BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20230023-GU

Petition for rate increase by Peoples Gas Systems, Inc.

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DOCKET NO. 20220219-GU

Petition for approval of 2022 depreciation study by Peoples Gas Systems, Inc.

_____/

DOCKET NO. 20220212-GU

Petition for approval of depreciation rate and subaccount for renewable natural gas facilities leased to others by Peoples Gas Systems, Inc.

_____/

VOLUME 6 - PAGES 842 - 1087

PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ANDREW GILES FAY COMMISSIONER ART GRAHAM COMMISSIONER GARY F. CLARK COMMISSIONER MIKE LA ROSA COMMISSIONER GABRIELLA PASSIDOMO
DATE:	Thursday, September 14, 2023
TIME:	Commenced: 9:00 a.m. Concluded: 9:22 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.)

I N D E X

EXHIBITS CONTINUED

NUMBER:		ID	ADMITTED
188	Rebuttal TO-2 analysis	863	908
189	Gas Operations Scorecard	896	908
14	As identified in the CEL		907
17	As identified in the CEL		907
187	As identified in the CEL		909
15	As identified in the CEL		955
190	Rule 25-7.045, F.A.C.	1067	1085
63-104	As identified in the CEL		1085

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

CHAIRMAN FAY: All right, everyone, welcome back this morning. Just a quick update as to how we will proceed for today.

We will continue with Mr. O'Connor's testimony, and then move into Mr. Garrett. And I think logistics-wise, after that, we would go into Richard and then Bluestone potentially, but if we have recommendations on any of those changes, knowing that we have witnesses in certain orders that we would like to take up, just speak up and I will make sure that legal knows and we will move them accordingly. I don't think we will have an issue getting everybody moving forward, but if something comes up, please let me know sooner than later to try to make it work.

With that said, we will probably work on the same schedule that we worked through yesterday, with the exception maybe, depending on the timing, we might go later tonight to get through with additional witnesses to make sure we have some time for Friday's hearing.

So with that, any questions? Ms. Wessling,

yes.

MS. WESSLING: I guess, I am not sure how widely shared this was, but the parties, and I think staff, we discussed this morning a potential order of witnesses that makes sense, given our estimates on the remaining cross-examination that we have.

CHAIRMAN FAY: Okay. So we have O'Connor that we would finish and then witness Garrett, and then after that?

MS. WESSLING: I believe Mr. McOnie has some travel obligations on Friday, so we were thinking collectively that it will go O'Connor, Garrett, McOnie, Kollen and potentially Bluestone, if there is time today, leaving Richard and Parsons for potentially tomorrow. Who I believe it would be the remaining two witnesses.

CHAIRMAN FAY: Okay. Great. And I think that's consistent with what legal had mentioned to me, is that correct? Okay.

All right. So seeing that that works for everybody. Yes, Mr. Moyle?

Okay. All right. With that, then, we will get going back into our cross on Mr. O'Connor.

Mr. Rehwinkel, whenever you are ready.

MR. REHWINKEL: I am ready. Good morning, Mr. Chairman and Commissioners. Thank you.

EXAMINATION continued

BY MR. REHWINKEL:

Q Good morning, Mr. O'Connor.

A Good morning.

Q I want to ask you to turn to page five -- actually, I think I gave you a note that said five, but let's go to page three, if we can, of your rebuttal testimony.

At the bottom of the page there, you start to explain the types of tasks or activities that your operations deals with on a regular basis, is that correct?

A Yes.

Q Okay. Now, I think we covered a little bit yesterday, but in regards to all of these tasks, Peoples is not finding itself in a deficient situation as far as the quality of service, is that correct?

A No, we -- no, we are not. We are not deficient in the quality of our service from a safety compliance, from a customer service perspective. We are very happy with our performance. However, when we look into the future, we do see that certain aspects of that is not sustainable because of our resourcing levels and,

hence, the resource request in 2024 for increased team members.

Q Okay. And going to E2-29 or just the next page, four, of your testimony, we see a little bit more explication starting on line five. You talk about your compliance and maintenance activities, such as atmospherance -- atmospheric inspections and main and service line leak surveying, right?

A Yes.

Q Those are areas that you are not deficient in at this time, right?

A No, we are not. As we look at all of our compliance requirements, we remain in compliance with all activities. And again, resourcing into the future is needed to continue to maintain our strong performance in that area.

Q Line 14, locates, I think your testimony is that you have had an upsurge in locate requests through the 811 system, but, again, you are meeting the requirements today, right?

A We are meeting the two-day requirement for all locate tickets that do come to Peoples Gas. This is an area, due to Florida's overall growth, where we are seeing profound increases in volumes. With that two-day requirement to respond and mark a gas line, it is

putting a heavy burden on our teams to be able to meet that requirement while continuing to do customer service and compliance work, and maintain proper safety.

Q Line four, the same question, just yes or no, leak and damage response, isn't it true you are in compliance with respect to those?

A I know you asked for a yes or no. We are compliant, or performing adequately on damage prevention and emergency response, but I will share a specific data point with you that is concerning from our perspective.

An industry average for leak response within 60 minutes is 98-and-a-half percent of the time, meaning as we get a leak call into our customer service area, we like to respond within 60 minutes of that leak. It could be very minor, it could be quite significant, and we want to be there within an hour.

For the past two years, '21 and '22, we have not achieved that 98-and-a-half percent response. We are approximately at 98 percent, and we are struggling to meet that 98-and-a-half percent again this year in 2023.

And to give you just a little more color on that, I will use an example with our Ft. Myers division. You know, our Ft. Myers division extends from the north in Port Charlotte all the way down to Marco Island. You

know, it's almost 100 miles north to south. We extend east to Immokalee. And to have roughly a team of 21, 22 team members cover that geography and be able to respond to a leak call in 60 minutes is getting harder and harder to do. Population growth, traffic issues, road construction all sort of issues are constraining our team. And so in this area, to your question, we are seeing a deterioration of that response rate, and that is concerning to Peoples.

Q On E2-32, which is page seven. I think we had discussed yesterday that you have no quantified metrics as far as so many tasks means you need to have so many people added, correct?

A That is correct, and I am glad you mentioned that again. I would love it if we had some sort of formulaic approach where we could say, you know, X amount of job activity equates to X number of team members. The simple reality is it doesn't work that way. So as much as we would like an objective metric, or series of metrics to dictate how we staff, the reality is we need to look at our experience levels, the workload, training requirements, a number of different factors to determine what a staffing level would be within a service area.

Q But just to be clear, you are here before the

Commission askings for them to authorize revenues from the customers to add people, right, in the future?

A Yes.

Q Okay. And it -- they have to make a decision about whether what you are asking for is reasonable under the circumstances, right?

A Yes.

Q And so your obligation to the Commission, if you want to get those -- if you want the customers to pay for that, is to justify the new adds, correct?

A Yes.

Q Okay. So let's go to page seven, line -- starting on line 18, I think there is a string of -- I think -- it's been a while since I have taken English grammar, but I think these are adjectives. On line 19, we see growing. On line 20, we see larger system. On line 21, more customer service compliance, maintenance, meter reading and other such activities. Line 22, strong economic and population growth. Those are the adjectives you use, but there is no quantification that links those numbers to what you are asking for in terms of adds, right?

A No, there is some quantification. I understand what you are trying to get at, but when we look at, for example, locates, we can see for the past

number of years significant increase in actual locate volume. We can also understand population growth. We have information from the Department of Transportation in terms of expected capital investment in road widenings and new road projects, and so we can draw some conclusions based on data around future projections of strong growth in the areas of our business.

Q Okay. And then if we look on the next page, I think page E2-33, looking at line 16, you reference FDOT road projects, and you use the word "potentially" lead to higher locate requests and higher damage to our system, do you see that?

A Yes.

Q But beyond saying the word "potentially", there is no quantification there that says what it will be, right?

A The quantification is on page nine in the expected Department of Transportation spending levels in the state of Florida. Road widenings, road projects typically drive locate volumes, the use of potentially is, you know, they are already driving some volumes. We expect that to increase in the future.

Q Okay. But what I am saying is potentially is somewhat an amorphous term. It doesn't have any exact quantification, right?

A That's correct, but I --

Q Okay.

A -- but we feel confident that this continued growth within the state of Florida will continue to drive locate increased volumes.

Q In your testimony talking about, you know, the string of adjectives and the use of the word "potentially" here, nowhere in your testimony in this regard do you discuss efficiencies or efficient systems that you have put in to tamp -- to dampen the increase in manpower needed to meet these tasks, is that correct?

A We do talk about efficiency. In the service area breakdowns, I provided our overall labor costs in the form of internal labor and external labor. We use this as a comparative metric. It's not a perfect metric. But when you look at our total labor costs per team member, you do see in many service areas a flat line, a somewhat declining line in areas that show that we are getting more from our team members per O&M labor dollar. I do think part of the story within those trend lines is efficiency.

The second point I would make is the discussion we started yesterday around the Work and Asset Management system. Although we have not -- we do not expect to see immediate efficiencies because we do

need to get that system working efficiently on behalf of our team members, it is the right thing to do for our customer, and we fully anticipate efficiencies in terms of productivity gains into the future beyond 2024.

Q Okay. But it's true, is it, that WAM is not, in your projections in your supporting testimony, WAM is not damping the employee adds that you are asking for, correct?

A In the 2024 -- no. In the 2024 test year, we did not include an efficiency gain, a cost reduction from the WAM implementation. In subsequent conversations with your office and staff, we did talk about bringing in some savings in the level of $750,000 to reduce our revenue requirement to be reasonable and understand that customers are looking for some efficiency gains.

The reality is, there is not efficiency gains to be realized in 2024. As I mentioned, it will take us some time to digest and really get WAM working the way it is intended to.

Q So while you are seeking to hire new team members, is what you call your employees, there really isn't a material dropoff in contractor resources associated with the bringing those, or onboarding those employees in the test year, right?

A There is a drop in resources. I will leave it to the Commission to decide what is material.

The way this works, when we hire new team members -- and, you know, this is just, I will call, normal business, we cannot release a contractor just because we hired someone. First of all, we need to make sure we have coverage for all the work that is going on. As I mentioned, there are training requirements to get new team members up to speed and able to perform our tasks.

The other is the commercial reality of engaging a contractor. You know, we could cancel a contract with a contractor tomorrow, if we need them next month, they may not be so willing to work for us. We may have contractual terms that we can't cancel the contract tomorrow. And so there is expected to be overlap between team member hires and contractors. However, you do see within field operations a decline in contractor costs, outside service costs in 2024 compared to 2022.

Q Is that about $1 million?

A Yes, it is.

Q Okay. Am I mistaken, or isn't it true that the adds that you talked about yesterday, some of the vacancies that you filled, I think 33 -- is that -- did

I get that number right?

A We have hired, in 2023, 29 of those replacement positions --

Q Okay.

A -- that were a total of 34.

Q Okay. I still got it wrong.

A Close.

Q Isn't it true that some of those hires came from the contractor workforce?

A They may have.

Q Okay. So now you bring those resources on, and now your contractors have less resources, is that how it works?

A It could work that way. You know, we have a very proactive constructive relationship with our contractors. We try not just to take their worker and bring them in-house and leave them holding the bag, so to speak, in terms of their responsibilities and obligations to Peoples Gas.

There are instances when we do post positions and there are contracted workforce that do find -- that are interested in working for Peoples Gas, and we do work through that process with our contractors as constructively as we can.

Q Okay. Let's go to E2-39, if we can.

A What page is that?

Q Oh, I apologize. It's 14 of your paper testimony. And this is the beginning of some graphs that show some achieved metrics, correct?

A Yes.

Q I guess achieved and forecast metrics, right?

A Yes.

Q Okay. So headcount compared to labor and outside services O&M, I stand fully ready to be corrected, as I have already several times in your testimony, but looking at the executive documents that I have seen so far, I don't see these metrics as part of the report card for gas ops when you report to Tampa Electric or Peoples board or Emera board, am I mistaken in that?

A No, you are not mistaken. This is a level of detail within field operations that probably is a little too detailed for board level material.

Q Okay. But this is not what you manage to in terms of your scorecard with the board, right?

A No, it is not. These are metrics that help us, on a comparative basis, to look at trending within each service area, allow us, to some extent, to compare different service areas in terms of their labor costs per headcount and their labor costs per work order.

These are not perfect data points. They are indicative. They inform us somewhat on some of these, but these are not complete data points that can be, you know, used from a goal setting and a metric perspective.

Q Okay. Thank you.

So let's go to E2-41, or page 16, and I want to go right down to lines 21 and 22.

Now, above this area here, lines 21 and 22, you talked about sort of favorable trends in these metrics that you put in your charge, right?

A Yes.

Q But when we get to line 21 and 22, it says: Although this trend shows a slight increase, this is justified given broader market conditions.

So am I to think, when I read this, that this is all good unless it's not, and then you just explain it away with vague term like that, is that how it works?

A No, that's not how it works.

So when we look at these stats, you know, we are being very transparent with here are our labor costs, here are our expected team members. In the instances you are referencing on lines 19 through 22, we actually show an increasing cost per work order, from $4.87 to $5.07, okay. We are not going to hide that. That's an increasing profile.

We are a growing company. We have inflationary pressures. We have a number of factors that are making it more expensive to run, to operate and maintain our system. I am not surprised that that stat is increasing, and I am happy to share it with you.

Q Thank you.

So on page E2-43, or 18 of your -- I think that's right -- yeah, 18. The Q&A here starting on line 14 through line 22, this is really the introduction to your TO-2, right, your Exhibit TO-2?

A If I understand what you are saying, yes. So TO-2 is a service area by service area breakdown of our resource plans. The resource plan of each service area supports the data within TO-2, and this answer that you are referencing is showing how we arrived at our plan team member additions.

Q See if -- and I don't want to put words in your mouth this time, but the core of the support that you are offering the Commission in your rebuttal is embedded in TO-2, right? This is -- this justifies the headcount adds to the paths that they were projecting, right?

A Yes, it does.

Q Okay. So let's go to Exhibit 26, which is -- I am still in the Case Center, but your TO-2, if we can.

Let's go to that exhibit. And I would like to go to page 14, if we could, which is the last page. And this is the -- this is the summary by -- rolled up -- everybody rolled up for all your districts, right?

A Yes, it is.

Q Okay. So just how this is set up, we have total headcount, in 2020 they start at number -- the number is 332, and you are asking by the end of '24 to have 430, or 98 additional employees, right?

A Yes.

Q Okay. And then I look at total orders, a little more than halfway down, you know, it shows 6.192 million forecasted to grow to 7.527 million in '24, 2024 --

A Yes.

Q -- right?

Okay. So those would be tasks that these employees would perform in the aggregate, right?

A Yes, they would be.

Q Okay. So what I would like to ask you, it would be easy to do some kind of, I guess it's about fourth grade math, and just take the employees and divide them by the task and get an employees to task number, right?

A Yes.

Q Okay. And that would generate a fairly simple ratio of employees to task?

A Yes, you could do that math.

Q Okay. So would you agree that a decline in the number of tasks per employees would, at some level, show efficiency in terms of -- if your tasks per employee decline, that would mean that you were able to serve your customers better?

A Yes. Task per employee, if that was declining --

Q Yes.

A -- so they are doing less tasks, that would mean they are being less productive.

Q Well, so is -- is the goal to get -- so if -- when you have 98 employees, you are seeking to -- or 98 additional employees, and you are doing 7.5 million tasks, you are saying that adding those employees and driving down the task for employee number would be less efficient?

A Yeah. So the way we can think about it -- I understand you are trying to get to that metric.

So first, these tasks are not created equal. Right now, it could take someone 30 minutes to do a locate, it could take someone an hour-and-a-half to -- for a meter set, okay. Right now, our data only

supports our ability to look at number of tasks, and so there is a level of subjectivity that is required by our experienced leadership in ops to say, how much can a team member perform to meet the workload required.

One of the exciting things about the Work and Asset Management system is once fully implemented and utilized, that data that I mentioned yesterday in my testimony, is going to give us a lot more really strong data to then provide better resource planning, because we are go to be able to break down every job type by minute. And so we can say, it takes you X amount of time to drive to a job, it should take you 15 minutes to do this job, and then we will be able to perform its management -- perform its management afterwards.

We are not at that level right now. That's one of the benefits of WAM once fully implemented. But right now, these job types are really just job activities, you know, one locate, one meter set. And so to try to draw and efficiency conclusion from that, I think, is difficult.

MR. REHWINKEL: So, Mr. Chairman, I am going to pass an exhibit out. I guess our next number is --

CHAIRMAN FAY: I believe we are at 188.

MR. REHWINKEL: 188. And it just says

rebuttal TO-2 analysis is the title.

(Whereupon, Exhibit No. 188 was marked for identification.)

BY MR. REHWINKEL:

Q Do you have one yet? Do you have one?

A Yes, I have it.

Q Okay. All right. So on this document, I have taken the data that's in -- that we just discussed, your employee adds by each district and the total orders, and I presented them in a table form with an accompanying chart. Do you see that? Will you accept my math subject to check?

A Yes.

Q Okay. So you see on page -- Bates page two of this, in 2020, you have 6.192 million tasks, and you project 7.527 million in 2024. I did a midpoint of historic going from '20 to '22, and it showed there was a 9.7 percent overall increase historically in the increase in your headcount. And then through '24, you would seek to increase that about another 10.8 percent, with an overall change in headcount of 21.5 percent. Does that look right to you?

A I don't see those percentages on that, but I am going to trust your math --

Q You are not on --

A -- I just have totals here.

Q Are you on Bates 2 of Exhibit 42? Yes.

A I don't have any percentages on mine.

MR. REHWINKEL: Mr. Chairman, excuse us. We have a logistical glitch here.

CHAIRMAN FAY: Okay. And I am the same as Mr. O'Connor. I don't have percentages on mine.

MR. REHWINKEL: Mr. Chairman, could we have five minutes to discuss how we might proceed? We had a cross-up in our exhibit production.

CHAIRMAN FAY: Okay. Sure.

(Brief recess.)

BY MR. REHWINKEL:

Q So striking the last question about percentages, would you agree that one could take -- do the simple math of headcount change and order change historically and projected and create a simple ratio from your data in TO-2?

A Yes, you can create that ratio to headcount over work orders.

Q Okay. And you create a graph using Excel to do that, right?

A Yes.

Q Okay. So you accept, subject to check, that we've done that with this exhibit?

A Yes.

Q Okay. So what I would like to do is just ask you if we could go through and look at a couple of examples of the changes that occur in certain of the districts. And I think we discussed it a little bit yesterday, but I just want to be clear, if you are hiring new adds for districts, there is different standards of living in certain areas. It might be more expensive in Sarasota and Southwest Florida than Panama City?

A Yes.

Q Okay. Do you have a pay differential?

A We do. For our south territory, which is Sarasota, Ft. Myers, Jupiter and Dade/Broward, we have a five-percent adder to base rates to account for the differences in the standard of living --

Q Okay.

A -- in the southern part of our state.

Q In this pot of 98 new employees, if I can call it that, they are not going to be fungible where you can move them around in the test year to kind of meet different demands? That -- the demand that you forecast has already been baked into your projection, right?

A Yes. The demand for each service area is our best estimate of what we can expect into 2024. It -- we

do have some employee movement from one service area to another, it's somewhat infrequent. From a budgeting and estimation perspective, we do our best to align, you know, the specific positions to the work requirements in each service area.

Q Okay. So when I look at orders per person on Bates 2, it shows that -- that -- and per person here means employee, do you understand it that way?

A Yes.

Q Okay. Not customer?

A Yes.

Q Okay. So in 2020, the math just yields 18,652 tasks, or orders were being processed -- I take that back. Six million tasks were being processed by 332 employees, giving a ratio of 18,652 system-wide. Do I have that right?

A Yes.

Q And by 2024, you are projecting that that ratio will decrease to 17,504, meaning 430 employees will be performing 7.5 million tasks; is that right?

A Yes.

Q Now, are you saying that this means that you are falling farther and farther behind even though you are adding 98 people?

A No, I don't think you can draw that

conclusion. It's a useful metric. It can be included in a whole bunch of other metrics, but I think you have to understand what is driving the headcount increase and, of course, the work order increase. It's not a simple, you know, numerator, denominator and draw a conclusion. There is much more behind it.

Q Okay. Let's go to Bates 15, if we can. Jacksonville. And if you are sys -- this -- Jacksonville's, in terms of orders per person, averages look close to the overall picture, right? You can compare Bates 2 and Bates 15. You start off with 17,651 orders per person, and by 2024, you are going to be at 18,595 per person. Do you see that?

A Yes, I do.

Q And there is some fluctuation over time, but the adds here are 17. So 17 people kind of -- you experience a little bit of increase in the orders per person, right?

A Yes.

Q Okay. Let's go to Lakeland, if we can. I don't know exactly, I lost my --

CHAIRMAN FAY: I believe it's the third page, Mr. Rehwinkel.

MR. REHWINKEL: Okay. Yeah, Bates No. 3, OPC Bates 3.

BY MR. REHWINKEL:

Q So we see Lakeland has nine employees in 2020 and is projected to go to 14. The orders per person there were almost half of the system average in 2020, right?

A Yes.

Q And these 14 people would be making that ratio decline to 7.1 -- or 7,106 --

A Yes.

Q -- right?

So why would you -- why you would add -- how do you explain that relative to Jacksonville and then the overall system average?

A Yeah, this is a great example of this may be a useful metric for comparative purposes to maybe generate the need to dig deeper into the data. But the reality is this metric is largely incomplete in terms of being able to explain what is actually going on within any of our service areas.

It might be useful if I -- you know, your Jacksonville example, you know, think about it from an emergency response perspective. Jacksonville represents an area of parts of nine counties, you know, Duval Counties, St. Johns, Clay, are growing very, very quickly, that area, those nine counties is larger than

some U.S. states from a geography perspective. And so to have adequate coverage throughout that area to serve our customers, to do all of the required compliance work, as well as to be prepared in an emergency response, a leak response kind of scenario, we need team members to be able to do that.

We also need those team members not to be burnt out in terms of being on call all the time. We try to have people on call one week per month, and without adequate team members, we are not always able to achieve that, and people do get burnt out from being on call at times.

And so back to your question, Mr. Rehwinkel. This metric, I understand what you are trying do with it, but it's incomplete because you need more of the story behind what is driving the team member increase, as well as what's driving the work order increase as well.

Q So Dade/Broward, let's look at Dade/Broward, which is on Bates 8. This shows, again, orders per person in 2020 about the system average, right?

A Yes.

Q And you are adding, through the end of '24, 25 employees to take the number from 18 to 23, and the orders per person goes to 20,414, right?

A The orders per person for Dade/Broward is 12,224.

Q I am sorry. I was looking on the wrong page again.

All right. Bates 10, OPC Bates 10, I apologize. So in 2020, the orders per person were 14,488, do you see that?

A Yes, I do.

Q And then addition of 16 employees yields an orders per person ratio of 12,210, right?

A Yes.

Q So how you would explain that in the context of the others?

A Dade/Broward is a little different from the rest of our service areas. It's the most urban service area that we serve our customers, and we are not seeing the same growth levels in terms of customer additions that we do in some of the other areas of Florida. However, the locate and leak response in Miami and Dade/Broward is still at a high level. It is -- it takes longer to drive throughout Miami and the surrounding area, and we need team members to be able to cover that system at a higher level than you might in other areas.

As a quick comparative, you know, we have 78

team members in Dade/Broward. I believe that's the highest number of team members we have in any of our service areas. Tampa is a littlest than that, but has more customers to serve. So this is a great example of the kind of work operations has to perform based on the conditions on the ground.

And just to give you a quick example of some of the difficulties unique to Dade/Broward. We've had some of our technicians get parking tickets responding to leaks, okay. We are literally driving to respond to a leak call, trying to find a place to park, trying to figure out what's going on, we get the work done, and part of the reward of doing that work is a parking ticket.

So it's that kind of environment that we are trying to be successful in, which requires, you know, team members who can respond at appropriate levels.

Q So let's look at Eustis on page 11. Eustis is at 10,837 in 2020, and almost identical to Dade/Broward in 2024, but no change in employees. How you would contrast those two?

A Eustis is, I believe, our -- well, maybe second smallest service area. A team of eight that is small but mighty. Not a lot of growth going on in that area right now, and so we maintain our team members.

That team is truly utility technicians. It's small enough where each of our team members there are trained in all tasks and can perform in any scenario. And like I said, the growth isn't as strong as it is in some other areas of the state.

Q So Panama City, if we can, on Bates 4 -- I hope I have that right, which I don't.

CHAIRMAN FAY: Sarasota, Mr. Rehwinkel?

BY MR. REHWINKEL:

Q 14, I think. Ms. Wessling has corrected me. It's page 14. Bates 14, do you see that?

A Panama City?

Q Yes.

A Yes.

Q So this is relatively flat in terms of the ratio -- actually, it inclines from 13,142 to 14,667, and the employees only increase one. What's going on there compared to the others?

A Panama City is another fairly stable service area. Decent levels of growth, probably in the neighborhood of about three percent annually. Continue to see locate work. There is a Margaritaville that's going in that is getting a lot of attention, and maybe more so now, and you are seeing the increasing trend line here.

Again, Mr. Rehwinkel, I appreciate the statistician in you in putting some of this information together. I think it's a data point that's useful but not fully complete. In this case, in Panama City, it's showing more orders per person over time, which means they are doing more per team member, which would be a positive trend.

Q Okay. But you would agree that the numbers and the employee adds, as we look at them, are kind of all over the place, right, by district?

A Yes. And that would be expected. Each service area is different. There are different dynamics. The conditions on the ground are different. Our customer profiles may be different. For example, Jacksonville includes a heavy industrial base. Ft. Myers does not.

So they -- while comparing each service area can be a useful exercise, there needs to be care taken to understand that sometimes it's not always an apples to apples comparison.

Q On -- let's put this Exhibit 188 aside. And you have your confidential book? If you could go to OPC Exhibit 2C, which I think has already been given a number.

CHAIRMAN FAY: Yep, 175, you are right, Mr.

Rehwinkel.

MR. REHWINKEL: Thank you.

BY MR. REHWINKEL:

Q So this is Exhibit 175. It's in the book, and it will be behind Tab 2. I don't know. Do you see that? Did you find that Exhibit 2C, do you see that?

A Yes, I do.

Q Okay. And this is the 2022 refresh from June 27, 2022, an excerpt from it?

A Yes.

Q You are familiar with this document, right?

A Yes, I am.

Q Okay. You would have been at this meeting?

A Yes.

Q Okay. So I just want you to go to page four, if you can, OPC Bates 4. And this is in 20 -- June of 2022, talking about potential opportunities, that's the header on the right-hand side, do you see that? Look at the Bates numbers in the lower right-hand corner. The dec page is 50.

A Yeah.

Q Are you there?

A Page 50, I don't have any Bates on these pages but --

Q Oh, really?

A -- page 50, challenges and opportunities?

Q Okay, yes.

A Yes.

Q Okay. Are you familiar with the opportunities that are discussed in the bullets two -- I mean, three and four?

A Yes.

Q Okay. Can you read those aloud? And I am not asking to you if -- I am not asking you to declassify them, but can they be read aloud?

A Yeah. The third bullet reads: Reduce dependency on external labor as internal resources become more available.

The forth bullet reads: Further WAM efficiencies.

Q Okay. Now, are -- do you agree that these are opportunities for gas operations?

A Yes.

Q Okay. They just don't appear in the before the test year, right?

A The third bullet, as I have sheen shown in my second exhibit in my rebuttal testimony, shows some reduction in outside services relative to the increase in team members, and so we begin to reflect that opportunity in 2024.

As I mentioned earlier, the WAM efficiencies in our original filing, we did not include any cost reductions. Again, subsequent conversations, we have discussed $750,000 of O&M reduction related to WAM.

Q Okay. And to be fair, the inclusion of the $750,000 that the company put forward, that would be a surrogate, if you will, for labor costs that would be offset, is that right?

A Yeah, I think that's -- that's a fair characterization. We do not have -- I do not have 750,000 right now that I feel I can cut from 2024. It would be a challenge immediately to try to incorporate that reduction. But to your point, it likely would require us to look at our labor, internal and external, costs to try to find some of those reductions.

Q Okay. Given that you haven't hired the 2024 cadre other than the one you said you pulled into '23, those employees could -- if you don't hire everybody, for whatever reason, you had labor market issues in bringing on resources, right?

A We have had labor challenges. It's a tight market.

Q Right. And you could have vacancies occur in '24, right?

A Yes, we could.

Q And by the time you get into '25, if WAM efficiencies start to come to the forefront, you might decide not to hire or fill those positions because you are -- as Mr. Richard mentioned before to me, you are sweating the asset, you are trying to get efficiencies out of it, right?

A That is true. We do need to sweat the asset. To be frank, we are also sweating meeting our customer needs.

Right now, the 2024 team member additions are needed. These are not nice have positions. These are positions that will allow us to continue to maintain our safety standards, our compliance standards, our customer service standards. There is a reason we are number one in JD Power for 10 years. There is a reason that we are very good on the compliance front.

And to bring it to life just a little bit more. We've seen some of the strain. When we talk about our staffing levels not always being sustainable. In Sarasota, we've had lower levels, and we had poor morale. We had some retention issues, and it was because people were overworked. We had people on call every other week, missing family events, missing sporting events. And we've made some really strong improvements by adding the 2023 hires to Sarasota, and

the 2024 hires will also help that.

And so it's a real thing. It's not just a number of, you know, how much more costs can we -- can we embed in 2024 and then, you know, maybe not use it all. These are required team members to perform what we need to perform in field operations.

Q Okay. But as we discussed yesterday, apprentices have a bit of a long lead time before they are going to be fully up to speed, right?

