multiplying the depreciation rate times the estimated plant balances as of January 1, 2023.

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[6] Plant investment represents 100% in the remaining life depreciation rate formula.

THEORETICAL RESERVE

Q. What purpose does the theoretical reserve serve in a depreciation study?

A. The theoretical reserve is a calculated reserve representing the theoretically correct reserve level if current life and salvage expectations had always been in effect. Rule 25-6.045(5)(d) requires a depreciation study to include a comparison of the book reserve to the theoretical reserve based on proposed rates and components for each account. This comparison is shown in the workbook on Revised Exhibit PSL-2, Sch. D and serves to quantify any reserve imbalances.[7]

Q. How does the Study determine the theoretical reserve?

A. The formula is:

Theoretical Reserve = Book Investment – Future Accruals – Future Net Salvage

Future accruals are determined from the estimated remaining life, average service life, and the estimated net salvage. The difference between the theoretically correct reserve and the book reserve is an imbalance, either a deficit or a surplus.

Q. Is it desirable for the depreciation reserve to conform to the theoretical reserve?

A. Yes. The remaining life rate design is self-correcting. By this I mean that the relative adequacy of the reserve causes this remaining life formula to self-adjust for over-or under-recovery, as well as for changes in projected life or salvage parameters. A reserve deficit will result in a higher remaining life depreciation rate because there is more that needs to be recovered over the remaining life. Conversely, a reserve surplus

[7] If the calculated theoretically correct reserve is more than the book reserve, a reserve deficiency is implied. Conversely, if the theoretical reserve is less than the book reserve, a reserve surplus is implied. Unless other actions are taken, the reserve imbalances are recovered over the remaining life of the subject account

will cause the remaining life depreciation rate to be less because there is less in the future that needs to be recovered. However, correction of major imbalances may be considered through reserve allocations or amortization.

Q. What were the results of the comparison of the book reserve with the calculated theoretical reserve?

A. A theoretical reserve analysis is shown in Sch. D of the workbook in Revised Exhibit PSL-2 indicating reserve imbalances for many accounts. These imbalances have generally been brought about by such things as changes in life and salvage projections, account activity not matching that provided in the depreciation rate design, and accounting changes. When the theoretical reserve is less than the book reserve, a surplus is indicated and decreases the remaining life depreciation rate. Conversely, a reserve deficiency is indicated with the theoretical reserve is more than the book reserve. This has the effect of increasing the remaining life depreciation rate to recover the deficiency over the remaining life.

Overall, the Study indicates a reserve surplus of ~~$20.2~~ $19.7 million on January 1, 2023, based on the proposed life and net salvage factors. This amount consists of a $20.7 million surplus in the distribution accounts and about $1 million deficit in the general plant accounts.

Q. What are your recommendations for the reserve imbalances you have identified?

A. I recommend correcting the calculated reserve imbalances for each distribution and non-amortizable general plant account over the remaining life of the given account. These recommendations are shown in the workbook on Revised Exhibit PSL-2, Sch. C.

Q. What are your recommendations for the reserve imbalance identified for the amortizable general plant accounts?

A. For the General Plant accounts subject to vintage group accounting approved in the 2019 depreciation review, I recommend amortizing the calculated reserve deficiency over a period of 5 years in an annual amount of $288,819. This recommendation is shown in the workbook on Revised Exhibit PSL-2, Sch. E.

Q. Did the Commission approve an amortization of the reserve deficiency associated with the General Plant Accounts proposed for vintage group accounting in the 2019 Depreciation Study?

A. Yes. Order No. PSC-2019-0433-PAA-GU ("Order"), issued October 22, 2019, in Docket 20190056-GU, approved a 5-year amortization of the calculated reserve deficiency associated with the General Plant accounts moving to vintage year accounting. The annual amortization amount approved was $270,196.

Q. Why is there now a need for another amortization for these amortized accounts?

A. At the time of the 2019 Study, it was assumed that all of the consolidated companies were using FPUC's Uniform System of Accounts ("USOA"). Subsequently though, it was discovered that different account systems were being used for the different companies resulting in a mismatch of investment and reserve for each affected account. All FPUC consolidated companies have now adopted the Chesapeake USOA and account investments and reserves have been corrected to the proper account. However, the 2019 mismatch resulted in inaccurate theoretical reserve and resulting deficiency calculations in that Study. The investments and book reserves shown on Revised Exhibit PSL-2, Sch. E, reflect the corrected investments and reserves based on a uniform accounting system across all consolidated companies as well as the retirement of assets since 2019 that reached an age equal to the approved life, and the Ordered annual reserve amortization expense. Because the calculated reserve imbalance in the last Study was based on inaccurate data, I recommend that a theoretical reserve analysis be performed again now that the account information has been corrected to reflect uniformity across all consolidated companies.

Q. Did you consider proposing reserve allocations between accounts?

A. Yes, I did. The Commission's policy with regards to reserve allocations has been to make them between accounts within the same function (distribution or general plant) to avoid any cross-subsidization issues. A review of Revised Exhibit PSL-2, Sch. C, shows that within the distribution accounts, nearly all of total net surplus is found in the Plastic and GRIP Mains accounts, attributable to the proposed life increase. The net surplus for these accounts is ~~$19.5~~ $19.1 million. A net reserve deficit of ~~$6.1~~ $4.3 million is found in the plastic and GRIP services accounts. I considered proposing a transfer of $6.1 million from the Plastic and GRIP Mains accounts to correct the deficit in the Plastic and GRIP Services accounts. This would have no effect on the depreciation rate proposed for the Plastic and GRIP Mains accounts and a decrease to the depreciation rate for the Plastic and GRIP Services accounts by 0.1 percent as shown on Revised Exhibit PSL-4. Considering the small impact, I propose that these reserve imbalances be recovered over the remaining life of each account. Additionally, the perceived surplus may be short-lived given the ever-increasing trend in removal costs as discussed in Revised Exhibit PSL-2.

Q. How was the difference between the book and theoretical reserve handled in FPUC's last depreciation study?

A. In FPUC's 2019 Depreciation Study, the Commission approved the use of the remaining life to correct the imbalances in Docket No 20190056-GU rather than ordering any reserve transfers between accounts. The reserve deficiency associated with implementing vintage group amortization of certain general plant accounts was approved to be amortized over five years, the time period between depreciation studies.

NET SALVAGE

Q. What is net salvage as determined for FPUC's plant assets?

A. Net salvage is the difference between realized salvage (gross salvage) and the cost to remove and dispose of the given asset. If the cost of removal is greater than the gross salvage realized, net salvage is negative. Conversely, if gross salvage is greater than the cost to remove the asset, net salvage is positive.

For most of the distribution accounts, net salvage is negative in that it costs more to remove the retired plant than the Company receives from selling the retired items. Salvage and cost of removal percentages are calculated by dividing the net of gross salvage and cost of removal by the original installed cost of the assets retired.

Q. How did you determine the net salvage percentages for each asset group in Distribution and General plant?

A. I first looked at the net salvage booked in each year since the last depreciation study. The average net salvage for 2017-2022, the years since the last depreciation study, is calculated with the intent to remove timing differences between retirement and salvage and cost of removal. Additionally, in the course of the study process and data collection, retirement and salvage adjustments were discovered that should have been made in prior years. These adjustments are shown on Sch. K and will be recorded in 2022. To the extent that retirements have been insignificant, reliance on Florida industry averages and judgment have been necessary.

Q. Is it sufficient to analyze historical data in forming your proposed life and net salvage factors?

A. No. While historical data are factors to consider, it is also important to incorporate Company-specific information, including pressures FPUC faces and how it is addressing those pressures. For example, Florida companies are subject to harsher operating and environmental conditions of heat, humidity, hurricane incidence, saltwater intrusion than companies in other states. Expensing/capitalization practices may also differ from state to state making it more appropriate to compare companies with similar procedures. Additionally, judgment, trends, and the magnitude of the potential change were considered. A comparison of the current-approved and proposed net salvage factors are shown in Sch. A of Revised Exhibit PSL-2.

Q. Please describe the major changes in the net salvage percentages for the various accounts.

A. Recommended net salvage factors decreased for 12 accounts, becoming more negative, while the remaining 12 accounts are unchanged. The trend toward higher negative net salvage is due to increased labor, safety, and environmental costs associated with retiring assets and the longer lives being projected. For accounts with miniscule retirements, historical activity is of little value. In such cases, as with changes in life estimates, I used the concept of moderation and gradualism in the net salvage recommendations and relied not only on experience but on net salvage values currently prescribed for other gas companies in Florida. The most significant changes of 20 percent or more (more negative) in net salvage factors were in:

- Distribution Plastic and Grip Mains, Accounts 376.1 and 376G, decreased from negative 16 percent to negative 25 percent.
- Distribution Steel Mains, Account 376.2, decreased from negative 28 percent to negative 40 percent.
- Distribution Plastic and Grip Services, Accounts 380.1 and 380G, decreased from negative 22 percent to negative 30 percent.
- General Plant Power Operated Equipment, Account 396, decreased from positive 10 percent to positive 5 percent.

