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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240026-EI

Petition for rate increase by Tampa Electric Company.
_______________________________________/

DOCKET NO. 20230139-EI

Petition for approval of 2023 depreciation and dismantlement study, by Tampa Electric Company.
_______________________________________/

DOCKET NO. 20230090-EI

In re: Petition to implement 2024 generation base rate adjustment provisions in paragraph 4 of the 2021 stipulation and settlement agreement, by Tampa Electric Company.
_______________________________________/

VOLUME 12 - PAGES 2666 - 2917

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN MIKE LA ROSA
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, August 29, 2024

TIME: Commenced: 8:00 a.m.
Concluded: 7:00 p.m.

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

TRANSCRIBED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
82-87	As identified in the CEL		2755
628-631	As identified in the CEL		2755
88-90	As identified in the CEL		2788
842	Appendix to Dr. J. Randall Wollridge's Testimony	2916	2916
63-71	As identified in the CEL		2916

P R O C E E D I N G S

(Transcript follows in sequence from Volume 11.)

CHAIRMAN LA ROSA: All right. So let's move to FIPUG's witnesses. Are you ready with them?

MR. MOYLE: I am, Mr. Chair.

We would call Jeff Pollock to the stand, and I made arrangements with your staff to put up Exhibit C27-2819. Mr. Pollock had some opening comments, but I think we will reference that exhibit in his opening comments.

CHAIRMAN LA ROSA: Yeah, let's get him sworn in if that's all right. Thank you.

Whereupon,

JEFFRY POLLOCK

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 LA ROSA: Excellent.

We are ready.

EXAMINATION

BY MR. MOYLE:

Q Please state your name and business address for the record.

A Jeffry Pollock.

Q And did you cause to be filed 38 pages of direct prefiled testimony with certain attachments and six exhibits in this case?

A Yes.

Q And if I asked you those questions that are in the prefiled testimony, would your answers today be the same as those that were set forth in the prefiled testimony?

A Yes.

Q And have you prepared a summary of your testimony?

A I have.

Q And you also prepared exhibits, did you not, JP-1 through 6?

A Yes.

Q And those are part of your testimony, and were done either by you or at your supervision?

A Yes.

Q Yes. Please provide the Commission with a summary of your testimony.

A Thank you. Good morning, Mr. Chairman and Commissioners.

The focus of my testimony is cost allocation rate design. As you know, cost allocation plays an important role in rate cases, and it strives to fairly allocate cost to customers and classes that cause the cost to which the utility seeks recovery. This is the theory of cost causation, the idea that we don't want to allocate cost to classes that aren't causing the costs that the utility incurs.

This point is addressed in my testimony, specifically that looking at cost causation, recognizing the system peaks and the system loads that drive the need for a utility's production and transmission investment, it follows that the allocation of production and transmission plant and related expenses should reflect TECO's system load characteristics. As the chart on the screen demonstrates pretty clearly, that TECO's load characteristics, if you look back through the years, 2020, and go through the years 2025, TECO has demonstrated a predominant summer peaking load pattern. And more recently, TECO is now projecting to be more winter peaking.

So we have looked at the 4CP method as mining both the summer and the winter peaks as the factors that drive the utility to incur production and transmission costs needed to maintain system reliability.

The summer months are also when the transmission system does -- the energy does not flow on the transmission lines as efficiently on hot human days -- humid days, as compared to cool, dry days.

The 4CP method was also unanimously agreed to in the 2021 rate case settlement and approved by the Commission, and it's a necessary and needed improvement over the 12 coincident peak, or 12CP method that has been used previously.

12CP gives equal weight to peak power demands in each of the months of the year. If 12CP was consistent with TECO's load characteristics -- the chart that you are seeing on the screen, in every month, would have a red bar to some degree. This -- obviously, TECO does not have a red bar in all 12 months.

More importantly, if TECO installed only enough capacity to serve the average of the 12 coincident peaks, it would not be able to serve all of the load during peak periods. The same is also true for distribution plant. There would be even a larger deficit there if you tried to use 12CP to design a distribution system.

Also, in the cost of service study, we address the minimum distribution system analysis. It's often referred to by the acronym MDS. We believe it should be used to classify a portion of the distribution network and used to allocate costs on a customer basis between customer classes. This approach is consistent with cost causation because, as described earlier, when TECO installs a distribution network, it does so to make the grid ready to serve customers.

Now, beyond the obvious physical attachment to the grid required to access the grid, the distribution system must also be able to provide voltage support, which is analogous to pressure in a water line, so you can't get water out of your hose if you don't have enough water pressure, and that's what voltage support is.

Without the voltage support, and without the physical connection to the customer, the distribution system can't deliver electricity from the transmission grid to the customer's meter. That's why a portion of the distribution network should be considered a customer cost, and allocated accordingly.

We believe, for those reasons, the MDS better reflects the cost drivers that cause TECO to build a distribution plant. And it's also -- MDS has also been an accepted practice, not just here in Florida, but in many other jurisdictions as well.

So the bottom line is, we recommend the Commission approve the 4CP method for production and transmission cost allocation, and to use the MDS approach to allocate a portion of the distribution network cost as a customer cost.

Additionally, I talk about rate design, which is a continuation of and extension of the cost allocation process. In a cost-based rate design, you try to track the customer demand energy charges to reflect the customer demand and energy related cost as defined in the cost of service study.