A Yes. It takes approximately 18 months for them to be able to be on call. That doesn't mean they can't do anything in those 18 months. There are job tasks, atmostpheric inspections, other job tasks that they can do, but being on call, responding to a hit line, takes approximately 18 months of training.

Q Thank you, Mr. O'Connor.

MR. REHWINKEL: Mr. Chairman, those are all the questions I have.

And again, I apologize for the sputtering of my presentation.

CHAIRMAN FAY: Okay. No worries, Mr. Rehwinkel.

MR. REHWINKEL: Thank you.

CHAIRMAN FAY: We know we changed some things up in this process, so --

MR. REHWINKEL: Thank you.

CHAIRMAN FAY: Mr. Moyle, you are recognized within your ready.

MR. MOYLE: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MOYLE:

Q Good morning, Mr. O'Connor.

A Good morning, Mr. Moyle.

Q I am going to have some questions for you on a few topics, and let me start just by picking up the, I call it the data-driven decision-making issue.

Would it be fair to say that the company recognizes that improvements are needed with respect to making operational decisions that can be enhanced by obtaining and evaluating data?

A Yes, that is fair to say. That is one of the benefits, intended benefits of the WAM implementation, it will improve our data collection, aggregation and analytic capabilities.

Q And the converse of that is, as we sit here today, with respect to decisions that were made to hire the additional FTEs that we are talking about, they were not benefited by the WAM system, correct?

A No, they were not. WAM was just implemented this year, 2023.

Q And the corollary of that is, is that the decisions about how many people are needed, they were made by people who, I am not saying they don't have knowledge, but they don't have any metrics, as I think OPC was making the point, there are no metrics, no recommendation, PHMSA, PSC, or anything, about how many people you need to safely run a gas company?

A The metrics that I believe you are referring to will be enhanced with the WAM implementation and its use. But there are metrics. You know, I have mentioned a few already, 98-and-a-half percent of the time do we respond within 60 minutes. If that is suffering, that's a very good data point for our leadership to understand that we may not have adequate team members to perform those roles. If we had serious compliance issues, if we are not able to serve our customers, those are all data points that are important when considering our staffing levels.

When you couple that information, and I grant it can definitely be improved over time, and it will be with the WAM implementation, but when you couple that with the expertise of our field operations leadership, we can make informed, and we do make informed decisions around our staffing. And the results show that.

You know, we are number one in JD Power for

the past 10 years. We must be doing something right. We are compliant. We keep our employees and the public safe. Those are all metrics that indicate that our resourcing levels are at, and are informed by sound decision-making.

Q And what's your -- what's a metric? What's your understanding of a metric? Give us your definition of it.

A It can be a number of things. It can be a formula. It can be a data point. It could be a customer response, you know, a verbal complaint or accolade. There is a lot of data points. And I think part of our job is to collect as much data as we possibly can, aggregate it, synthesize it, and then determine what it is telling us.

Q So the customer complaints, you wouldn't -- somebody calls up and raises problems, anecdotally, you would agree that's not probably the best way to make a decision. A better way to make a decision is to track the number of customer complaints per thousand customers, and you say, we have three customer complaints per thousand, or whatever, that would be a metric it?

A Can be a metric, absolutely. But a single customer complaint, if you understand the root cause of

it, can be very, very informative. And so, you know, it is an opportunity to improve, and we can use that in that way.

Q Right. You had given -- in that answer that you provided just a minute ago, you had said -- let me ask you this: Do you have, as we sit here today, is the company having serious compliance issues?

A No.

Q Okay. As we sit here today, is the company not able to serve its customers adequately?

A No, we are serving them adequately.

Q So when you talked about that metric, those metrics are being met as we are here today?

A Yes, those metrics are being met as we are here today, and they reflect sound resource planning --

Q Right.

A -- from the past number of years that have led us to this point.

Q And those are pretty serious metrics for the business you are in, are they not?

A Yes, they are.

Q And another metric that you measure yourself by is safety. The company is able, as we sit here today, to safely run its system, are they not?

A Yes, they are, but part of our --

Q That's good. I am trying to do yes/no and move through.

MR. MEANS: Mr. Chairman, I would politely direct Mr. Moyle to page three of the prehearing order, which states that the witness may explain his or her answer. I understand the need for brevity and to keep things moving, but I would appreciate if the witness is allowed to explain his response.

CHAIRMAN FAY: Yeah, Mr. Moyle, I don't have any issue with him providing clarification.

Mr. O'Connor, if you can just try to make that clarification pinpointed specifically to Mr. Moyle's question. I think you have established some point repetitively, and so those are all in the record, and we've got those, and if you can address the question, then I am absolutely going to allow clarification.

BY MR. MOYLE:

Q We are shooting for a Friday checkered flag, so I'm trying to move on. But go ahead, if you feel you need to explain that further.

A I will just say on the safety front, because it is our number one priority, yes, you know, we are -- we have some really strong good safety stats right now,

but part of our safety culture is looking around the corner, is understanding what's going on. Our team drives 7,000 miles a year, we always have to be vigilant, and so we are not resting on those laurels, and so it does require thinking ahead in terms of what else may be required from a resourcing perspective.

Q Mr. Rehwinkel challenged you with some mathematical equations, and you accepted his math. I have a couple of follow-ups on the 98.5 metric that's been mentioned a couple of times.

If you are at 98 percent of a 98.5 percent metric, you are meeting that goal 98, 99 percent of the time?

A If we are at 98 percent, we are meeting it at 98 percent.

Q The goal is 98.5, and you are meeting it at 98 percent, right?

A The goal is for all leak response within -- responding to leaks within 60 minutes. We do that -- the goal is to do it 98.5 percent of the time. Right now, we are doing it approximately 98 percent through 2022. And year-to-date through 2023, I believe we are around 96 percent.

Q So you are missing it by a little bit?

A Yes.

Q And who's 98.5 percent, who -- is that an internal company goal? Is that a PSC goal? Is that a PHMSA goal? Where does that come from?

A That is an internal goal, but it is an industry standard, if you will, around emergency response. If you think about a leak, you want to get there and understand what's going on in the name of public safety.

Q And the way safety works in the natural gas world is you do have regulatory bodies that oversee safety, correct? PHMSA, which is the feds, the Florida PSC, OSHA, you have a number of regulators that are responsible for safety, is that correct?

A Yes.

Q Does the company maybe place more emphasis or importance on regulatory compliance with these governmental entities as compared to, you know, an internal goal that may not have gone through as rigorous a process as a governmental rule?

A Are you referring to safety goals?

Q Yes. The 98.5 specifically.

A I wouldn't say we put more emphasis on one metric or goal over the other. You know, generally speaking, we want each of our team members to go home the way they arrived to work each day.

Q Do you know if other utilities with these internal goals you mentioned, you think some of them do this, do they have different metrics than PGS has, you know, a 75-minute or 90 -- a 90-percent compliance rate, down one way or the other?

A I don't know specifically what each other LDC may have. I do know our 98.5 percent metric is an industry metric and supported with -- through AGA, the American Gas Association.

Q Okay. You have engineering training, correct?

A No, I do not.

Q Oh, you don't. I am sorry.

Do you know, from -- this is a safety related question. Do you know if methane, that's the natural gas that you use in your business, right?

A Yes.

Q Do you know, is it heavier or lighter than air?

A It's lighter. It gets disbursed.

Q So from a safety standpoint, that means that if you have a leak in a pipe, then it comes out, but it goes up and disperses rapidly as compared to maybe something like gasoline, gasoline is heavy -- is heavier than air?

A Yes.

Q Okay. You would agree that just those facts by themselves make the natural gas business, with respect to leaks, not as dangerous as, say, a gasoline leak?

A I wouldn't go that far, you know, because leaks could occur. Natural gas will migrate along the path of least resistance. If you have a leak in an urban environment, that may be a sewer line. That may be a water line, and not necessarily just into the atmosphere. And so, yes, it will disperse into the air eventually, but there is -- there can be quite a high level of hazard associated with migrating of natural gas.

Q Shared services, you all are making use of shared services that are provided by another corporate sibling, is that right?

A Yes, Peoples Gas uses -- has shared service arrangements with Tampa Electric.

Q Okay. And there was a bit of a restructuring, or review, or change with respect to shared services given the 2023 Transaction; is that right?

A I believe Ms. Wesley spoke to this, that the 2023 Transaction was, unto itself, it didn't necessarily drive significant changes in the shared service arrangements that are in place. We'll look to Tampa

Electric for shared services as needed, depending on our business need.

Q But part of that was your company, PGS picked up some additional responsibilities that were previously done by the entity providing the shared services, isn't that right?

A Yes, I think in some areas of our business, we have stood up certain functional areas that were previously shared.

Q Like procurement, for example?

A Yes.

Q And as we sit here today, can you tell the Commission whether -- that the result of the 2023 Transaction with respect to shared services, whether that is saving PGS money or costing PGS money in terms of its impact on the company?

MR. MEANS: Mr. Chairman, I have got to object. This is not the witness who's covering the 2023 Transaction, so it's outside the scope of his testimony.

CHAIRMAN FAY: Mr. Moyle?

MR. MOYLE: He is the VP for Operations and responsible for all the operations. I would assume that includes procurement and things like that. I think this is, you know, one question I have of

him, whether it's costing them more money or less money. He is here saying, we want you to raise rates for operation, I think it's fair.

CHAIRMAN FAY: Yeah, I mean, I don't really have an issue with the question, Mr. Means. You said this is your only question on this line?

MR. MOYLE: That's right.

CHAIRMAN FAY: Okay. Go ahead.

THE WITNESS: I believe this is a question for witness Richard. Procurement isn't in my area, as much as I would love to answer you, Mr. Moyle, but Mr. Richard would be able to handle that for you.

BY MR. MOYLE:

Q Okay. We've had a little bit of a conversation about risk, and we talked a little bit about risk in your deposition previously. I want to spend a few minutes on that topic.

You suggested that the relative risk of natural gas companies, you weren't able to distinguish greatly between natural gas companies and electric companies, like who might have the greater risk, is that fair?

A Yes. In my -- in my deposition, you asked me, you know, which was riskier, and I gave you a similar answer as Ms. Wesley gave you yesterday, that it is

quite a complex question.

Q And one question that I didn't ask you previously that I will ask you today is, if you focused simply on the cost of repairing a system, electric versus natural gas, wouldn't it be true that, like the hurricane that just came through here a few weeks ago, that the costs for repair are greater in the context of an electric company as compared to a natural gas company, given that your lines are underground and protected as compared to a lot of the electric lines being above ground and being subject to trees falling in them, and other things like that?

A I am not an expert on costs for hurricane recovery on the electric side. I understand what you are saying, and somewhat agree that, you know, it could be a lower cost given that our pipes are in the ground, but every storm is different, and I don't know if you can fully draw that conclusion.

Q Okay. Previously, there has been some discussion about an affiliated company that's also in the natural gas business that the PSC has jurisdiction over, SeaCoast. You have been here throughout the hearing and have heard mention of SeaCoast, correct?

A Yes, I have.

Q Yeah. Do you have any role with respect to

SeaCoast?

A The only role with respect to SeaCoast for our gas operations is that we do perform some O&M work on those transmission pipes. As Ms. Wesley mentioned, there is four pipes. And to the extent that our team members work on those, from an operational perspective, we directly charge their time and materials to SeaCoast.

Q So if one of those lines has an operational issue, do you get that call, as VP of Operations, for PGS?

A I may get that call, or the local leadership may get that call.

Q So there are different ways in which to run a company that provides natural gas. You can have employees, like PGS has, or you can contract out or charge back, like you described, like SeaCoast does; is that right?

A Yes.

Q Okay. Have you done any analysis as to the relative cost and benefits of having a contractual relationship that SeaCoast has with PGS, how that compares from a cost standpoint vis-a-vis having full-time equivalent employees?

A No, I have not done any analysis.

Q You mentioned in response to a question from

OPC, that you have in place differential payments for your employees based on geographic location, is that right?

A Yes.

Q And is that something that you all do internally, or is that something that the Commission -- you ask the Commission to consider and take action and say, well Miami-Dade real estate is higher, it's more expensive, please provide a five-percent increase on salary for our workers either working or living in Miami-Dade, could you explain your understanding of that, please?

A Yes. We did our -- we did a compensation study to understand that the differential with our southern Florida service areas partly because we were having some retention and attraction issues for those areas. We needed workers and we were having a really hard time trying to attract and keep them. And so our HR team led a compensation review of those areas, and the result of that was a five-percent adjustment to the base salaries that I mentioned previously.

Q Have you done it anywhere other than Miami-Dade?

A We have not looked at other areas in terms of a pay differential. Witness Bluestone will be able to

more completely talk about our compensation approach.

Q And just one quick question on the development issue. You all are asking the Commission to award you economic development funds, is that right?

A Yes.

Q Yeah. And we've talked about metrics, but as we sit here today, there is no measurement as to kind of a return on investment of those economic dollars that the company makes with respect to its expenditures on economic development, correct?

A Correct.

Q I want to ask you a couple of questions about the 811 system. That's the locate program, right?

A Correct.

Q I think there is a more official name for it than the locate program or 811, is there not?

A Sunshine 811, Call Before you Dig.

Q Okay. And that's a statutory provision that directs people, before they start digging, to make a call to an essential entity that then takes that information and tries to locate or help locate where lines are essentially, is that right?

A Yes. Someone will call 811, provide information around excavation, digging activity. That information will be provided to utilities so that we can

properly locate our lines and protect our system.

Q And you have referenced the 811 system a few times in your testimony --

A Yes.

Q -- right?

And tell me the point you are making when you reference the 811.

A When we think about the workload increase, now and into the future, locates is a significant driver. It is likely the primary driver. There is so much growth in Florida, those volumes of locates are really adding a heavy workload to our teams, where some team members, you know, are complaining that, man, I miss gas work because I do is locate lines. I paint the ground and put flags on to make sure that no one is hitting our system.

It is a heavy, heavy volume right now. We are not complaining. Florida is growing. But it is a very big increase and workload for our teams.

Q And part of that, Florida is growing and you provided growth rates, but part of it also is, is that not everybody complies with the obligation to call, isn't that right?

A That's correct.

Q And indeed, the company has recognized that,

and has established certain goals to say, we got to get more people on board with this calling, because a lot of times they are not calling and they are damaging our equipment, correct?

A That's correct. We had about 1,800 damages in 2022. About half of those were in instances where no one called in.

MR. MOYLE: Can I just have a second to consult with counsel? I have a document that I would like to ask a question about, but it's confidential, so I don't want to ask confidential information in the question.

CHAIRMAN FAY: Okay, go ahead.

MR. MOYLE: Thank you, Mr. Chair.

I am going to ask the question, and then if I need the exhibit, I will use the exhibit. It depends on his answer.

CHAIRMAN FAY: Okay. Go ahead.

BY MR. MOYLE:

Q With respect to the number of locate tickets, the trend for that is not that it's going up, but that it's staying largely the same, correct?

A No. So the locate tickets, I believe it's about a five-percent increase from '22 over 2021.

MR. MOYLE: So I would like to have the

witness look at a confidential document. It's a OPC's Exhibit 71C, as in cat.

CHAIRMAN FAY: Okay. I have that as the last exhibit.

MR. MOYLE: It's entitled, the description is Gas Operations Scorecard.

CHAIRMAN FAY: Okay. And just to keep things consistent, we are going to go ahead and mark this 189.

(Whereupon, Exhibit No. 189 was marked for identification.)

BY MR. MOYLE:

Q You can tell me when you are there.

A I am there.

Q Okay. On page 02 -- well, let's just use the OPC number. It's 02, there is also a 246 in the middle of the page. The yellow metric that has two arrows going sideways, there is also a green metrics that have an arrow going up, and red metrics that have an arrow going down. Do you have an understanding of what a yellow metric with two arrows going sideways represents?

A Yes. This is a dashboard showing 2023 targets on some key operational metrics. The yellow arrow is pointing in both direction, would indicate that current trends and expectations are consistent with that target.

The one you are referencing, on locates, was 675,000 in 2023.

Q And you all also had a program that you put in place to say, we have a goal to contact 50 percent of our contractors who we've had problems with, who have caused damage to our system to get with them and meet with them and say, hey, you got to do a better job on your locate, isn't that true?

A That is true.

Q And just curious, given that they cause problems, why was the goal 50 percent as compared to 75 percent or 100 percent?

A The goal was 50 percent because we needed to get started. It's a heavy resource need, and so we don't have enough resources to meet with every contractor that hits us. That would be a list of hundreds and hundreds of contractors, and so the goal was to target those that most frequently hit us and have those conversations.

The other part of it, some contractors don't want to meet with us. They don't really want to hear what we say about not hitting our line. They just want to do their work.

Q Yeah. So with respect to the increase, I mean, Florida is growing, but some of the increase in

the locate tickets, you would acknowledge, could be the result of your goal to meet with 50 percent of the contractors and kind of get them more on board with the program, that's fair, isn't it?

A That is fair, and that would be an outstanding outcome. If we had more -- if we could double the number of locates, that would be great in terms of people calling in.

We can't protect our pipe if we don't know where they are. If they are calling in a ticket, at least we can try to protect our type.

Q Do you have an idea -- we talked about this a little bit in your deposition, but in terms of when somebody does damage your pipe, you all go after them and try to get repaid for that damage, is that right?

A That's right. If a contractor, a third-party, hits our pipe without a locate ticket, we are able to seek reimbursement.

MR. MOYLE: Mr. Chairman, those are all the questions I have. Thank you.

CHAIRMAN FAY: Okay. Staff?

MR. SANDY: There is no questions from staff.

CHAIRMAN FAY: Okay. Commissioners?

Commissioner Clark and then Commissioner Passidomo.

COMMISSIONER CLARK: Thank you.

Mr. O'Connor, I am following up on the line of questioning from Mr. Moyle, and also from Mr. Rehwinkel, regarding the 811 calls as well.

I am just doing simple math, and I see 618,000 calls. In your opening statement, I thought I heard you say that that was a 31-percent increase. You said you have been seeing a five-percent increase, but didn't, your opening statement, didn't you say a 31-percent increase?

THE WITNESS: I hope I didn't misspeak. It was a 31,000 ticket increase.

COMMISSIONER CLARK: Okay. I am sorry. That's what I heard, the 31,000 increase, okay.

At the same time, if you do the simple math, that's 2,376 calls per day, and that's 297 calls per hour. If you were able to do a resolve in a half of an hour, you still have to have 150 employees per day dedicated to just taking 811 calls.

Can you tell me what the current ratio between contractors that are performing this service for you and in-house employees and how that is trending?

THE WITNESS: It's a complicated item, just

because it depends on each service area.

We have moved to bring more -- more labor in-house to do our locate work. We still utilize some outside contractors, but it really depends on each service area. And to your point on the volume, we try to clear as many as we. Some aren't anywhere near our pipe, and we are able to clear those tickets without any, you know, visit to the field. And then we need to prioritize those tickets amongst dedicated locaters, internal or external, or other our other technicians to pick up the volume.

COMMISSIONER CLARK: Well, and I was -- my thought process was, this is not a single person performance. The person who is typically going to do the locate isn't the one taking the call. They are not the one scheduling the visit. They are not the ones doing the work order. How does that process work in terms of have you allocated a time amount to each call that -- I am trying to get to how much does this cost your company, and how much of this are we passing on to the consumers?

I fully support the 811 system and the safety aspect of it, but at a point in time, there has object some cost allocation that's going to be laid

back out for the services that we are providing. And maybe that needs to be the contractor, maybe that he needs to be the developer, but not necessarily all being consumed by the utility.

THE WITNESS: Yeah, I love that idea. And the reality is we are not there right now.

I don't have a cost per locate for you right now, and that goes to some of the limitations we have with our data. We do have specific employees that only do locate work, but then we also have employees that do who calculate work as well as other job activities.

But I agree with your point, that there are a lot of costs that are incurred from locating. Right now, the gas utility is expected to bear that cost in full, and developers and contractors really have the option to even call in to generate that volume.

COMMISSIONER CLARK: And my last question, and I am going to try to guard the sensitivity of the confidential nature of the document as well, but as I am looking at the last document that Mr. Moyle had referred to, I am looking at how damage assessments are broken out in terms of what would be considered high risk damages versus -- how do

you -- how do you classify those different categories? I just want to understand that better.

THE WITNESS: Very simply, a high risk locate would be any locate where we know mechanized equipment is being used. So they are drilling, they are excavating. And the idea being that, you know, if they are drilling, they may be in an urban environment, gas migration underground could be at risk. If they are excavating, you know, maybe it's a larger pipe, that kind of thing. It's not someone's back yard and they are putting in irrigation system.

All damages are risky, but the higher risk designation is for what we try to deem as more of a bigger pipe or urban environment due to mechanized equipment.

COMMISSIONER CLARK: Thank you, Mr. Chair.

CHAIRMAN FAY: Great.

Commissioner Passidomo.

COMMISSIONER PASSIDOMO: Thank you.

Thank you, Mr. O'Connor. My questions are kind of more towards PHMSA requirements. I sit on the NARUC Pipeline Safety Subcommittee, and so a lot of things that we are discussing are new PHMSA requirements, is a big topic of our conversation,

so I didn't know if you had mentioned yesterday if there is a specific number of new employee hires, when OPC was kind of going through that document about new hires, if any of those you can say were specifically required hires for the new PHMSA requirement?

THE WITNESS: We have one additional employee in 2024 within our pipeline compliance group, and that is intended to assist with regulations that are coming that require, you know, obviously compliance from an engineering and construction, as well as operational perspective, with the recordkeeping and the management around auditing as well.

COMMISSIONER PASSIDOMO: But no specific, like, additional employees for responding to leaks or things like that? There is not a specific number that they are asking that you need to have on hand?

THE WITNESS: No. So within the headcount requested for field operations, they would be handling leak calls and responses. There are no specific headcount for only leak response, but more the technician.

COMMISSIONER PASSIDOMO: Okay. Yeah, I mean,

just doing a quick search through the CFR, it looks like subsection 191 of Title 49, it requires no longer than one hour after confirmed discovery, operators must give notice. I mean, to me, that seems like pretty quick turnaround, that you would need to have people on hand to respond quickly. I mean, the risk is high.

And so kind of following up with that, I just -- we kind of were talking -- Mr. Moyle was talking about what are the requirements, but you said they were more like industry standards, going beyond regulations. Do you have -- you know, other than the advantageous aspect towards the company and the consumer, like potential liability concerns, is that another thing where you would be on the hook for going beyond that one-hour -- one-hour mark of notice?

THE WITNESS: No, I don't believe we -- I don't really have any liability concerns in terms of not being able to be there in 60 minutes, but a safety issue, and we want to be able to respond.

Oftentimes, Fire Departments will be there before we are for a leak call, and may have already addressed the issue. But it is our system, we need to be there to make sure it's safe. I don't have

specific liability concerns around that metric.

COMMISSIONER PASSIDOMO: That's my questions, Mr. Chairman.

CHAIRMAN FAY: Okay. Great.

I just got two quick questions for you, Mr. O'Connor.

So on the 94.5 percent, which has been discussed continuously, you stay at the 94 percent. What's the real world sort of application of that? So you have a certain amount that they actually get out to that location within the 60 minutes, which meets your requirement, I am presuming the others get out there, just not within that 60 minutes, correct?

THE WITNESS: That's correct. And just 98.5 percent.

CHAIRMAN FAY: 98, I apologize. Thank you.

THE WITNESS: But yes, I mean, our intent, and our average is about 32 minutes on all calls, which is really good. But the goal around within 60 minutes from a safety perspective, we may be there in an hour and five minutes and, you know, we are still addressing that leak.

CHAIRMAN FAY: Right. And your currently 2023 numbers are at 96 percent?

THE WITNESS: That's correct.

CHAIRMAN FAY: So the real application of that is make it at the later time, you have a very broad territory. I mean, isn't there just sort of a reality from a percentage perspective that, you know, unless geographically you change some things, those numbers won't meet whatever this requirement is?

THE WITNESS: That is an aspect of it, yes. Some of our areas are just growing further and further out, and so it's literally impossible to drive to a leak within 60 minutes.

But to your point, we are looking at, are there adjustments in terms of how we organize ourselves so that we can respond within that timeframe.

CHAIRMAN FAY: Go great.

And then the external affairs folks are under you, under your purview?

THE WITNESS: Yes.

CHAIRMAN FAY: Okay. So in your testimony, you just briefly mentioned some of the engagement of that division and how they engage with political office holders. I wanted to make sure I got calculator on that. You are speaking to

specifically to individuals holding public office, either local, state, whatever it may be, and not political activity?

THE WITNESS: That's correct. There is no political activity in external affairs.

CHAIRMAN FAY: Okay. That's all I have, Mr. Means.

MR. MEANS: Thank you, Mr. Chairman. Just one question.

FURTHER EXAMINATION

BY MR. MEANS:

Q Mr. O'Connor, I believe I heard you say earlier that all of your team members collectively drive 7,000 miles per year, is that correct?

A No, that's not correct. In total, seven million miles.

MR. MEANS: Thank you. That's all I have.

CHAIRMAN FAY: Okay. All right. Let's move some exhibits in, Mr. Means?

MR. MEANS: Yes. Thank you.

I would like to move in Exhibits 14 and 27 on the comprehensive exhibit list into the record.

CHAIRMAN FAY: Okay. I have Exhibits 14 and 27 without objection, show those entered.

(Whereupon, Exhibit Nos. 14 & 27 were received

into evidence.)

MR. REHWINKEL: OPC would move 188.

CHAIRMAN FAY: Okay. OPC 188 without objection, Mr. Means?

MR. MEANS: No.

CHAIRMAN FAY: Okay. Show that entered.

(Whereupon, Exhibit No. 188 was received into evidence.)

MR. MOYLE: FIPUG would move 189.

CHAIRMAN FAY: Okay. Any objection?

MR. MEANS: No.

CHAIRMAN FAY: No. Okay. With that, show 189 entered into the record.

(Whereupon, Exhibit No. 189 was received into evidence.)

CHAIRMAN FAY: Mr. Means.

MR. MEANS: May Mr. O'Connor be excused?

CHAIRMAN FAY: Mr. O'Connor, you are excused.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN FAY: Great.

Now, Mr. Means, do we want toking ahead and take up Mr. Rutkin's testimony before we move on to Mr. Garrett?

MR. REHWINKEL: Mr. Chairman, I apologize, I

overlooked --

CHAIRMAN FAY: Go ahead, Mr. Rehwinkel.

MR. REHWINKEL: -- 187 from yesterday. I had not gone back in time, so I forgot about that.

CHAIRMAN FAY: No. You are correct. Yeah. Okay. So without objection, on 187, PGS?

MR. WAHLEN: Mr. Chairman, Peoples Gas would move the --

CHAIRMAN FAY: One second, Mr. Wahlen, just really quick. Showing no objection, show 187 also entered.

That's it for you Mr. Rehwinkel?

MR. REHWINKEL: Yes.

(Whereupon, Exhibit No. 187 was received into evidence.)

CHAIRMAN FAY: Okay. I am sorry, Mr. Wahlen, go ahead.

MR. WAHLEN: Peoples would like to move the prepared direct testimony of Lew Rutkin, Junior, and Exhibit 15 into the record.

CHAIRMAN FAY: Okay. Without objection, showing testimony as though read entered into the record and Exhibit 15 entered into the record.

(Whereupon, prefiled direct testimony of Lew Rutkin, Jr., was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20230023-GU

IN RE: PETITION FOR RATE INCREASE

BY PEOPLES GAS SYSTEM, INC.

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

LEW RUTKIN, JR.

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PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

LEW RUTKIN, JR.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

LEW RUTKIN, JR.

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

A. My name is Lew Rutkin, Jr. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Peoples Gas System, Inc. ("Peoples" or the "company"), as its Vice President of Gas Supply and Development.

Q. Please describe your duties and responsibilities in that position.

A. I lead our Gas Supply and Development team, which performs several functions for Peoples. The team is responsible for ensuring that the company has adequate gas supply and pipeline transportation capacity to serve our growing system and performs our natural gas commodity and transportation trading activities. It manages the company's Natural Choice Transportation Service and Individual Transportation Services programs as approved by the Florida Public Service Commission ("Commission"). It also coordinates the company's system expansion activities for large commercial and industrial

customers, electric power generators, and customers who are interested in using compressed natural gas ("CNG"), liquified natural gas ("LNG"), and renewable natural gas ("RNG") as part of their energy solutions. I will refer to these customers collectively as "Large Customer(s)" in my direct testimony.

Q. Please summarize your educational background and business experience.

A. I began working for our affiliate, Tampa Electric Company ("Tampa Electric"), as a cooperative education student in 2001, graduated from the University of South Florida with a Bachelor of Arts degree in Mathematics in 2003, and then joined Tampa Electric as a risk analyst. I left Tampa Electric in 2005, and from 2005 to 2019 worked for three different competitive energy companies where I performed a variety of functions, including: (1) gas supply management; (2) marketing and trading derivative and physical structures, including exchange futures, fixed-price swaps, basis swaps, swing swaps, storage spreads, exchange options, and forward physical gas; and (3) developing and marketing two interstate natural gas pipeline systems (Gulfstream Natural Gas System and Sabal Trail Transmission pipeline) that serve the state of Florida. I rejoined the TECO Energy family in 2019 as

Director of Gas Supply and Development for Peoples. I was promoted to my current position in 2021.

Q. Please describe the company's Gas Supply and Development team.

A. Peoples' Gas Supply and Development team consisted of 28 team members as of December 31, 2022 and is expected to grow to 38 team members by December 31, 2024. I will discuss the addition of 11 team members between 2023 and 2024 later in my direct testimony, which includes the replacement of one team member that left in January 2023. Approximately half of my team is focused on gas supply, pipeline transportation capacity, resource planning, and gas trading activities. Another portion of my team manages relationships with existing and new Large Customers and another portion is dedicated to supporting customers pursuing LNG, CNG, or RNG options for gas service. Our relationship managers stay alert for opportunities to: (1) serve new customers by expanding our system and (2) serve existing customers who plan to use more gas by expanding our system. I will discuss the growth of the Gas Supply and Development team later in my direct testimony.