Explanations for these changes are addressed in Revised Exhibit PSL-2, pp. 3-25, including discussion of the factors impacting removal costs.

REMAINING LIFE ANALYSIS

Q. How were the recommended average remaining lives determined for each account?

A. Remaining life expectancies for each account were determined using the same approach used by the FPSC for FPUC over the past 20+ years. The recommended average service life (projection life) and January 1, 2023, calculated average age for each account were used with the selected Iowa Curve life table to determine the average remaining life. The Life Tables I used in the remaining life expectancy determinations were obtained from GTE-INC.[8] These are standard Iowa Curve life tables that can also be replicated from other sources.[9]

For example, an account with a life of 30 years following an S3 retirement dispersion (survivor or mortality curve) would, at age 9.5 years, have an average remaining life of 20.52 years, rounded to 21 years. The life table used is attached as Exhibit PSL-3. For accounts where the average age is not found in the life table, the remaining life is determined by extrapolation. For example, using the same service life and curve shape as above, at age 9.7 years, the average remaining life is 20.3 years, rounded to 20 years.

Projection Life 30 Years	
Age	Remaining Life
9.5	20.52
9.7	*X*
10.5	19.54

$$(9.7-9.5)/ (10.5-9.5) = (X-20.52)/(19.54-20.52)$$

$$0.2/1 = (X-20.52)/-0.982$$

$$X-20.52 = -0.1964$$

$$X = 20.52 - 0.1964$$

$$X = 20.324 \text{ rounded to 20 years}$$

[8] The life tables obtained from GTE-INC are comprised of two volumes, each consisting of 646 pages, too voluminous to copy and attach to this testimony.

[9] Frank K. Wolf and W. Chester Fitch, *Depreciation Systems*, Iowa State University Press, 1992, p. 40 and Appendix 1, pp. 305-338; Robley Winfrey, *Bulletin 125: Statistical Analyses of Industrial Property Retirements*, 1935 as revised 1967, Iowa State University Engineering Publications and Communications Services, pp. 102-106; Robley Winfrey, *Bulletin 155: Depreciation of Group Properties*, 1942, Iowa State University Engineering Publications and Communications Services, pp. 124-127.

Q. How did you determine the average service lives?

A. First, I compiled data from FPUC's Annual Status Reports since the last depreciation study, as well as its General Ledger, Fixed Asset System, and 5-Year Plan. I then reviewed and compared this data for accuracy and followed-up on all discrepancies with Company personnel having knowledge of the property being studied and/or Company practices.

I reviewed each account's average retirement rate over the period since the last depreciation study and curve shape underlying the currently prescribed average remaining life. This data, along with the January 1, 2023, calculated average age of the account's surviving investments, indicated the need for little to no modification to the expected curve shape underlying the currently approved average remaining life. Retirement activity averaging less than one percent since the Company's 2019 Depreciation Study provides insufficient data to perform any meaningful statistical analyses for life characteristics, therefore it was necessary to rely on life characteristics for similar plant of other Florida gas companies to make a complete analysis. The use of Florida industry averages has been a common practice of the FPSC for many years. The current average service life underlying the approved average remaining life for each account was compared to the range of average lives used by Florida companies. The assumption is that the same type of plant, located in the same environment is likely to follow similar life patterns unless otherwise warranted by specific company planning. Average retirement rates since the last depreciation study were calculated for each account and compared to those implied retirements at the January 1, 2023, average age of the underlying current curve shapes to determine if any modifications are warranted.

Q. Please describe some of the changes in the average service lives for the various Distribution and General Plant accounts.

A. For the Distribution and General plant accounts, there are 18 accounts with increased average service lives and 6 accounts where there is no change. Of the 18 accounts with increased average service lives, 14 are distribution and four are general plant. Increased average service lives are generally recommended in accounts where there have been scant retirements and the recommendations represent a move closer to the top of the range of other Florida companies. In the distribution accounts, one account has an increased average service life of 40 years; two accounts have increased average service lives of 20 years; three accounts have increased average service lives of 10 years; and ~~six~~ eight accounts have increased average service lives less than 10 years. For the non-amortizable general plant accounts, the average service life for one account increased six years; one account increased four years; and two accounts increased two years.

V. CHANGE IN DEPRECIATION EXPENSE AS A RESULT OF THE PROPOSED DEPRECIATION RATES

Q. What is the purpose of this section of your direct testimony?

A. This section of my direct testimony discusses the change in depreciation expenses resulting from the proposed depreciation rates and components. I specifically detail the major changes in depreciation expense.

Q. Please summarize the depreciation Study results with respect to changes in depreciation expense?

A. The depreciation rates based on the recommended life, salvage, and reserve levels, reflect a decrease in annual depreciation expenses of about $1.5 million. These expenses are based on estimated January 1, 2023, estimated investments. Revised Exhibit PSL-2, Sch. C, shows this decrease is comprised of a decrease of $1.6 million in Distribution Plant and a slight increase of $44 thousand in General Plant.

As shown in the workbook on Revised Exhibit PSL-2, Sch. C, about 95% of the total decrease in estimated annual depreciation expenses is in Distribution Plant, specifically three accounts: Accounts 376.1 and 376G, Plastic and GRIP Mains; and Account 382, Meter Installations. Accounts 376.1 and 376G have increased average service lives and slightly more negative net salvage. Account 382 has an increase in life and slightly more negative net salvage. Changes in parameters affect the reserve position, which is evident in these accounts.

The slight increase in expenses in General Plant is due to the increased average service life for the passenger cars and light trucks accounts and also for power operated equipment netted with the amortization of the general plant reserve deficiency.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

CHAIRMAN FAY: And I have 13 through 16 as well.

BY MR. MUNSON:

Q Ms. Lee, are you prepared to present a summary of your testimony?

A I am.

Q Please proceed.

A Good morning, Mr. Chairman and Commissioners.

My revised direct testimony sponsors the 2023 FPUC depreciation study for the consolidated gas companies in which it requested revised depreciation rates and amortization is to be effective January 1st, 2023, coinciding with new revenue rates.

The study is found on revised Exhibit PSL-2 and contains two major parts. No. 1, a narrative explaining the determination of the proposed depreciation parameters for every account. And No. 2, the study workbook containing the supporting data and resulting depreciation rates, amortization schedules and expenses estimated as of January 1st, 2023.

The purpose of the depreciation study is to determine the appropriate life of salvage value for each account, review the reserve level and develop resulting depreciation rates. The proposed depreciation components are shown in the study workbook revised

Exhibit PSL-2, Schedules A and B. The resulting depreciation rates and amortization schedules are shown on Schedule C, and reflect an annual decrease in depreciation expenses of about $1.5 million compared to existing rates. This includes a proposed five-year amortization of the reserve deficit associated with the amortized general plant accounts. All the decrease in depreciation expenses is found in the distribution accounts and reflects proposed increase lives, offset to some extent by increased negative net salvage values.

This concludes the summary of my revised direct testimony, and I would like to thank you for your time this morning.

MR. MUNSON: Mr. Chair, at this time, we tender the witness for cross-examination.

CHAIRMAN FAY: Okay. Great. Ms. Christensen. You are recognized.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Ms. Lee.

A Good morning.

Q I have a few questions for you this morning. Can I turn your attention to page nine of your direct testimony?

A Is that the revised direct?

Q I don't know if it's impacted by the revised direct, but let's go ahead and use the testimony as originally filed, and then we will talk about the revised as we go through, and if there is a change, you can let me know.

A Okay. I do not have the original direct testimony. I have the revised.

Q Okay. Well, we will do the best we can, then.

A Yes.

Q Okay. Looking on page nine of the testimony you originally filed, I think on lines 15 through 18, you discuss the factors you considered when estimating the service lives, is that correct?

A Okay. That is not -- that's not on my page nine. I am sorry.

Q All right. Well, let me ask you this: You mentioned -- when you were considering the factors in estimating service lives, you mentioned in your testimony, and I can't give you a page reference because it seems we are off -- of aged retirement data, aged distribution and lives of other Florida companies, is that correct?

A That is correct.

Q Okay. And regarding the lives of other Florida companies, you refer to the service lives

approved by the Commission for other Florida utilities, is that correct?

A Or other Florida Gas distribution companies, yes.

Q Okay. And out of these three factors, aged retirement data, aged distribution and lives of other Florida utilities, you would say that you placed the greatest weight or consideration on the lives of other Florida Gas utilities, is that correct?