One of the concerns that we have about the proposed rate designs that TECO is proposing are the elimination of the seasonal rates, and to implement a super off-peak period that would establish very low energy prices during daytime hours when most of the system peaks generally occur, especially in the summer months.

Notwithstanding its recent investments in generation, renewable generation, TECO remains a strongly summer peaking system. Like I said, these summer peaks occur during the daytime hours, and the vast majority of the daytime hours that would now -- are now considered on peak would become super peak. That leaves customers somewhat confused because, for many years, customers have been under the assumption that use during the daytime hours, when the company's demands are high, that they should cut back and conserve on that use. And now, TECO is now telling customers just the opposite message, which, again, is very confusing.

So both eliminating seasonal rates and establishing a super off-peak period during daytime hours, we believe, sends the wrong price signals. It will further complicate matters for customers to adapt to this new regime.

I would also observe that no other Florida utility has a similar super off-peak period. Accordingly, we think the Commission should retain the seasonal rates and reject the super off-peak period rate design proposal.

I will conclude my summary just with a brief discussion of return on equity. My colleagues and I, we testify in many states around the country in certain issues and, to some degree, we also include ROE. The return on equity midpoint requested by TECO, if granted, is exceedingly high as compared to other electric utilities across the country. I prepared an exhibit, this JP-1 that, that shows that the average return on equity awarded by commissions throughout the country during 2023 and 2024 is 9.78 percent; and in 2024 alone is a little lower, 9.72 percent.

With that, I appreciate your attention, and that concludes my summary.

CHAIRMAN LA ROSA: Thank you.
MR. MOYLE: Mr. Pollock is available for cross.
CHAIRMAN LA ROSA: Thanks.
OPC.
MR. REHWINKEL: No questions.
CHAIRMAN LA ROSA: Florida Rising/LULAC.
MR. MARSHALL: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MARSHALL:
Q Good morning.
A Good morning.
Q Since we have this chart up, let's start here. This chart is a composite of actual peaks for 2020 through 2023, and then is blended with projected peaks for 2024 and 2025?
A Correct.
Q You would agree that a class cost of service study is used to determine each customer class's responsibility for the utility's costs?
A Yes.
Q If we could go to Exhibit FLL-171, this is going to be master page F3.3-5296. And this is going to be -- this is an excerpt that you included in your work papers from the NARUC Electric Utility Cost Allocation

Manual?

A Yes.

Q If I could direct your attention to the second page of that exhibit, on master page 5297. It says that, quote: To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Do you see that?

A Yes.

Q Do you agree with that?

A Generally, yes.

Q And regarding the minimum distribution system in your testimony, that's in regards to assigning distribution plant costs?

A Correct.

Q If I could direct your attention to the third page of that document. So this is going to be master page 5298. And it says: Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is

that costs are incurred to serve area load, rather than a specific number of meters; is that right?

A That's what it says. Yes.

Q Line drops and customer meters must change with each new customer, is that right?

A I am sorry, what did you say?

Q Line drops and --

A You mean service drops?

Q Service drops, yes, is another way of saying that. Service drops and customer meters must change with each new customer, is that right?

A Yes.

Q And if that --

A Well, not necessarily. You could have customers leave a home and the same meter is still installed, the same service drop is still installed.

Q But that meter and that service drop wouldn't be used if the customer leaves the home and there is no account there anymore.

A The physical equipment serving that customer would not be used if the customer is not a customer.

Q And that isn't necessarily true for line transformers, is it?

A Well, line transformers are shared with multiple customers, but that doesn't -- again, that doesn't necessarily mean that those line transformers go away. You have to have more line -- the more customers you serve, the more line transformers you have to have over time. So it's not a one-for-one. The customer doesn't leave and you don't lose the line transformer. You build out the line transformers in anticipation of serving a certain number of customers in a certain area, and as well as meeting their electricity peak demands.

Q Now, the 4CP method at issue in this case allocates costs based on each class's projected coincident peak during the months of January, June, July and August of the test year?

A In this case, yes.

Q And do you believe that peak demand drives cost causation for TECO?

A Yes.

Q As in those four projected coincident peaks are what's driving the cost on TECO's system?

A The four projected system peaks indicate when the system is most likely to be under the greatest stress and cause the need for additional capacity. And that's why you use a representation of the time periods that create that stress, and the loads that contribute to that capacity need. So that's why we use four coincident peak to reflect that capacity stress on the system.

Q And so you believe that those four projected coincident peaks are what's driving the cost on TECO systems?

A The representation of the four coincident peaks, yes. That's correct. Assuming that the projections are 100 percent accurate, then those would be the factors that will primarily will cause the company to have to extend capacity to serve customers, and to provide a reliable service.

Q You didn't include an analysis of TECO's generation investments as part of your direct testimony?

A No.

Q And you didn't conduct an analysis of the firm capacity values of the solar that TECO is adding to its system as part of your direct testimony?

A I have reviewed all of that in preparing my testimony. I am certainly aware of the different generation mix that the company has, and utilities, overall, have to serve their customers.

Q But you -- to go back to my question, you didn't conduct an analysis of the firm capacity values of the solar that TECO is adding to its system as part of your testimony?

A No, the type of generation is not directly relevant to determining what method should be used to allocate costs to customers, because the cost allocation is load driven, it's not resource driven.

Q You testified that TECO is currently projecting to be winter peaking in 2025 with a peak in January?