Q. What are the purposes of your prepared direct testimony in this proceeding?

A. The purposes of my direct testimony are to: (1) describe the company's system of distribution pipeline, contracted pipeline capacity, and supply arrangements, and how Peoples manage and expand those system assets to serve our growing small and Large Customer base; (2) describe how the company developed our 2024 test year revenue forecast for the Large Customer classes; (3) discuss the major capital projects Peoples is undertaking to serve Large Customers from our last general base rate proceeding to the 2024 test year, (4) describe how the company is investing to support customers who seek innovative CNG, LNG, and RNG energy solutions; and (5) demonstrate that the level of Gas Supply and Development area operations and maintenance ("O&M") expenses in the company's 2024 test year is reasonable and prudent. I will also explain the company's proposed Minimum Volume Commitment Gas Transportation Agreement.

Q. Did you prepare an exhibit to support your prepared direct testimony?

A. Yes. Exhibit No. LR-1, entitled "Exhibit of Lew Rutkin, Jr." was prepared under my direction and supervision and accompanies my prepared direct testimony. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and

belief. It consists of these four documents:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-sponsored by Lew Rutkin, Jr.
Document No. 2	Articles on benefits of CNG, LNG, and RNG
Document No. 3	Peoples' RNG Florida Trend Article
Document No. 4	Capital Projects Summary

PEOPLES' DISTRIBUTION SYSTEM

Q. Describe the system of distribution pipeline, contracted transportation capacity, and supply arrangements used by Peoples to serve its customers.

A. Peoples receives natural gas from the Florida Gas Transmission ("FGT"), Gulfstream, Southern Natural Gas Company ("SONAT"), Sabal Trail interstate, and SeaCoast intrastate pipelines and distributes that gas to its customers using a distribution system consisting of gas mains, laterals, and service lines, and ancillary equipment such as meters, regulators, and pressure monitoring equipment. Peoples had approximately 14,900 miles of gas mains in service as of December 31, 2022.

The company purchases gas (the commodity) at market prices

from dozens of suppliers, brokers, and marketers and ensures that it has adequate interstate and intrastate transportation capacity to deliver the gas it purchases to customers on its system. Peoples ensures that it has enough distribution pipeline capacity so customers that purchase gas commodity directly from suppliers, brokers, or pool managers, and transportation capacity from interstate or intrastate pipelines, can receive the gas they buy at delivery points on the company's distribution system. Ensuring that Peoples has adequate gas supply and transportation capacity is an important function of the Gas Supply and Development team. The team works with the company's Operations and Engineering teams to monitor projected and actual demand, pipeline pressures and other operating information to ensure Peoples can serve our customers.

Q. How does the company manage its gas supply and transportation capacity arrangements to benefit customers?

A. The Gas Trading and Transportation group in Peoples' Gas Supply and Development team develops and executes strategies that: (1) lower the overall gas supply costs to our customers and (2) optimize our pipeline transportation agreements to manage risks related to extreme weather events and high gas supply prices. The trading group continuously evaluates ways

to mitigate risk exposure to fuel supply, transportation, and pricing changes that may adversely affect our customers. The company's diverse pipeline transportation portfolio, and our working relationships with large shippers, enable Peoples to meet growing customer demand in a safe and reliable manner, even during extreme weather events, periods of commodity price volatility, and when operational challenges occur.

Q. How does the company identify the need to expand its distribution system or pipeline transportation capacity?

A. In two primary ways. Peoples works with real estate developers to ensure that the company install gas distribution facilities to meet expected demand from residential and small commercial customers and the Gas Supply and Development team works with Large Customers and those seeking to use or develop CNG, LNG, and RNG to plan for and meet the demand in these market segments. Both teams collaborate with our engineering team led by company witness Christian C. Richard to plan the most efficient way to expand our system to meet customer demand for supply and transportation arising from all customer classes. I will discuss the expansion of our facilities to meet Large Customer demand later in my direct testimony. Witness Richard describes the company's planning processes in his direct testimony.

Q. How many Large Customers does Peoples serve?

A. As of December 31, 2022, Peoples served 405 Large Customers which includes 53 industrial and power generation customers. By December 31, 2024, Peoples expect to serve approximately 415 Large Customers, including 61 industrial and power generation customers. The company considers our Large Customer group to include customers that take service under our GS-4, GS-5, WHS, SIS, IS, ISLV, and CIS rate schedules or pursuant to special contracts authorized by the Commission.

Q. Is Large Customer demand for natural gas growing in Florida?

A. Yes. As company witnesses Dr. Richard K. Harper and Helen J. Wesley explain in their direct testimonies, Florida's population growth and economic success has been remarkable, especially over the past few years. Customer interest in sustainable and renewable energy continues to grow and has expanded beyond solar. Although natural gas prices recently have been volatile, the abundant supply of domestic natural gas has reduced the cost of natural gas well below levels a decade ago and has made the United States a major exporter of natural gas. The price of natural gas and its clean energy attributes has made natural gas a cost-effective and environmentally friendly alternative to coal, diesel, heavy

oil, and propane. As of February 28, 2023, as posted on the CME Group's website, the average natural gas price for all future contract months through December 2023 was $3.27/MMBtu. The price of crude oil and propane were $12.96/MMBtu and $9.56/MMBtu respectively as posted on the CME Group's website. In other words, natural gas is currently 65 percent less expensive than the closest alternative. These factors have increased demand for natural gas from Peoples' Large Customers.

LARGE CUSTOMER REVENUE FORECASTING

Q. Please describe how Peoples forecasts therms and base revenue for Large Customers.

A. Forecasting therms for base revenues for Large Customers is a joint effort by the company's Gas Supply and Development team and Finance department. This portion of the company's overall revenue forecast does not require economic modeling and regression techniques like those used by company witness Eric Fox for residential and small commercial customers.

Rather, since a large volume of demand is concentrated in a small number of Large Customers, the company develops its Large Customer demand and revenue forecast by examining prior and expected usage on a customer-by-customer basis. As part

of this process, members of our Gas Supply and Development team communicate with our Large Customers about their planned natural gas usage and transportation needs for the budget period and beyond. Peoples uses customer-specific projected usage and applicable rates and charges to forecast revenues for the customers taking service under our GS-4, GS-5, WHS, SIS, IS, ISLV and CIS rate schedules, or service pursuant to a special contract.

The company includes therms and revenue projections for new Large Customers in our financial forecasts based on the specific service characteristics of the new customer, including projected demand, and the in-service date of any facilities being built to serve a new customer.

Q. Did Peoples use the process described above to forecast revenues from Large Customers in the 2024 test year?

A. Yes. The projected revenues from Large Customers in 2024 are shown on MFR schedule G-2, page 8, which I co-sponsor with Peoples' witness Rachel B. Parsons.

Q. Describe how Peoples prepares the off-system sales forecast?

A. The amount of off-system sales ("OSS") net revenue budgeted

for 2024 at approximately $2.5 million projection was based on historical OSS net revenues. Although in 2022, Peoples had experienced a significant increase in revenues due to favorable natural gas price spreads and higher market demand conditions. These factors resulted in a $3.1 million increase above the budgeted $1.4 million margin to the bottom line. OSS revenues for 2024 are expected to moderate due to lower natural gas prices and less favorable market conditions.

LARGE CUSTOMER SYSTEM EXPANSION AND CAPITAL PROJECTS

Q. How does Peoples determine the need to expand its distribution system to serve Large Customers?

A. The company's internal need determination process for Large Customer expansions begins with communications between members of our Gas Supply and Development team and existing or potential new Large Customers. Our Gas Supply and Development team members routinely communicate with existing and potential new Large Customers to understand whether they can benefit by: (1) building a new facility that uses natural gas, (2) converting existing manufacturing and industrial processes to utilize natural gas, or (3) expanding their existing use of natural gas. Our Gas Supply and Development team members often work with local economic development organizations when they target new large commercial and

industrial businesses for location or relocation within a local area.

Once Peoples understand what a Large Customer needs or wants, the Gas Supply and Development team works with Peoples' operations and engineering teams to determine whether the increased customer demand can be served by existing capacity of our distribution facilities or whether the company needs to construct new distribution infrastructure (considering sufficient upstream transportation capacity) to serve the customer. It also considers the impact of residential and small commercial growth in the area. The key issue in this evaluation is whether the company's existing infrastructure and transportation arrangements can safely and reliably deliver the forecasted volumes and pressures of gas to the customer without impairing safe and reliable service to our existing customers.

If the company can serve the Large Customer's needs with existing distribution infrastructure, Peoples will offer to serve the customer pursuant to the applicable rate schedule and regulations in our tariff. If Peoples must build new distribution infrastructure to serve the Large Customer, members of our Gas Supply and Development team collaborate with the company's engineering team to evaluate the options

for building new infrastructure, identify the most cost-effective way to meet the demand, and develop cost estimates to determine whether the company should offer service under an existing rate schedule or standard contract, or alternatively, enter a special contract with the Large Customer.

The processes described above occurs in concert with the company's overall process of monitoring its distribution system for changes in volumes and pressures, planning to serve forecasted peak demand, complying with new safety requirements, and identifying projects to improve overall system reliability, resiliency, and efficiency ("RRE"). This overall planning process is detailed by witness Richard in his prepared direct testimony.

Q. How does the general body of ratepayers benefit from the addition of Large Customer loads?

A. Large Customers generate annual throughput of at least 250,000 therms, which is equivalent to the annual throughput of approximately 1,000 residential customers. This additional load broadly results in increased system utilization, thus bringing scale benefits to every capital dollar spent by spreading capital costs over larger billing determinants and

thus lowering fixed costs for all rate payers.

Q. What major capital projects has the company constructed to serve Large Customers since its last general base rate proceeding?

A. Peoples has constructed several major capital projects for Large Customers since its last general base rate proceeding, including the FGT to Big Bend Lateral. As part of this project, the company constructed approximately nine miles of transmission pipeline to provide additional gas transportation capacity to Tampa Electric at its Big Bend Power Station. The total cost of the project is being recovered by Peoples from Tampa Electric using a distribution rate that recovers Peoples' revenue requirement on a levelized basis over the life of the contract. This rate base addition was prudent, because it was needed by our customer, was constructed in a cost-effective manner, and is supported by customer specific revenues.

Q. Is the company planning major projects to Large Customers for periods beyond the 2024 test year?

A. Yes. The company is planning to construct pipeline infrastructure facilities to enable the transportation of

capacity from the FGT pipeline in northeast Florida to an LNG facility in the Jacksonville area, that serves the marine industry and others. This project, which Peoples call the FGT to the Jacksonville Export Facility ("JEF") Project, is expected to be under contract by the end of the second quarter of 2023, under construction by the third quarter of 2024, and in-service by the third quarter of 2025, which is later than the company projected in our 2023 and 2024 capital budgets. In addition, the cost estimates for the project in the initial budgets have changed. However, due to its size and the length of time it will take to build, the project will be eligible to accrue an Allowance for Funds Used During Construction ("AFUDC") and the capital cost will not be included in the company's rate base calculation for the 2024 test year. This project is a clear example of how our natural gas infrastructure can enable the cost-effective and carbon-friendly use of natural gas to fuel the marine industry for years to come.

INVESTING IN INNOVATION AND CLEAN ENERGY SOLUTIONS

Q. Is the way customers think about and use natural gas evolving?

A. Yes, natural gas has essentially replaced coal, diesel, and heavy oil as the fuel choice for electric generators in Florida. CNG and LNG have become increasingly popular as

alternative ways to fuel motor vehicle fleets and marine vessels. The abundant, low cost of domestic natural gas and existing natural gas infrastructure have helped position the United States as a significant exporter of natural gas to countries around the world.

In addition, environmental concerns have driven corporate commitments to reduce greenhouse gas emissions across their value chain and increased customer interest in innovative, Florida-sourced, carbon-friendly renewable energy solutions like RNG. As explained in witness Wesley's direct testimony, Peoples is committed to advancing the growth of RNG, LNG, and CNG because: (1) our customers value sustainability and environmental stewardship, (2) sustainable natural gas service is important to the future of Florida, and (3) it is simply the right thing to do. Offering service to support LNG, CNG, and RNG enables Peoples to lead and participate in a cleaner energy future for Florida. These solutions are cost effective and make an immediate impact on emission levels.

Q. What are the environmental benefits of CNG, LNG, and RNG?

A. LNG and CNG use for transportation, results in lower emissions (SO_X, NO_X, and greenhouse gases) compared to fuel oil or diesel. RNG facilities capture and clean methane that would

have ordinarily been emitted to the atmosphere from landfills, wastewater treatment facilities or livestock farms, and conditions this potentially environmentally hazardous waste product into pipeline quality natural gas and transports it for end-use via a pipeline system. Document No. 3 in my exhibit contains a collection of articles explaining the environmental benefits of CNG, LNG, and RNG.

COMPRESSED NATURAL GAS

Q. What role does CNG play in Florida?

A. CNG is growing in popularity as a safe, alternative fuel for fleets of vehicles. Owners and operators of large motor vehicle fleets in Florida are turning to CNG as an affordable and sustainable way to power their vehicles – especially mass transit buses, garbage collection trucks and large trucks. The Jacksonville Transportation Authority plans to convert a large portion of its fleet to CNG by 2023. Major metropolitan transit agencies are expanding their use of CNG. Growth in the CNG market is being driven by the affordability of natural gas, the reliability of natural gas via underground pipelines, the availability of proven gas compression and natural gas engines, and the attractiveness of CNG to entities that seek cost-effective ways to achieve sustainability and carbon reduction goals. The company's sales to CNG filling

stations measured in therms grew 2.1 percent from 2020 to 2021, and 7.7 percent from 2021 to 2022.

Q. How does Peoples serve customers who seek CNG?

A. Peoples currently serves approximately 60 CNG filling stations in Florida. The company owns and operates one CNG facility that provides CNG services for the City of Orlando's refuse trucks. Projects to serve new CNG customers benefit the company and its customers by increasing the throughput of natural gas through the company's system, which in turn increases the volume of gas over which the company's fixed costs can be recovered when setting rates. The company invested about $1.0 million dollars in 2022 to serve new CNG stations and expects to add new CNG customers in 2023 and 2024. It is difficult to predict when CNG customers will seek service from Peoples, and most of them can be served with existing infrastructure, so the company's 2023 and 2024 financial forecasts do not include any capital expenditures specifically for serving new CNG customers. Peoples intends to continue to support local governments, motor vehicle fleet owners, and CNG providers as they seek to develop CNG stations and convert vehicle fleets from gasoline or diesel to CNG.

LIQUIFIED NATURAL GAS

Q. What role does LNG serve in Florida?

A. LNG is quickly becoming very important to Florida's maritime industry for powering vessels (including container ships and the cruise ship industry) and as a cost-effective way to export natural gas around the world. Nine cruise ships that will be fueled by LNG are expected to be served from Florida ports by 2027, and five of those are already in service and operate out of Florida ports. This represents a substantial capital investment in the order of approximately $1.0 billion per vessel by the maritime industry to allow for the conversion of these vessels to use LNG. The peninsular shape of Florida, its geographic location, and the significant and growing water-borne shipping activities operating from Florida's numerous deep-water, high-volume ports make our state attractive for LNG providers.

The aerospace industry is shifting to more sustainable fuels and LNG represents an excellent choice. Space Florida is at the center point for the use of LNG as an aerospace fuel. The space industry has plans to power launch vehicles with LNG for space missions due to its high energy content. With the increase in launches from the space industry, fuel sources are needed nearby to support efficient refueling at launch sites.

Consequently, because LNG is a carbon friendly alternative and provides environmental and economic benefits to customers using it, demand for pipeline infrastructure and LNG facilities to support the economic development of Florida's LNG market is growing. LNG export, marine, aerospace, and rail sectors are developing markets for Florida and LNG.

Q. How does Peoples serve customers who operate LNG facilities?

A. Peoples currently provides natural gas to two operating LNG facilities in Jacksonville, and both facilities plan to expand over the next few years. The company supports these customers by providing gas distribution facilities that deliver industrial quantities of natural gas. Peoples has an LNG service tariff, but the LNG tariff excludes liquefaction services. In most instances, Peoples will be a distribution infrastructure provider to LNG and the company is not proposing to change the liquefaction restriction in its LNG tariff in this proceeding. LNG creates long-term infrastructure for the State of Florida resulting in direct investment in Florida, high-paying local jobs, and promoting economic development in the state. Peoples will continue to support the growing demand for LNG to supply marine and other industries, including natural gas exports to other parts of the world. The availability and expansion of natural gas

distribution systems in Florida, including Peoples, enables the market development of LNG which produces further economic opportunities for our State.

RENEWABLE NATURAL GAS

Q. What is renewable natural gas?

A. RNG is a natural by-product of above-ground decomposing waste, and contrasts with traditional natural gas that was formed underground from decomposing materials over long periods of time. When organic waste from farms, landfills, and wastewater facilities decomposes, it releases methane, a powerful greenhouse gas, into the atmosphere. Naturally occurring methane (CH_4) and carbon dioxide (CO_2) emissions from energy and anthropogenic waste are two of the largest contributors to climate change in the United States. According to the United States Environmental Protection Agency, methane emissions make up about 10.9 percent of the human-caused greenhouse gas (GHG) emissions in the United States.

Q. How do RNG projects work?

A. RNG projects: capture methane from landfills, livestock farms, and wastewater treatment plants; remove the harmful

constituents; condition the natural gas to gas pipeline quality specifications; and inject it into a pipeline system for consumption by natural gas customers. These projects can be considered carbon neutral or carbon negative because they take methane that otherwise would have been emitted into the atmosphere and create clean natural gas which can be injected into Florida's pipeline system. RNG is unique as a fuel source because it simultaneously reduces greenhouse gas (GHG) emissions from both methane and carbon dioxide on a net basis.

Q. What role can RNG play in the energy future for Florida?

A. RNG can be an important part of a sustainable, reliable, and affordable energy future for Florida and can provide real benefits.

Rather than generating out-of-state jobs to extract traditional natural gas and deliver it to Florida, RNG projects developed in Florida are local investments that create local jobs and promote economic development in Florida, not elsewhere.

RNG can contribute diversity to the state's fuel portfolio, providing Floridians with a local fuel source that displaces natural gas that would otherwise be supplied from outside the

state. Having localized and distributed RNG supply increases the resiliency of Florida's natural gas distribution system and mitigates the risks associated with potential pipeline or upstream supply disruptions.

RNG is a natural complement to solar and other renewable energy options like wind. These renewable options are intermittent energy sources dependent upon weather conditions, so RNG can be used to generate electricity and maintain the reliability of the electric supply system when the weather or time of day is not favorable for other renewable options.

RNG can also bring added reliability and resiliency to underserved or hard-to-serve rural areas because it can be sourced and produced locally.

Q. How will Peoples support the development of RNG in Florida?

A. Peoples' size, the resources available to it, the expertise of its team members, and the size and reach of its distribution system uniquely position Peoples to support the growth of RNG in Florida. The statewide reach of the company's existing gas distribution system is near landfills, wastewater treatment plants, and livestock farms that are

potential RNG production sites. Peoples is actively working with RNG developers and facility owners to evaluate RNG potential at sites throughout the state. The company is making investments to support RNG using our renewable natural gas tariff Rate Schedule Renewable Natural Gas Services ("RNGS").

Q. What investments has Peoples made in RNG?

A. Peoples is investing approximately $62.0 million to support or construct three of the first operating RNG facilities in Florida, namely New River RNG, Brightmark RNG and Alliance Dairies RNG. A general description and illustration of the company's RNG activities are included in Document No. 4 of my exhibit.

Q. When will these three RNG projects be in-service?

A. Absent unforeseen circumstances, Peoples expects these three projects to be in service by the time this rate proceeding goes to final hearing. Once in service, these projects will generate enough RNG to serve approximately 40,000 residential customers, or approximately ten percent of the company's residential customers.

Q. Are the three RNG projects the same?

A. No. The projects are different and reflect the suite of services Peoples can provide to support RNG development. Two of the projects, Brightmark and New River, which I discuss later, use the company's Rate Schedule RNGS and cost of service pricing to support the efforts of two RNG developers.

Alliance Dairies is a unique project between a dairy owner and Peoples, under which Peoples has made rate base investments in RNG facilities and will recover its capital investment through a revenue-sharing arrangement with the farmer that monetizes the environmental attributes arising from the project. I will explain each of these projects in more detail.

NEW RIVER RNG PROJECT

Q. Please describe the New River project.

A. The New River RNG project was developed under the company's RNG tariff and provides cost of service-based recovery to Peoples for the facilities required to transport RNG produced and conditioned at the New River landfill into Peoples' pipeline system. Peoples will test the RNG to be produced by the landfill to ensure that it meets pipeline quality standards before it is injected into our gas distribution system and then on to the FGT interstate pipeline. Peoples

expects the peak daily amount of RNG to be transported through our system from New River will be equivalent to the daily natural gas demand of approximately 30,000 residential customers.

Q. Please describe the contract that governs the New River project.

A. The Renewable Natural Gas Services Agreement ("RNGSA") that governs the relationship between the operator of the New River RNG conditioning facility, Opal Fuels, is a cost-of-service agreement which fully recovers the investment by Peoples over a 20-year term. The agreement includes guarantees and firm commitments by Opal Fuels to meet the full revenue requirements of the project. Peoples will not own the environmental attributes generated by the project; they will be owned by the developer, who can market the environmental attributes at its discretion. Opal Fuels will own the title to the gas produced at the facility and will sell it in the open market.

Q. What is the projected in-service date for the New River project?

A. The total capital investment made by Peoples for the New River

project is approximately $8.2 million. The project is in-service, operating and transporting RNG.

Q. Is the company's investment in facilities to serve the New River RNG facility prudent?

A. Yes. The company's New River Project RNG is prudent. It was constructed to meet a specific customer need and the revenue requirement associated with the project will be recovered over the life of the contract via payments from the customer. Although the RNG generated by the project will not be owned by Peoples, the New River RNG project will generate the environmental, resiliency, and other RNG benefits previously described in my direct testimony.

BRIGHTMARK RNG PROJECT

Q. Please describe the Brightmark RNG project.

A. The Brightmark RNG project was developed under Peoples' RNG tariff and is composed of RNG collection, conditioning, and transportation facilities required to transport RNG produced and conditioned at the Larson Dairy Farm into the FGT and Florida Southeast Connection interstate pipeline systems. Peoples will test the RNG produced by the project to ensure the gas specifications meet the requirements of each

respective interstate pipeline system before injection. Peoples expects the peak daily amount of RNG to be transported through our system from Brightmark will be equivalent to the daily natural gas demand from about 8,000 residential customers. Peoples will not own the environmental attributes created by the project; they will be owned by the developer, who can market them at their own discretion. Brightmark will own title to the gas produced at the facility and will sell it in the open market.

Q. Please describe the contract that governs the Brightmark RNG project.

A. The RNGSA between Peoples and Brightmark, a Chevron-backed developer, is a cost-of-service agreement that fully recovers the revenue requirement associated with the company's investment in the project over a 15-year term. Under the contract, Brightmark will construct, and Peoples will purchase, the digester, biogas conditioning equipment, and RNG transportation facilities necessary to collect, condition, transport and inject the RNG from the project and Peoples will charge Brightmark a levelized, cost of service-based rate over the life of the contract. Brightmark is responsible for the operation and maintenance of the digester, biogas collection line and biogas conditioning

equipment. Peoples will retain ownership and be responsible for the O&M expense of the RNG transportation facilities associated with the project during and after the term of the agreement. The agreement includes guarantees and a firm commitment by Brightmark to pay the full revenue requirements of the project.

Q. What is the total capital investment and projected in-service date for the Brightmark RNG project?

A. Including spend from 2021, the total capital investment made by Peoples for the Brightmark project is expected to be approximately $42.7 million. Absent unforeseen circumstances, the project is estimated to be in service during the second quarter of 2023.

Q. Has Peoples proposed a special depreciation rate for the RNG facilities associated with the Brightmark project?

A. Yes. Peoples filed a petition with the Commission on December 15, 2022, seeking approval of a depreciation rate with a 15-year life for use with the Brightmark RNG assets. The petition was assigned Docket No. 20220212-GU and appears to be on a procedural schedule that will run parallel to this case.

Q. Why did the company propose a 15-year life for depreciation of the Brightmark RNG assets?

A. The company proposed using a 15-year life for these assets to match depreciation cost recovery with the company's revenue stream under the contract, and so the net book value of the Brightmark RNG assets will be zero when the contract expires and title to the RNG assets will be transferred to Brightmark. This proposal honors the matching principle for ratemaking and will prevent the company from recording a loss on the disposition of the assets or having a depreciation reserve deficiency at the end of the term of the agreement. Company witness Dane A. Watson discusses the proposed depreciation rate for the Brightmark RNG assets further in his prepared direct testimony.

Q. Is the company's investment in the Brightmark RNG project prudent?

A. Yes. The company's Brightmark RNG project is prudent. The company's involvement in the project meets a specific customer need and the revenue requirement associated with the project will be recovered over the life of the contract via monthly service charge payments for the Brightmark RNG assets and related RNG transportation facilities. Although the RNG

generated by the project will not be owned by Peoples or provided by Peoples to its customers, the Brightmark project will generate the environmental, resiliency, and other RNG benefits previously described in my testimony.

ALLIANCE DAIRIES RNG PROJECT

Q. Please describe the Alliance Dairies RNG project.

A. As part of the Alliance Dairies RNG project, Peoples has constructed and will own the RNG conditioning, and transportation facilities required to transport RNG produced at the Alliance Dairies Farm into the FGT interstate pipeline system. The RNG produced by the project will be tested by Peoples to ensure the gas specifications meet the requirements of FGT's interstate pipeline system before injection into the pipeline system. Peoples expects the peak daily amount of RNG to be transported through our system from the Alliance Dairies Farm to be equivalent to the daily natural gas demand of about 6,000 residential customers.

Q. Who will own the RNG facilities associated with the project?

A. Alliance Dairies will own the digester and all facilities on the farm side of the digester. Peoples will own the RNG conditioning, and transportation facilities on the pipeline

side of the digester and has included that investment in its proposed rate base for the 2024 test year. However, as mentioned above, Peoples will recover its capital investment through a revenue sharing arrangement with the farmer that monetizes the environmental attributes of the project.

Q. Who will own the RNG created by the project?

A. Peoples will own the RNG arising from the project and will market the environmental attributes associated with the RNG through a relationship the company has with an environmental attribute broker. The environmental attributes associated with the Alliance Dairies RNG project will essentially be stripped from the "green" RNG and monetized by selling the attributes in an environmental credit market. Peoples will own the resulting "brown gas" for use by its customers.

Q. What does the company propose to do with the brown gas arising from the Alliance Dairies RNG project?

A. The company proposes that the brown gas remaining after the environmental attributes are monetized, be provided to Peoples' gas supply customers through the Purchased Gas Adjustment Cost Recovery Clause ("PGA") at a zero-commodity price resulting in immediate savings to all gas supply

customers.

Q. What impact will the Alliance Dairies RNG project have on the company's revenue requirement for the 2024 test year?

A. Even though the investments and expenses of the Alliance Dairies RNG project will be included "above-the-line" for ratemaking in the 2024 test year, the value of environmental attributes expected from the project will support the overall revenue requirement of the project in the 2024 test year and beyond. Peoples' witness Parsons will explain this further in her prepared direct testimony.

Q. Please describe the contract that governs the Alliance Dairies RNG project and the structure of payments to Alliance Dairies.

A. Peoples has entered into a Biogas Incentives agreement with Alliance Dairies under which Peoples will own the RNG generated by the project as well as the environmental attributes associated with the Alliance Dairies RNG project. Peoples will make monthly payments to Alliance Dairies based on the monetized value of the environmental attributes associated with the RNG.

The agreement was structured so that revenues from the sale of the environmental attributes associated with the RNG created by the project will be Peoples' primary source of cost recovery for its capital investment in the project. The payments by Peoples to Alliance Dairies were structured to ensure Peoples retains a greater percentage of project revenues until the company's project costs are fully recovered. Based on current projections, Peoples expects to recover the full cost of its investment in RNG facilities for the Alliance Dairies RNG project by 2030. The parties adopted this approach to accelerate cost recovery for Peoples and to mitigate any financial risks the project may have on the company's general body of ratepayers.

Q. What is the total capital investment and projected in-service date for the Alliance Dairies RNG project?

A. The total capital investment made by Peoples for the Alliance Dairies RNG project is approximately $11.0 million, which includes spending in 2021. Absent unforeseen circumstances, the company expects the Alliance Dairies RNG project to be in service by the end of the second quarter of 2023.

Q. Does the Alliance Dairies RNG project benefit the company's customers?

A. Yes. The project is prudent and benefits the company's customers in several ways.

First, as previously mentioned, Peoples proposes that the brown gas remaining after the environmental attributes of the RNG generated by the project have been sold will be provided to Peoples' customers through the PGA at a zero-commodity price. Since the cost of the Alliance Dairies RNG facilities owned by Peoples will be recovered via revenue from the sale of environmental attributes, Peoples' customers will essentially receive the brown gas from the project for free. The company expects the annual commodity value of the Alliance Dairies brown gas to be approximately $396,000 every year assuming the market value of traditional natural gas is $3.00/MMBtu.

Second, the projected revenue stream from the sale of the environmental attributes will support the revenue requirement for the project in the 2024 test year and beyond. This is forecasted to be true even though the investments and expenses of the Alliance Dairies RNG project will be included "above the line" for ratemaking in the 2024 test year.