A That is correct, considering the limited amount of retirement data that Florida Public has been experiencing.

Q Okay. And you would say that considering the lives of other Florida utilities has been a fairly common practice of yours in prior depreciation studies?

A I am sorry, would you repeat the question?

Q Yes. And you would -- you would say that it's been your practice to consider the lives of other Florida utilities, and that's been a fairly common practice of yours in your prior depreciation studies, correct?

A For Florida Public Utilities, or practically for any company that is experiencing very minimal retirement information, yes.

Q Okay. You indicate that for many of FPUC's

accounts, there has been insufficient retirement history to make a statistical analysis meaningful so your reliance on the industry average is necessary, is that correct?

A That is correct. The retirement rate for many of the accounts has been less than one percent, making statistical analysis not reliable in life determinations.

Q Okay. And you say the phrase industrial or industry averages, but to be clear, you are relying only on the Florida natural gas utilities in your analysis, is that correct?

A That is correct.

Q Okay. And further along in your testimony, you state that Florida utilities have similar operating conditions -- or similar operating environments and weather and environmental conditions, is that correct?

A That is correct.

Q Did you provide any specific analysis in this case to show how the weather in Florida directly impacts the service lives of gas assets?

A In my -- in my rebuttal testimony, I believe I have.

Q Okay. And as part of your direct testimony, you did not do that?

A I don't recall in my direct testimony. No.

Q Okay. And then further in your testimony, you state that the Florida companies are subject to harsher operating and environmental conditions of heat, humidity, hurricane incidences and saltwater intrusion the company -- other than companies in other states. Let me say that again because I think that was a little awkward.

In your testimony, you state the Florida companies are subject to harsher operating conditions than other companies in other states such as heat, humidity, hurricane incidences and saltwater intrusion; is that correct?

A That is correct.

Q Did you provide any specific analysis in this case to show these factors directly impact the service lives of these gas assets?

A Any specific evidence? No.

Q Okay. Did you provide any specific analysis comparing the environmental conditions in Florida with those of other states?

A No.

Q Okay. Do other states experience heat, humidity and their own unique environmental factors that might affect the service lives of the gas assets in

those states?

A I am sure some would, not to the extent that the Florida companies do, both gas and electric.

Q Okay. Let me ask you a few questions regarding your revised testimony. You filed that revised testimony on September 9th in this case, is it that correct?

A Correct.

Q And that testimony addressed several errors that were contained in your direct testimony, is that a correct statement?

A I am not sure I would call them errors, but they were oversights. That is correct.

Q Okay. Could you summarize what those -- and we will use your terminology -- oversights were and how it affected the depreciation results?

A On pages one and two of my revised testimony, I go through every instance where there was a change, and it was -- most of the changes were done in the workbook that were a flow-thorough into the schedules in PSL-2. And in some cases, the average ages were not calculated correctly, others were one account, at least for one account they were not. There were some vintages missing. And for other cases, I think there were some -- we found that adjustments needed to be made either to the account balance or to the reserve balance.

Q And generally can you address what the cause of those oversights were?

A I think I just did.

Q Were there any -- is there any other -- just an oversight in the account balances and such? I am just trying to see if there was any, like, specific cause for it, or if it was just a general --

A Actually, it came about in responding to some discovery, and there was an error that we discovered. And then we decided to go back and look at the workbook itself, and that's how we came across these other problematic areas that needed to be addressed.

Q Okay. Fair enough. Thank you.

I have no other west. Thank you, Ms. Lee.

CHAIRMAN FAY: Great. Ms. Christensen.

Mr. Moyle?

MR. MOYLE: I have just a couple of questions.

CHAIRMAN FAY: Okay.

EXAMINATION

BY MR. MOYLE:

Q Where do the companies that are at issue in this case operate?

A Marianna, Central Florida and West Florida, Northwest Florida.

Q And Central Florida as well?
A Well, I am talking about the Palm Beach area.
Q Okay. And in your testimony, you said you were -- looked in Florida. Did you consider looking in South Georgia as a comparable for the operations of the company in Marianna?
A No, I did no not.
Q Yeah. And you said that there wasn't enough information or data to do an analysis of FPUC entities, I think you used one percent, is that right?
A That is correct. It is well-known in the depreciation field that retirements -- retirement rates of less than one percent yield very unreliable statistical analysis results.
Q What's the percent that you need to have a comfort level that you have enough information? I mean, if one percent doesn't work, what does work?
A Well, certainly anything I would say five, 10 percent. Enough data that you could have -- that you could have a valid mortality curve. But even then, that doesn't mean that the statistical analysis is going to be meaningful.
Q Why not?
A It depends on the -- it depends on the dispersion of the retirements. In other words, how the

retirements come in.

You could have, let's say for all intents and purposes, a square wave. Everything will live to a certain point and everything dies at one time; or you can have something like an R1 curve, which means retirements are going to start off right at the beginning and for mortality and then taper down.

The problem is you could have a massive amount of data, but you may not have enough to accurately -- not accurately, but realistically plot a curve.

MR. MOYLE: Okay. That's all I have. Thank you.

CHAIRMAN FAY: Great. Thank you.

Staff?

MR. SANDY: No cross, Mr. Chair.

CHAIRMAN FAY: Okay. Commissioners?

All right. Mr. Munson, redirect?

MR. MUNSON: No redirect. Thank you, Mr. Chairman.

CHAIRMAN FAY: Okay. Mr. Munson, go ahead and enter 13, 14, 15 and 16 into the record without objection?

(Whereupon, Exhibit Nos. 13-16 were received into evidence.)

CHAIRMAN FAY: And, Mr. Munson, would you like your witness excused for now?

MR. MUNSON: Yes, please.

CHAIRMAN FAY: All right. Ms. Lee, we will see you back for rebuttal.

THE WITNESS: Thank you.

CHAIRMAN FAY: Thank you.

Ms. Keating, you are recognized for your next witness.

MS. KEATING: Thank you, Mr. Chair. FPUC calls John Taylor to the stand.

Whereupon,

JOHN TAYLOR

was called as a witness, having been previously duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MS. KEATING:

Q Good morning, Mr. Taylor.

A Good morning.

Q Would you please state your full name and business address for the record?

A John Taylor. 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina, 29926.

Q And by whom are you employed and in what capacity?

A I am a managing partner with Atrium Economics.

Q And on whose behalf are you appearing in this proceeding today?

A It Florida Public Utilities Company.

Q And did you cause to be prepared and filed in this proceeding 27 pages of direct testimony?

A I did.

Q Do you have any changes or corrections to that testimony?

A I do not.

MS. KEATING: Mr. Chair, we would ask that the direct testimony of Mr. Taylor be inserted into the record as though read.

CHAIRMAN FAY: Okay. Show it inserted.

(Whereupon, prefiled direct testimony of John D. Taylor was inserted.)

BEFORE

THE

FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA PUBLIC UTILITIES COMPANY

DOCKET NO. 20220067-GU

DIRECT TESTIMONY

OF

JOHN D. TAYLOR

May 24, 2022

INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Florida Public Utilities Company. ("FPUC" or the "Company").

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

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner.

Q. Have you prepared an Appendix describing your professional qualifications?

A. Yes. Appendix A to my Direct Testimony presents my professional qualifications.

Q. What was Atrium's assignment in this proceeding?

A. FPUC requested Atrium to forecast Test Year Billing Determinants, support a proposed consolidated rate class structure, develop the required embedded class cost of service study ("COSS"), and support its rate design efforts. In this regard, I am sponsoring the COSS that allocates FPUC's gas distribution costs to its proposed rate classes, class revenue increase apportionment, proposed rate design, and associated tariffs. In addition, I am sponsoring several Minimum Filing Requirements ("MFR") schedules required by the Florida Public Service Commission ("FPSC" or the "Commission").

Q. Which MFR Schedules are you sponsoring?

A. Exhibit JDT-1 lists the consolidated MFRs that I am sponsoring or co-sponsoring. A summary of these MFRs is provided below.

- E-1: Page 1: This schedule summarizes therm sales and revenue computed using present rates under the present rate structure.
- E-1: Page 2: This schedule summarizes therm sales and revenue computed using present rates and projected billing determinants under the present and proposed rate structures.
- E-1: Page 3: This schedule summarizes therm sales and revenue computed using proposed rates and projected billing determinants under the proposed rate structure.
- E-2: Pages 1 and 2: This schedule is a comparative schedule that summarizes data shown within the E-1 schedules.
- E-4: Page 1: This schedule demonstrates monthly sales for the historical years of 2018, 2019, 2020, the historical base year ending December 31, 2021, and the project test year. It also shows the historical sales that occurred, by rate schedule, coincident with each historical peak month.
- E-5: All pages: These schedules illustrate monthly bill comparisons under present and proposed rates by rate class.
- E-7: This schedule develops the average meter set and service cost by the current and proposed rate classes.
- E-8: The schedule is used for documenting the direct assignment of facilities.
- G-2 Page 6: This schedule provides the calculation for revenue and cost of gas for the projected 2022 year (historical base year +1).
- G-2 Page 7: This schedule provides the calculation for revenue and cost of gas under the present rate for the test year 2023.