A That's according to the company, yes.

Q You didn't conduct an analysis of the likelihood of TECO's forecasted January system peak materializing?

A No. And, in fact, I was pretty skeptical about that, given the history that they only had had an occasional winter peak, but the company is now saying, we are going to be winter peaking.

Q If I could direct your attention to FLL-169. This is going to be master page F3.3-4625 -- I am sorry, 4265.

A Yeah. Okay. Yeah. Thank you.

Q This was one of your work papers for your testimony?

A It is.

Q And that part one we looked at earlier is derived from the data that's included here?

A Correct.

Q And if I look at the tab graph data, it shows

January -- and that's the chart we were looking at earlier?

A   Yes, it is.

Q   It has January as being at 85.35 percent of the system peak?

A   Yes.

Q   For actual data for 2022 through 2023, I think this is what you were alluding to earlier, it was substantially lower than that, ranging between 66.12 percent and a high of 85.18 percent?

A   Yes. That's correct.

Q   And only starting with the projected data for 2024 and 2025, does it jump to 100 percent?

A   Yes.

Q   And that's what brings that average up to 85.35 percent?

A   Yes.

Q   For 2022, through -- I am sorry, for 2020 through 2023 actual data, May exceeded that 90-percent threshold three out of the four years?

A   It was right on the -- right on the bubble, yes.

Q   And in 2020, the system peak was actually in September?

A   Yes.

Q And September has exceeded the 90-percent threshold three out of the four years for actual data, 2020 through 2023, and clocking in at 89.83 percent in the fourth year?

A That's correct.

Q And October actually exceeded the 90-percent threshold for two out of the four years?

A Yes.

Q Wouldn't you agree that TECO's summer reserve margin is 50 percent higher than the reserve margin TECO sets for itself at 20 percent?

A I am sorry, what?

Q In other words, TECO's summer, actual summer were -- are you aware that TECO sets a planning reserve margin of 20 percent?

A Yes.

Q And have you looked at TECO's actual summer reserve margins?

A I haven't looked at the actuals lately, no.

Q Would it surprise you if it's around 30 percent?

A I have no way to evaluate that.

Q If that was true, wouldn't you agree that it isn't summer peaks that are driving TECO's generation investments in this case?

A Well, you know, and any particular summer is going to be a function of whatever weather conditions occur during that summer, or economic conditions, for that matter. So it's not surprising that the utility would have variable reserve margins even during the summer months, looking back.

Q If I could next -- and then you haven't looked at TECO's projected summer reserve margins for the test year.

A I have looked at the 10-year site plans and the projections there. Yes.

Q But do you know if that included a 30-percent reserve margin for the summer?

A I don't recall, no.

Q Okay. If I could next direct your attention to Exhibit FLL-170. This is going to be master F3.3-5295A. This, again, is one of your work papers for your testimony in this case?

A Yes, it is.

Q And this is a cost of service study?

A That's -- yes, this is the company's cost of service model.

Q And so you used TECO's 4CP with MDS cost of service that they filed as the baseline for this?

A Yes.

Q And then you allocated the gasifier that TECO had -- well, let me ask it this way: What modifications did you make to TECO's cost of service study?

A So, made several modifications. One, the production tax credits, we changed from a production rate-based allocator to an energy allocator, because the production tax credits are generated for every megawatt hour that is generated from tax credit eligible resources like solar projects.

The second change we made was to classify the gasifier and Big Bend scrubber costs, reclassifying from energy to demand, because they are part of the, you know, production plant system that is used to meet the system peaks.

Q And just to be clear, under this cost of service study, you allocate the cost of the solar plants based on those three summer peaks and one winter peak, but then allocate the energy from the solar based on -- that's the PTCs based on the energy of solar based on energy?

A Okay. So all plant, integrated plant, is allocated the same way, on the basis of the four peaks, regardless of what kind of plant it is, solar, combustion turbine, base load, combined-cycle. It really -- it doesn't matter. Technology doesn't matter because it's all one integrated system, and so that was -- all those costs were allocated the same way.

The production tax credits, however, are based on, as I said, based on the megawatt hours that are generated from solar plants.

Q And so you did allocate the solar plants the same way, using that 4CP methodology, but the credits based on energy?

A The tax credits, yes.

Q If I could direct your attention to allocation -- the tab allocation assignments.

UNIDENTIFIED SPEAKER: Oh, my gosh. Okay. One second.

THE WITNESS: Yeah, normally I can do just do it with a right click --

UNIDENTIFIED SPEAKER: Allocation.

THE WITNESS: -- allocation assignment. Normally it's just right click and we can just --

UNIDENTIFIED SPEAKER: Yeah. It's not --

THE WITNESS: It's not doing that. All right. We will just have to do it the brute way.

UNIDENTIFIED SPEAKER: Okay, you are good?

THE WITNESS: I will try that. This is a big model. Allocation assignment. Yes. Thank you.

MR. MARSHALL: If I could just have a moment, Mr. Chairman, I am also having trouble finding it myself in this Excel sheet. It's quite long. Hold on a second.

THE WITNESS: Technology is great until it doesn't work.

BY MR. MARSHALL:

Q Maybe you can help me out, Mr. Pollock. In here -- in this document, you calculate the --

A It's not my model.

Q -- you calculate the revenue requirement spread to the different classes in here, correct?

A Okay.

Q With your modifications?

A Yes.