Third, the project will allow the company's customers to participate in an RNG project that will deliver sustainable,

carbon-negative, pipeline-quality gas produced and distributed in Florida, that can be used in homes and businesses.

Fourth, because the RNG from Alliance Dairies will be produced in Florida, it can be delivered to customers in Florida without paying the interstate transportation charges needed to deliver traditional natural gas purchased out of state into Florida. If the company had to purchase interstate transportation capacity to deliver an equivalent amount of traditional natural gas from out-of-state to Peoples' system, the annual cost would be approximately $93,000, which represents an avoided cost benefit to Peoples' customers.

Fifth, the company's customers will benefit because Peoples' involvement in the project will provide the company with valuable experience operating an RNG facility for the purposes of potentially offering add-on renewable products to all customers in the future.

Q. How does the Alliance Dairies RNG project mitigate risks to the company's general body of ratepayers?

A. Whenever the company builds facilities to serve new Large Customers or greater demand from an existing Large Customer,

it faces a risk that the customer will go out of business before the company gets full cost recovery of its investment to serve the customer. The significance of this risk is a function of numerous factors, including general business conditions, market forces impacting the specific industry in which the customer operates, and the long lives used to calculate depreciation rates for public gas utilities like Peoples.

The risks associated with the Alliance Dairies RNG project are modest and have been mitigated by the design of the transaction.

First, the company's total investment in the project is approximately $11.0 million, which is modest by utility project standards.

Second, the company is not constructing or owning the digester, which is one of the more expensive components of the project.

Third, the company has performed due diligence on Alliance Dairies and has found it to be one of the most professionally operated dairies in Florida, and if the growing base of Florida consumers continue to drink milk, the risk of major

market changes that would put the dairy out of business seems remote.

Fourth, the revenue payments under the contract have been designed in favor of Peoples in the early years of the contract to promote full cost recovery by Peoples in approximately seven years, which is a short period by traditional utility standards.

TEST YEAR OPERATIONS AND MAINTENANCE EXPENSES

Q. What amount of Gas Supply and Development O&M expense was incurred in 2022?

A. The total O&M expenses attributable to base rates in 2022 was $2.6 million. This total amount is primarily reflected in the amounts for FERC Accounts 920 and 921 shown on MFR schedule G-2, page 17.

Q. What are the projected O&M expenses for your area in 2023 and 2024?

A. The totals in 2023 and 2024 are $2.8 million and $3.6 million, respectively. The distribution of these amounts is primarily within the amounts for FERC Accounts 920 and 921 shown on MFR schedule G-2, page 17.

Q. Why is the total projected amount of 2024 O&M expenses for your area higher than the actual amount in 2022?

A. The total in 2024 is $1.0 million higher than in 2022. Approximately $600,000 of this increase is labor costs that were budgeted on a trended basis as described by company witness Donna L. Bluestone in her direct testimony. The remainder of the increase is not trended labor costs.

Q. Why are not trended labor costs increasing from 2022 to 2024?

A. Most of the O&M expenses incurred in the Gas Supply and Development area are labor related, so our O&M expense levels have been influenced by the need to add personnel to meet Florida's significant growth, and by upward market pressures on labor and wage rates.

The company has expanded Gas Supply and Development's responsibilities to include: (1) enhancing the trading and transportation group to manage our system of gas supply and transportation; (2) meet increased gas demand across multiple gas markets, including new pipeline development to serve end users in RNG, industrials and LNG; and (3) development of a resource planning team to provide forecasting and analytical support to expand our system efficiently and effectively.

Q. Why does the company need to add personnel in the Gas Supply and Development Area?

A. Peoples intends to add new Gas Supply and Development positions in the next couple years, equivalent to six replacement positions in 2023 and two replacement positions and three new positions in 2024, exclusive of any allocations. These positions are listed on MFR G-2, page 19e and are needed so the Gas Supply and Development team can perform its enhanced responsibilities described above, and to help the company respond to the growth of Florida and changing market conditions and customer expectations. Finding qualified persons to fill these positions has been a challenge in the current labor market but Peoples has been pleased with our ability to hire talented people so far. The challenges of the current labor market are explained in witness Bluestone's direct testimony and have been experienced in the Gas Supply and Development area.

Q. Why is the level of Gas Supply and Development O&M expenses in the 2024 test year reasonable?

A. The projected O&M expenses are based on current market costs with reasonable inflationary adjustments and represent best estimates of anticipated O&M expenses in 2024. The additional

team members to be hired in 2023 and 2024 are needed so the Gas Supply and Development team can continue to support Peoples' efforts to provide safe and reliable gas system to its growing customer base.

MINIMUM VOLUME COMMITMENT GAS TRANSPORTATION AGREEMENT

Q. What new form of agreement is Peoples proposing to add it its tariff?

A. As discussed in company witness Karen L. Bramley's direct testimony, Peoples is proposing to add a new minimum volume commitment gas transportation form agreement to ensure that certain industrial and large commercial customers requesting gas transportation service that need construction of new mains and/or additional facilities are bound by contract to use and pay for the transportation service requested. The proposed changes will protect the general body of ratepayers and should be approved.

SUMMARY

Q. Please summarize your prepared direct testimony.

A. Peoples' customers have the choice to use natural gas or other alternatives for their energy needs. Our focus on meeting customer expectations and understanding their daily

operational and future needs through regular interactions has placed us in a position to be the preferred choice for providing affordable and reliable energy. As a result, Large Customers are increasing seeking natural gas as an environmentally beneficial option for power generation, transportation and other direct end-uses. Further, Peoples' Gas Supply and Development activities and costs are reasonable and appropriately position Peoples to meet future Large Customer demand while prudently managing its costs. Peoples is committed to providing safe and reliable service and have reinforced our ability to mitigate the effect of peak pricing on our customers during volatile energy market events, evidenced by the outcome of a significant supply disruption event, Storm Uri in 2021. Our system integrity was maintained throughout the event and did not result in a single service interruption to our customers.

Peoples is proud of the work the company is doing to support the development of Florida's economy by making low-cost and clean natural gas accessible to more customers as well as supporting the development of sustainable energy solutions including CNG, LNG, and RNG.

Q. Does this conclude your prepared direct testimony?

A. Yes.

(Whereupon, Exhibit No. 15 was received into evidence.)

CHAIRMAN FAY: All right. Next what we will do is we will just take a quick break for our IT folks to make sure we've got Mr. Garrett set up. I think we have tested him multiple times this morning, so let's do 10:45, which is seven minutes from now, we will start back with Mr. Garrett.

(Brief recess.)

CHAIRMAN FAY: All right. Let's get started back.

We'll have -- PGS, call your next witness.

MR. WAHLEN: I think this is --

MS. CHRISTENSEN: Chairman, that's OPC's witness.

CHAIRMAN FAY: Oh, I apologize. OPC your next -- your first witness, I should say.

MS. CHRISTENSEN: We would call David Garrett to the stand. I would ask that the Chair have him sworn in.

CHAIRMAN FAY: Yep.

Mr. Garrett, if you can just I raise your right hand.

Whereupon,

DAVID J. GARRETT

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

THE WITNESS: I do.

CHAIRMAN FAY: Okay.

MS. CHRISTENSEN: Okay. And I believe Mr. Garrett, while he can hear us, I don't know if he can see the live stream, so --

CHAIRMAN FAY: He doesn't have a visual.

MS. CHRISTENSEN: Right, but he has audio, so we will just go through the best we can.

CHAIRMAN FAY: Perfect.

MS. CHRISTENSEN: Okay.

EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Garrett, can you please state your full name and your business address for the record, please?

A My name is David Garrett. My address is 101 Park Avenue, Suite 1125, Oklahoma City, Oklahoma, 73102.

Q And did you cause to be filed prefiled direct testimony consisting of 98 pages in this docket?

A Yes.

Q And do you have any corrections to your testimony at this time?

A No.

Q And if I were to ask you the same questions today, would your answers be the same?

A Yes.

MS. CHRISTENSEN: Commissioner, I would ask that the testimony be entered into the record as though read.

CHAIRMAN FAY: Okay. Show it entered.

(Whereupon, prefiled direct testimony of David J. Garrett was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Petition for Rate Increase by Peoples Gas System, Inc.	DOCKET NO: 20230023-GU
Peoples Gas System's Petition for Rate Approval of 2022 Depreciation Study	DOCKET NO: 20220219-GU
Peoples Gas System's Petition for Approval of Depreciation Rate and Subaccount for Renewable Natural Gas Facilities Leased to Others	DOCKET NO: 20220212-GU

DIRECT TESTIMONY
OF
DAVID J. GARRETT

ON BEHALF OF

FLORIDA OFFICE OF PUBLIC COUNSEL

JUNE 22, 2023

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Part Two: Depreciation

LIST OF APPENDICES

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting PLLC.

Q. Please summarize your educational background and professional experience.

A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the Oklahoma commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the Oklahoma commission, I formed Resolve Utility Consulting PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. I am a member of the Oklahoma Bar, but I am not providing legal advice in this proceeding or the State of Florida. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

[1] Exhibit DJG-1.

Q. Describe the purpose and scope of your testimony in this proceeding.

A. I am testifying on behalf of the Florida Office of Public Counsel ("OPC") in response to the petitions for rate increase and approval of the depreciation study and depreciation rates by Peoples Gas System ("PGS" or the "Company"). Specifically, I address the cost of capital and fair rate of return for PGS in response to the direct testimony of Company witness Dylan D'Ascendis. I also address the Company's proposed depreciation rates in response to the direct testimony of Company witness Dane A. Watson, who conducted the Company's depreciation study.

II. EXECUTIVE SUMMARY

A. Part One: Cost of Capital

Q. Describe PGS's position regarding the awarded rate of return in this case.

A. PGS proposes an awarded ROE of 11.0%.[2] PGS also proposes a capital structure consisting of approximately 55% equity and 45% debt.[3] Mr. D'Ascendis relies on the Discounted Cash Flow Model ("DCF Model"), the Capital Asset Pricing Model ("CAPM"), and other risk premium models as part of his recommendation.

Q. Please summarize your analyses and conclusions regarding PGS's cost of equity.

A. PGS has proposed an excessive awarded ROE in this case. Analysis of an appropriate awarded ROE for a utility should begin with a reasonable estimation of the utility's

[2] Direct Testimony of Dylan W. D'Ascendis, p. 5, lines 1-12.

[3] *Id.* PGS is proposing a capital structure consisting of 40.48% long-term debt, 4.84% short-term debt, and 54.68% equity. Throughout my testimony, I refer to these figures in rounded numbers, and I refer to the Company's proposed total debt ratio as 45% and equity ratio as 55% from investor-supplied sources.

cost of equity. In estimating PGS's cost of equity, I performed a cost of equity analysis on a proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, I evaluated the results of the two most widely used and widely accepted financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. I conducted two variations of both the CAPM and DCF Model. The results are shown in the figure below.

Figure 1:
Cost of Equity Model Results

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	8.5%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.1%
DCF Model (Analyst Growth)	8.3%
DCF Model (Sustainable Growth)	7.5%
Average	**8.1%**
Range	**7.5% - 8.5%**

As shown in this figure, the results of my modeling range from 7.5% - 8.5%.[4]

Q. Please provide further explanation about your cost of equity range.

A. The range of cost of equity estimates is relatively wide in this case because of the discrepancy between PGS's proposed debt and equity ratios and the proxy group's average debt and equity ratios. PGS's proposed debt ratio of 45% is notably lower than

[4] Exhibit DJG-13.

the average debt ratio of the proxy group, which is 51%, and conversely the Company's requested equity ratio of 55% is higher than the average equity ratio of the proxy group of 49%. This means that PGS has less financial risk relative to the proxy group. Thus, in order for the indicated cost of equity under the CAPM to be correct, we must adjust the result based on PGS's lower risk profile. We can accomplish this through a mathematical model called the Hamada model (described below in more detail in Section IX. B). Application of the Hamada model shows that PGS's cost of equity under its equity-rich capital structure is only 8.1%. However, if we impute a ratemaking capital structure for PGS that is equal to the proxy group average, then PGS's cost of equity estimate is 8.5%.

Q. Based on the results of your cost of equity analyses, what is your recommendation to the Commission PGS's authorized rate of return.

A. I recommend the Commission adopt a 9.0% awarded ROE for PGS. I also recommend the Commission adopt a ratemaking capital structure for PGS consisting of a total equity ratio that is equal to the average debt ratio of the proxy group – 49%. Despite the fact that the indicated cost of equity for PGS under my CAPM analyses is only 8.5%, it is my opinion that a 9.0% awarded ROE for PGS could be considered reasonable under the circumstances. This is primarily due to the fact that PGS's current awarded ROE of 9.9% significantly exceeds any reasonable estimate of the Company's market-based cost of equity. One could argue that it is preferable for awarded ROEs to gradually change, rather than abruptly. An awarded ROE of 9.0% would partially mitigate the excess transfer of wealth from Florida customers to shareholders while

gradually moving the Company toward an actual market based ROE. My recommendations are presented in the following figure.[5]

Figure 2:
Awarded Return Recommendation

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	46.0%	5.54%	2.55%
Short-Term Debt	4.8%	4.85%	0.23%
Common Equity	49.2%	9.00%	4.43%
Total	100.0%		7.21%

As shown in this figure, adopting my proposed ROE and capital structure (and adopting the Company's proposed cost of equity) results in an authorized rate of return of 7.21%.

B. Part Two: Depreciation

Q. Summarize the key points of your testimony regarding depreciation.

A. In this case, Mr. Watson is proposing depreciation rates based on projected plant and reserve balances as of December 31, 2024. The depreciation rates proposed by Mr. Watson result in a proposed annual depreciation accrual increase of $9.0 million.[6] In addition, Mr. Watson calculates a reserve surplus of $120 million as of this depreciation

[5] Exhibit DJG-2. This weighted average cost of capital is based on investor-supplied sources of capital and reflects PGS's requested costs of short-term and long-term debt. For OPC's recommended cost of debt and consolidation of all OPC cost of capital adjustments, please see the direct testimony of OPC witness Lane Kollen, who presents a recommended weighted average cost of capital based on all capital components..

[6] Direct Testimony of Dane A. Watson, p. 10, lines 12-17.

study date.[7] I analyzed Mr. Watson's depreciation study as of December 31, 2024 (the "2024 Study"), and I recommend service life adjustments for several accounts. Including OPC's service life adjustments, OPC's primary recommendation for depreciation rates and the reserve surplus are based on plant and reserve balances as of December 31, 2023 (the "2023 Study").

Q. Please summarize the results of your analyses under the 2023 Study and 2024 Study.

A. Adopting my proposed service life adjustments under the 2023 Study results in an annual depreciation accrual of $77.9 million and equates to an adjustment reducing the Company's proposed annual depreciation accrual by $16 million, as summarized in the table below.

Figure 3:
Primary Recommendation – Adjusted 2023 Study Results

Plant Function	Company Proposal (2024) Rate	Company Proposal (2024) Accrual	OPC Proposal (2023) Rate	OPC Proposal (2023) Proposal	OPC Adjustment Rate	OPC Adjustment Adjustment
Intangible	6.60%	$ 8,287,773	6.39%	$ 7,119,431	-0.20%	$ (1,168,342)
Distribution	2.50%	79,497,074	2.23%	65,901,840	-0.26%	(13,595,235)
General	6.85%	5,520,935	6.35%	4,261,768	-0.50%	(1,259,167)
RNG/LNG	3.44%	605,050	3.45%	606,895	0.01%	1,845
Total Plant Studied	2.76%	$ 93,910,832	2.47%	$ 77,889,934	-0.28%	**$ (16,020,898)**

[7] I calculate a substantially similar reserve surplus of $120 million - *see* Exhibit DJG-23; see also Exhibit DJG-36 for reserve development.

This approach results in an adjustment reducing the Company's proposed depreciation accrual by $16 million.[8] In addition, my adjusted service life parameters under the 2023 Study results in a calculated depreciation surplus of $221 million.[9] It is OPC's recommendation to amortize the reserve surplus adopted by the Commission over 10 years, as explained in more detail in the direct testimony of OPC witness Lane Kollen. The depreciation rates and reserve surplus based on my adjustments under the 2023 Study represent OPC's primary recommendation to the Commission.

Q. Are you also proposing to the Commission any alternative recommendations regarding these issues?

A. Yes. It is OPC's position that the most reasonable approach to take regarding these issues is outlined in our primary recommendation. However, in the event the Commission does not adopt my primary recommendation, the Commission can consider two alternative approaches. The first alternative approach would be to adopt all of Mr. Watson's proposed service lives and net salvage rates, but still have the depreciation rate and reserve surplus calculations based on plant and reserve balances at December 31, 2023. The results of this first alternative approach are summarized in the following figure.

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[8] *See* Exhibit DJG-18; *see also* Exhibits DJG-24 for rate calculations; *see also* DJG-40 for 2023 adjusted remaining life development.

[9] Exhibit DJG-27. This amount assumes that the Dade City Connector Project will be in-service pursuant to Paragraph 4(c)(ii) of the 2020 Settlement Agreement approved in Order No. PSC-2020-0485-FOF-GU. To the extent that PGS fails to demonstrate that it will be in-service before December 31, 2023, I reserve the right to amend my testimony accordingly.

Figure 4:
First Alternative Recommendation – Unadjusted 2023 Study Results

Plant Function	Company Proposal (2024) Rate	Company Proposal (2024) Accrual	OPC Proposal (2023) Rate	OPC Proposal (2023) Proposal	OPC Adjustment Rate	OPC Adjustment Adjustment
Intangible	6.60%	$ 8,287,773	6.39%	$ 7,119,431	-0.20%	$ (1,168,342)
Distribution	2.50%	79,497,074	2.46%	72,749,052	-0.03%	(6,748,022)
General	6.85%	5,520,935	6.35%	4,261,768	-0.50%	(1,259,167)
RNG/LNG	3.44%	605,050	3.45%	606,895	0.01%	1,845
Total Plant Studied	2.76%	$ 93,910,832	2.69%	$ 84,737,146	-0.06%	**$ (9,173,686)**

This approach results in an adjustment reducing the Company's proposed depreciation accrual by $9.2 million.[10] In addition, adopting the Company's unadjusted service lives and net salvage rates based on 2023 plant and reserve balances results in a calculated depreciation surplus of $159 million.[11]

OPC's second alternative for consideration is to apply my service life adjustments to calculate the depreciation rate and reserve surplus to 2024 plant and reserve balances. The results of this approach are summarized in the following table.

[10] *See* Exhibit DJG-26; *see also* Exhibit DJG-41 for 2023 unadjusted remaining life development.

[11] Exhibit DJG-28.

Figure 5:
Second Alternative Recommendation – Adjusted 2024 Study Results

Plant Function	Company Proposal Rate	Company Proposal Accrual	OPC Proposal Rate	OPC Proposal Proposal	OPC Adjustment Rate	OPC Adjustment Adjustment
Intangible	6.60%	$ 8,287,773	6.60%	$ 8,287,773	0.00%	$ -
Distribution	2.50%	79,497,074	2.26%	71,968,327	-0.24%	(7,528,747)
General	6.85%	5,520,935	6.85%	5,520,935	0.00%	-
RNG/LNG	3.44%	605,050	3.44%	605,050	0.00%	-
Total Plant Studied	2.76%	$ 93,910,832	2.53%	$ 86,382,085	-0.22%	**$ (7,528,747)**

This approach results in an adjustment reducing the Company's proposed depreciation accrual by $7.5 million.[12] In addition, this approach results in a calculated depreciation surplus of $187 million.[13]

My primary recommendation and the alternative recommendations are summarized in the following table.

[12] *See also* Exhibits DJG-18, DJG-19, and DJG-20 for rate calculations and adjustments; see also Exhibit DJG-37 for remaining life development.

[13] Exhibit DJG-22; *see also* Exhibit DJG-35 for reserve development.

Figure 6:
OPC's Primary Recommendation and Alternatives

	Recommendation and Alternatives	Accrual Adjustment	Reserve Surplus
1	• Adopt depreciation rates based on plant at 12-31-23 • Adopt OPC's proposed service life adjustments	$ (16,020,898)	$ 221,024,192
2	• Adopt depreciation rates based on plant at 12-31-23 • Adopt PGS's proposed service lives	$ (9,173,686)	$ 159,474,313
3	• Adopt depreciation rates based on plant at 12-31-24 • Adopt OPC's proposed service lives	$ (7,528,747)	$ 186,552,361

My service life adjustments are discussed in more detail in the depreciation section of my testimony.

Q. Please explain why it is OPC's primary recommendation to use year-end 2023 plant and reserve balances to determine the appropriate depreciation rates.

A. As explained in the direct testimony of OPC witness Lane Kollen, it is not appropriate to use a depreciation study date of December 31, 2024 to develop depreciation rates that will be effective on January 1, 2024. Doing so creates a mismatch in plant that effectively results in excessive depreciation expense in the test year. As discussed above, the difference in the annual accrual amount between the 2024 Study and 2023 Study using unadjusted parameters is more than $9 million.[14]

[14] Please see the direct testimony of OPC witness Lane Kollen for further discussion.

PART ONE: COST OF CAPITAL

III. REGULATORY STANDARDS

Q. Discuss the legal standards governing the awarded rate of return on capital investments for regulated utilities.

A. In *Wilcox v. Consolidated Gas Co. of New York*, [15] the United States Supreme Court first addressed the meaning of a fair rate of return for public utilities. The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[16] Later in two landmark cases, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, [17] the Court held:

> 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 . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. 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.

In *Federal Power Commission v. Hope Natural Gas Company*,[18] the Court expanded on the guidelines set forth in *Bluefield* and stated:

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[15] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[16] *Id*. at 48.

[17] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

[18] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944) (emphasis added).

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses *but also for the capital costs of the business*. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The cost of capital models I have employed in this case are in accordance with the foregoing legal standards.

Q. Is it important that the awarded rate of return be based on the Company's actual cost of capital?

A. Yes. The *Hope* Court makes it clear that the allowed return should be based on the actual cost of capital. Under the rate base, rate of return model, a utility should be allowed to recover all its reasonable expenses, its capital investments through depreciation, and a return on its capital investments sufficient to satisfy the required return of its investors. The "required return" from the investors' perspective is synonymous with the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of return should be based on the actual cost of capital:

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[19]

[19] A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 21 (The MIT Press 1984).

The models I have employed in this case closely estimate the Company's true cost of equity. If the Commission sets the awarded return based on my lower, and more reasonable rate of return, it will comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of return much *higher* than the true cost of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to shareholders. As Dr. Morin notes:

> [I]f the allowed rate of return is greater than the cost of capital, capital investments are undertaken and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to the equity holders, and the stock price increases. In this case, the wealth transfer occurs from ratepayers to shareholders.[20]

Thus, it is important to understand that the *awarded* return and the *cost* of capital are different but related concepts. The two concepts are related in that the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. On the other hand, the two concepts are different in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Awarded returns are set through the regulatory process and may be influenced by factors other than objective market drivers. The cost of capital, on the other hand, should be evaluated objectively and be closely tied to economic realities. In other words, the cost of capital is driven by stock prices, dividends, growth rates, and — most importantly — it is driven by risk. The cost of capital can be estimated by financial

[20] Roger A. Morin, *New Regulatory Finance* 23-24 (Public Utilities Reports, Inc. 2006) (1994).

models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. Describe the economic impact that occurs when the awarded return strays too far from the U.S. Supreme Court's cost of equity standard.

A. As discussed further in the sections below, Mr. D'Ascendis's recommended awarded ROE is much higher than the Company's actual cost of capital based on objective market data. When the awarded ROE is set far above the *cost* of equity, it is contrary to the U.S. Supreme Court's standards that the awarded return should be *based on the cost of capital*. If the Commission were to adopt the Company's position in this case, it would be permitting an excess transfer of wealth from Florida customers to Company shareholders. Moreover, establishing an awarded return that far exceeds the true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. This is yet another reason why it is crucial for regulators to focus on the target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions which may be higher and slow to adapt to lower ROEs based on market conditions. Moreover, awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the true cost of equity as estimated through objective models is not influenced by these

factors but is instead driven by market-based factors. If regulators rely too heavily on the awarded returns from other jurisdictions, it can create a cycle over time that bears little relation to the market-based cost of equity. In fact, this is exactly what we have observed since 1990.

Q. Please illustrate and compare the relationship between awarded utility returns and market cost of equity since 1990.

A. As shown in the figure below, awarded returns for public utilities have been above the average required market return since 1990.[21] Because utility stocks are consistently far less risky than the average stock in the marketplace, the cost of equity for utility companies is *less* than the market cost of equity. This is a fact, not an opinion. The graph below shows two trend lines. The top line is the average annual awarded returns since 1990 for U.S. regulated utilities. The bottom line is the required market return over the same period. As discussed in more detail later in my testimony, the required market return is essentially the return that investors would require if they invested in the entire market. In other words, the required market return is essentially the entire market's cost of equity. Since it is undisputed (even by utility witnesses) that utility stocks are less risky than the average stock in the market, then the utilities' cost of equity must be less than the market cost of equity.[22] Thus, awarded returns (the solid line) should generally be *below* the market cost of equity (the dotted line), since awarded returns are supposed to be based on the actual market cost of equity.

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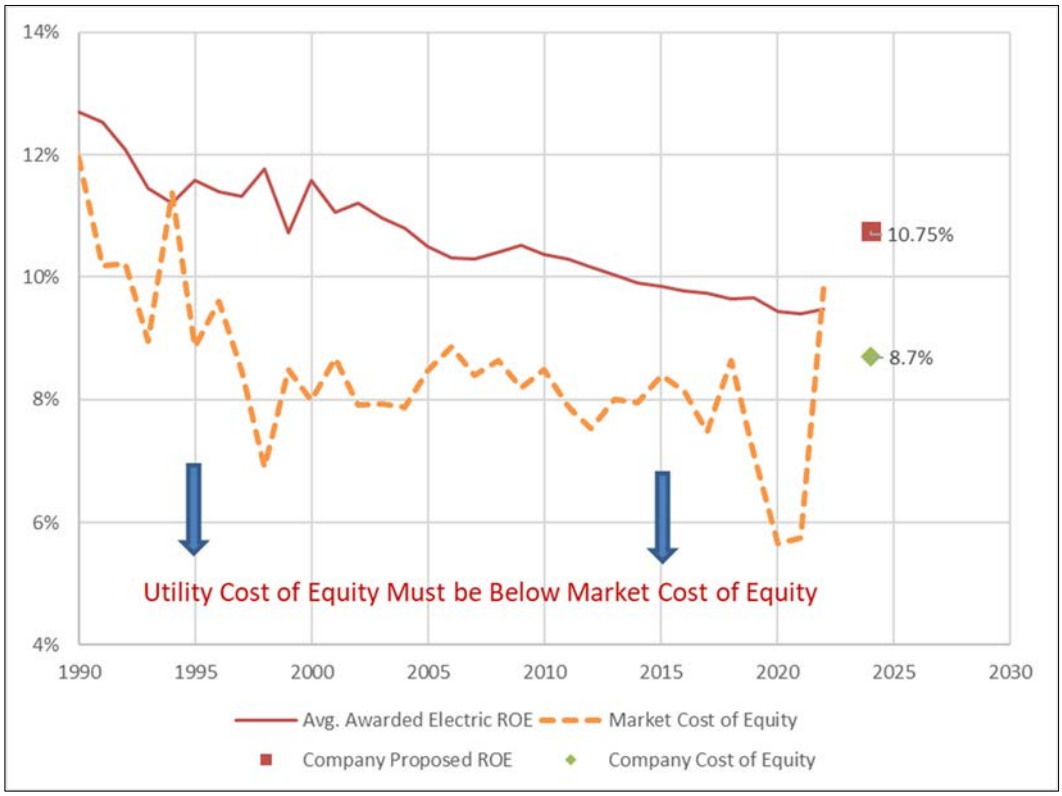
[21] *See* Exhibit DJG-14.

[22] This fact can be objectively measured through a term called "beta," as discussed later in the testimony. Utility betas are less than one, which means utility stocks are less risky than the "average" stock in the market.

Figure 7:
Awarded ROEs vs. Market Cost of Equity



Because utility stocks are less risky than the average stock in the market, utility cost of equity is below market cost of equity (the dotted line in this graph). However, as shown in this graph, awarded ROEs have been consistently above the market cost of equity for many years. The recent increase in the year-end market cost of equity estimate for 2022 resulted in the average awarded ROEs for 2022 to fall slightly below the market cost of equity. As discussed in more detail later in my testimony, my current estimate for the market cost of equity is 9.3%.[23] Thus, PGS's cost of equity estimate should be lower than 9.3%. Regardless, it is important for the Commission to focus primarily on

[23] *See* Exhibit DJG-10.

the results of the cost of equity models when considering a fair awarded ROE, even when considering the average of past awarded ROEs.

Q. Have other analysts commented on this national phenomenon of awarded ROEs exceeding the market-based cost equity for utilities?

A. Yes. In his article published in Public Utilities Fortnightly in 2016, Steve Huntoon observed that even though utility stocks are less risky than the stocks of competitive industries, utility stocks have nonetheless outperformed the broader market.[24] Specifically, Huntoon notes the following three points which lead to a problematic conclusion:

> 1. Jack Bogle, the founder of Vanguard Group and a Wall Street legend, provides rigorous analysis that the long-term total return for the broader market will be around 7 percent going forward. Another Wall Street legend, Professor Burton Malkiel, corroborates that 7 percent in the latest edition of his seminal work, *A Random Walk Down Wall Street*.
>
> 2. Institutions like pension funds are validating [the first point] by piling on risky investments to try and get to a 7.5 percent total return, as reported by the Wall Street Journal.
>
> 3. Utilities are being granted returns on equity around 10 percent.[25]

In a follow-up article analyzing and agreeing with Mr. Huntoon's findings, Leonard Hyman and William Tilles found that utility equity investors expect about a 7.5% annual return.[26]

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[24] Steve Huntoon, "Nice Work If You Can Get It," Public Utilities Fortnightly (Aug. 2016).