- G-2 Page 8-11: This schedule provides the calculation for revenue and cost of gas under the proposed rates for the test year 2023.
- H Schedules: The H Schedules reflect the Commission provided MFR template for the Fully Allocated Embedded Cost of Service displaying the cost for providing service to each rate class.

Q. Please summarize your testimony.

A. In my testimony, I present the forecasted Test Year Billing Determinants and the process and determinations made in an effort for rate structure consolidation. I then present the COSS and discuss its results, present the revenue increase apportionment to FPUC's rate classes, and present the rate design proposals filed by FPUC in this proceeding. My testimony consists of this introduction and summary section and the following additional sections:

- Development of Billing Determinants and Associated Revenues
- Embedded Class Cost of Service Study
- Principles of Sound Rate Design
- Proposed Consolidation of Existing Rate Schedules
- Determination of Proposed Class Revenues
- Proposed Rate Design

Q. In addition to the MFR Schedules you listed, are you sponsoring any exhibits as part of your direct testimony?

A. Yes, I am sponsoring Exhibits JDT-1 through JDT-4, prepared by me or under my direct supervision. The attachments are as follows:

Table 1 – Exhibits to Direct Testimony of John D. Taylor

Exhibits JDT-1	MRFs Sponsored by John D. Taylor
Exhibits JDT-2	Billing Determinants Forecasting Methodologies
Exhibits JDT-3	Existing Class Conversion to Proposed Rate Classes
Exhibits JDT-4	Alternative Bill Impact by Current Rate Class

I. DEVELOPMENT OF BILLING DETERMINANTS AND ASSOCIATED REVENUES

Q. Are you presenting the historical base year and forecasted test year billing determinants and test year revenues?

A. Yes. This information is provided on MFR Schedule E-1. The starting point on Schedule E-1 (1of3) is the historical 2021 base period number of bills, therm sales, and associated revenues. Then on Schedule E-1 (2 of 3), projected bills and normalized therm sales are presented to reflect projected values under the present rate structure to demonstrate the difference between the base year and projections. Additionally, Schedule E-1 (2 of 3) is presented using the proposed rate structure to show the transition from the current rate classes to the proposed rate classes, further described in Section IV. Finally, Schedule E-1 (3 of 3) is presented for the proposed rates and associated revenue based on the proposed rate structure.

Q. How are the forecasted test year revenues developed for each rate class?

A. Forecasted Test Year revenue is an estimate of the revenue based on forecasted billing determinants and the rates in place when filing for a rate change. It is developed by multiplying forecasted billing determinants for each rate class, comprised of total annual therms and bill counts (customer counts x 12) to the current rates. The billing determinants used to produce the Forecasted Test Year revenue are also used to estimate the revenue from proposed rates.

Q. Please describe how the forecast of annual therms and customer counts was completed?

A. The process contained five steps:

1 - Extraction and Transformation of Annual Data: The first step was to extract and transform the annual customer datasets from 2012 to 2021, representing ten years and 120 months of data. These datasets contained individual customer usage by month and allowed for significant granularity in the data and analytics utilized in the statistical analyses.

2 - Alignment and Categorization of Customers: The next step in the process was to align the data sets across three categories (1) business units, (2) rate classes, and (3) customer classes, so residential and non-residential customers on the same classes can be reviewed separately. This resulted in unique forecast groups that could be further analyzed.

3 – Geo-Location and Incorporation of Weather Data: Once the annual data sets were combined across 96 months and collated into rate classes and customer classes, weather data was incorporated into the data set. In this step, we geo-located all customers using their service address and appropriately assigned HDD values to customer rate classes and business units to their nearest weather station. As a result, six different weather stations were used in different proportions for each combination forecast group that reflected the distribution of customer's assigned weather station within each forecast group.

<u>4 – Initial Statistical Review</u>: Time-Series Decomposition of each forecast group was calculated to identify trends and seasonal patterns within the data. In addition, correlation calculations were analyzed to ascertain which forecast groups' demonstrated weather-sensitive usage across the 120 months. Data was analyzed to ascertain which forecast groups contained trending customer counts. Lastly, a statistical analysis was conducted, which indicated customer usage was not dependent on natural gas prices.

<u>5 – Forecast of Customer Count and Use Per Customer</u>: The last step was to forecast Customer Count & Use per Customer using multiple linear regression and Autoregressive Integrated Moving Average (ARIMA) [1] models those forecast groups exhibiting weather-sensitive loads and trending customer counts. Model comparison was performed by back-testing each model on the last 24 months in order to assess accuracy and statistical diagnostics. The model with the highest accuracy and successful model diagnostics tests was chosen as the final forecasting model.

Q. How were these results used to develop the forecasted billing determinants and forecasted customer counts?

A. The Company has four gas business units throughout Florida and 54 different tariffed rate classes. Customer growth for each division and rate class was forecasted individually and then aggregated to get total company level forecasts. The following methods were applied to the customer groups to develop billing determinant projections:

- Use per Customer - Forecasted customer counts are multiplied by the use per customer projections developed in the regression analysis discussed above.

[1] ARIMA models are commonly used to gain insight and develop forecasts from time series data. The features of an ARIMA model is that it uses lagged moving averages to predict future averages taking into account, trends, seasonality, and randomness in a data set; while weighing more recent data points more.

- Use per Customer Growth Rate – Current use per customer is escalated using the projected percent change produced by the regression analysis.
- Historical Base, Average or Adjusted - Historical base period relies on the 2021 data. Average uses 2019-2021 average billing determinants. In some instances, classes were adjusted to known events that will impact their forecasted usage.

Please see Exhibit JDT-2 for the methods applied to each customer class to determine forecasted customer count and billing determinants.

Q. Were the projections reviewed for reasonability by any other parties?

A. After the projections were completed, they were also reviewed by FPUC personnel familiar with customer growth and usage trends across the four gas business units.

Q. Did you adjust the forecast to account for recent economic trends, global energy markets, or changes in usage occurring from Coronavirus disease 2019 ("COVID-19")?

A. No. The estimates were developed by rigorously analyzing historical data and applying robust ARIMA and Multiple Linear Regression models, commonly used for demand forecasting across multiple industries. By back-testing models over the past two years (i.e. January 2020-December 2021) we were able to see that both models maintained a high degree of accuracy throughout this time-period. With exceptions of a few months due to COVID-19 related economic shocks, the high-degree of accuracy that was able to be maintained highlights the success of this statistical modelling process. In addition, the high-level of testing accuracy showcases the natural consumption and trends of customers and usage within forecasted groups.

While natural gas prices are seeing recent increases and possible future volatility due to instability in global natural gas markets, statistical analysis indicated usage was not dependent on gas prices. Lastly, economic trends and changes in housing markets impact demand for natural gas services and usage levels, but these variables are difficult to predict and can lead to careless extrapolations. The United States economy and Florida's economy have recovered from the initial impact of COVID-19, but recent market losses and high inflation rates may put a damper on economic growth. The benefit of an ARIMA model is its unbiased processing of time-series data where it is not necessary to adjust for specific occurrences of outliers through 'dummy variables' or include multiple variables that can only have marginal impacts on the forecast. In short, the forecast is robust and rigorous and represents an accurate expectation of the future without assumptions about the occurrence of extreme non-typical situations – or at least extreme non-typically situations that have not occurred over the last ten years.

Q. How are rate class revenues presented in the MFRs?

A. Projected revenues by customer class presented monthly on Schedules G-2 Pages 6 through 11, depicting the development of the proposed revenues for the bridge (historical base year +1) and test years under the current rates, and test year revenues under the proposed rates. Customer bills and associated billing determinants were determined based on the process discussed above and incorporated into Schedule G-2 Pages 6 through 11. Schedule G2 Page 6 reflects revenues for the bridge between the historical and test year under the current rates. Similarly, Schedule G-2 Page 7 reflects revenues for the projected test year under present rates. Finally, Schedule G-2 Page 8 derives revenues based on the projected customer bills and billing determinants under the proposed rates.