Q And where is that?

A When you say the spread, you mean the difference between what and what? What are we spreading?

Q You know, like the -- as part of the cost of service, the revenue requirement will get, as a function of the cost of service, will get allocated to the different classes, resulting in different increases in base rates; is that right?

A Yeah. If you go to -- Exhibit JP-4 might be the place to go there. So if you go to -- well, what is

-- XL row 96 on JP-4, it shows total sales revenue requirement. So that would be the -- essentially assigning, I think, if I am reading the model, right, assigning the revenue requirements based on each class producing the same rate of return. So that's moving all the rates immediately to cost using this methodology.

Q Thank you --

A Is that what you were looking for?

Q -- you found what I was looking for.

A Okay.

Q That's perfect. Thank you.

A All right. Does that mean I -- did I get a bonus point for that?

Q So if I am reading your data correctly here, it shows that before the -- well, in that row 99, it shows a required increase of 17 percent system wide, is that right?

A Yes.

Q And the LS classes actually have a negative number.

A Correct.

Q And -- because in your allocation, you didn't give any class a rate cut, right?

A So you are -- now you are talking about Exhibit JP-5?

Q I think it's tab -- I am sorry, Tab Exhibit JP-4.

A Well, four tells you what the cost of service -- if you set the rates at cost of service, what the increases would be. Five is -- then shows the recommended allocation using that cost study. And what I did -- oh, wait a minute. I am just -- okay. Yeah. And what that shows is that I used the cost of service study, and the Commission has typically applied gradualism constraints. They said, look, we can't move -- although we want all customers to pay cost-based rates, we can't do it in one step, because to do that will cause rate shock. Either some class's rates are going to go way up or, in some cases, for LS and LS facilities, rates would go way down. We are going to try to balance that as best as we can.

So what I did was assign no rate increase to, to the lighting rates because, as we indicated earlier, they were already above cost of service before any rate increase. And then I spread the remainder of the increase to produce the same rates of return. So all the other classes, other than lighting, produce the same rate of return.

Q And directing your attention back to tab Exhibit JP-4, line 99, this shows the required -- if you

were just doing it flat and not applying any principle, to required increase by class?

A Yes.

Q And it has the system-wide increase at 17.0 percent?

A Correct.

Q And it shows the class GSD at 28.8 percent?

A Yes.

Q And that's already over one-and-a-half times the system average increase?

A Yes.

Q And as the revenue requirement goes down, the differential would be even higher in order to -- for the classes to achieve parity, is that right?

A When you say the differential, you mean the relative increase by each class?

Q Correct.

A It -- yeah, mathematically it would change, definitely.

Q And this cost of service study of 4CP with MDS with the modifications you have made, is the cost of service study most friendly to large commercial and industrial customers that's been filed in this case?

A I don't know about friendly. I don't -- I don't know --

Q How about assigns the least amount of rate increase to them?

A It assigns -- it assigns the -- well, first of all, in terms of GSLD subtran, it still assigns it fairly above system average increase, so it's not friendly in that sense. It just assigns costs the way the costs are incurred and caused by each class.

Q But assigns -- of all the costs of service studies filed in this case, assigns the least amount of cost to those classes?

A In terms of -- and when you say these classes, you are talking about the nonresidential classes in general?

Q The nonresidential and non-GS.

A Well, other -- yes. Other cost of service studies like 12CP do assign more costs to classes that -- whose loads are not as seasonal as to other classes. So, yes, the GSLD classes would be assigned more costs under 12CP than under 4CP.

Q And you would agree that the cost of service study that's been filed in this case that assigns the least cost, relatively speaking, to residential customers and general service customers would be the 12CP and 50 percent AD cost of service.

A I haven't looked at the results of that study.

I don't know. But my assumption would be very favorable for residential customers.

Q Great. Thank you for your patience and working through that Excel and your help in getting there.

MR. MARSHALL: And that's my all my questions, Mr. Chairman.

CHAIRMAN LA ROSA: Great. Thank you.

Let's go FEA.

CAPTIAN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: Okay. Florida Retail.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions.

CHAIRMAN LA ROSA: Staff.

MR. MARQUEZ: No questions.

CHAIRMAN LA ROSA: Commissioners, do we have questions?

Seeing -- oh, sorry. Commissioner Passidomo, you are on recognized.

COMMISSIONER PASSIDOMO: Thank you, Mr. Chair.

Okay. I -- just questions about some of the methodology. So just for clarification, with the

4CP method, more costs are going to be allocated to residential customers instead of large commercial and industrial customers, is that correct?

THE WITNESS: Yes. To the extent that load is more weather sensitive, that's correct. And to the extent that weather is what's driving the high loads, what's driving the need for capacity, that's right.

COMMISSIONER PASSIDOMO: And then do those large and commercial -- so I am trying to -- okay. Do large commercial and industrial customers who take service under an interruptible or curtailable tariff benefit from the credit they are going to receive under these tariffs?

THE WITNESS: So the interruptible credit is not -- or the -- that issue is not even reflected in the cost study, because the credit is a separate issue. So this cost study treats all customers as if they take completely 100 percent firm service, and then the credit is applied separately to that.

COMMISSIONER PASSIDOMO: Did you -- is there some sort of analysis that we can look at to be able to understand those benefits of the credit for those large customers? I am just trying to understand, you know, if -- I hate to say, like, you know, the -- to characterize it as like almost like a double dip sort of situation, but that --

THE WITNESS: Yes.