[25] *Id*.

[26] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

Q. Summarize the legal standards governing the awarded ROE issue.

A. The Commission should strive to move the awarded return to a level more closely aligned with the Company's actual, market-derived cost of capital while keeping in mind the following legal principles discussed below.

1. Risk is the most important factor when determining the awarded return. The awarded return should be commensurate with those on investments of corresponding risk.

The legal standards articulated in *Hope* and *Bluefield* demonstrate that the Court understands one of the most basic, fundamental concepts in financial theory: the more (less) risk an investor assumes, the more (less) return the investor requires. Since utility stocks are very low risk, the return required by equity investors should be relatively low. I have used financial models in this case to closely estimate PGS's cost of equity, and these financial models account for risk. The public utility industry is one of the least risky industries in the entire country. The cost of equity models confirm this fact in that they produce relatively low cost of equity results. In turn, the awarded ROE in this case should reflect the fact that PGS is a relatively low-risk company.

2. The awarded return should be sufficient to assure financial soundness under efficient management.

Because awarded returns in the regulatory environment have not closely tracked market-based trends and commensurate risk, utility companies have been able to remain more than financially sound, perhaps despite management inefficiencies. In fact, the transfer of wealth from ratepayers to shareholders has been so far removed from actual cost-based drivers that even under relatively inefficient management a utility could remain financially sound. Therefore, regulatory commissions should

strive to set the awarded return to a regulated utility at a level based on accurate market conditions to promote prudent and efficient management and minimize economic waste.

IV. GENERAL CONCEPTS AND METHODOLOGY

Q. Discuss your approach to estimating the cost of equity in this case.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. These models are the DCF Model and the CAPM. The specific inputs and calculations for these models are described in more detail below.

Q. Please explain why multiple models are used to estimate the cost of equity.

A. The models used to estimate the cost of equity attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of running the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple

models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. Please discuss the benefits of choosing a proxy group of companies in conducting cost of capital analyses.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly traded company. There are advantages, however, to conducting cost of capital analysis on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly traded firms, such as stock prices and dividends.

Q. Describe the proxy group you selected in this case.

A. In this case, I chose to use the same proxy group used by Mr. D'Ascendis. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.[27] By using the same proxy group, we can remove a relatively

[27] *See* Exhibit DJG-3.

insignificant variable from the equation and focus on the primary factors driving the Company's excessive cost of equity estimate in this case.

V. RISK AND RETURN CONCEPTS

Q. Discuss the general relationship between risk and return.

A. As discussed above, risk is the most important factor for the Commission to consider when determining the allowed return and there is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

Q. Discuss the differences between firm-specific risk and market risk.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[28] There are several other types of firm-specific risks, including: (1) "financial risk" — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" — the risk that a firm will default on its debt securities; and (3) "business risk" — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return

[28] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62-63 (3rd ed., John Wiley & Sons, Inc. 2012).

in that particular company. While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[29]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During 2001, Enron Corp.'s stock fell from $80 per share to less than $1 per share, and the company filed for bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would have lost the entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because her portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various *market* risk factors that occurred that year, including the terrorist attacks on September 11th, which affected all stocks in the market. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

[29] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

Q. Can investors minimize firm-specific risk?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[30] If someone irrationally invested all their funds in one firm (such as Enron), they would be exposed to all the firm-specific risk *and* the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can essentially eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[31]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large, diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[32] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

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[30] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179-80 (3rd ed., South Western Cengage Learning 2010).

[31] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

[32] *Id*.

Q. Is it well-known and accepted that, because firm-specific risk can be easily eliminated through diversification, the market does not reward such risk through higher returns?

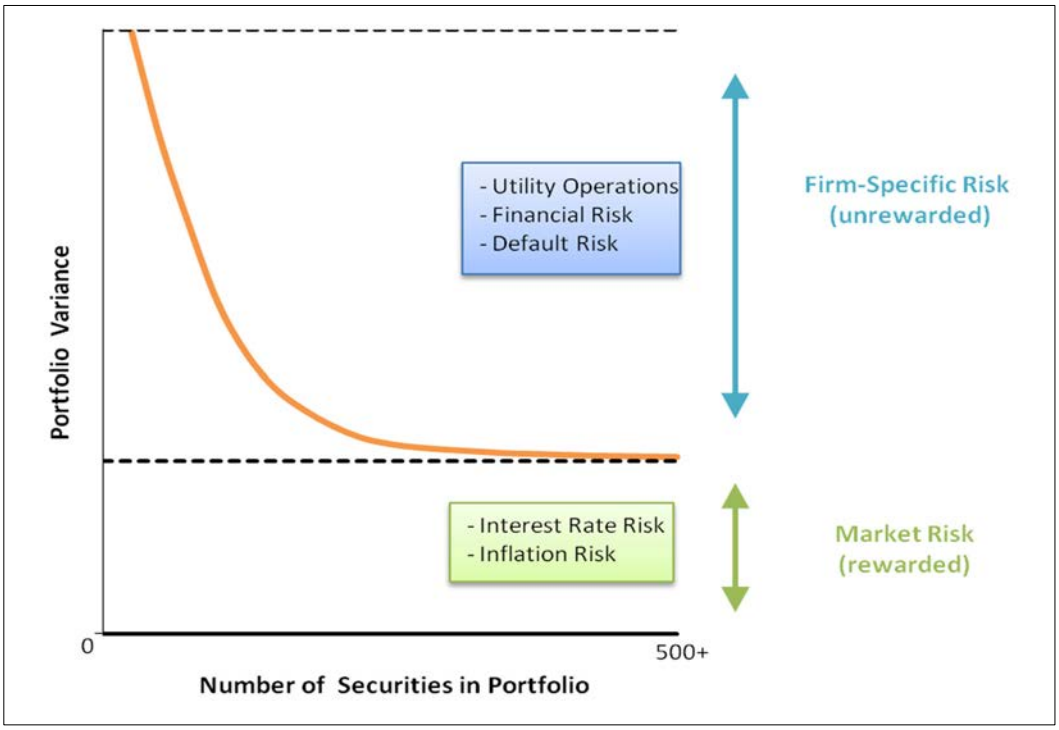
A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing:

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).[33]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

[33] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

Figure 8:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus the type of risk the Commission should consider when determining the allowed return.

Q. Describe how market risk is measured.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market

portfolio. The result of this calculation is called "beta."[34] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk, such that if the market increases (decreases) by 1.0%, a stock with a beta of 0.5% will, on average, only increase (decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[35]

Q. Are public utilities characterized as defensive firms that have low betas, low market risk, and are relatively insulated from overall market conditions?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[36] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive

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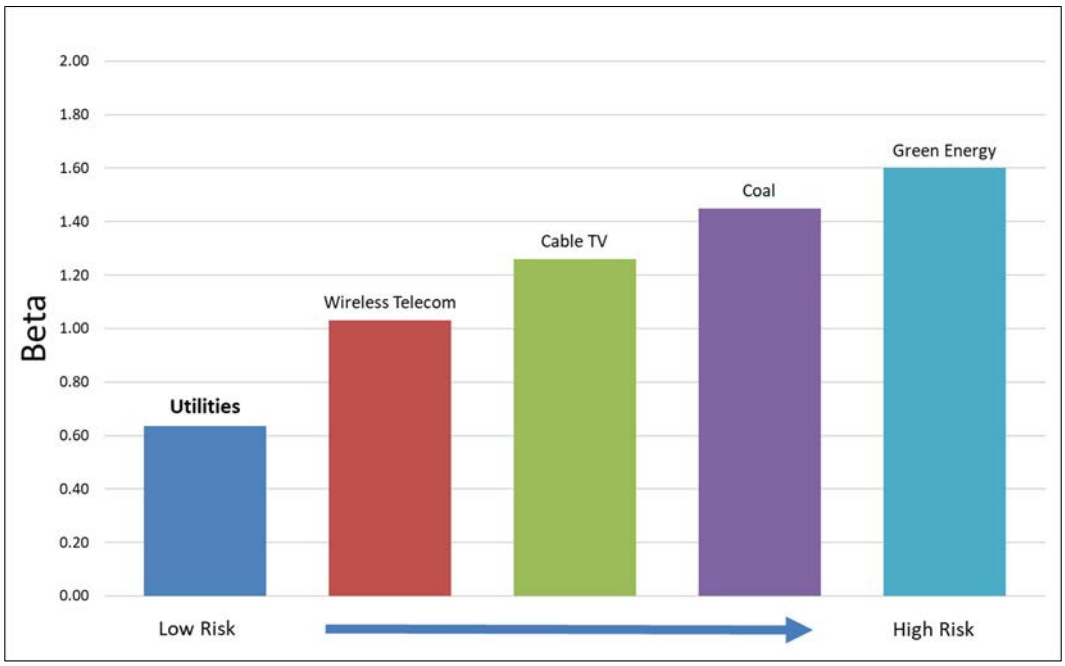
[34] *Id*. at 180-81.

[35] Though it will be discussed in more detail later, Exhibit DJG-9 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

[36] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[37] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[38]

Figure 9:
Beta by Industry



The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be

[37] *Id*. at 383.

[38] *See* Betas by Sector (US) available at http://pages.stern.nyu.edu/~adamodar/ (2018). (After clicking the link, click "Data" then "Current Data" then "Risk / Discount Rate" from the drop down menu, then "Total Beta by Industry Sector"). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not widely fluctuate. So, while it is recognized and accepted that utilities are defensive firms that experience little market risk and are relatively insulated from market conditions, this fact should also be appropriately reflected in the Company's awarded return.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. Describe the DCF Model.

A. The DCF Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model are discussed in more detail in Appendix A.[39]

Q. Describe the inputs to the DCF Model.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

[39] *See* Exhibit DJG-42 for all appendices.

A. Stock Price

Q. How did you determine the stock price input of the DCF Model?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[40] Analysts sometimes rely on average stock prices for longer periods (*e.g.*, 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[41] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. Why did you use a 30-day average for the current stock price input?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding, there is a significant length of time from when an application is filed, and testimony is due. Choosing a current stock price for one particular day could raise a separate issue

[40] Exhibit DJG-4.

[41] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 357 (3rd ed., South Western Cengage Learning 2010). The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model that is ultimately used to set rates for several years, especially if a stock is experiencing some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[42]

B. Dividend

Q. Describe how you determined the dividend input of the DCF Model.

A. The dividend term in the DCF Model represents dividends per share (d_0). I used forward-looking annualized dividends published by Yahoo! Finance for the dividend input to my constant growth DCF Model.[43] Dividing these dividends by the stock prices for each proxy company results in the dividend yield for each company.[44]

Q. Are the stock price and dividend inputs for each proxy company a significant issue in this case?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. D'Ascendis, there is not a statistically significant difference between them because

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[42] Exhibit DJG-4. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[43] Exhibit DJG-5.

[44] *Id*.

utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be conducted on utilities. The differences between my DCF Model and Mr. D'Ascendis's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

C. Growth Rate

Q. Please summarize the growth rate input in the DCF Model.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input (g) must be estimated. As a result, the growth rate is often the most contentious issue related to DCF Model inputs in utility rate cases. The DCF Model used in this case is based on the sustainable growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a sustainable growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a sustainable rate forever. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the sustainable growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet least understood, aspects of cost of equity estimations in utility regulatory proceedings. Therefore, I will provide a more detailed explanation on the various determinants of growth below.

Q. Describe the various determinants of growth that can be considered for the growth rate input in the DCF Model.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on a long-term growth rate in dividends. This is also known as a "sustainable" growth rate, since this is the growth rate assumed for the company's dividends in perpetuity. That is not to say that these growth determinants cannot be considered when estimating sustainable growth; however, as discussed below, sustainable growth must be constrained much more than short-term growth for young firms with high growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the source of confusion in this area.

1. Historical Growth

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are a historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth. In general, however, revenue growth tends to

be more consistent and predictable than earnings growth because it is less likely to be influenced by accounting adjustments.[45]

2. Analyst Growth Rates

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. Analyst growth rates, including the limitations with using them in the DCF Model to estimate utility cost of equity, are discussed in more detail below.

3. Sustainable Growth Rates

To make the DCF Model a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being sustainable. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "sustainable," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by ratepayer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

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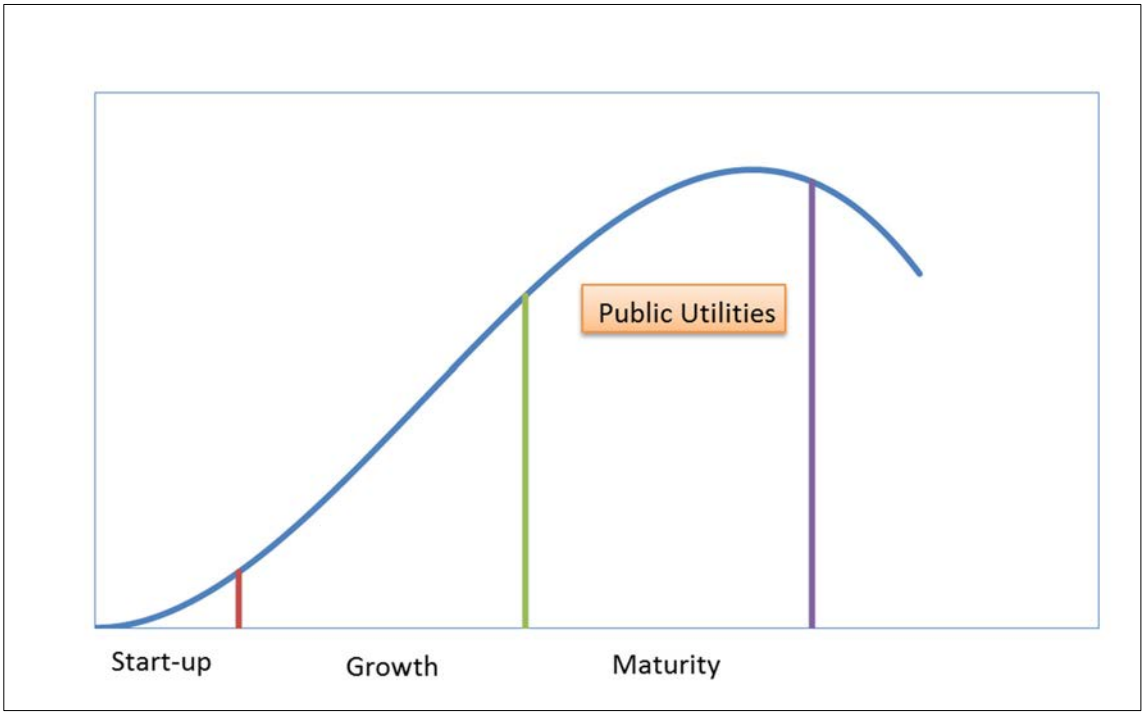
[45] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, p. 279 (3rd ed., John Wiley & Sons, Inc. 2012).

Figure 10:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one sustainable growth rate.

Q. Should the annual sustainable growth rate used in the DCF Model exceed the annual growth rate of the aggregate economy?

A. No. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[46] Thus, the sustainable growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: "[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[47]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is less than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross Domestic Product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's 2022 Long-Term Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.9%.[48]

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[46] *See Id.* at p. 306.

[47] *Id.*

[48] Congressional Budget Office, The 2022 Long-Term Budget Outlook, https://www.cbo.gov/system/files/2022-07/57971-LTBO.pdf.

Q. Please illustrate the sustainable growth rate determinants you considered for your DCF Models.

A. The following figure compares the growth rate determinants I considered in my DCF analysis in this case.[49]

Figure 11:
Sustainable Growth Rate Determinants

Terminal Growth Determinants	Rate
Nominal GDP	3.9%
Real GDP	1.7%
Long-Term Growth Ceiling	**3.9%**

Each of these growth determinants avoids the circular reference problem inherent in other growth determinants such as dividends and earnings growth when conducting a DCF Model on a regulated utility for purposes of setting a fair awarded ROE (because the awarded ROE more directly impacts earnings and dividends).

Q. Please describe the growth rates you used in your DCF Models.

A. For my "sustainable growth" variation of the DCF Model, I used the projected long-term GDP growth rate of 3.9%. As discussed above, it is reasonable to conclude that the long-term growth of a domestic firm cannot outpace the growth rate of the aggregate economy in which it operates (as measured by U.S. GDP in this case). For the "analyst growth" variation of the DCF Model, I considered projected short-term dividend growth rate estimates published by Value Line.[50] I show this variation of the

[49] Exhibit DJG-6.

[50] Exhibit DJG-7.

DCF Model because it is often presented in rate cases by ROE witnesses and considered by regulators when assessing the awarded ROE.

Q. What are the final results of your DCF Models?

A. For my DCF Models, I considered two variations: one using a sustainable growth rate and one using analysts' growth rates. The sustainable growth rate DCF Model produced a cost of equity indication of 7.5%. The analyst growth variation of the DCF produced a result of 8.3%.[51]

Q. Why do analyst growth variations of the DCF Model not reflect an accurate estimate of PGS's cost of equity?

A. To understand why analyst growth rates unreasonably inflate cost of equity estimates in the DCF Model, it is important to understand the difference between "quantitative" and "qualitative" growth determinants. Assessing "quantitative" growth simply involves mathematically calculating a historic metric for growth (such as revenues or earnings) or calculating various fundamental growth determinants using various figures from a firm's financial statements (such as ROE and the retention ratio). However, any thorough assessment of company growth should also be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve sustainable growth in earnings. Therefore, it is important to begin the analysis of PGS's growth rate with this simple, qualitative question: how is this regulated utility going to achieve a sustained growth in earnings? If this question were asked of a competitive firm, there could be several answers

[51] Exhibit DJG-7.

depending on the type of business model, such as launching a new product line, franchising, rebranding to target a new demographic, or expanding into a developing market. Regulated utilities, however, cannot effectively and sustainably engage in these types of potential growth opportunities.

Q. Why is it important to emphasize real, qualitative growth determinants when analyzing the growth rates of regulated utilities?

A. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the "return on rate base" model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective. These two factors are (1) rate base, and (2) the awarded ROE.

Q. How does rate base distort growth projections for utilities?

A. Under the return on rate base model, a utility's rate base is multiplied by its awarded rate of return to produce the required level of operating income. Therefore, increases to rate base generally result in increased earnings. Thus, utilities have a natural financial incentive to increase rate base regardless of whether such increases are driven by a corresponding increase in demand. In other words, utilities can "grow" their earnings by simply retiring old assets and replacing them with new assets. Likewise, if a competitive, unregulated firm announced plans to close production plants and replace them with new plants, it would not be considered a real determinant of growth unless analysts believed this decision would directly result in increased market share for the company and a real opportunity for sustained increases in revenues and earnings. In the case of utilities, the mere replacement of old plant with new plant does

not increase market share, attract new customers, create franchising opportunities, or allow utilities to penetrate developing markets, but may result in short-term, quantitative earnings growth. However, this growth in earnings was merely the quantitative byproduct of the return on rate base model, and not an indication of real, fair, or qualitative growth. Of course, utilities might sometimes add new plant to meet a modest growth in customer demand. However, as the foregoing discussion demonstrates, it would be more appropriate to consider load growth projections and other qualitative indicators, rather than mere increases to rate base or earnings, to attain a fair assessment of growth.

Q. How does the awarded ROE often distort growth projections for utilities?

A. If we give undue weight to analysts' projections for utilities' earnings growth, it will not provide an accurate reflection of real, qualitative growth because a utility's earnings are heavily influenced by the ultimate figure that all this analysis is supposed to help us estimate: the awarded return on equity. This creates a circular reference problem or feedback loop. In other words, if a regulator awards an ROE that is above market-based cost of capital (which is often the case, as discussed above), this could lead to higher short-term growth rate projections from analysts. If these same inflated, short-term growth rate estimates are used in the DCF Model (as they often are by utility witnesses), it could lead to higher awarded ROEs; and the cycle of inflated awarded ROE continues. Therefore, it is not advisable to simply consider the quantitative growth projections published by analysts, as this practice will not necessarily provide fair indications of real utility growth.

Q. Are there any other problems with relying on analyst growth projections?

A. Yes. While the foregoing discussion shows two reasons why we cannot rely on analysts' growth rate projections to provide fair, qualitative indicators of utility growth in a stable growth DCF Model, the third reason is perhaps the most obvious and undisputable. Various institutional analysts, such as Zacks, Value Line, and Bloomberg, publish estimated projections of earnings growth for utilities. These estimates are short-term growth rate projections, ranging from 3–10 years. However, many utility ROE analysts (including Mr. D'Ascendis here) inappropriately insert these short-term growth projections into the DCF Model as if they were long-term growth rate projections. For example, assume that an analyst at Bloomberg estimates that a utility's earnings will grow by 7% per year over the next three years. This analyst may have based this short-term forecast on a utility's plans to replace depreciated rate base or on an anticipated awarded return that is above market-based cost of equity (*i.e.*, the "circular reference" problem). When a utility witness uses this figure in a DCF Model, however, it is the witness, not the Bloomberg analyst, that is testifying to the regulator that the utility's earnings will qualitatively grow by 7% per year over the long-term, which is an unrealistic assumption and a fundamentally different conclusion from that of the analyst.

A. Response to Mr. D'Ascendis's DCF Model

Q. Please summarize the results of Mr. D'Ascendis's DCF analyses.

A. Mr. D'Ascendis's DCF analyses produced several results. His traditional constant growth DCF Model produced an average result of 10.12%,[52] which is notably higher than my estimate.

Q. Do you agree with Mr. D'Ascendis's DCF results?

A. No. A cost of equity above 10% is significantly higher than any reasonable estimate for a low-beta security under current market conditions (discussed in more detail in the CAPM section). Mr. D'Ascendis's DCF Model incorporates numerous growth rates that are unreasonably high and are not sustainable. For example, Mr. D'Ascendis assumes a long-term growth of 7.7% for Atmos Energy Corp., which is about two times greater than the projected, long-term nominal U.S. GDP growth. This means Mr. D'Ascendis's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long term, especially a regulated utility company with a defined service territory. Furthermore, Mr. D'Ascendis used short-term, quantitative growth estimates published by analysts. As discussed above, these analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for short-term growth. While an analyst at Value Line might believe that Atmos's earnings will grow by more than 7% each year over the next *several* years, it is Mr. D'Ascendis, not the Value Line analyst, who is suggesting to the Commission that Atmos's earnings will grow by more

[52] Direct Testimony of Dylan W. D'Ascendis, Exhibit DWD-1, Document No. 3.

than 7.5% each year, every year, for many decades into the future.[53] This assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. Further, it is unreasonable to use short-term growth estimates from third party analyst in a long-term analysis which should use long-term grown rate assumptions. Essentially, Mr. D'Ascendis used the incorrect inputs for his DCF Model. Short-term growth rates published by analysts are not long-term growth rates by definition. The growth rate assumptions used by Mr. D'Ascendis for many of the proxy companies suffer from the same unrealistic assumptions, and they are not sustainable.[54] As a result, his DCF cost of equity estimates are generally overstated. Therefore, if his DCF cost of equity estimates are accepted and relied on to establish the award ROE, it produces an unreasonable result and, thus, would result in customers paying unnecessarily high rates.

VII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Describe the Capital Asset Pricing Model.

A. The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[55] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are

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[53] *Id*. Technically, the constant growth rate in the DCF Model grows dividends each year to "infinity." Yet, even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

[54] *Id*.

[55] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

discussed further in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of *risk* in the business is a most important factor" in determining the allowed rate of return,[56] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding *risks*."[57] The CAPM is a useful model because it directly considers the amount of risk inherent in a business and directly measures the most important component of a fair rate of return analysis: Risk.

Q. Describe the inputs for the CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is discussed separately below.

A. The Risk-Free Rate

Q. Please explain the risk-free rate.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities

[56] *Wilcox*, 212 U.S. at 48 (emphasis added).

[57] *Hope Natural Gas Co.*, 320 U.S. at 603 (emphasis added).

essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. Is it preferable to use the yield on long-term Treasury bonds for the risk-free rate in the CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. As a result, short-term Treasury bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted in a risk-free rate of 3.81%.[58]

B. The Beta Coefficient

Q. How is the beta coefficient used in this model?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (less) than one is more (less) risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta

[58] Exhibit DJG-8.

may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. In contrast, stocks with betas of less than one are less sensitive to market risk.

Q. Describe the source for the betas you used in your CAPM analysis.

A. I used betas recently published by Value Line Investment Survey. The beta for each proxy company is less than 1.0, and the average beta for the proxy group is only 0.84.[59] Thus, we have an objective measure to prove the well-known concept that utility stocks are less risky than the average stock in the market. While there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line in the interest of minimizing controversy.[60]

C. The Equity Risk Premium

Q. Describe the equity risk premium.

A. The final term of the CAPM is the equity risk premium ("ERP"), which is the required return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts agree that "the single most important variable for

[59] Exhibit DJG-9.

[60] *See* Appendix B for a more detailed discussion of raw beta calculations and adjustments.

making investment decisions is the equity risk premium."[61] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. Historical Average

Q. Describe the historical equity risk premium.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. What are the limitations of relying solely on a historical average to estimate the current or forward-looking ERP?

A. As I mentioned, many investors use the historic ERP because it is convenient and easy to calculate. But what matters in the CAPM model is the current and forward-looking risk premium.[62] Some investors may think that a historic ERP provides some indication of what the prospective risk premium is; however, there is empirical evidence to

[61] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 4 (Princeton University Press 2002).

[62] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

suggest the prospective, forward-looking ERP is actually *lower* than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[63] This is due in large part to what is known as "survivorship bias" or "success bias" — a tendency for failed companies to be excluded from historical indices.[64] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP:

> The result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent.[65]

Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[66]

Regardless of the variations in historic ERP estimates, many leading scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium

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[63] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 194 (Princeton University Press 2002).

[64] *Id*. at 34.

[65] *Id*. at 194.

[66] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition* 17 (New York University 2015).

going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[67]

Q. Did you rely on the historical ERP as part of your CAPM analysis in this case?

A. No. Due to the limitations of this approach, I primarily relied on the ERP reported in expert surveys and the implied ERP method discussed below.

2. Expert Surveys

Q. Describe the expert survey approach to estimating the ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers, and other executives around the country and asking them what they think the ERP is. The IESE Business School conducts such a survey each year. Their 2023 expert survey reported an average ERP of 5.7%.[68]

3. Implied Equity Risk Premium

Q. Describe the implied equity risk premium approach.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many

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[67] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

[68] Pablo Fernandez, et al., *Survey: market Risk Premium and Risk-Free Rate used for 80 countries in 2023* (IESE Business School 2020), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4407839 IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

years.[69] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: The current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). Equation 1 below shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: The implied market return.[70]

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[69] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102-110 (Management Science Vol. 3, No. 1 Oct. 1956).

[70] *See* Exhibit DJG-10 for detailed calculation.

Equation 1:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

where:

V_{500}	=	*current value of index (S&P 500)*
$CY_{1\text{-}5}$	=	*average cash yield over last five years (includes dividends and buybacks)*
g	=	*compound growth rate in earnings over last five years*
R_F	=	*risk-free rate*
K	=	*implied market return (this is what we are solving for)*
TV	=	*terminal value* $= CY_5 (1+R_F) / K$

The discount rate is called the "implied" return because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP as shown in Equation 2.

Equation 2:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. Discuss the results of your implied ERP calculation.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of

9.3%. I subtracted the risk-free rate of 3.81% to arrive at the implied equity risk premium of 5.5%.[71] Dr. Damodaran, one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. He calculates monthly and annual implied ERPs with this method and publishes his results. Dr. Damodaran's average ERP estimate for May 2023 using several implied ERP variations was 5.1%.[72] Similarly, Kroll (formerly Duff & Phelps) publishes estimates of ERP, the most recent of which was 6.0%.[73]

Q. What are the results of your final ERP estimate?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys, the estimated ERP reported by Kroll, the estimated ERP calculated by Dr. Damodaran, and the implied ERP based on my calculations.[74] The results are presented in the following figure:

[71] *Id*.

[72] http://pages.stern.nyu.edu/~adamodar/.

[73] Kroll, Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 – Present (Oct. 2022).

[74] *See also* Exhibit DJG-11.