II. EMBEDDED CLASS COST OF SERVICE STUDY

Q. What is the general purpose and use of a COSS in regulatory proceedings?

A. The purpose of a COSS is to allocate the gas distribution utility's overall adjusted test year costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. Conducting a COSS represents an attempt to analyze to what degree each group of customers causes the utility to incur costs to provide service. Finally, COSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class, help determine the individual class revenue responsibility, and provide guidance with rate design. Using the cost information per unit of demand, customer, and energy developed in the COSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Are there factors that influence a gas utility's overall cost allocation framework when performing a COSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation to allocate costs to customer groups. Cost causation addresses the question - which customer or group of customers causes the utility to incur particular costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors which can influence the cost allocation methods used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility. It is important to understand these considerations because they influence the overall context of a utility's cost of service study and indicate where efforts should be focused to conduct a more detailed analysis of the utility's gas system.

Q. Please describe the cost of service model utilized to develop the COSS?

A. The Excel-based cost of service model used was provided by the PSC and is required to be submitted as part of the Minimum Filing Requirements (MFR).[2] The required cost of service model is within the MFR H Schedules. It consists of several pages utilized to allocate various components of the Company's revenue requirements prescribed by the Excel model's built-in formulas and logic. It summarizes the results of these allocations showing the current rate of return for each rate class and the revenue requirement at an equal rate of return.

Q. Is the COSS filed in this proceeding aligned with previous cost of service studies filed by the Company in past rate case proceedings?

A. In the Company's previous three rate case filings[3], the Company relied on the Cost of Service Model provided by the PSC and required to be submitted as part of the Minimum Filing Requirements. While a comprehensive review was not undertaken to detail every difference between these filings and the present H Schedule, I reviewed these past

[2] The information required by Commission Form PSC 1027 (12/20), entitled "Minimum Filing Requirements for Investor Owned Natural Gas Utilities," which is incorporated into rule 25-7.039, and is available at http://www.flrules.org/Gateway/reference.asp?No=Ref-12643.

[3] Florida Public Utilities Company (Natural Gas Division) 2009 Rate Case – Docket No.: 080366-GU | Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas 2007 Rate Case Docket No. 09125-GU | Florida Public Utilities Company-Indiantown Division 2003 Rate Case Docket No. 030954-GU

filings, and they appear to align with the methods employed in this case.

Q. What was the source of the cost data analyzed in the Cost of Service Model?

A. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and schedules in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel. For instance, the weighted customer allocation factor used in MFR Schedule H was developed based on the average cost of providing a meter and service for each rate class, as shown in MFR Schedule E-7 for the current and proposed rate structures.

Q. How are the FPUC rate classes structured for purposes of conducting the Cost of Service Model?

A. As discussed in section III below, the Company proposes 16 consolidated rate classes and developed the COSS using relative costs and usage details for these 16 consolidated rate classes.

Q. Please describe the organization of the Cost of Service Model?

A. The Cost of Service model starts with the population of Schedule H-3. Within Schedule H-3, all projected expenses (operating, maintenance, depreciation, amortization, income taxes, and taxes other than income taxes), rate base, and accumulated depreciation are listed by FERC general ledger and plant account classifier. Schedule H-3 classifies costs as Customer, Capacity, and Commodity. Then Schedule H-2 allocates these classified costs to each rate class included in the COSS. Schedule H-1 summarizes these allocations, illustrating the deficiency for each rate class and the current rate of return.

Q. Please describe the content of Schedule H-1, which summarizes the results of the COSS?

A. The difference between the computed revenue requirement and the revenue that would be derived without making any rate changes equals the Company's Net Operating Income deficiency, as shown on Schedule H-1 / Schedule D. The Rate of Return is determined by subtracting the revenue derived from each rate class from the expenses attributable to each rate class and then dividing the result by the rate base attributed to each rate class. Schedule H-1 / Schedule C within the PSC provided H Schedule contains two pages. Page 1 contains the rate of return projected to be otherwise realized by rate class, absent a rate increase in the results for the projected test year. Page 2 shows the rate of return resulting from each rate class providing an equal rate of return, commonly referred to as parity. An additional page (Page 3) was added to this template showing the Company's proposed revenue targets by rate class, further described in Section V below. [4] Lastly, H-1 Schedule A contains the Company's proposed revenue targets by rate class, the proposed customer charge rates, and proposed volumetric rates.

Q. Please summarize the results of COSS.

A. Table 2 below presents a summary of the results of the COSS that can be reviewed in detail within MFR Schedule H-1 Schedule D (page 5 of 6). The COSS shows an overall revenue deficiency to the Company of $24,061,982.

[4] The PSC provided MFR template Schedule H-1 / Schedule B contained a line item titled 'STAFF PROPOSED RATES', which was linked to the revenues on Schedule H-1 / Schedule C – showing the revenues for each class at equal rates of return. This page was maintained but the line item 'STAFF PROPOSED RATES' was changed to 'REVENUES AT EQUAL RETURN' denoting revenues were set at equal rates of return as shown on Schedule H-1 / Schedule C.

Table 2 - Summary Results of the Company's COSS

Rate Class	Current Revenues	Cost to Serve	Deficiency/ (Surplus)	Current Rate of Return
Residential - 1	$ 5,457,010	$ 14,128,326	$ 8,671,315	-11.44%
Residential - 2	$ 10,328,828	$ 20,340,879	$ 10,012,051	-6.61%
Residential - 3	$ 13,056,717	$ 14,351,536	$ 1,294,819	5.62%
Residential Standby Generator	$ 303,620	$ 579,384	$ 275,765	-6.49%
General Service - 1	$ 1,230,993	$ 1,860,588	$ 629,595	-1.87%
General Service - 2	$ 5,456,957	$ 5,217,182	$ (239,775)	8.78%
General Service - 3	$ 7,450,797	$ 6,713,188	$ (737,610)	9.96%
General Service - 4	$ 13,895,724	$ 12,262,074	$ (1,633,650)	10.29%
General Service - 5	$ 5,205,845	$ 5,429,641	$ 223,796	7.07%
General Service - 6	$ 4,367,327	$ 5,030,163	$ 662,836	5.47%
General Service - 7	$ 2,691,137	$ 3,829,088	$ 1,137,951	2.56%
General Service - 8	$ 4,411,913	$ 9,334,864	$ 4,922,951	-1.52%
Commercial - Interruptible	$ 3,156,442	$ 1,974,888	$ (1,181,554)	18.35%
Commercial - NGV	$ 395,638	$ 390,112	$ (5,526)	8.05%
Commercial - Outdoor Lighting	$ 137,878	$ 49,980	$ (87,897)	41.69%
Commercial Standby Generator	$ 169,139	$ 286,053	$ 116,914	-4.52%
Total Base Rate Revenue	**$ 77,715,965**	**$ 101,777,947**	**$ 24,061,982**	
Other Operating Revenue	**$ 3,589,353**			
Total Distribution Margin Revenue	**$ 81,305,318**			**2.51%**

Table 2 presents the revenue deficiency/(surplus) for each rate class and the class rate of return on the net rate base at present rates. Regarding rate class revenue levels, Table 2 shows that all classes except GS-2, GS-3, GS-4, Commercial-Interruptible, Commercial-NGV, and Outdoor Lighting are being charged rates that recover less than their indicated costs of service.

III. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

1) Cost of Service;

2) Efficiency;
3) Value of Service;
4) Stability/Gradualism;
5) Non-Discrimination;
6) Administrative Simplicity; and
7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James C. Bonbright in Principles of Public Utility Rates; Columbia University Press (1961).

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, these principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. There are tensions between cost and value of service principles and efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination; and between the value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process. For FPUC, these unique circumstances are related to the effort of rate consolidation, which adds another competing element in rate design reviews.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which included the design of a consolidated rate structure, the apportionment of the revenues to be recovered among rate classes, and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process must, in part, be influenced by judgmental evaluations.

IV. PROPOSED CONSOLIDATION OF EXISTING RATE SCHEDULES

Q. Does the Company propose any modifications to its existing rate classes?

A. Yes. The Company proposes consolidating its current 54 tariffed rate classes across four service territories into 16 rate classes, as shown in Table 2 below.