COMMISSIONER PASSIDOMO: -- if there is a benefit of a credit as well, and then there is also going to be having -- you are going to have, you know, less cost share. I just want to kind of work that out.

THE WITNESS: Yeah. No, that's a great point. I mean, yes, the customers do receive a credit for being interruptible, but that benefit doesn't come for free, because an interruptible customer has to have, obviously, the ability to curtail when they are called by the cust -- by the company, you know, in certain conditions, or they face some pretty substantial penalties. And it's not cost-free to interrupt the manufacturing process too.

So they go into the interruptible low with the knowledge that, for a benefit for agreeing to be interrupted, I am going to get paid a credit that reflects the value of that interruptible service. But I have to also balance the fact that being in that situation, and the fact that I can be called to be interrupted at any time, that that's going to also incur additional costs that are going to offset that benefit.

COMMISSIONER PASSIDOMO: Okay. Yeah, I understand. All right. Thank you.

THE WITNESS: Thank you.

CHAIRMAN LA ROSA: Seeing no further questions, I will send it FIPUG for redirect.

MR. MOYLE: Thank you.

FURTHER EXAMINATION

BY MR. MOYLE:

Q Just a couple of quick questions.

You were asked a number of questions by Mr. Marshall about the cost of service studies. Isn't it a fundamental premise with respect to cost of service, that those who cause the costs should pay for those costs that they cause?

A Yes. Yes. Cost causation is foundational to doing a cost of service study for ratemaking purposes.

Q Yeah. And is that analogous to pay your fair share?

A Yes.

Q And is that what you did in your work here?

A Yes, but also using a cost study that I thought better reflected cost causation principles than the alternatives that have been considered, both in this case and in past cases.

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

CHAIRMAN LA ROSA: Great. Thank you.

Are there exhibits you would like to enter into the record? FIPUG, are there exhibits to enter into the record?

MR. MOYLE: Oh, I am sorry. Yes, we would like to offer into evidence Mr. Pollock's exhibits, and I can --

MS. HELTON: Those are 82 to 87.

MR. MOYLE: 82 to 87, correct. And also, I would like to admit his prefiled testimony into the record. I am not sure we did that at the start, but both of -- the exhibits and the testimony should all be in the record.

CHAIRMAN LA ROSA: Okay. Are there -- is there objections? Are there objections? Seeing none, show them entered into the record.

(Whereupon, prefiled direct testimony of Jeffry Pollock was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	DOCKET NO. 20240026-EI Filed: June 6, 2024

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
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C27-2802

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI Filed: June 6, 2024**

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LIST OF EXHIBITS

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GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
2021 Agreement	Stipulation and Settlement Agreement in Docket No. 20210034-EI
AD	Average Demand
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost-of-Service Study
CT	Combustion Turbine
FIPUG	Florida Industrial Power Users Group
Future Solar Projects	TECO's Eight Proposed Solar Facilities
IOU	Investor-Owned Utility
Gulf Power	Gulf Power Company
kW / kWh	Kilowatt / Kilowatt-Hour
MDS	Minimum Distribution System
MFR	Minimum Filing Requirement
MW / MWh	Megawatt(s) / Megawatt-Hour
O&M	Operation and Maintenance
PTC	Production Tax Credit
ROE	Return on Equity
RRA	Regulatory Research Associates
TECO	Tampa Electric Company

C27-2804

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 14323 South Outer Forty Rd., Suite 206N, St. Louis, MO 63017.

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

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science in electrical engineering and a Master of Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in the United States and in several Canadian provinces. This includes frequent appearances in rate cases and other regulatory proceedings before this Commission. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). A substantial number of FIPUG members purchase electricity from Tampa Electric Company (TECO). They consume significant quantities of electricity, often around-the-clock, and require a reliable affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and substantial interest in the issues raised in and the outcome of this proceeding.

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Q WHAT ISSUES DO YOU ADDRESS?

A First, I present an overview of TECO's proposals, including the primary cost drivers for the proposed base revenue increases. Second, I address the following specific issues:

- Class cost-of-service study (CCOSS);
- Class revenue allocation; and
- Rate design.

Q ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP?

A Yes. My colleague, Mr. Ly, will address the cost-effectiveness of TECO's proposed eight "Future Solar Projects," including the conditions that the Commission should impose if these projects are approved.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-6**.

Q ARE YOU ACCEPTING TECO'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. In various places, I use TECO's proposed revenue requirement to illustrate certain cost allocation and rate design principles. These illustrations, in no way, provide an endorsement of TECO's revenue requirement or any other proposals on issues not addressed in my testimony.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Overview

- TECO's proposed base revenue increase and subsequent year adjustments are being driven by $2.6 billion of rate base additions and related costs (*i.e.,* operation and maintenance (O&M), depreciation, and property taxes), and higher cost of capital, which is primarily driven by an increase in the return on equity (ROE) from 10.2% under the Stipulation and Settlement Agreement (2021 Agreement) which resolved TECO's last rate case in 2021 to 11.5%.[1]

- Approximately $786.4 million of plant additions are for eight Future Solar Projects. As Mr. Ly testifies, the cost-effectiveness of the Future Solar Projects is highly questionable.

- TECO's proposed 11.5% ROE is 172 basis points higher than the 9.78% average ROE authorized by state regulatory commissions nationwide for other vertically-integrated electric investor-owned utilities (IOUs) in rate case decisions in 2023 and through May 2024.