Figure 12:
Equity Risk Premium Results

IESE Business School Survey	5.7%
Kroll (Duff & Phelps) Report	6.0%
Damodaran (average)	5.1%
Garrett	5.5%
Average	**5.6%**

I used the average ERP result of 5.6% in my CAPM.[75]

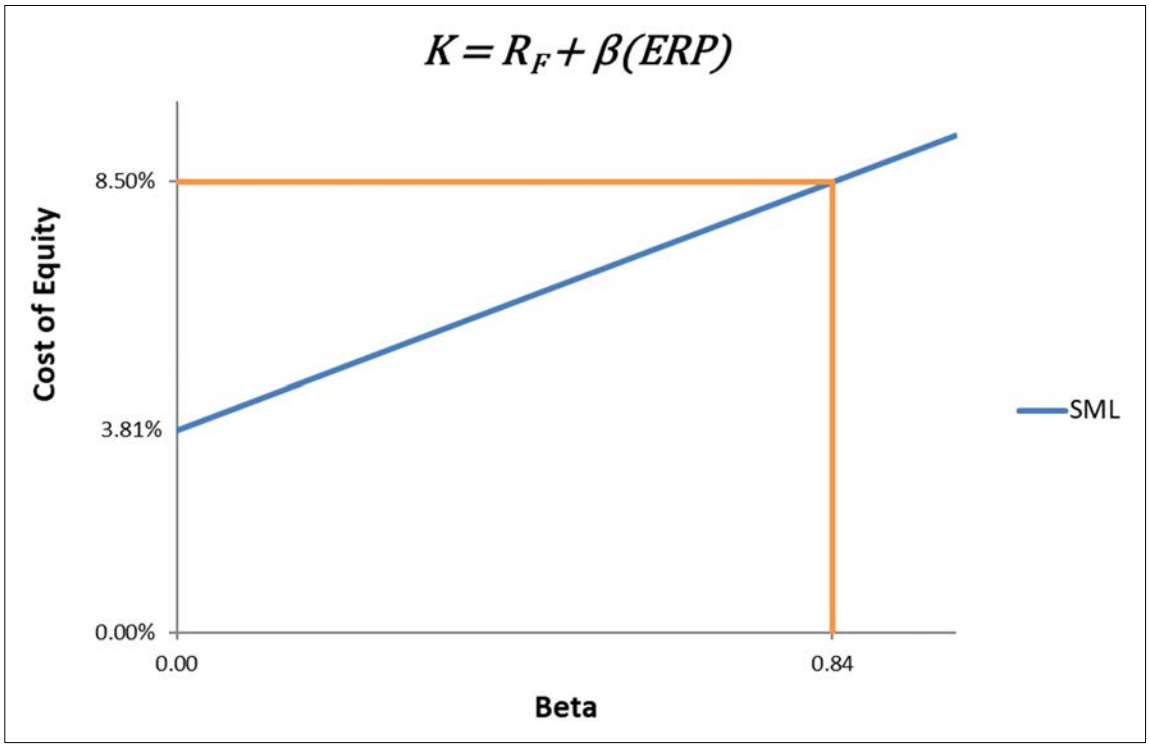
Q. Please explain the final results of your CAPM analysis.

A. Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, I estimate that the Company's CAPM cost of equity is 8.5% (but only if imputing the average capital structure of the proxy group for PGS).[76] The CAPM can be displayed graphically through what is known as the Security Market Line ("SML"). The figure below shows the expected return (cost of equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

[75] Exhibit DJG-11.

[76] Exhibit DJG-12.

Figure 13:
CAPM Graph



The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.84 for the proxy group, the estimated CAPM cost of equity for the Company is 8.5%.

D. Response to Mr. D'Ascendis's CAPM Analysis and Other Issues

Q. Please summarize the results of Mr. D'Ascendis's CAPM analysis.

A. Mr. D'Ascendis's CAPM returned an average result of 11.5%.[77]

[77] Direct Testimony of Dylan W. D'Ascendis, p. 55, lines 12-21.

Q. Do you believe the results of Mr. D'Ascendis's CAPM indicate a reasonable cost of equity estimate for PGS?

A. No. The main problem with Mr. D'Ascendis's CAPM cost of equity result stems primarily from his estimate of the ERP. In my response to Mr. D'Ascendis's CAPM results, I also address his other risk premium model and his empirical CAPM analysis.

1. Equity Risk Premium

Q. Did Mr. D'Ascendis rely on a reasonable measure for the ERP?

A. No. Mr. D'Ascendis used an ERP of 9.75% in his CAPM, which is significantly higher than the estimates reported in expert surveys and estimated by other analysts. As part of Mr. D'Ascendis's EPR analysis, he considered market data as old as 1926.[78] Treasury yields nearly a century old have no bearing on the current and forward-looking ERP, which is what matters when conducting an accurate CAPM analysis. The ERP is one of three inputs in the CAPM equation, and it is one of the most single important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The average ERP produced from my various sources is only 5.6%.[79] This means that Mr. D'Ascendis's ERP estimate is nearly twice as high as the average ERP from reputable sources.

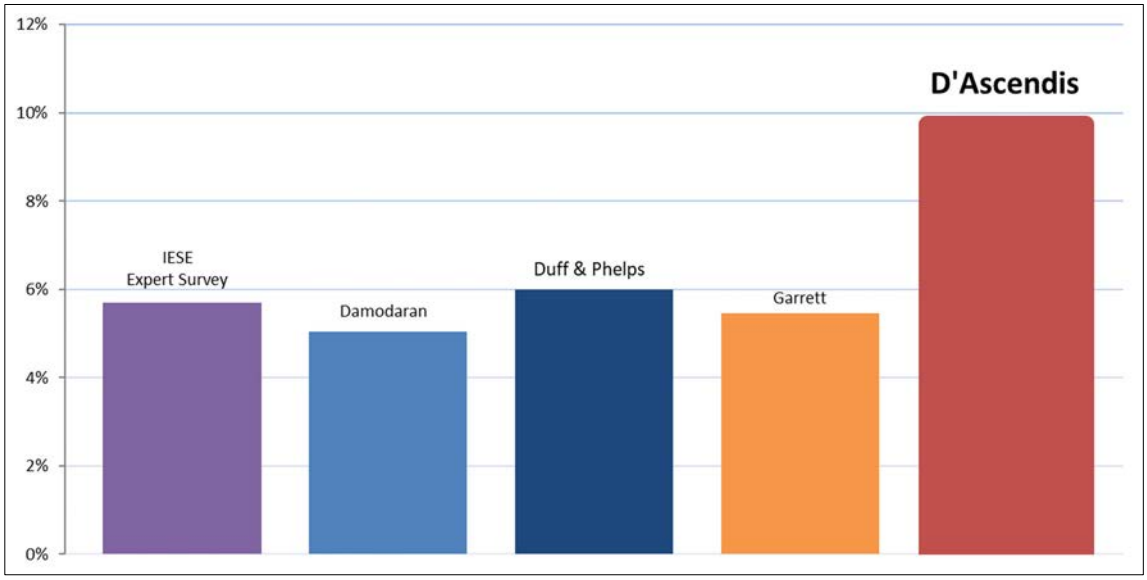
[78] Direct Testimony of Dylan W. D'Ascendis, Exhibit DWD-1, Document No. 5.

[79] Exhibit DJG-11.

Q. Please discuss and illustrate how Mr. D'Ascendis's ERP compares with other estimates for the ERP.

A. As discussed above, the 2022 IESE Business School expert survey reports an average ERP of 5.6%. Similarly, Kroll recently estimated an ERP of 6.0%. The following figure illustrates that Mr. D'Ascendis's ERP estimate is far out of line with industry norms.[80]

Figure 14:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP (as well as my estimate), which do not have a wide variance, Mr. D'Ascendis's ERP estimate is clearly not within the range of reasonableness. As a result, his CAPM cost of equity estimate is overstated and unreliable.

[80] The ERP estimated by Dr. Damodaran is the average of several ERP estimates under slightly differing assumptions.

2. Other Risk Premium Analyses

Q. Did you review Mr. D'Ascendis's other risk premium analyses?

A. Yes. I am addressing Mr. D'Ascendis's other risk premium analyses in this section because the CAPM itself is a risk premium model. In this case, Mr. D'Ascendis conducted his own "risk premium model," which includes several variations with different assumptions.[81]

Q. Do you agree with the results of Mr. D'Ascendis's risk premium analysis?

A. No. Mr. D'Ascendis's risk premium models rely in part on Utility bond yields dating back to 1928.[82] However, data that old is of questionable relevance because cost of equity estimation is essentially a forward-looking process. Analysts can look to the recent past in order to arrive at reasonable forward-looking projections. For example, I use a recent 30-day average of stock prices and Treasury bond yields in my CAPM and DCF models. In contrast, it is unreasonable to consider data nearly 100 years old as having any meaningful impact on the current and forward-looking cost of equity for PGS. In addition, another one of Mr. D'Ascendis's risk premium model variations considers authorized ROEs from other jurisdictions dating back to 1980. As discussed earlier in my testimony, awarded ROEs are consistently higher than market-based cost of equity, and they have been for many years. Thus, these types of risk premium "models" effectively perpetuate the discrepancy between awarded ROEs and market-based cost of equity. Since awarded ROEs are consistently higher than market-based

[81] Direct Testimony of Dylan W. D'Ascendis, pp. 28-48.

[82] Id. at p. 40, lines 1-6.

cost, a model that simply compares the discrepancy between awarded ROEs and any market-based factor (such as bond yields) will simply ensure that the discrepancy continues.

Furthermore, the risk premium analysis offered by Mr. D'Ascendis is completely unnecessary when we already have a real risk premium model to use: the CAPM. The CAPM itself is a "risk premium" model; it takes the bare minimum return any investor would require for assuming no risk (the risk-free rate), then adds a *premium* to compensate the investor for the extra risk he or she assumes by buying a stock rather than a riskless U.S. Treasury security. The CAPM has been utilized by companies around the world for decades for the same purpose we are using it in this case – to estimate cost of equity.

Unlike the CAPM, which is found in almost every comprehensive financial textbook, the types of risk premium models used by Mr. D'Ascendis in this case are almost exclusively found in the texts and testimonies of utility witnesses. Specifically, these risk premium models attempt to create an inappropriate link between market-based factors, such as interest rates, with awarded returns on equity. Inevitably, this type of model is used to justify a cost of equity that is much higher than one that would be dictated by market forces.

3. Empirical CAPM

Q. Please summarize Mr. D'Ascendis's Empirical CAPM ("ECAPM") analysis.

A. Mr. D'Ascendis offers another version of the CAPM called ECAPM. The premise of the ECAPM is that the standard CAPM underestimates the return required from low-

beta securities, such as those of the proxy group. Mr. D'Ascendis's ECAPM produced an average result of 11.8%.[83]

Q. Do you agree with Mr. D'Ascendis's ECAPM results?

A. No. The premise of Mr. D'Ascendis's ECAPM is that the standard CAPM underestimates the return required from low-beta securities. There are several problems with this concept, however. First, the Value Line betas both Mr. D'Ascendis and I used in the real CAPM have already been adjusted upward to account for the theory that low-beta stocks might have a tendency to be underestimated. Second, there is empirical evidence suggesting that the type of beta-adjustment method used by Value Line actually overstates betas from consistently low-beta industries like utilities. According to this research, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average, which ultimately results in betas that are lower than those published in Value Line.[84] Finally (and most pertinently), Mr. D'Ascendis's ECAPM still suffers from the same overestimated ERP input discussed above. Regardless of the differing theories regarding the mean reversion tendencies of low-beta securities, Mr. D'Ascendis's ECAPM should be disregarded for its ERP inputs alone which were based on old, out-of-date data resulting in unreasonable ERP twice that of industry experts.

[83] Direct Testimony of Dylan W. D'Ascendis, Exhibit DWD-1, Document No. 5.

[84] *See* Appendix B for further discussion on these theories.

VIII. OTHER ISSUES

Q. Are there other issues raised by Mr. D'Ascendis in his testimony that you would like to respond to.

A. Yes. In his testimony, Mr. D'Ascendis suggests that several other factors should have increasing effects on the cost of equity estimate, including business risks, PGS's relative size, and flotation costs. Mr. D'Ascendis also conducted a cost of equity analysis on a group of non-utility companies.

A. Firm-Specific Business Risks

Q. Please describe Mr. D'Ascendis's testimony regarding business risks.

A. In his direct testimony, Mr. D'Ascendis suggests that various firm-specific risk factors should have an increasing effect on PGS's cost of equity, including the risks associated with the regulatory environment, environmental compliance, and other business risks.[85]

Q. Do you agree with Mr. D'Ascendis that these firm-specific risk factors should influence PGS's cost of equity or awarded ROE?

A. No. The Commission should not consider these firm-specific business risk factors in making their decision on a fair awarded ROE for PGS. As discussed above, it is a well-known concept in finance that firm-specific risks are unrewarded by the market. Scholars widely recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing.[86] Unlike interest rate risk, inflation risk, and other market risks that affect all companies in the stock market, the

[85] See Direct Testimony of Dylan W. D'Ascendis, pp. 13-15.

[86] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

risk factors discussed by Mr. D'Ascendis are merely business risks specific to PGS. Investors do not require additional compensation for assuming these firm-specific business risks. Moreover, the financial models themselves do not include inputs for business risk.

B. Small Size Effect

Q. Please describe Mr. D'Ascendis's position regarding the size effect.

A. Mr. D'Ascendis suggests that PGS's size should somehow have an increasing effect on its cost of equity estimate.[87] Mr. D'Ascendis proposes an upward adjustment of 20 basis points basis points to account for the size effect (as well as other business risks).[88]

Q. Do you agree with Mr. D'Ascendis regarding the size effect?

A. No. The "size effect" phenomenon arose from a 1981 study conducted by Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[89] According to Ibbotson, Banz's size effect study was "[o]ne of the most remarkable discoveries of modern finance."[90] Perhaps there was some merit to this idea at the time, but the size effect phenomenon was short lived. Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for

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[87] *See* Direct Testimony of Dylan W. D'Ascendis, pp. 65-70.

[88] *Id*. at Exhibit DWD-1, Document No. 1.

[89] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

[90] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

approximately two years. . . ." [91] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph of the Optimists*, the authors conducted an extensive empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[92]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium," yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

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[91] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

[92] *Id*. at 133.

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[93]

In addition to the studies discussed above, other scholars have concluded similar results. According to Kalesnik and Beck:

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[94]

For all of these reasons, the Commission should reject the arbitrary size premium proposed by the Company.

C. Non-Regulated Cost of Equity Model

Q. Please describe Mr. D'Ascendis's cost of equity model conducted on non-price regulated companies.

In addition to conducting a cost of equity analysis on the utility proxy group, Mr. D'Ascendis also conducted a similar type of analysis on a group of non-utility

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[93] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

[94] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwic84ykqNL_AhWmmWoFHbwzCpcQFnoECAsQAQ&url=https%3A%2F%2Fwww.researchaffiliates.com%2Fcontent%2Fdam%2Fra%2Fpublications%2Fpdf%2F284-busting-the-myth-about-size.pdf&usg=AOvVaw3Yw7SggIT0R8KvzGmYkuAp&opi=89978449 (emphasis added).

companies. The indicated cost of equity produced by this model is 12.36% - the highest of all of Mr. D'Ascendis's models.[95]

Q. Do you agree with the results of Mr. D'Ascendis's non-utility cost of equity model?

A. No. In fact, I disagree with the entire premise of the model. Non-utility companies are relatively incomparable to PGS compared with the utility proxy group. Thus, the results obtained from this model will be inferior to the results obtained from any model (conducted properly) on the utility proxy group. The risk profiles of competitive firms will tend to be higher than those of low-risk utilities; thus, their cost of equity estimates will generally be higher. Not surprisingly, the results of Mr. D'Ascendis's non-utility model produce the highest cost of equity out of all of his various models.[96] There is simply no marginal value added to the process of estimating utility cost of equity by using non-utility, non-regulated firms in a proxy group instead of firms with relatively similar risk profiles to the regulated utility being analyzed.

D. Flotation Costs

Q. Please summarize Mr. D'Ascendis's flotation cost adjustment.

A. Mr. D'Ascendis adds an additional 12 basis points to his overall cost of equity estimate to account for flotation costs.[97]

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[95] Direct Testimony of Dylan W. D'Ascendis, Exhibit DWD-1, Document No. 1.

[96] *Id*.

[97] *Id*.

Q. Do you agree with Mr. D'Ascendis's flotation cost adjustment?

A. No. When companies issue equity securities, they typically hire at least one investment bank as an underwriter for the securities. "Flotation costs" generally refer to the underwriter's compensation for the services it provides in connection with the securities offering. However, Mr. D'Ascendis's flotation cost allowance is inappropriate for several reasons, as discussed further below.

1. Flotation costs are not actual "out-of-pocket" costs.

The Company has not experienced any out-of-pocket costs for flotation. Underwriters are not compensated in this fashion. Instead, underwriters are compensated through an "underwriting spread." An underwriting spread is the difference between the price at which the underwriter purchases the shares from the firm, and the price at which the underwriter sells the shares to investors.[98] Accordingly, the Company has not experienced any out-of-pocket flotation costs, and if it has, those costs should be included in the Company's expense schedules.

2. The market already accounts for flotation costs.

When an underwriter markets a firm's securities to investors, the investors are aware of the underwriter's fees. The investors know that a portion of the price they are paying for the shares does not go directly to the company, but instead goes to compensate the underwriter for its services. In fact, federal law requires that the

[98] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 509 (3rd ed., South Western Cengage Learning 2010).

underwriter's compensation be disclosed on the front page of the prospectus.[99] Thus, investors have already considered and accounted for flotation costs when making their decision to purchase shares at the quoted price. As a result, there is no need for shareholders to receive additional compensation to account for costs they have already considered and agreed to. Similar compensation structures are in other kinds of business transactions. For example, a homeowner may hire a realtor and sell a home for $100,000. After the realtor takes a six percent commission, the seller nets $94,000. The buyer and seller agreed to the transaction notwithstanding the realtor's commission. Obviously, it would be unreasonable for the buyer or seller to demand additional funds from anyone after the deal is completed to reimburse them for the realtor's fees. Likewise, investors of competitive firms do not expect additional compensation for flotation costs. Thus, it would not be appropriate for a commission standing in the place of competition to award a utility's investors with this additional compensation.

3. It is inappropriate to add any additional basis points to an awarded ROE proposal that is already far above the Company's cost of equity.

For the reasons discussed above, flotation costs should be disallowed from a technical standpoint; they should also be disallowed from a policy standpoint. The Company is asking this Commission to award it a cost of equity that is more than 150 basis points above its market-based cost of equity. Under these circumstances, it is

[99] *See* Regulation S-K, 17 C.F.R. § 229.501(b)(3) (requiring that the underwriter's discounts and commissions be disclosed on the outside cover page of the prospectus). A prospectus is a legal document that provides details about an investment offering.

especially inappropriate to suggest that flotation costs should be considered in any way to increase an already inflated ROE proposal.

IX. CAPITAL STRUCTURE

Q. Describe in general the concept of a company's capital structure.

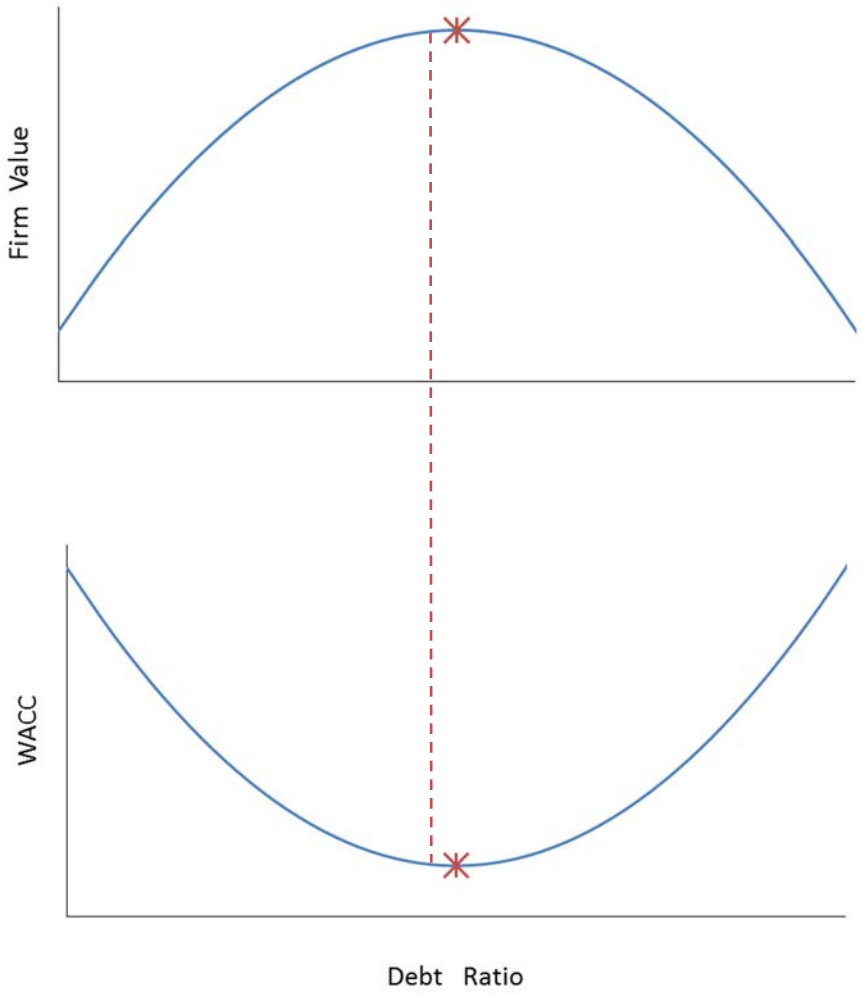
A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issuances that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their weighted average cost of capital ("WACC") by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. Is it true that, by increasing debt, competitive firms can add value and reduce their WACC?

A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the likelihood of loss increases. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater

return on their investment. Thus, if debt financing is too high, the firm's WACC will increase instead of decrease. The following figure illustrates these concepts.

Figure 15:
Optimal Debt Ratio



As shown in this figure, a competitive firm's value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the

additional risks to both bondholders and shareholders, as each type of investor will demand higher returns for the additional risk they have assumed.[100]

Q. Does the rate base rate of return model effectively incentivize utilities to operate at the optimal capital structure?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base, rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 3:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

where:

RR	=	*revenue requirement*
O	=	*operating expenses*
d	=	*depreciation expense*
T	=	*corporate tax*
$\boldsymbol{r}$	=	***weighted average cost of capital (WACC)***
A	=	*plant investments*
D	=	*accumulated depreciation*

As shown in Equation 3, utilities can increase their revenue requirement by increasing their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

[100] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 440-41 (3rd ed., South Western Cengage Learning 2010).

Q. Can utilities generally afford to have higher debt levels than other industries?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. Utilities, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[101]

Note that the author explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure.

Q. Describe the approach you used to assess the reasonableness of PGS's capital structure for ratemaking purposes?

A. To assess a reasonable capital structure for PGS, I examined the capital structures of the proxy group. The cost of equity indicated under the CAPM is inseparable from the proxy group capital structures. For comparative purposes, I also looked at debt ratios observed in other industries. I discuss each of these approaches in more detail below.

[101] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 196 (3rd ed., John Wiley & Sons, Inc. 2012).

A. Proxy and Industry Debt Ratios

Q. Please describe the debt and equity ratios of the proxy group.

A. According to the debt ratios recently reported in Value Line for the utility proxy group (the same proxy group used by Mr. D'Ascendis), the average debt ratio of the proxy group is 51%.[102] This is notably higher than PGS's proposed debt ratio of only 45%. Conversely, the equity ratio of the proxy group is 49% and PGS's proposed equity ratio is considerably higher at 55%.

Q. Why is it critical to consider the capital structures of the proxy group when assessing a fair capital structure for PGS?

A. The cost of equity of any particular company is necessarily connected with its capital structure. This is because there is a direct relationship between risk and return. That is, the higher (lower) risk, the higher (lower) expected return. All else held constant, companies with higher amounts of leverage have higher levels of financial risk. Since we are using a proxy group of companies to assess a fair cost of equity estimate for PGS, we must also factor in the capital structures of those companies into the analysis – failing to do so is an analytical error. Since PGS's debt ratio is lower and the equity ratio is higher than the proxy group average, it has less financial risk than the proxy group. This discrepancy in debt ratio and equity ratio must be accounted for. This issue will be discussed in more detail below in my Hamada model analysis.

[102] Exhibit DJG-15.

Q. Please describe the debt ratios recently observed in competitive U.S. industries.

A: There are nearly 2,000 companies in the U.S. with debt ratios higher than 50% and equity ratios lower than 50%.[103] The following figure shows a sample of these industries with debt ratios higher than 56% and equity ratios lower than 44%.

[103] Exhibit DJG-16.

Figure 16:
Industries with Debt Ratios Greater than 56%

Industry	# Firms	Debt Ratio
Air Transport	21	84%
Hotel/Gaming	69	82%
Hospitals/Healthcare Facilities	34	82%
Retail (Automotive)	30	78%
Brokerage & Investment Banking	30	76%
Computers/Peripherals	42	71%
Bank (Money Center)	7	68%
Cable TV	10	68%
Food Wholesalers	14	67%
Advertising	58	67%
Oil/Gas Distribution	23	66%
Rubber& Tires	3	65%
Transportation (Railroads)	4	65%
Real Estate (Operations & Services)	60	64%
Retail (Grocery and Food)	13	64%
Retail (Special Lines)	78	64%
Recreation	57	62%
Insurance (Life)	27	61%
Trucking	35	61%
Packaging & Container	25	61%
Power	48	60%
Telecom. Services	49	60%
Telecom (Wireless)	16	60%
R.E.I.T.	223	60%
Auto & Truck	31	59%
Utility (General)	15	59%
Household Products	127	58%
Office Equipment & Services	16	58%
Environmental & Waste Services	62	57%
Utility (Water)	16	57%
Retail (Distributors)	69	57%
Transportation	18	57%
Green & Renewable Energy	19	57%
Total / Average	**1,349**	**65%**

Many of the industries shown here, like public utilities, are generally well-established industries with large amounts of capital assets. The shareholders of these industries

generally prefer these higher debt ratios to maximize their profits. There are several notable industries that are relatively comparable to public utilities. For example, the Cable TV, Telecom, Power, and Water Utility industries have debt ratios of at least 60% and equity ratios of 40% or lower.

Q. Please summarize the results of your capital structure analyses and your recommendation regarding capital structure.

A. The results of my analyses are summarized in the following figure:

Figure 17:
Capital Structure Analysis – Summary of Results

Source	Debt Ratio	Equity Ratio
Cable TV	68%	32%
Power	60%	40%
Telecom (Wireless)	60%	40%
Proxy Group of Utilities	**51%**	**49%**
PGS Proposed	**45%**	**55%**

As shown in this figure, PGS's proposed debt ratio is clearly too low (and its equity ratio is too high). This results in excessively high capital costs and utility rates. My analysis indicates that PGS's total debt ratio for ratemaking should be 51%, and the equity ratio should be no more than 49%.

B. The Hamada Model: Capital Structure's Effect on ROE

Q. Have you considered the impact that your capital structure recommendation could have on the company's indicated cost of equity?

A. Yes. I assessed the impact of my capital structure proposal on the Company's cost of equity estimate by using the Hamada model.

Q. What is the premise of the Hamada model?

A. The Hamada formula can be used to analyze changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be removed, which is accomplished through the Hamada formula. The Hamada formula for unlevering beta is stated as follows:[104]

Equation 4:
Hamada Formula

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c)\left(\frac{D}{E}\right)\right]}$$

where: β_U = *unlevered beta (or "asset" beta)*
β_L = *average levered beta of proxy group*
T_C = *corporate tax rate*
D = *book value of debt*
E = *book value of equity*

Using Equation 4, the beta for the firm can be unlevered, and then "relevered" based on various debt ratios (by rearranging this equation to solve for β_L).

Q. Please summarize the results of the Hamada formula based on your proposed capital structure for the company.

A. The average capital structure of the proxy group consists of 51% debt and 49% equity. Because PGS's debt ratio is so much lower than that of the proxy group, when we "relever" PGS relative to the proxy group, it results in a much lower ROE than if PGS

[104] Damodaran *supra* n. 18, at 197. This formula was originally developed by Hamada in 1972.

had been operating with a capital structure equal to that of the proxy group. This makes sense because PGS is much less risky relative to the proxy group due to the decreased amount of debt in its capital structure. The results of my Hamada model are presented in the figure below.[105]

Figure 18:
Hamada Model ROE

Unlevering Beta			
Proxy Debt Ratio		51%	[1]
Proxy Equity Ratio		49%	[2]
Proxy Debt / Equity Ratio		1.0	[3]
Tax Rate		25%	[4]
Equity Risk Premium		5.6%	[5]
Risk-free Rate		3.8%	[6]
Proxy Group Beta		0.84	[7]
Unlevered Beta		0.47	[8]

[9]	[10]	[11]	[12]
Relevered Betas and Cost of Equity Estimates			
Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity
0%	0.0	0.47	6.4%
20%	0.3	0.56	6.9%
30%	0.4	0.63	7.3%
40%	0.7	0.71	7.8%
45%	0.8	0.77	8.1%
51%	1.0	0.84	8.5%
60%	1.5	1.01	9.4%

[105] Exhibit DJG-17.

According to the results of the Hamada model, if the Commission adopts my capital structure recommendation, PGS's indicated cost of equity estimate (under the CAPM) would be 8.5%. However, if the Commission accepts PGS's proposed capital structure, the Company's cost of equity estimate would be 8.1%.

PART TWO: DEPRECIATION

X. DEPRECIATION STANDARDS AND SYSTEMS

Q. Discuss the standard by which regulated utilities are allowed to recover depreciation expense.

A. In *Lindheimer v. Illinois Bell Telephone Co.*, the U.S. Supreme Court stated that "depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence."[106] The *Lindheimer* Court also recognized that the original cost of plant assets, rather than present value or some other measure, is the proper basis for calculating depreciation expense.[107] Moreover, the *Lindheimer* Court found:

[106] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934).

[107] *Id*. (Referring to the straight-line method, the *Lindheimer* Court stated that "[a]ccording to the principle of this accounting practice, the loss is computed upon the actual cost of the property as entered upon the books, less the expected salvage, and the amount charged each year is one year's pro rata share of the total amount."). The original cost standard was reaffirmed by the Court in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 606 (1944). The *Hope* Court stated: "Moreover, this Court recognized in [*Lindheimer*], supra, the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required."

> [T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.[108]

Thus, the Commission must ultimately determine if the Company has met its burden of proof by making a convincing showing that its proposed depreciation rates are not excessive.

Q. Should depreciation represent an allocated cost of capital to operation, rather than a mechanism to determine loss of value?