Table 3 – Proposed Rate Classes and Applicability

Proposed Rate Classes	Applicability (Therms)
Residential – 1 - Closed	< 100
Residential - 2 - Closed	≥ 100 < 250
Residential - 3	≥ 250 or New Customers
Residential Standby Generator	n/a
General Service - 1	< 1000
General Service - 2	≥ 1000 < 5,000
General Service - 3	≥ 5,000 < 10,000
General Service - 4	≥ 10,000 < 50,000
General Service - 5	≥ 50,000 < 250,000
General Service - 6	≥ 250,000 < 500,000
General Service - 7	≥ 500,000 < 1,000,000
General Service - 8	≥ 1,000,000
Commercial - Interruptible	≥ 100,000
Commercial - NGV	n/a
Commercial - Outdoor Lighting	n/a
Commercial Standby Generator	n/a

Q. Is the Company proposing full consolidation of rates across all business units?

A. Given the existing large rate disparity across the Company's business units, the proposed consolidation is one of rate structure and not full consolidation of rates. The proposed rate classes listed in Table 3 above will be available across all existing FPUC business units, but the rates charged will be unique to three service areas. As further discussed in Section VII, the Company proposes fully consolidating the rate classes and rates for Florida Public Utilities Company (Natural Gas Division) and Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas. The proposed rate classes will also be utilized for Florida Public Utilities Company-Fort Meade and Florida Public Utilities Company-Indiantown Division, but the rates will differ. As such, there will be three sets of proposed rates applicable to three service areas: (1) Florida Public Utilities Company (Natural Gas Division) and Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas, (2) Florida Public Utilities Company-Fort Meade and (3) Florida Public Utilities Company-Indiantown Division.

Q. Why is the Company proposing this consolidation of rate classes?

A. The Company undertook a review of its current rate structures across all four business units and found the current rate structures are overly stratified and the overall number of different rate classes unnecessary. For instance, the Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas relies on 25 different tariffed rate classes, with five closed to new customers. The Company retained Atrium Economics to review these current rate structures and develop a consolidated structure to modernize and align rate classes across all four business units. The principles of rate design discussed in Section II above were relied on as guiding principles, where efforts were made to balance concepts of cost of service, efficiency in rates, simplicity, and feasibility – ultimately resulting in alignment and modernization through a consolidated rate structure. Atrium worked collaboratively with FPUC personnel in this review and the development of the consolidated structure presented in this testimony.

Q. What analyses were utilized in developing the proposed rate classes?

A. Atrium performed a detailed analysis of the customers' premises and related annual consumption of therms based on the historical year 2021 to recommend customer transition to the proposed classes. The primary guiding principles to transition customers from existing classes to the new ones were customer type and annual consumption. All customers were grouped into homogeneous groups to understand the Company's customer structure from the consolidated perspective and their consumption behaviors. The current rate structures, represented by 54 distinct tariffed rate classes, were reviewed to develop reasonably aligned applicability ranges across a more manageable number of rate classes. The analysis and recommended transition of the current customers to the proposed classes were reviewed with FPUC personnel before finalizing the proposed rate classes.

Q. Are customers on existing rate classes all moving to the same proposed consolidated rate class?

A. No. Given the differences in the current rate structures across the business units, the consolidation process could not match each present rate class to a proposed rate class. If there were a one-to-one matching between existing and proposed rate classes, dozens of rate classes would remain. Instead, new applicability thresholds resulted in customers on the same existing rate class moving to different proposed rate classes. For instance, the Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas includes a rate class Firm Transportation Service - 1, which contains both residential and non-residential accounts. Customers on this rate class were migrated to Residential 1, Residential 2, Residential 3, General Service-1, and General Service-2. Each individual customer was assigned to the proposed consolidated classes according to their customer type and annual consumption. As a result, the conversion schedules were developed to transition forecasted customer counts and billing determinants to the proposed classes, as depicted in Exhibit JDT-3.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach to apportion FPUC's proposed revenue increase to its rate classes.

A. The apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines related to the design of utility rates. The various criteria that were considered in the process included: (1) class contribution to present revenue levels, (2) customer impact considerations, and (3) cost of service.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of FPUC's interclass revenue proposal?

A. Yes. Using FPUC's proposed revenue increase and the results of the COSS, Atrium evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with FPUC personnel and management, ultimately decided upon one of those options as the preferred method. The first option evaluated was to set revenues to the cost to serve for each rate class resulting from the methods employed in the COSS, as shown in MFR Schedule H page 2 of 6. However, this fully cost-based option was not the preferred solution, as there were large increases required for some of the rate classes. For instance, moving the Residential-1 rate class to their cost to serve would require an $8.7M increase to their current revenues of $5.5M, representing a 146% increase, as shown on MFR Schedule H-1 page 2 of 6. A second option considered was assigning the increase in revenues to FPUC's proposed customer classes based on an equal percentage basis of its current non-gas revenues. In other words, every rate class would receive the same percentage increase on a fully consolidated basis. However, when this option was evaluated, significant increases were developing for customers served on FPUC's existing rate classes for the Fort Meade and Indiantown business units. Given the relatively lower total revenue contributions from these business units, it was determined to first set these business units' average increase to 19% for Ft. Meade and 24% for Indiantown. This created a safeguard for these customers so they would not receive significant increases resulting from the consolidation of rates across all four divisions.

Q. Once the total revenues were set for these two divisions, how was the remaining revenue apportioned to the other two business units?

A. After further discussions and review, it was determined the current rates were adequately similar to facilitate full consolidation of rates for (1) Florida Public Utilities Company (Natural Gas Division) and (2) Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas. The remaining revenue requirement was apportioned to the consolidated rate classes for those customers historically served from these two business units, in varying proportions. While efforts were made to move each rate class closer to their cost to serve, this movement was mitigated in an effort to limit customer bill impacts. The result of this approach is reflected on MFR

Schedule H-1 page 1 of 6 and in Table 4 and Table 5 below. Table 4 shows the proposed based rate revenues for each rate division. Table 5 summarizes the proposed revenue change for each rate class and the percent change in total revenues resulting from the above-described process.

Table 4 – Proposed Revenues by Rate Division

Rate Class	Proposed Revenue	Indiantown	Ft. Meade	CFG & FPUC
Residential - 1	$ 6,556,821	$ 28,616	$ 40,806	$ 6,487,400
Residential - 2	$ 12,630,036	$ 77,232	$ 48,257	$ 12,504,548
Residential - 3	$ 14,636,336	$ 32,734	$ 17,413	$ 14,586,190
Residential Standby Generator	$ 449,720	$ -	$ -	$ 449,720
General Service - 1	$ 1,508,776	$ 2,928	$ 6,606	$ 1,499,242
General Service - 2	$ 7,127,922	$ 3,365	$ 21,819	$ 7,102,738
General Service - 3	$ 10,216,479	$ 5,852	$ 15,002	$ 10,195,625
General Service - 4	$ 19,345,105	$ 2,559	$ 33,407	$ 19,309,139
General Service - 5	$ 7,516,343	$ -	$ 35,860	$ 7,480,483
General Service - 6	$ 6,909,833	$ -	$ -	$ 6,909,833
General Service - 7	$ 4,240,887	$ -	$ -	$ 4,240,887
General Service - 8	$ 6,162,549	$ -	$ -	$ 6,162,549
Commercial - Interruptible	$ 3,645,154	$ -	$ -	$ 3,645,154
Commercial - NGV	$ 518,135	$ -	$ -	$ 518,135
Commercial - Outdoor Lighting	$ 66,160	$ -	$ -	$ 66,160
Commercial Standby Generator	$ 247,691	$ -	$ -	$ 247,691
Total Base Rate Revenue	**$ 101,777,947**	**$ 153,286**	**$ 219,169**	**$101,405,492**
Other Operating Revenue	**$ 3,589,353**			
Total Distribution Margin Reven	**$ 105,367,301**			

Table 5 - Proposed Class Revenue Apportionment

Rate Class	Current Revenues	Proposed Revenues	Proposed Increase	Percent Increase
Residential - 1	$ 5,457,010	$ 6,556,821	$ 1,099,811	20%
Residential - 2	$ 10,328,828	$ 12,630,036	$ 2,301,207	22%
Residential - 3	$ 13,056,717	$ 14,636,336	$ 1,579,619	12%
Residential Standby Generator	$ 303,620	$ 449,720	$ 146,100	48%
General Service - 1	$ 1,230,993	$ 1,508,776	$ 277,783	23%
General Service - 2	$ 5,456,957	$ 7,127,922	$ 1,670,966	31%
General Service - 3	$ 7,450,797	$ 10,216,479	$ 2,765,682	37%
General Service - 4	$ 13,895,724	$ 19,345,105	$ 5,449,381	39%
General Service - 5	$ 5,205,845	$ 7,516,343	$ 2,310,498	44%
General Service - 6	$ 4,367,327	$ 6,909,833	$ 2,542,506	58%
General Service - 7	$ 2,691,137	$ 4,240,887	$ 1,549,751	58%
General Service - 8	$ 4,411,913	$ 6,162,549	$ 1,750,636	40%
Commercial - Interruptible	$ 3,156,442	$ 3,645,154	$ 488,712	15%
Commercial - NGV	$ 395,638	$ 518,135	$ 122,497	31%
Commercial - Outdoor Lighting	$ 137,878	$ 66,160	$ (71,718)	-52%
Commercial Standby Generator	$ 169,139	$ 247,691	$ 78,552	46%
Total Base Rate Revenue	**$ 77,715,965**	**$ 101,777,947**	**$ 24,061,982**	**31%**

VI. PROPOSED RATE DESIGN

Q. Please summarize the proposed rate design.

A. As mentioned previously in this testimony, FPUC is proposing three groups of unique rates: (1) Florida Public Utilities Company (Natural Gas Division) and Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas, (2) Florida Public Utilities Company-Fort Meade and (3) Florida Public Utilities Company-Indiantown Division. The first step in the rate design process was to set Customer Charges for each rate class. As with the appointment of revenues, setting the customer charges for the consolidated rate classes was done to minimize bill impacts for customers with different usage ranges and differing existing customer charges. Thus, consideration was given to current customer charges across the group of customers on the consolidated rate class.