- Florida is viewed as a very constructive regulatory environment for IOUs. Further, a large percentage (38% to 43%) of TECO's annual revenues are collected in various cost recovery mechanisms that allow rates to be adjusted outside of base rate cases. Thus, it is clear that TECO faces significantly less regulatory risk than many of its peer IOUs. Accordingly, the lower regulatory risk should be reflected in the ROE authorized for TECO.

Class Cost-of-Service Study

- TECO is proposing to set rates using a CCOSS that allocates production and transmission plant and related expenses using the Four Coincident Peak (4CP) method. Additionally, TECO is proposing to classify a portion of the distribution network as a customer-related cost – a process referred to as Minimum Distribution System (MDS).

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[1] *In re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 20210034-EI, Corrected 2021 Agreement at 5-6 (Oct. 13, 2021). See also, *Final Order Approving Stipulation and Settlement Agreement Between Tampa Electric Company and All Intervenors* (Nov. 10, 2021) and Letter indicating "Trigger Mechanism" has gone into effect (Oct. 25, 2021).

- The 4CP method recognizes the reality that TECO is a strongly summer-peaking utility with an occasional secondary winter peak. The summer and winter peak demands drive the need to install capacity to maintain system reliability. The 4CP method is based on demands that occur coincident with the (January, June, July, and August) test-year peak demand. 4CP recognizes that it is the summer with a secondary winter peak demands that primarily drive the need for new capacity additions to maintain reliability. Furthermore, TECO experiences its lowest reserve margins during the summer months — this is also when the transmission system experiences its lowest load carrying capability.

- 4CP is a necessary improvement over the Twelve Coincident Peak (12CP) method that has been used in past rate cases. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. If system planners installed capacity sufficient to serve the average of 12 monthly peak demands, TECO would not be able to serve all of its load during the peak periods. In contrast, the 4CP approach and analysis is focused on cost causation.

- TECO's MDS analysis should be adopted. MDS classifies a portion of the distribution network as a customer-related cost. This is consistent with the principles of cost causation; that is, when TECO installs a distribution network, it does so, in part, to provide the voltage support and the readiness to serve new customers, irrespective of the amount of power and energy they will consume. Thus, MDS better reflects the drivers that cause a utility to incur these costs.

- MDS is an accepted practice. It was approved for both Gulf Power Company (Gulf Power) and TECO in their last rate cases.

- Production tax credits (PTCs) were allocated in the same manner as production rate base. However, unlike investment tax credits, which reduce production capital costs, production tax credits are earned for every megawatt-hour (MWh) generated by a TECO-owned solar project. Accordingly, PTCs should be allocated on an energy basis.

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<u>Class Revenue Allocation</u>

- TECO has followed the Commission's long-standing policy to move all rates closer to cost using a proper CCOSS.

- The proper application of gradualism would be to limit the increase to any customer class to not exceed 1.5 times the system average base revenue increase, and no class should receive a rate decrease.

<u>Rate Design</u>

- TECO is proposing to eliminate seasonal rates to achieve simplicity and understandability. TECO is also proposing to implement a "Super Off-Peak" period that would establish very low energy prices during the daytime hours year-round.

- Notwithstanding its recent investments in renewable generating assets, TECO remains a strongly summer-peaking system, and these system peaks have occurred during daytime hours.

- The proposed Super Off-Peak period is also based on an assumption that TECO will continue to expand its investment in renewable generating assets. However, it is highly questionable whether TECO has adequately demonstrated that the proposed Future Solar Projects are cost-effective, as discussed fully by my colleague, Mr. Ly.

- Eliminating seasonal rates is not consistent with cost causation. Further, it is premature to establish a Super Off-Peak period during daytime hours to reflect existing and continued renewable investment. Both changes would send the wrong price signals as well as complicate matters for customers, contrary to TECO's stated intentions. Accordingly, the Commission should reject these rate design proposals.

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2. OVERVIEW

Q WHAT BASE RATE INCREASES IS TECO PROPOSING TO IMPLEMENT?

A TECO is proposing a $296.6 million (20%) base revenue increase in 2025 followed by subsequent year adjustments of $100 million (5.6%) in 2026 and $71.8 million (3.8%) in 2027.[2]

Q HAVE ANY OTHER BASE RATE INCREASES BEEN IMPLEMENTED RECENTLY?

A Yes. TECO implemented three base rate increases pursuant to the 2021 Agreement. The last of these increases was implemented just this year. Over the three years, the cumulative base revenue increase was 21.2%.

Q WHAT ARE THE PRIMARY REASONS FOR TECO'S PROPOSED RATE INCREASE?

A TECO expects to add nearly $2.6 billion of rate base through 2027. Of the $2.6 billion of rate base additions, $1.2 billion is comprised of:

- Eight new solar projects: $786.4 million;[3]
- Four new two-hour battery energy storage system projects: $156 million;[4] and
- Various resiliency projects: $294.4 million.[5]

An additional $523.7 million of rate base additions is for office and support spaces.[6]

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[2] Petition at 5, 10.

[3] Prepared Direct Testimony and Exhibit of Kris Stryker at 8.

[4] *Id*. at 29.

[5] Prepared Direct Testimony and Exhibit of Carlos Aldazabal at 44, 49-50, 68.