A. Yes. While the *Lindheimer* case and other early literature recognized depreciation as a necessary expense, the language indicated that depreciation was primarily a mechanism to determine loss of value.[109] Adoption of this "value concept" would require annual appraisals of extensive utility plant, and thus, is not practical in this context. Rather, the "cost allocation concept" recognizes that depreciation is a cost of providing service, and that in addition to receiving a "return on" invested capital through the allowed rate of return, a utility should also receive a "return of" its invested capital in the form of recovered depreciation expense. The cost allocation concept also satisfies several fundamental accounting principles, including verifiability, neutrality, and the matching principle.[110] The definition of "depreciation accounting" published by (a predecessor to) the American Institute of Certified Public Accountants ("AICPA") properly reflects the cost allocation concept:

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[108] *Id*. at 169.

[109] *See* Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 71 (Iowa State University Press 1994).

[110] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* 12 (NARUC 1996).

> Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.[111]

Thus, the concept of depreciation as "the allocation of cost has proven to be the most useful and most widely used concept."[112]

Q. Discuss the definition and purpose of a depreciation system, as well as the depreciation system you employed in this case.

A. The legal standards set forth above do not mandate a specific procedure for conducting a depreciation analysis. These standards, however, direct that analysts use a system for estimating depreciation rates that will result in the "systematic and rational" allocation of capital recovery for the utility. Over the years, analysts have developed "depreciation systems" designed to analyze grouped property in accordance with this standard. A depreciation system may be defined by several primary parameters: 1) a *method* of allocation; 2) a *procedure* for applying the method of allocation; 3) a *technique* of applying the depreciation rate; and 4) a *model* for analyzing the characteristics of vintage property groups.[113] In this case, I used the straight line method, the average life procedure, the remaining life technique, and the broad group model to analyze the Company's actuarial data; this system would be denoted as an "SL-AL-RL-BG" system. This depreciation system conforms to the legal standards set forth above and is commonly used by depreciation analysts in regulatory proceedings.

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[111] American Institute of Accountants, *Accounting Terminology Bulletins Number 1: Review and Résumé* 25 (American Institute of Accountants 1953).

[112] Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 73 (Iowa State University Press 1994).

[113] Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 70 (Iowa State University Press 1994).

I provide a more detailed discussion of depreciation system parameters, theories, and equations in Appendix C.

XI. SERVICE LIFE ANALYSIS

Q. Describe the process you used to estimate service lives for the Company's accounts.

A. The study of retirement patterns of industrial property is derived from the actuarial process used to study human mortality. Just as actuarial analysts study historical human mortality data in order to predict how long a group of people will live, depreciation analysts study historical plant data in order to estimate the average lives of property groups. The most common actuarial method used by depreciation analysts is called the "retirement rate method." In the retirement rate method, original property data, including additions, retirements, transfers, and other transactions, are organized by vintage and transaction year.[114] The retirement rate method is ultimately used to develop an "observed life table," ("OLT") which shows the percentage of property surviving at each age interval.

An OLT curve by itself, however, is rarely a smooth curve, and is often not a "complete" curve (i.e., it does not end at zero percent surviving). To calculate average life (the area under a curve), a complete survivor curve is needed. The Iowa curves are empirically derived curves based on the extensive studies of the actual mortality patterns of many different types of industrial property. The curve-fitting process

[114] The "vintage" year refers to the year that a group of property was placed in service (aka "placement" year). The "transaction" year refers to the accounting year in which a property transaction occurred, such as an addition, retirement, or transfer (aka "experience" year).

involves selecting the best Iowa curve to fit the OLT curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. The first step of my approach to curve-fitting involves visually inspecting the OLT curve for any irregularities. For example, if the "tail" end of the curve is erratic and shows a sharp decline over a short period of time, it may indicate that this portion of the data is less reliable, as further discussed below. After inspecting the OLT curve, I use a mathematical curve-fitting technique which essentially involves measuring the distance between the OLT curve and the selected Iowa curve in order to get an objective, mathematical assessment of how well the curve fits. After selecting an Iowa curve, I observe the OLT curve along with the Iowa curve on the same graph to determine how well the curve fits. I may repeat this process several times for any given account to ensure that the most reasonable Iowa curve is selected.[115]

Q. Do you always select the mathematically best-fitting curve?

A. No. Mathematical curve fitting is an important part of the curve-fitting process because it promotes objective, unbiased results. While mathematical curve fitting is important, however, it may not always yield the optimum result; therefore, it should not necessarily be adopted without further analysis.

Q. Should every portion of the OLT curve be given equal weight?

A. Not necessarily. Many analysts have observed that the points comprising the "tail end" of the OLT curve may often have less analytical value than other portions of the curve.

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[115] *See* Appendix D for a more detailed discussion of Iowa curves; *see* Appendix E for a more detailed discussion of actuarial analysis.

In fact, "[p]oints at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of the exposures."[116] In accordance with this standard, an analyst may decide to truncate the tail end of the OLT curve at a certain percent of initial exposures, such as one percent. Using this approach puts a greater emphasis on the most valuable portions of the curve. For my analysis in this case, I not only considered the entirety of the OLT curve, but I also conducted further analyses that involved fitting Iowa curves to the most significant part of the OLT curve for certain accounts. In other words, to verify the accuracy of my curve selection, I narrowed the focus of my additional calculation to consider the top 99% of the "exposures" (*i.e.*, dollars exposed to retirement) and to eliminate the tail end of the curve representing the bottom 1% of exposures.

Q. Please describe the data bands you considered in your service life analysis.

A. In service life analysis, data "bands" refer to the period of placement and experience years being analyzed. According to Mr. Watson, "[p]lacement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period."[117] In his workpapers, Mr. Watson presents the results of several different banding periods for each account in the depreciation studies as part of his service life analysis. Generally, I reviewed and considered all of this information, as well as the other information presented in the

[116] Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 46 (Iowa State University Press 1994).

[117] Direct Testimony of Dane A. Watson, Exhibit No. DAW-1, Document No. 2.

depreciation studies and Mr. Watson's testimony. In the account-specific graphs below, I present OLT curves that are comprised of placement and experience years from 1983-2021, which is also one of the banding periods Mr. Watson apparently considered.[118] While I also considered the other banding periods Mr. Watson presented, I focused on OLT curves under the 1983-2021 placement and experience bands because this time period strikes a good balance between considering a sufficient amount of data for analysis and considering relatively newer data. In this particular case, most of the accounts discussed below have been affected by asset replacement programs in which relatively newer assets may have different life characteristics than older assets. Thus, it can be instructive to focus on relatively newer vintage years when conducting analyses.

Q. Is there a trade-off from an analytical perspective from focusing on relatively newer vintage years?

A. Yes. While analyzing relatively newer vintages may give better indications of remaining life for a group of assets, the trade-off is that the OLT curves derived from the data are relatively shorter. This means that a wider range of Iowa curves may provide relatively close fits to the OLT curve.

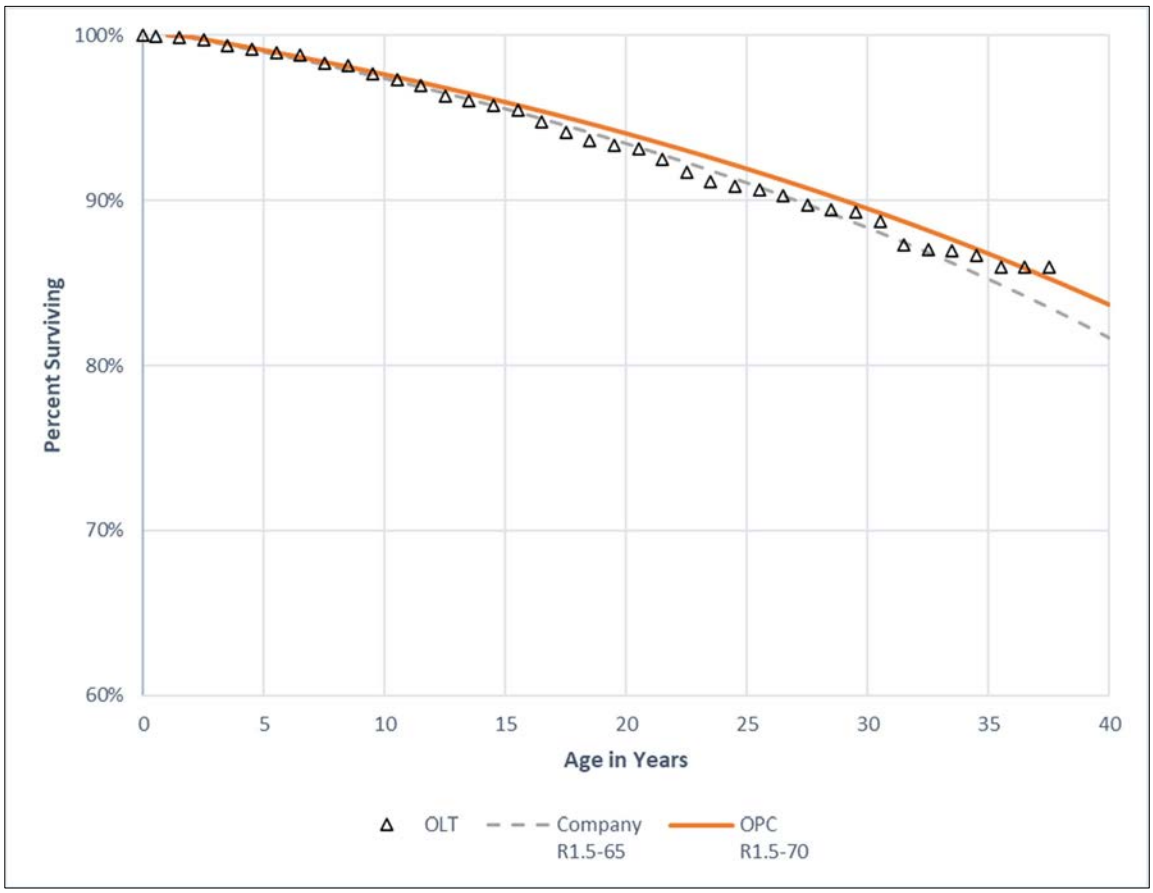
[118] *See* Exhibit DJG-34 for OLTs considered from the depreciation study workpapers and used in the following graphs to compare Iowa curves.

A. Account 376.00 – Steel Mains

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. The observed survivor curve is derived from the OLT calculated from the Company's aged plant data. Thus, as set forth above, the OLT curve is not an estimate; rather, it represents actual data and retirement experience. The OLT curve is represented by the black triangles in each of the following figures. Mr. Watson selected the R1.5-65 Iowa curve for this account, and I selected the R1.5-70 Iowa curve. Both Iowa curves are displayed in the graph below, along with the OLT curve.

Figure 19:
Account 376 – Steel Mains



As shown in the graph, both Iowa curves provide relatively close fits throughout the OLT curve. As discussed in the depreciation study, a cast iron and bare steel replacement program "ramped up" beginning in 2013, and the assets retired came from vintages from the 1930s – 1960s.[119] Thus, it can be instructive to focus on relatively newer vintages in this account for statistical analyses.

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. While it is sometimes clear from a visual perspective which Iowa curve provides a closer fit to the observed data, the results can also be verified mathematically. Mathematical curve fitting essentially involves measuring the distance between the OLT curve and the selected Iowa curve. The best mathematically-fitted curve is the one that minimizes the distance between the OLT curve and the Iowa curve, thus providing the closest fit. The "distance" between the curves is calculated using the "sum-of-squared differences" ("SSD") technique. Specifically, the SSD between the Company's curve and the OLT curve is 0.0047, and the SSD between the R1.5-70 curve I selected and the OLT curve is 0.0008, which means it results in a closer mathematical fit to the OLT curve.[120]

[119] Direct Testimony of Dane A. Watson, Exhibit DAW-1, Document 2, p. 34.

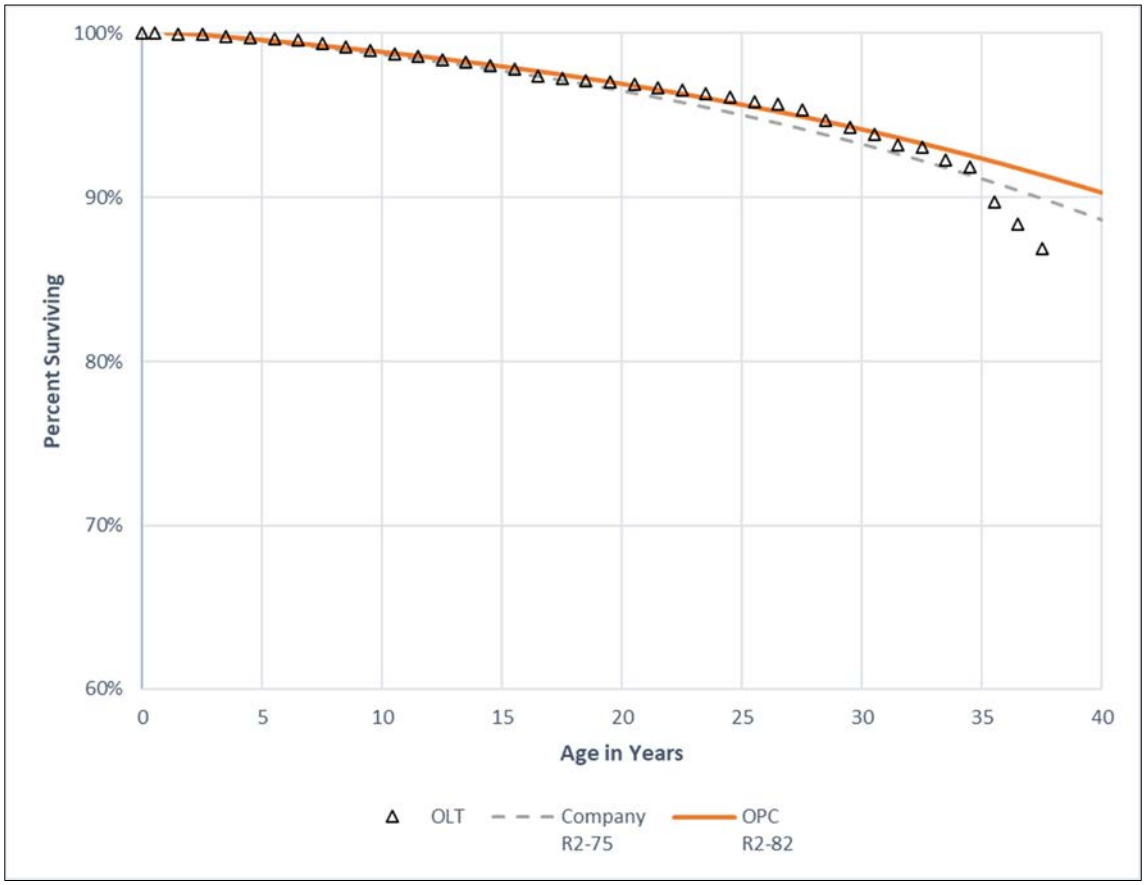
[120] Exhibit DJG-29.

B. Account 376.02 – Plastic Mains

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Watson selected the R2-75 curve, and I selected the R2-82 curve. Both curves are shown in the graph below, along with the OLT curve.

Figure 20:
Account 376.02 – Plastic Mains



As shown in this graph, both Iowa curves provide relatively close fits to the OLT curve. According to the depreciation study, the Company's Problematic Plastic Pipe replacement program that began around since 2015 focused on early 1970s vintage

pipe.[121] Thus, it can be instructive to focus on relatively newer vintages in this account for statistical analyses.

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The SSD between the Company's Iowa curve and the OLT curve is 0.0039, and the SSD between the R2-82 Iowa curve I selected and the OLT curve is 0.0032, which means it results in a slightly closer fit.[122]

C. Account 379 – Measuring and Regulating Station Equipment – City Gate

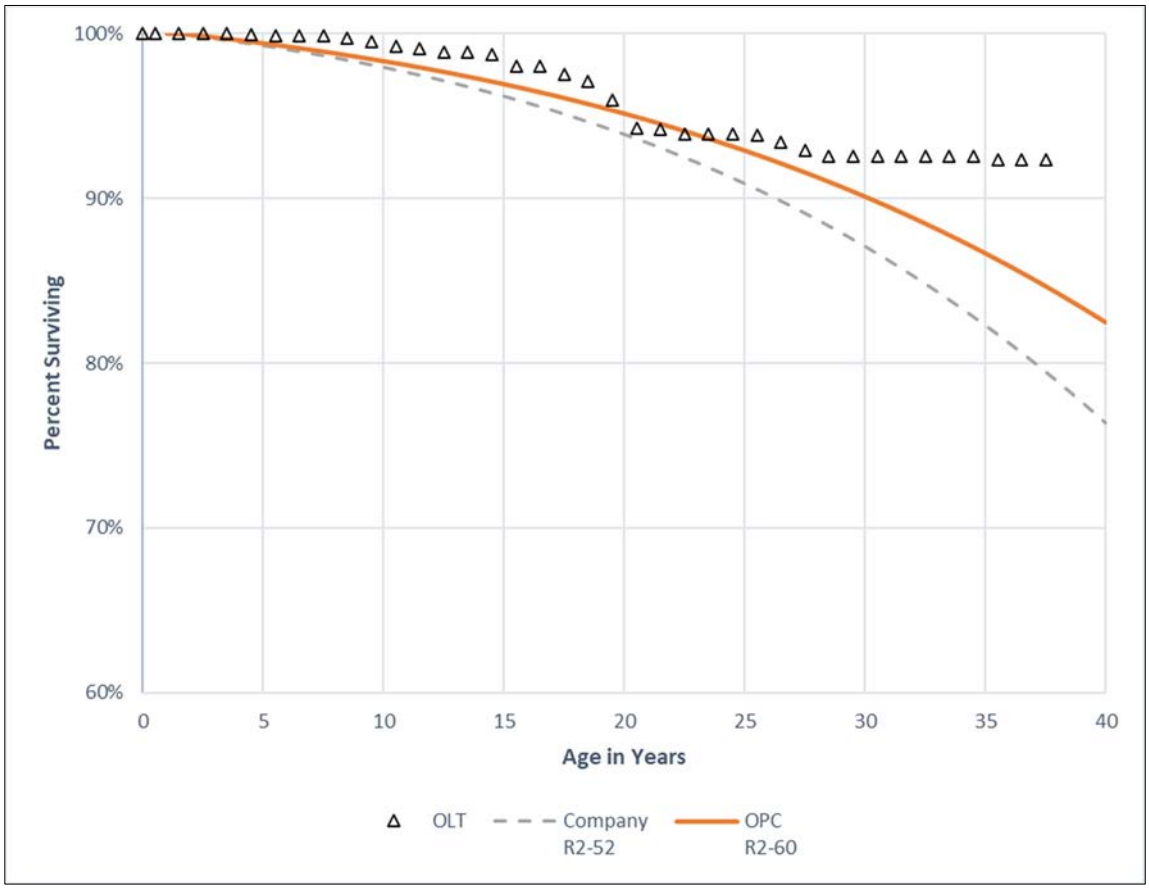
Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Watson selected the R2-52 curve, and I selected the R2-60 curve. Both Iowa curves are shown in the graph below, along with the OLT curve.

[121] Direct Testimony of Dane A. Watson, Exhibit DAW-1, Document 2, p. 37.

[122] Exhibit DJG-30.

Figure 21:
Account 379 – M&R Station Equipment – City Gate



Due to the shape of the OLT curve for Account 379, selecting an Iowa curve that results in a very close fit (as with the two accounts discussed above) results in an unreasonably long service life estimate for this account. Thus, both Iowa curves do not give much statistical weight to the data towards the end of the OLT curve. However, the Iowa curve selected by Mr. Watson is notably shorter than the curve shape the data points otherwise indicate throughout the majority of this OLT curve. According to the depreciation study, the Company is beginning to build new city gates and is doing more capital improvements than in the past. In addition, the depreciation study acknowledges that newer stations are expected to last longer than older ones, and that

"[a]ctuarial analysis also shows a longer life for this account [123] While I agree with Mr. Watson that the service life should be longer for this account, I do not believe that his proposed average life of 52 years is long enough given the data presented at this time.

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The SSD between the Company's Iowa curve and the OLT curve is 0.1242, and the SSD between the R2-60 Iowa curve I selected and the OLT curve is 0.0417, which means it results in a slightly closer fit.[124]

D. Account 380.02 – Plastic Services

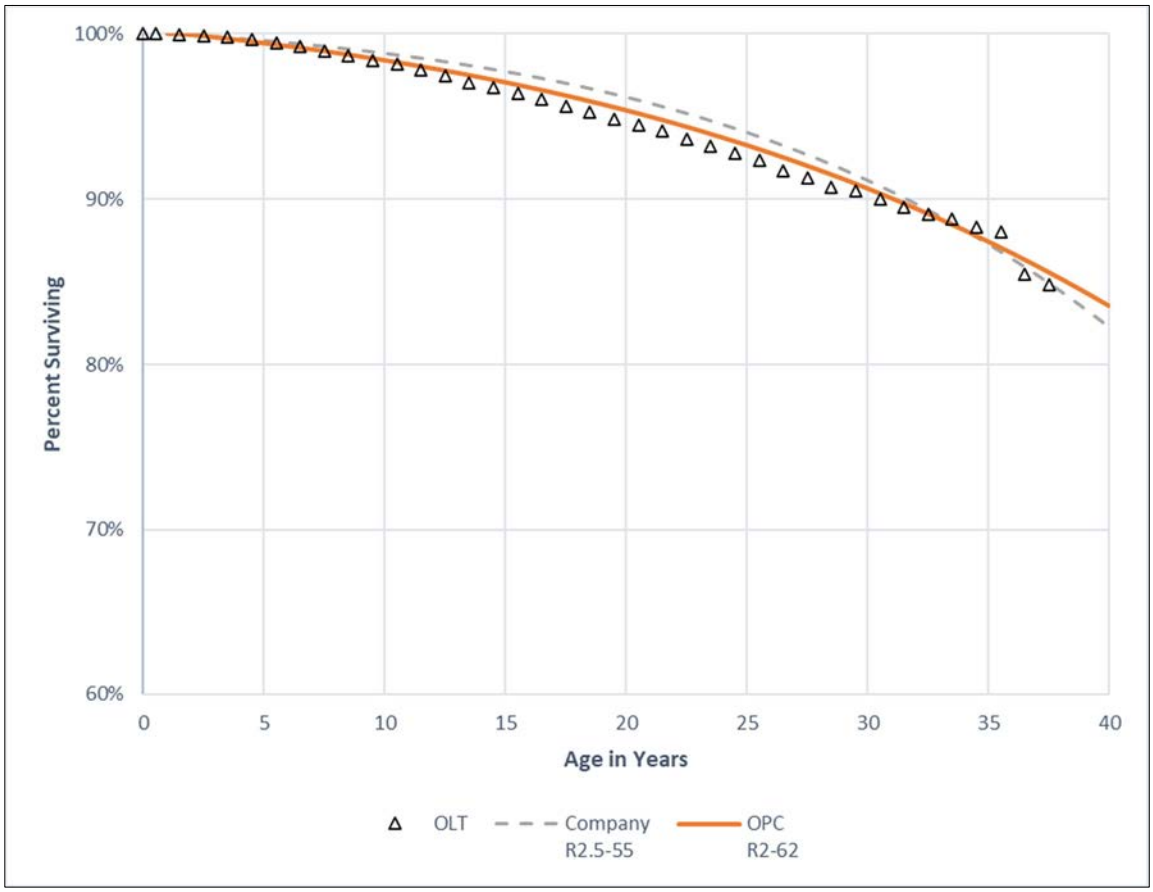
Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Watson selected the R2.5-55 curve, and I selected the R2-62 curve. Both Iowa curves are shown in the graph below, along with the OLT curve.

[123] Direct Testimony of Dane A. Watson, Exhibit DAW-1, Document 2, pp. 42-43.

[124] Exhibit DJG-31.

Figure 22:
Account 380.02 – Plastic Services



As shown in this graph, both Iowa curves result in relatively close fits to this OLT curve. According to the depreciation study, when steel mains are replaced, where there is a plastic service, they will replace with a plastic service. Mr. Watson also believes that the actuarial analysis for this account supports a 55-year average life, but the graph presented in the depreciation study for this account considers placement years dating back to 1959. The more recent placement band used in my graph above indicates a slightly longer service life (albeit based on a shorter OLT curve).

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The SSD between the Company's Iowa curve and the OLT curve is 0.0028, and the SSD between the R2-62 Iowa curve I selected and the OLT curve is 0.0012, which means it results in a slightly closer fit.[125]

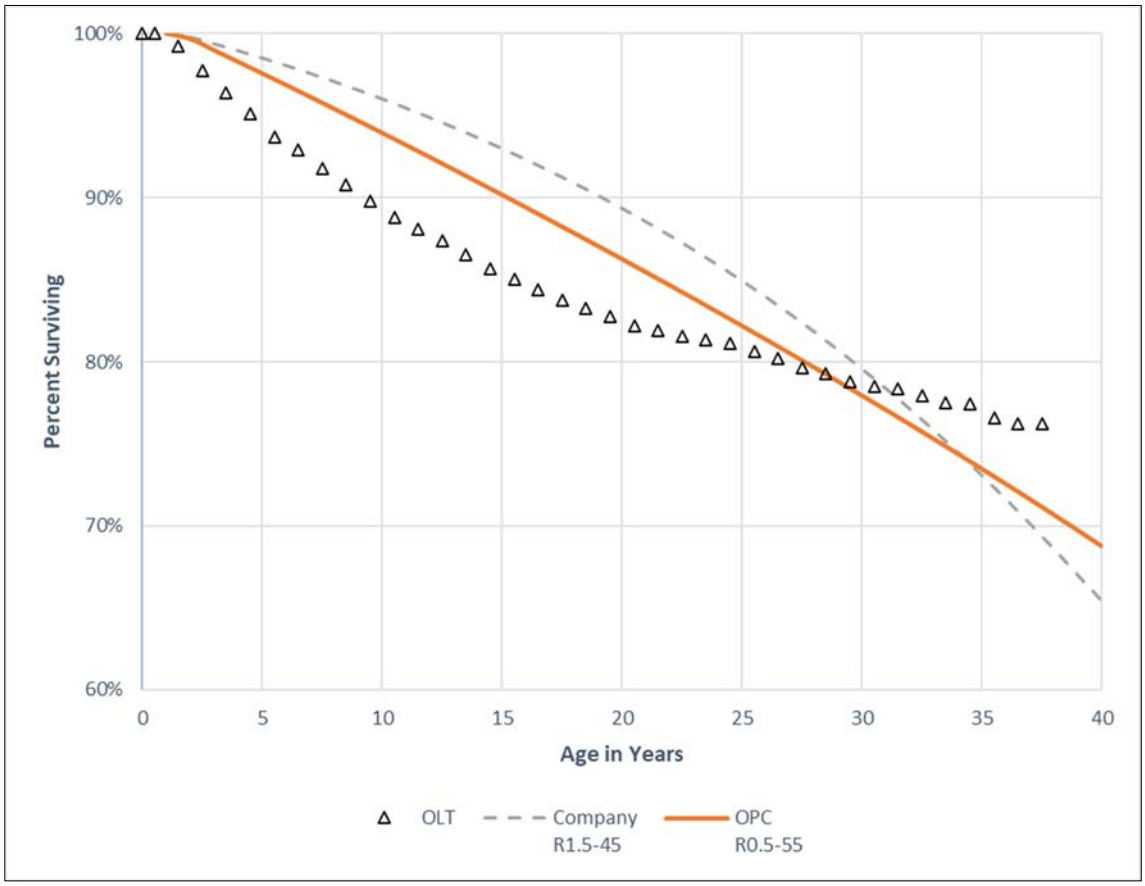
E. Account 382 – Meter Installations

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Watson selected the R1.5-45 curve, and I selected the R0.5-55 curve. Both of these Iowa curves are shown in the graph below, along with the OLT curve.

[125] Exhibit DJG-32.

Figure 23:
Account 382 – Meter Installations



The unusual shape of the OLT curve for this account makes it impractical to find an Iowa curve that provides as close a fit compared with the other accounts presented above. Nonetheless, the relevant retirement data comprising the OLT curve should be considered in the curve-fitting process to a greater extent than what is suggested by Mr. Watson's Iowa curve selection. The R1.5 curve-type does not have a sufficiently flat shape and trajectory to reflect the retirement pattern displayed in the OLT curve (albeit an unusual one).

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The SSD between the Company's Iowa curve and the OLT curve is 0.0892, and the SSD between the R0.5-55 Iowa curve I selected and the OLT curve is 0.0345, which means it results in a slightly closer fit.[126]

XII. THEORETICAL RESERVE SURPLUS

Q. Please describe the theoretical reserve.

A. In contrast to the book reserve, the theoretical reserve represents the accumulated depreciation balance that would currently exist, in theory, if the currently-approved depreciation parameters (i.e. life and net salvage) had been implemented throughout the life of the assets being studied. There is almost always a difference between the book reserve and theoretical reserve, particularly because both calculations are always changing. If the book reserve exceeds the theoretical reserve, this imbalance is called a reserve deficiency (since, in theory, the utility should have a higher accumulated depreciation balance). In contrast, if the theoretical reserve exceeds the book reserve, it creates a reserve surplus.

Q. Do remaining life depreciation rates allocate the reserve imbalance over the remaining life o plant?

A. Yes. The key feature of remaining life depreciation rates (as opposed to whole life depreciation rates), is that the perpetual imbalance between the book and theoretical reserve is mathematically allocated over the remaining life of plant. Thus, in most

[126] Exhibit DJG-33.

cases a separate or manual reserve imbalance allocation or amortization is not conducted. However, the greater the reserve imbalance is, the more appropriate it arguably becomes to consider a manual reserve amortization over a period of time that is shorter than the composite remaining life of plant in order to rectify the imbalance more quickly.