The result of this analysis is that for the residential classes (RS-1, RS-2, and RS-3) and small general service customers (GS-1 and GS-2), the customer charges were set below the customer unit costs within the COSS; see MFR Schedule H-1 page 5 of 6. For instance, had we strictly used the COSS model results, the monthly Customer Charge for Residential-3 would be $37.87. Instead, we propose a $26.50 per month customer charge for the Residential-3 rate class. Existing customer charges were above the unit costs for the larger general service classes, which is a desirable outcome for these size customers. This represents the recovery of fixed demand-related costs through the fixed monthly customer charge, rather than demand rates which are not in place for any of the 54 existing rate classes.

In addition, the customer charge rates for the Residentials and Commercial Standby Generator Service were moved closer to the indicative unit costs in the COSS to reflect they are being provided access to the distribution system but may use gas rarely, if ever at all.

Lastly, the Company developed a new block rate structure for its largest industrial customers and proposed to close the two smallest residential classes to new customers.

Q. Why does the Company propose to close the two smallest residential classes to new customers?

A. The initial goal of the consolidation was to limit residential customers to one rate class; however, given the numerous rate classes currently in place for the Company, large bill impacts were occurring from this consolidation to a single residential rate. Separating residential customers into three distinct groups allowed for rate design that provides bill impact relief to the smallest customers, given the smallest residential customers are proposed to remain below their cost to serve. However, the Company is proposing revenues for Residential-3 close to their indicated cost of service; i.e., the COSS shows a total revenue requirement of $14,351,536 (see MFR Schedule H-1 Schedule D), and the proposed revenues from this class are $14,636,336 (see Table 4 above). As a result, any new residential customers on FPUC's system will be served under Residential-3, ensuring that new customers contribute their cost to serve and are not subsidized by other rate classes.

Q. Why are volumetric block rates introduced for the proposed General Service-8 Class?

A. Block volumetric charges were introduced for General Service-8 to mitigate bill impacts on the Company's largest customers. Customers that migrated to General Service-8 were previously on FPUC – Large Volume Transportation Service rate and Central Florida Gas's Firm Transportation Service – 10, Firm Transportation Service – 11, and Firm Transportation Service – 12. The volumetric block charges allowed for the mitigation of bill impacts by a closer alignment between the current volumetric rates across these existing rate classes and proposed rates.

Q. Have you provided a schedule detailing the proposed rates and corresponding revenues?

A. Yes. MFR Schedule H-1 Schedule A contains the proposed customer charges and volumetric charges and the corresponding revenues generated for each of the proposed rate classes for the three rate divisions: (1) Florida Public Utilities Company (Natural Gas Division) and Florida Division of Chesapeake Utilities Corporation d/b/a Central Florida Gas, (2) Florida Public Utilities Company-Fort Meade and (3) Florida Public Utilities Company-Indiantown Division. The PSC provided version of MFR Schedule H-1 Schedule A was amended to reflect the proposal to develop three rate divisions. Each of these three sections follows the same format of developing rates, first calculating the portion of revenues recovered through the customer charge and then recovering the remaining targeted revenues through the volumetric charges. Further, the proposed block rate structure for the General Service-8 rate class is shown in this schedule.

Q. What are the corresponding bill comparisons for FPUC's customers served under its existing rate schedules?

A. As required by MFR Schedule E-5, the Company's prepared bill impacts for each of the existing rate classes. These bill impact tables are developed for each unique mapping of existing rate classes to the proposed consolidated rate class structure. Providing these bill impacts in the required MFR format resulted in dozens of tables due to the mappings from existing rate classes to proposed rate classes. For instance, under the proposed rate classes, customers on Central Florida Gas's existing rate schedule Firm Transportation Service – 1 would migrate to five distinct consolidated proposed rate classes: (1) Residential-1, (2) Residential-2, (3) Residential-3, (4) General Service-1, and (5) General Service-2. As such, there are five distinct bill impact analyses for this one existing rate class.

Q. What other bill impact analyses are you providing for review?

A. Additional bill impact analyses specific to base rate changes were developed to provide insights into the average customer bill impact for customers moving from their existing rate classes to the proposed rate classes. These bill impacts of an average customer were reviewed while apportioning the total revenue increase to each rate class and setting the proposed customer and volumetric charges. The primary focus in developing base rates was monitoring the bill changes associated with transitioning customers to the proposed classes based on their annual consumption levels. While the range of customers transitioning from the current classes varies, the goal was to limit increases for the majority of the customers within the proposed class. To accomplish this, the weighted average bill impact was developed to account for the number of customers and their proportionate contribution to the overall bill changes for the entire proposed class. For example, as demonstrated in Exhibit 4 Page 1, the total Residential Class - 3 includes 19,490 customers; within that class, 15,664 or 81% of customers on average will expect an 11.1% of the annual bill increase while 2,493 or 13% of customers will expect an average increase of 24.8%. As a result, the overall prorated weighted average impact based on the proposed base rates for the Residential Class - 3 is 12.7%, as depicted in Exhibit 4 Page 2. As described above in Section V, the cost to serve was considered, resulting in some classes moving closer to parity, ensuring other classes were not materially moving away from parity, and existing rate subsidies among rate classes were not increased.

Q. Does this conclude your prefiled direct testimony?

A. Yes.

BY MS. KEATING:

Q And, Mr. Taylor, you did also cause to be prepared and filed Exhibits JDT-1 through 4?

A I did additional.

Q Do you have any changes or corrections to those exhibits?

A No, I do not.

MS. KEATING: Mr. Chair, I believe those exhibits are marked on staff's Comprehensive Exhibit List as Exhibits 17 through 19.

CHAIRMAN FAY: Okay. Correct.

MS. CRAWFORD: Mr. Chairman, I -- just for clarity, I believe that's on the staff Exhibits 17 through 20. Four exhibits.

MS. KEATING: Ms. Crawford is correct.

CHAIRMAN FAY: 17 through 20. Thank you, Ms. Crawford.

MS. KEATING: That goes to show you how good my math is.

BY MS. KEATING:

Q Mr. Taylor, did you prepare a summary of your direct testimony?

A I did.

Q Would you please go ahead and present that?

A Good morning, Commissioners. Thank you for the opportunity to address you today.

My direct testimony describes the method employed to develop the forecasted test year billing determinants, supports the proposed consolidated rate class structure, summarizes the required embedded class cost of service study and supports the company's rate design proposals.

The company has 54 distinct tariff rate classes across four business units, and is proposing to consolidate these 54 rate classes into 16. The forecast developed for these 16 rate classes were established by a rigorously analyzing historical data over 9 million data points across 10 years, and applying several statistical analysis techniques commonly used for forecasting.

The regressions in forecast considered overall trends in customer growth, average use per customer, response to the weather and known changes. The results of this process are the basis for the weather normalized forecasted test year billing determinants.

Next I present the cost of service study, the purpose of which is to allocate the company's overall adjusted test year cost to each rate class in a manner that reflects the manner of cost to providing service to each class. The Excel-based cost of service model presented in my testimony was provided by the Commission and is required to be submitted as part of the MFRs.

Lastly, I present the proposed revenue targets and rates for the consolidated structured, which are developed to balance concepts of cost of service, efficiency in rates, simplicity and feasibility, ultimately resulting in alignment and modernization. A significant driving component of the revenue targets by class and rate design was the review of bill impacts for groups of customers.

Given the existing rate disparity across the company's business units, the proposed consolidation is one of rate structure and not complete consolidation of rates. As such, there are three sets of proposed rates applicable to three services areas. First, Florida Public Utilities Company in Central Florida Gas. Second, FPUC's Fort Meade business unit. And third, FPUC's Indiantown business unit.

This concludes my summary, and I would like to thank Commissioners for their time this morning.

Q Thank you, Mr. Taylor.

MS. KEATING: Mr. Chair, the witness is tendered for cross.

CHAIRMAN FAY: Great. Thank you.

Ms. Christensen?

MS. CHRISTENSEN: No questions for the witness.