[6] *Id.* at 57, 65.

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Additionally, TECO is proposing higher depreciation and dismantling expenses and a much higher cost of capital. This includes an increase in ROE from 10.2% to 11.5% ROE.[7] ***The 130-basis points of higher ROE drives about $80 million (nearly 20%) of the proposed $468.5 million base revenue increase.***

Q PLEASE DESCRIBE THE PROPOSED NEW SOLAR PROJECTS.

A The Future Solar Projects represent about 490 megawatts (MW) of *nameplate* capacity. Two projects will be commissioned in December 2024, two projects in December 2025, and four projects will be commissioned between May and December 2026. TECO estimates that the Future Solar Projects (including land) would cost $1,609 per kilowatt (kW). When complete, TECO projects that solar will provide approximately 18% of customer energy needs.

Q WHAT ARE YOUR SPECIFIC CONCERNS ABOUT THE FUTURE SOLAR PROJECTS?

A TECO asserts that the Future Solar Projects would save $798 million in fuel costs over their expected 35-year lives and generate another $252 million in PTCs.[8] However, Mr. Ly has determined that $157 million of these savings are avoided carbon emissions that are valued based on a hypothetical, non-existent carbon tax or fee. Further, the projected PTCs, which comprise a significant portion of the benefits of the Future Solar Projects, are dependent upon these resources generating at the levels expected by TECO. Thus, it is essential to condition approval of these projects by

[7] Petition at 6.

[8] Prepared Direct Testimony and Exhibit of Jose Aponte, Exhibit No. JA-1, Document No. 11.

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imposing a construction cost cap and performance guarantees to ensure that customers actually receive the benefits projected, as discussed by Mr. Ly.

Q WHAT ARE YOUR SPECIFIC CONCERNS WITH TECO'S PROPOSED RETURN ON EQUITY?

A TECO's proposed 11.5% ROE is excessive when compared to the ROEs authorized by state regulatory commissions in rate cases decided in 2023 and 2024 for vertically-integrated electric IOUs. A list of authorized ROEs for vertically-integrated electric IOUs in electric rate cases decided in 2023 and 2024 through May is provided in **Exhibit JP-1**. As can be seen, the average authorized ROE by state regulators is 9.78% for the period.

Q ARE FLORIDA ELECTRIC IOUS DEMONSTRABLY MORE RISKY THAN VERTICALLY-INTEGRATED ELECTRIC IOUS IN OTHER REGULATED STATES?

A No. First, the regulatory climate in Florida is very supportive of the Florida electric IOUs which translates into lower risk for investors. This directly reflects the Commission's ratemaking policies, which include: the use of a projected test year and multi-year rate plans; timely cost recovery as reflected in both interim rate increases and in the various cost recovery clauses that allow rates to be adjusted outside of a rate case; allowing a return on construction work in progress; and authorizing securitization for storm damage and other major events. These risk-lowering policies are described in a 2021 assessment of Florida regulation conducted by Regulatory Research Associates (RRA) which ranked Florida above 46 other states for investor supportiveness by giving it a score of Above Average/2. RRA stated:

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> ***Florida regulation is viewed as quite constructive from an investor perspective*** by Regulatory Research Associates, a group within S&P Global Commodity Insights. In recent years, ***the Florida Public Service Commission has issued a number of decisions, most of which adopted multiyear settlements that were supportive of the utilities' financial health***. Florida has not restructured its electric industry, and the state's utilities remain vertically integrated and are regulated within a traditional framework. PSC-adopted equity returns have tended to exceed industry averages when established, and ***the commission utilizes forecast test years and frequently authorizes interim rate increases. As a result, utilities are generally accorded a reasonable opportunity to earn the authorized returns.*** In addition, a constructive framework is in place for new nuclear and integrated gasification combined cycle coal power plants that allows a cash return on construction work in progress for these investments outside of the base rate case process. Whether any of the state's electric utilities will proceed with the construction of nuclear power plants in the foreseeable future remains questionable given the challenges such projects posed for utilities in neighboring states in recent years. State law permits the electric utilities to securitize certain nuclear generation retirement or abandonment costs, and one of the state's major companies has done so. ***Mechanisms are in place that allow utilities to reflect in rates, on a timely basis, changes in fuel, purchased power, certain new generation, conservation, environmental compliance, purchased gas and other costs. Additionally, the state has been very proactive in providing utilities cost-recovery mechanisms for costs related to major storms. Additionally, in 2019 the state adopted a Storm Protection Plan Cost Recovery Clause that allows utilities to seek more timely recovery of storm hardening investments outside a general rate case.*** RRA currently accords Florida regulation an Above Average/2 ranking. (Section updated 4/29/21)[9] (emphasis added)

The Commission's ranking remains at Above Average/2.[10] Only one state regulatory commission, Alabama, is ranked higher than the Florida Commission.

[9] RRA Assessment of the Florida Public Service Commission.

[10] RRA Regulatory Focus, RRA State Regulatory Evaluations – Energy at 5 (Mar. 1, 2024).

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Q WHAT PERCENTAGE OF TECO'S REVENUES ARE SUBJECT TO RECOVERY UNDER THE VARIOUS COST RECOVERY MECHANISMS AUTHORIZED BY THE COMMISSION?

A TECO collected between 38% and 43% of its annual sales revenues under each of the five currently-effective cost-recovery mechanisms, as shown in Table 1.