Q. Is the reserve imbalance significant in this case?

A. Yes. To be clear, the amount of the reserve imbalance will depend on the depreciation parameters authorized by the Commission. However, even if the Commission adopts Mr. Watson's proposed depreciation parameters without any adjustment, it will still result in a reserve surplus of about $120 million.[127] This represents a reserve variation percentage of 15% (which is calculated by dividing the total reserve variation by the total theoretical reserve). In this case, the amount of the reserve imbalance will also depend on whether the Commission adopts OPC's primary recommendation to authorize depreciation rates based on plant and reserve balances at year-end 2023 instead of year-end 2024.

Q. How many reserve imbalance calculations are available depending on the Commission's decisions?

A. There are at least four reserve surplus calculations the Commission can consider, depending on its findings regarding the appropriate depreciation study date and

[127] Mr. Watson and I calculated a substantially similar reserve surplus under the Company's proposed depreciation parameters. *See* Direct Testimony of Dane A. Watson, p. 24, line 9 (in which he calculates a reserve surplus of $119.6 million); *see also* Exhibit DJG-23 (which shows my calculated reserve surplus of $120.2 million).

depreciation parameters.[128] The total reserve surplus calculations are presented in the following figure:[129]

Figure 24:
Reserve Surplus Amount by Scenario

	Recommendation and Alternatives	Reserve Surplus
1	• Adopt depreciation rates based on plant at 12-31-23 • Adopt OPC's proposed service life adjustments	$ 221,024,192
2	• Adopt depreciation rates based on plant at 12-31-23 • Adopt PGS's proposed service lives	$ 159,474,313
3	• Adopt depreciation rates based on plant at 12-31-24 • Adopt OPC's proposed service lives	$ 186,552,361

The fourth outcome would be based on adopting Mr. Watson's proposed depreciation parameters without adjustment (resulting in a reserve surplus of about $120 million).

Q. Regardless of the ultimate amount of the reserve surplus, what is OPC's position regarding the amortization period?

A. As discussed in the direct testimony of OPC witness Lane Kollen, it is OPC's recommendation that the reserve imbalance be amortized over a period of 10 years.

[128] Since other intervenors may recommend various service life and net salvage adjustments, and the Commission may adopt such adjustments on an account-by account basis, there are many possible reserve surplus outcomes. However, the different scenarios presented in my testimony essentially result in four primary outcomes.

[129] *See* Exhibits DJG-22, DJG-27, and DJG-28; *see also* Exhibits DJG-38 and DJG-39 for 2023 adjusted and unadjusted reserve development, respectively.

Q. Have you also presented depreciation rates based on using your adjusted theoretical reserve balances instead of the book reserve?

A. Yes. I have calculated two additional scenarios which use my theoretical reserve surplus calculations as the reserve balances used to calculate remaining life depreciation rates (one for the 2023 Study, and one for the 2024 study.[130] Under these scenarios, the reserve surplus itself would not be used to directly reduce the annual depreciation rate accrual, but instead could be treated entirely separate from the annual accrual amount.[131]

Q. Does this conclude your testimony?

A. Yes. To the extent I have not addressed an issue, method, calculation, account, or other matter relevant to the Company's proposals in this proceeding, it should not be construed that I agree with the same.

[130] *See* Exhibit DJG-21 and Exhibit DJG-25.

[131] See the direct testimony of OPC witness Lane Kollen for further discussion.

BY MS. CHRISTENSEN:

Q Mr. Garrett, did you prefile with your testimony 42 exhibits attached to it, labeled DJG-1 through DJG-42?

A Yes.

Q And do you have any corrections to your exhibits?

A No.

Q I would ask at this time that you present your summary of your testimony?

A All right.

My direct testimony in this case addressed the cost of capital and fair rate of return for PGS in response to the direct testimony of company witness Dylan D'Ascendis. I also address the company's proposed depreciation rates in response to the direct testimony of company witness Dane Watson, who conducted PGS's depreciation study.

Regarding the cost of capital issues, PGS proposes an awarded ROE of 11 percent, PGS also proposes a capital structure consisting of approximately 55 percent equity and 45 percent total debt.

PGS has proposed an excessive awarded ROE in this case in that it greatly exceeds a reasonable estimate of its cost of equity. Analysis of an

appropriate awarded ROE for a utility should begin with a reasonable estimate of a utility's cost of equity. In estimating PGS's cost of equity, I analyzed proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, I evaluated the results of the two most widely used model for of calculating -- for estimating cost of equity in utility rate proceedings, the Capital Asset Pricing Model and Discounted Cash Flow Model, or CAPM and DCF models.

The results of my cost of equity models indicate a range for PGS's cost of equity from 7.5 percent to 8.5 percent. The range of cost of equity estimates is relatively wide in this case because of the discrepancy between PGS's proposed capital structure and the proxy group's average capital structure.

PGS's proposed debt ratio of 45 percent is notably lower than the average debt ratio of the proxy group, which is 51 percent. This means that PGS has less financial risk relative to the proxy group. Thus, in order for the indicated cost of equity under the CAPM to be accurate, we must adjust the result based on PGS's lower risk profile. We can accomplish this through a mathematical model called the Hamada Model.

Application of the Hamada Model shows that PGS's cost of equity under its equity rich capital

structure is only 8.1 percent. However, if we impute a ratemaking capital structure for PGS that is equal to the proxy group average, then PGS's cost of equity is 8.5 percent.

I recommend the Commission adopt a 9.0 percent awarded ROE for PGS. I also recommend the Commission adopt a ratemaking capital structure for PGS consisting of an equity ratio that is equal to the average equity ratio of the proxy group, which is 49 percent.

Despite the fact that the indicated cost of equity for PGS under my CAPM analysis is only 8.5 percent, it is my opinion that a nine-percent awarded ROE for PGS is reasonable under the circumstances. This is primarily due to the fact that PGS's current awarded ROE of 9.9 percent is significantly higher than a reasonable estimate of the company's market-based cost of equity.

One could argue that it is preferable for awarded ROEs to gradually change rather than abruptly. An awarded ROE of 9.0 percent would partially mitigate the excess wealth transfer from Florida customers to shareholders, while gradually moving the company toward actual market-based cost of equity.

Regarding depreciation issues, company witness Mr. Watson proposed depreciation rates based on

projected plant and reserve balances as of December 31st, 2024. The depreciation rates proposed by Mr. Watson result in a proposed annual depreciation increase of $9 million. In addition, Mr. Watson calculates a reserve surplus of $120 million as of this depreciation study date.

I analyzed Mr. Watson's depreciation study as of December 31st, 2024, which we referred to as the 2024 study, and I recommend service life adjustments for several accounts, including OPC's service life adjustments, OPC's primary recommendation for depreciation rates and the reserve surplus are based on plant and reserve balances based on December 31st, 2023, for the 2023 study.

Adopting my proposed service life adjustments under the 2023 study results in an annual depreciation accrual of 77.9 million, and equates to an adjustment reducing the company's proposed annual depreciation accrual by 16 million. In addition, my adjusted service life parameters under the 2023 study results in a calculated depreciation surplus of $221 million.

It is OPC's recommendation to amortize the reserve surplus adopted by the Commission over 10 years. In the event the Commission does not adopt our primary recommendation, I also presented alternative

recommendations.

The first alternative approach would be to adopt all of Mr. Watson's proposed service lives and net salvage rates, but still have a depreciation rate and reserve surplus calculations based on plant and reserve balances at December 31st, 2023. This approach results in an adjustment reducing the company's proposed depreciation accrual by $9.2 million, and it results in a reserve surplus of $159 million.

OPC's second alternative for consideration is to apply my service life adjustments to calculate the depreciation rate and reserve surplus to the 2024 depreciation study. This approach results in an adjustment reducing the company's proposed depreciation accrual by $7.5 million, and it results in a reserve surplus of $187 million.

This concludes my testimony summary.

MS. CHRISTENSEN: We tender the witness for cross.

CHAIRMAN FAY: Okay. Thank you, Ms. Christensen.

Mr. Garrett, just real quick before I tender you for cross. I am not sure if you followed any of the previous witnesses for this docket, but what we ask witnesses to do are answer a yes or no. If

you need clarifying to the question, then you can try provide that and, you know, we encourage you to do so. We just ask that you provide that clarity specific to the question asked, and be mindful of being repetitive as to certain points.

So with that, Mr. Wahlen.

MR. WAHLEN: No questions.

CHAIRMAN FAY: Okay. Staff?

MR. DOSE: Thank you. Daniel Dose on behalf of the Office of General Counsel.

EXAMINATION

BY MR. DOSE:

Q Mr. Garrett, I would like to bring your attention to your direct testimony, Exhibit DJG-25. Let me know when you are there.

A Let's see. Yes, I am there.

Q Okay. Is it correct that this exhibit shows how your proposed depreciation rates were developed when using depreciation study dating ending December 31st, 2023?

A Yes.

Q Please turn to page two of this exhibit and look at the number on the last line in column five, it should be 665,270,132.

A Yes.

Q Is it correct that based on this number, you calculated a theoretical reserve surplus in the amount of $221 million? That would be found in Exhibit DJG-27 on page two.

A DJG-27 on page two? Yes.

Q And OPC witness Kollen recommended to amortize this amount of surplus over 10 years in his direct testimony, correct?

A Yes. That's right.

Q Please look at the footnotes of Exhibit DJG-25, specifically footnotes six through nine. Let me know when you are back there.

A Okay.

Q Is it correct that your proposed depreciation rates shown on column nine were determined by subtracting theoretical reserve in column five from depreciable base in column four, and then dividing that result by the remaining life in years in column seven?

A Yes.

Q I would now like to direct your attention to Commission Rule 25-7.045, Florida Administrative Code, you should have gotten a copy of that earlier. Do you see that rule?

A I don't believe I have that.

Q You would have gotten a copy of it this

morning.

A I did receive a document this morning that's dealing with treasury yields.

MS. CHRISTENSEN: Correct. We did not receive that exhibit that you are talking about, the copy of the rule.

CHAIRMAN FAY: I will just give you a moment and make sure we've got it. If not, we can email it to you, Mr. Garrett, so just -- can we do that?

Mr. Garrett. I know you can't see us, but just bear with us for one second. We want to make sure we've got it in front of you before this line of questioning.

BY MR. DOSE:

Q All right. We just sent you an email of a copy of it.

A Okay. I don't see it yet. I am also in the case -- the on-line case portal, the case assignment -- I forgot what you call it now, but --

Q Case Center.

A Right. I -- for some reason, I don't have the pending emails, but.

MR. DOSE: Did you get an email of it yet?

MS. CHRISTENSEN: We received --

THE WITNESS: Not yet.

MS. CHRISTENSEN: Yeah, I was going to say, we received the earlier email regarding the 30-year treasury lives, but we haven't seen this email come through yet.

MR. SANDY: I'm sending a copy to all the parties again to make sure everybody's got it.

CHAIRMAN FAY: Okay. We will give it a second. And I say this only half jokingly, Mr. Garrett, but make sure you didn't put us in spam or junk mail maybe.

THE WITNESS: I did double check that, and I don't see anything there either.

CHAIRMAN FAY: Okay. The other option, at least, Mr. Dose, I mean, we can obviously refer him to the administrative code and the rules, but we will give it a second, Mr. Garrett, because there is really no reason, if you received the treasury exhibit of that same email, that you wouldn't have received this.

And are you -- Ms. Christensen, are you receiving either of these?

MS. CHRISTENSEN: I received a copy of the first email that was sent by Mr. Sandy this morning at 9:08, along with Mr. Garrett. And that's the only email we've received regarding staff exhibits.

CHAIRMAN FAY: Okay. So the one that was just sent, you don't have yet?

MS. CHRISTENSEN: It's not coming through yet.

CHAIRMAN FAY: Okay.

MS. CHRISTENSEN: He does have access to the case management system. If the rule has been uploaded there, we might be able to access it through that.

CHAIRMAN FAY: Yeah. I am not sure if it's on Case Center. We will wait.

MR. DOSE: It should be available on Case Center now.

CHAIRMAN FAY: Okay. Can you help get him there?

THE WITNESS: I am on Case Center. The page I see says, case assignment and scheduling record.

CHAIRMAN FAY: No, that wouldn't be it.

MR. REHWINKEL: The email just showed up.

CHAIRMAN FAY: That's good news.

THE WITNESS: Is there somewhere else I need to go on Case Center?

CHAIRMAN FAY: Do we know where it's uploaded? And it does seem like, Mr. Garrett, that Mr. Rehwinkel just received the email that Mr. Sandy sent out, so you still don't see anything on your

end?

MS. CHRISTENSEN: It looks like the email came through. Is it coming through on you your end?

THE WITNESS: It's not yet.

MS. CHRISTENSEN: Okay. If you can check case management, do you have your -- your ability to have the little tickers on for auto follow and auto direction under present? Do you have those on?

THE WITNESS: No, I don't yet, but I am turning them on right now. Auto follow. Auto direction. They are on now.

MR. SANDY: And I would encourage Mr. Garrett to refresh, that may also assist, but if need be, we can resend it.

THE WITNESS: I did get --

CHAIRMAN FAY: He just got your email.

THE WITNESS: I did get the email now, yeah.

MS. CHRISTENSEN: Okay. Wonderful.

CHAIRMAN FAY: We will give you a second to go ahead and open up that exhibit.

THE WITNESS: Okay.

CHAIRMAN FAY: And I know for purposes of the record, this is our rule, but we will go ahead and number this 190.

(Whereupon, Exhibit No. 190 was marked for

identification.)

BY MR. DOSE:

Q All right. Mr. Garrett, do you have that rule pulled up now?

A I do.

Q Okay. Would you please look at rule Section (1)(e), which contains the Commission's formula for remaining life rate. Let me know when you see that.

A Okay.

Q Is it the correct that the rule's prescribed way to determine to the remaining life rate is by subtracting book reserve for depreciable base, and then dividing that result by the average remaining life in years?

A In addition to net salvage, yes.

Q Okay. So is it correct that you subtracted theoretical reserve from depreciable base in your calculation of depreciation rather than book reserve, as the rule prescribes?

A I think for just the purposes of this calculation, I was working with Lane Kollen on this, and we wanted to present a set of depreciation rates that considered the theoretical reserve. It's not our primary recommendation, but in this particular set of rates, we are subtracting the theoretical reserve in

that numerator.

Q Okay. So you are subtracting theoretical reserve instead of book reserve?

A Yes, in Exhibit DJG-25, for this set of rates.

Q Okay. So moving on to your ROE calculations. You recommended an allowed return on equity of 9.0 percent, is that correct?

A Yes.

Q And would you agree that PGS's current allowed ROE is 9.9 percent?

A Yes.

Q So you are recommending that the Commission reduce PGS's allowed ROE by 90 basis points, correct?

A Yes.

Q And in your testimony, you said that this will allow PGS to maintain its financial integrity with the ROE of 9.0 percent, is that accurate?

A Yes.

Q Did you perform any quantitative analysis to determine what affect or a reduction of 90 basis points to PGS's allowed ROE would have in its financial integrity, or financial metrics?

A Well, the analysis I performed is the cost of equity analysis. And with the awarded ROE being set higher than the company's cost of equity, that should,

under efficient, prudent and economical management, allow PGS an opportunity to remain financially healthy.

Q Okay. But you didn't perform any quantitative analysis on what effect this reduction would have?

A Not outside of the -- all of the analysis presented in my testimony and exhibits.

Q Did you perform any separate analysis?

A There is no analysis that I performed that I did not present in my testimony and workpapers.

Q And did you testify in PGS's rate case in 2020?

A Yes.

Q Okay. To clarify for the record, that was Docket No. 20200051-GU. And in the 2020 rate case, you recommended an allowed ROE of 9.5 percent, is that correct?

A Yes.

Q And in that same 2020 rate case, you testified that based on your quantitative analysis of the market cost of equity, you testified that the market cost of equity for PGS was 6.9 percent, correct?

A Yes. That's right.

Q And in this rate case, you have testified that based on your quantitative analysis, the market cost of equity for PGS is 8.1 percent if PGS uses an equity

ratio of 54.7 percent, correct?

A Yes. That's right.

Q Okay. So you would agree, then, that your financial modeling in your testimony indicates that the market-based cost of equity has increased by at least 120 basis points, or 1.2 percent, since the 2020 rate case?

A Yes, from 6.9 percent -- if you are using the 8.1 percent number in this case and the 6.9 percent number in the previous case, then that's accurate and shouldn't be too big of a surprise given the increases in the -- well, essentially the risk rate, which is driven by interest rates.

Q And did you use the same financial modeling techniques and assumptions in this case as you did in the 2020 case to determine your market-based cost of equity for PGS?

A Essentially, yes, I would have conducted a CAPM and DCF model in those -- in the 2020 case as well.

Q And did you make any adjustments to the results of your financial models in this case to reflect PGS's separation from Tampa Electric into its own stand-alone corporation?

A I made no separate quantitative adjustment for that.

Q Okay. So no?

A No. I mean, when you -- yeah, I have not done that.

Q Would you agree that your recommended ROE of 9.0 percent is 50 basis points lower than the ROE of 9.5 percent that you recommended in 2020, even though your analysis indicates the cost of equity has increased?

A Yes, both of my recommendations in each case were based on gradualism, and necessarily gradualism has to depend on your starting point and your ending point. The starting point being the current authorized ROE, and the ending point ideally moving toward market-based cost of equity. So in that regard, the recommendations are consistent, but you are correct about the numbers, the 9.5 percent and the 9.0 percent.

Q And on pages 14 and 15 of your direct testimony, you cited the U.S. Supreme Court's Hope decision. You of stated that the Hope decision makes it clear that the allowed return on equity should be based on the actual cost of capital, is that correct?

A Yes.

Q Is there any definitive statement in the Supreme Court's Hope decision that states the allowed ROE should be based on the actual cost of capital?

A Those exact words aren't stated in the

decision. I think that's my interpretation of it, and I don't think it's one that is controversial or really disputed. I don't think I have ever really heard, like, an opposing witness or a utility witness dispute that point, so I think it's fairly well agreed on.

Q But there is no definitive statement in the actual decision?

A Right. That -- those words exactly don't appear in the opinion.

Q Okay. Moving onto your DCF model. You used the Constant Growth Rate Discounted Cash Flow Model in your cost of equity analysis, correct?

A Yes. I relied on two different variations of the DCF model, and one I do refer to as a sustainable growth rate model, if that's what you are referring to. I guess they are both constant growth rate models, but one is using analyst growth rates for the growth rate input, and the other one is using -- is considering the growth rate on U.S. GDP as kind of a cap for long-term growth.

Q And in your DCF model, you use a sustainable growth rate of 3.9 percent, correct?

A Yes, in that variation of the DCF model.

Q And this 3.9 percent is the nominal gross domestic product as reported by the Congressional Budget

Office's 2022 long-term budget outlook, correct?

A Yes.

Q You used the GDP as the growth rate in your DCF model because you believed that the long-term growth of a utility such as PGS can't exceed the growth of the aggregate economy, correct?

A I think when conducting the DCF as a cost of equity model, that GDP growth can be considered as a cap. Quantitively, utilities earnings, of course, can grow by more than that. A lot of that would depend on, you know, the rates set by commissions and other things. But when we are trying to estimate cost of equity, I think fundamentally, we should consider, at least consider and see the results of this model that uses GDP as a cap on long-term growth.

Q But you would agree that it's possible for a utility, including a utility like PGS, to grow at a rate greater than the GDP of 3.9 percent for an extended period of time?

A For an extended period, yeah, theoretically it could grow, I mean, if you had a commission that was awarding go -- just to make this is a very simple hypothetical, but if they wanted a 10-percent rate increase every year, and the Commission awarded that, perhaps earnings would grow by 10 percent per year

forever -- well, not forever, but for a long time. But eventually if, you know, an earnings growth rate is higher than GDP, that company's earnings would he eventually surpass GDP.

So I don't think it's disputed that that is an impossibility. I realize that could be many -- that could be quite a bit in the future, but mathematically that is what would occur. And so that's why -- this is not an idea I came up with, of course, but many analysts would say you have got to be careful on your constant growth rate input not being too high.

Q Could you please turn to Exhibit DJG-14, and let me know when you are there.

A Okay. I am there.

Q In column two, you list the average annualized -- average annual authorized ROE for gas utilities. For 2022, what is the average authorized ROE?

A In this exhibit, showing 9.53 percent.

Q And where did you obtain that information?

A I believe I obtained that from other cases that were reporting that based on the EEI data, or perhaps from the RRA regulatory focus. One of those two.

Q Okay. Does RRA regulatory focus sound more accurate?

A It's possible that it -- that that number did come from there. And I can't recall, as I sit here, whether that was all cases, or litigated cases, or what. But I am kind of presenting this number as just a general example to show a trend, of course, not basing my recommendation on that number.

Q Would the RRA major rate case decisions sound right?

A Yes. Yes.

Q Now, if you could please turn to Exhibit DJG-12, and let me know when you are there.

A Okay. I am there.

Q This page summarizes the results of your CAPM analysis, is that correct?

A Yes.

Q And to derive the CAPM result of 8.5 percent, you used the risk-free rate of 3.8 percent, is that correct?

A Yes.

Q And on Exhibit DJG-8, you calculated the risk-free rate, is that correct?

A Yes.

Q And you used the daily treasury yield curves on 30-year U.S. Treasury bonds from April 14th, 2023, through May 25th, 2023; is that correct?

A Yes.

Q And the average daily rate you calculated was 3.81 percent, correct?

A Yes.

Q Are you aware of what the current 30-year U.S. Treasury bond yield is today?

A Oh, today, or for yesterday.

Q Yesterday.

A Yes.

Q And what is that?

A I have that --

Q And what is that as of September 13th?

A It's 4.34 percent.

Q And if you used 4.34 percent in your CAPM analysis, the updated result would be 9.05 percent, would you degree, subject to check?

A If we just changed that one number?

Q Yes.

A If you just changed the one number, it would have an increasing effect. Of course, you know, that's not how the modeling -- it's, you know, not advisable to do that with the modeling. You would want to conduct the full -- the full modeling to reflect any other market changes. But if you wanted to cherrypick that one -- that one metric and just increase it, it would

have an increasing affect on the results.

And another example of that is, like, the equity risk premium, since I filed this testimony, Kroll has downgraded their equity risk premium estimate from six to five-and-a-half percent. So that would have a decreasing affect on the results. So, you know, it just highlights that you wouldn't want to just change one metric.

But the answer to your question is, yes, if you just increased the risk-free rate based on the treasury yield, it would have an increasing affect on the CAPM results.

Q Okay. But would you agree that interest rates have gone up significantly since you did your analysis?

A They've gone up. They could go back down, you know. They are always -- they are always changing.

Q Okay. And again, just one more time, subject to check, would you say that 9.05 percent would be accurate based on the current treasury bond yield?

A If you just want to change that one metric. Yes, if you just changed that, it would be about nine percent, which is equal to my recommendation, interestingly enough.

MR. DOSE: Okay. No further questions. Thank you.

CHAIRMAN FAY: Okay. Commissioners? No. Redirect?

FURTHER EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Garrett, have you ever been involved in a case where an ROE witness has provided a quantitative analysis of the impact of a recommended change in the ROE on a -- on the financial health of a utility?

A No, I have never seen that, and I think I asked it in discovery too, and, you know, the responses aren't very fruitful from the utility, because, I mean, it would involve assuming, I mean, every single financial decision the company is going to make going forward, you know, it's basically entire financial picture in all of its decisions it's going to make, and how that could impact cash flow and credit ratings. So any model that I represent is, of course, going to be picked apart, it could be by anybody, because I am having to assume all the decisions a company is going to make going forward.

What the Commission should focus on is setting a fair awarded ROE that should be based on, at least the starting place, the cost of equity. And then at that point, when it's built into the revenue requirement, you are essentially turning it over to the company then to

manage the company in an efficient and economical manner. But the Commission can know that at that point it's given the company the opportunity to do that. There is no predict whether it whether or not. I don't have any reason to believe that company management is not capable of doing that. I am sure they are. But at that point, the onus is on them to do that.

Q And would it ever be appropriate for an ROE witness to give such an opinion?

A Well, I don't know if it would be inappropriate, but it would be unusual. As I said to your previous question, I don't think I have ever seen -- if I have understanding the analysis that was being asked about, I don't think I have ever seen an analysis quiet like that.

Q Okay. And if the cost of equity is established lawfully and accurately by the Commission, and is lower than previously lawfully and accurately established cost of equity, can the utility claim that its financial health has been degraded by the Commission?

A Can you repeat that one more time?

Q Sure.

If the cost of equity is established lawfully and accurately by the Commission, and then is lower --

and is lower than a previously lawfully and accurately established cost of equity, can the utility claim that its financial health has been degraded by the Commission?

A I don't think so. I mean, under a certain hypothetical, if an awarded ROE, which I have never even scene, I don't, think proposed in any case, if is it was just so punitively low, five percent -- I don't know what it would be -- I am sure at some point the utility could say, hey, even under the greatest management, you are putting us in financial trouble, Commission. But in the United States, in the history of regulation, I have never seen an ROE, awarded ROE that low.

Q And do you recall being asked by staff counsel regarding your opinion that the Hope decision requires that you base the awarded ROE on the actual cost of capital, do you recall that testimony?

A Yes.

Q And, Mr. Garrett, you have testified in numerous jurisdiction across the country, correct?

A Yes, in about half the states.

Q Okay. In those jurisdictions, do they require for an ROE to be established that a market-based analysis be presented to establish that ROE?

A I am not aware of a Commission rule that

specifically requires that, if that's what you are asking.

Q I am not asking about a rule. But as a matter of course, when you present ROE testimony in the other jurisdictions, do -- is it generally accepted and generally presented, you use a discounted cash flow model and a CAPM model to establish what the ROE would be?

A Yes. That's what I was trying to explain on cross, is that I have never seen that -- I mean, I make this point in every testimony, you know, this part of my testimony is generally repeated in all of my testimony when I am talking about the basic standards, and utility witnesses like Mr. D'Ascendis generally do the same thing.

And that point that I have made about my kind of interpretation of Hope, I don't recall that that's ever been disputed or a contentious issue. And kind of to your question, every witness is presenting the CAPM and DCF, because what they are essentially saying is this is my estimate for the company's cost of equity. And sometimes the cost of equity estimate lines up exactly with the witness' awarded ROE recommendation. But in this particular case, and in the 2020 PGS case, my awarded ROE recommendation is higher than my cost of

equity estimate based on gradualism.

Q And I believe you talked a little bit about gradualism. Were you -- are you aware of what the awarded ROE was in the prior case in 2008, 2009 timeframe for PGS, as compared to what you recommended in the 2020 case?

A I believe at the time, PGS's current authorized ROE was 10.75 percent. So we were historically low interest rates at the time, so it's not surprising that if you are really running the CAPM model in an objective, you know, academically sound way, it's going to be a low result during that very low interest rate environment.

So when I was talking earlier about the starting place and ending place, PGS's current authorized ROE at the time was 10.75 percent, and I am estimating a seven-percent cost of equity. Well, that's a pretty big gap that would, when you are applying gradualism to, that's where I got to the 9.5 percent, because in my judgment, I felt like that was a substantial move, but still one that was fair at the time.

And in this case, our starting point and ending point is different. We are starting at 9.9 percent. The ending point I am saying, let's say

ideally, if you are moving toward market-based cost of equity, which is about 8.5 percent, in my opinion, with the capital structure adjustment, then nine percent represents a similar type of gradual move, a meaningful but still a gradual one.

Q Okay. Thank you.

MS. CHRISTENSEN: I have no further questions.

CHAIRMAN FAY: Okay. Let's see here. You have exhibits, Ms. Christensen?

MR. SANDY: Excuse me, Mr. Chair, I believe we have a very limited recross that is within the scope of the redirect, if the Chair will permit it.

CHAIRMAN FAY: Yes. I mean, I will allow some fairly -- that redirect got a little bit broad, but if you could make sure you keep your questioning narrow to that redistrict, then.

MR. DOSE: Just one question.

FURTHER EXAMINATION

BY MR. DOSE:

Q Mr. Garrett, would you agree that credit rating agencies consider awarded ROEs in setting a credit rating?

A I believe they do -- they do consider it. I think they are primarily concerned with cash flow metrics, but, yes, I mean, they do consider that, is my

understanding.

MR. DOSE: Nothing further. Thank you.

CHAIRMAN FAY: Okay.

All right. Ms. Christensen, exhibits?

MS. CHRISTENSEN: Yes. I would move Mr. Garrett's exhibits, I think it's 63 through 104.

CHAIRMAN FAY: That is what I have also.

Staff, does that sound right, 63 through 104 on the CEL? All right. Without objection show those entered.

(Whereupon, Exhibit Nos. 63-104 were received into evidence.)

CHAIRMAN FAY: All right. And then, staff, we have Exhibit 190, which was the rule, I believe.

MR. DOSE: I think that's right.

CHAIRMAN FAY: Yeah. We will go ahead and just enter that just to keep everything organized, without objection? All right. So show that rule entered.

(Whereupon, Exhibit No. 190 was received into evidence.)

CHAIRMAN FAY: All right. With that, Ms. Christensen.

MS. CHRISTENSEN: Yes, I would ask that Mr. Garrett be excused.

CHAIRMAN FAY: Okay. Mr. Garrett, thank you for your time this morning.

THE WITNESS: Thank you all.

(Witness excused.)

(Transcript continues in sequence in Volume 7.)

CERTIFICATE OF REPORTER

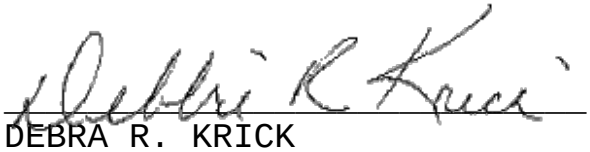
STATE OF FLORIDA)
COUNTY OF LEON)

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 18th day of September, 2023.



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