CHAIRMAN FAY: Okay. Mr. Moyle?

MR. MOYLE: Just a few.

EXAMINATION

BY MR. MOYLE:

Q So what's your understanding as to why all the rates were consolidated from 54 down to 16?

A I believe it was a combination of administrative simplicity and ensuring that it's ease of customer understanding. You know, the rate structures that were currently in place were, I would say somewhat antiquated, overly complicated and were ripe for some alignment and modernization.

Q With respect to the consolidation, did you identify any negative effects on industrial customers through the consolidation of rates, and if so, could you explain that those were?

A No, I don't think we identified any negative effects to industrial customers. We did develop a block rate structure for one of the larger industrial classes to take into account bill impacts and try to moderate the increase that certain customers would have seen through the alignment of rates.

MR. MOYLE: Thank you. That's it.

CHAIRMAN FAY: Staff?

MR. SANDY: Yes, Mr. Chairman, I have a few questions.

EXAMINATION

BY MR. SANDY:

Q Mr. Taylor, in addition to your witness testimony, you also sponsored some answers to discovery requests in this matter. You should have a copy of one of those requests right in front of you that would be listed as, for the sake of the record, FPUC's response to Staff Interrogatory No. 86B. Have you got a copy of that in front of you right there?

A I do. Could you let me know what set that is?

Q That would be the ninth set of staff's interrogatories.

A Thank you.

Q Let me know when you are there and we can proceed.

A I have it in front of me.

MR. SANDY: And, Mr. Chairman, for identification purposes, I would mark this as CEL Exhibit --

CHAIRMAN FAY: 124, is that right?

MR. SANDY: I would actually mark it as 124. However, for reference, this response is already in

CEL Exhibit 110 that is admitted into the record, but we can converse about it as 124 if we need to.

CHAIRMAN FAY: Okay. Go ahead.

(Whereupon, Exhibit No. 124 was marked for identification.)

BY MR. SANDY:

Q Now, Mr. Taylor, ultimately your response for 86B has to do with an FPUC customer class, is that right?

A I am sorry, can you repeat that?

Q Sure. Sure. Sure. Sure.

So ultimately, your response to that particular question revolves around a customer class of the utility, would you agree with me there?

A It looks like the response has a couple tariffed rate classes, Transportation Service 3, national gas vehicle from Transportation Service B, potentially a couple more here in the document.

Q Well, I would like to ask you specifically about the customer class labeled Natural Gas Vehicle Transportation Service. Do you see that there, probably in about the middle of the page?

A I do.

Q Okay. Now, is it right to say that you provided use per customer forecasts in that answer for

2022 and 2023?

A I believe this is a percentage difference that was requested in the question rather than a forecasted number.

Q Okay. Is it fair to say that the percentage difference that you lay out under the column 2022 Forecasted is negative 16?

A Yeah. So just to be clear here. The document that was referenced in the question, which is an Excel workbook as an attachment to staff POD 2-10 was used to calculate these percentage differences. I believe the attachment to staff POD 2-10 was supplemented. So I am not sure if the supplemented attachment impacts what was presented in the question in this response or not.

Q Okay. Well, what my questions ultimately revolve around your decision-making on methodology more than anything else, and so maybe that will help flesh things out ultimately.

Is it fair to say that you relied upon a historic average in providing answers for that particular question?

A Yes. Again, that supplemental response, I believe, updated that historic number, but it was some historic number for 2017 through 2021, and then the forecast that I developed for 2022 and 2023.

Q Okay. And so I am looking at your answer there, and it has listed for 2017 and 2018 zero percentage, would you agree with me there? Do you see that there in the page?

A Yes.

Q Okay. Would that indicate, then, that in working up your historic average that you were utilizing the years 2019, 2020 and 2021?

A I believe that any instance in which we used a historic average was a three-year average. Correct.

Q Was a three-year average.

So this gets me to my ultimate questions, which is why did you use a historic average in lieu of the use per customer year-over-year growth rate analysis?

A That's a great question. The -- in JDT-2, you can see the methodology for each of the rate classes that were used for forecasting, you know, in instances in which we chose to use either a base period or an average historic period is because there was not robust progression analysis resulting from analyzing those particular rate classes, or the rate class was small enough in which a statistical analysis would not be appropriate.

So for natural gas vehicle, it's a pretty small number of customers, and the choice was made to use a average historic basis.

Q Okay. And in utilizing that historic average, why didn't you rely on five years worth of information as opposed to a three-year average?

A In most instances, I try to rely on some more recent average data than five years. I think the last three years can be more predictive than the last five years.

Q Okay. I am not asking necessarily for math on the fly or anything. Is it fair to say that if you would have utilized a five-year average, that may have rendered a different result in your calculations?

A Yeah, any -- in any instance in which you use a five-year average instead of a three-year average, insomuch as the first two years are different than the next three years, the average would be different.

Q Okay. And would it also be true -- and again, I am not asking for any math on the fly or anything, but would utilizing a year-over-year growth analysis, ultimately changed or altered your conclusions as opposed to utilizing the historic average which you relied upon in answering this question?

A Yes. Mathematically that's true.

Q Okay.

MR. SANDY: Mr. Chairman, may I have a moment?
CHAIRMAN FAY: Yes.
MR. SANDY: Thank you, sir.
BY MR. SANDY:
Q The last question I have for you, Mr. Taylor, is: Would you agree with me that the use per customer rate, save for the last three years, looks as if it's increasing year-over-year? In other words, is on an upward trajectory?
A Are you asking about the actual use per customer or a weather normalized use per customer? And are you asking for the entire company or a particular rate class? I just want to make sure I answer correctly.
Q Sure. That's perfectly legitimate. I would ask you to rely upon the information set forth in your answer for 86 bravo.
A Are we still focused on the natural gas vehicle?
Q We are. We are, sir.
A All right. Then can you repeat the question?
Q Certainly.
Would you agree with me, that in the numbers as set forth there, it looks as if use per customer, at least for the last three years, looks as if it's on an

upward swing, in other words it's increasing?

A I would -- I would love like to have that supplemental response in front of me so I could tell you what the actual data is. I think based on this answer, you are asking me if the percen-- if there is a percentage increase that is repeating over '19, '20 and '21. And that is accurate. So there is an increase that is occurring in the last few years based on this data.

Q Okay. With that in mind, where it looks as if -- I think we can agree that it looks as if that there is an increase in usage, how, then, would you reconcile the -- the, I guess the negative 16 as set forth in your answer for the forecasted for 2022?

A Well, the supplemental response that we have updated '19, '20 and '21, so the numbers would not result in a negative, you know, the -- I think what you are seeing is you are seeing a percentage increase and then an average forecast that's lower than that percentage increase. I believe that the supplemental response has updated numbers for '19, '20 and '21, which would better align with our forecast.

MR. SANDY: I have no further questions, Mr. Chair.

CHAIRMAN FAY: Okay.

MR. SANDY: Thank you, Mr. Taylor.
THE WITNESS: Thank you.
CHAIRMAN FAY: Thank you.
Commissioners?
Okay. Ms. Keating, redirect?
MS. KEATING: Just a couple, Mr. Chair.
CHAIRMAN FAY: Go ahead.

FURTHER EXAMINATION

BY MS. KEATING:
Q Mr. Taylor, I want to stay on the same line of questioning that staff was asking you about just to make sure we are clear.
So looking at that same discovery response that staff has provided to you, for 27 and 2018, do you know if there were any customers on that service for that time period?
A I don't know if there were any customers on that services, but I know that in the forecast, there is only three customers. It's a pretty small rate class.
Q Got you.
And you talked a little bit about the increasing percentages year-over-year. Would you look at 2020 and 2021?
A Yes.
Q That reflects a percentage increase, but there

is a significant decrease in the amount of increase, would you agree?

A   Correct. Whenever you are looking at percentage change, it's best to have the actual numbers so you can see the magnitude and what's occurring with the data rather than just relying on a percent.

Q   All right. Thank you, Mr. Taylor.

MS. KEATING: That's all I have.

CHAIRMAN FAY: Okay. Thank you.

Ms. Keating, we will show Exhibits 17 through 20 entered into the record without objection.

MS. KEATING: Thank you, Mr. Chair.

(Whereupon, Exhibit Nos. 17-20 were received into evidence.)

CHAIRMAN FAY: All righty. And I believe Mr. Taylor does not have rebuttal, so, Ms. Keating, would you like to excuse your witness?

MS. KEATING: I would.

CHAIRMAN FAY: Okay.

THE WITNESS: Thank you for the time.

CHAIRMAN FAY: You are excused. Thank you.

MS. KEATING: Thank you, Mr. Chair.

(Witness excused.)

(Transcript continues in sequence in Volume 4.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 31st day of October, 2022.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024