Table 1
Percent of Revenues Collected Under the Various Commission-Approved Cost Recovery Mechanisms

Mechanism	2023	2024	2025
Fuel	36%	30%	28%
Conservation	2%	1%	3%
Environmental	1%	1%	1%
Storm Protection	2%	4%	4%
CETM	2%	3%	3%
Total Cost Recovery	43%	38%	38%

Source: MFR Schedule C-2.

Q IS THERE ANY APPRECIABLE REGULATORY LAG IN BASE RATE CASES?

A No. There is no appreciable regulatory lag in setting base rates. The Commission is required to render a decision within eight months after a base rate case is filed. However, because the Commission has authorized the use of a fully projected future test year, the rates approved by the Commission and placed in effect during the test year will exactly recover the projected test-year cost to serve – unless, of course, actual sales, investment, and expenses vary from the utility's projections. Further, the Commission has consistently allowed utilities to propose subsequent year adjustments that provide for cost recovery of specific assets placed in service after the rate case test-year. Thus, there is virtually no regulatory lag in recovering the costs of future plant additions.

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Q WHAT DOES THE ABSENCE OF ANY APPRECIABLE REGULATORY LAG MEAN IN SETTING AN AUTHORIZED RETURN ON EQUITY FOR TECO?

A The absence of any appreciable regulatory lag in setting base rates also reduces TECO’s regulatory risk. This, coupled with this Commission’s other supportive ratemaking policies (*i.e.,* future rather than historical test year, the ability to adjust rates outside of a base rate case through separate cost recovery mechanisms) demonstrate how TECO’s regulatory risk is no higher (and arguably lower) than for most other regulated vertically integrated electric IOUs. Therefore, the lower regulatory risk should translate into a lower ROE than for other electric IOUs regulated by less supportive commissions.

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3. CLASS COST-OF-SERVICE STUDY

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each customer class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups, or classes. Most of a utility's costs are incurred to jointly serve many customers, therefore the CCOSS provides a mechanism for allocating the utility's costs to customers in a reasonable way based on cost-causation. For purposes of rate design and revenue allocation, customers are grouped into homogeneous customer classes according to their usage patterns and service characteristics. A more in-depth discussion of the procedures and key principles underlying CCOSSs is provided in **Appendix C**.

Q HAS TECO FILED ANY CLASS COST-OF-SERVICE STUDIES IN THIS PROCEEDING?

A Yes. TECO filed two CCOSSs:

- 4CP/MDS; and
- 12CP & 1/13th (or 8%) Average Demand (AD) – *i.e.,* 12CP+8% AD.[11]

Of the two studies, TECO (and FIPUG) supports the 4CP/MDS.

[11] Note, this approach is often referred to as Peak and Average and is used interchangeably with 12CP+8% AD herein.

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Q WHAT IS THE DIFFERENCE BETWEEN THE 4CP/MDS AND 12CP+8% AD CLASS COST-OF-SERVICE STUDIES?

A The 4CP/MDS CCOSS allocates production and transmission plant using the 4CP method. As discussed later, 4CP allocates costs based on each rate class's demand that is projected to occur coincident with (*i.e.,* on the same date and hour as) the system peak demands in the months January, June, July, and August. MDS classifies a portion of the distribution network as a customer-related costs. As discussed later, the distribution network includes plant investment in FERC Account Nos. 364-367 and related expenses. Customer-related distribution plant and related costs are allocated based on the number of customers in each customer class, while the corresponding demand-related network costs are allocated on each class's peak demand, irrespective of when that peak demand occurs.[12]

The 12CP+8% AD study allocates approximately 92% of production and transmission plant based on each rate class's demand that is projected to occur coincident with each of the 12 monthly system peaks and approximately 8% on each rate class's share of Florida retail average demand. Average demand is the same as allocating costs on an annual energy usage.

Q WHICH STUDY IS PREFERABLE?

A As explained later, 4CP/MDS is preferable to the 12CP+8% AD.

[12] As discussed in **Appendix C**, distribution facilities are electrically closer to customers than generation and transmission facilities. Thus, using each class's peak demand (rather than the demand coincident with the system peak or CP demand) best reflects the expected demand that determines how distribution facilities are sized.

Q DO YOU HAVE ANY CONCERNS WITH EITHER THE 4CP/MDS OR 12CP+8% AD CLASS COST-OF-SERVICE STUDY?

A Yes. In both studies, TECO allocated PTCs on production rate base. However, PTCs are earned on each MWh that is generated from TECO's owned solar plants over the first ten commercial operating years. Thus, PTCs should be allocated on an energy basis.

<u>Allocation of Production and Transmission Costs</u>

Q PLEASE EXPLAIN THE 4CP METHOD.

A The 4CP method allocates costs based on each class's projected coincident peak during the months January, June, July, and August of the test year.

Q IS THE 4CP METHOD CONSISTENT WITH COST CAUSATION?

A Yes. Peak demand drives cost causation. In order to meet its obligation to serve firm loads, electric utilities must plan to install sufficient capacity to meet the expected peak demand with a cushion for unplanned outages, unexpected weather, and load forecast error. The 4CP method reflects the reality that TECO's load is highly weather-sensitive. Although TECO has historically been a summer-peaking utility, it has, on occasion, experienced a winter peak. A history of TECO's monthly system peaks is provided in **Exhibit JP-2**, which is also summarized in Chart 1 on the following page.

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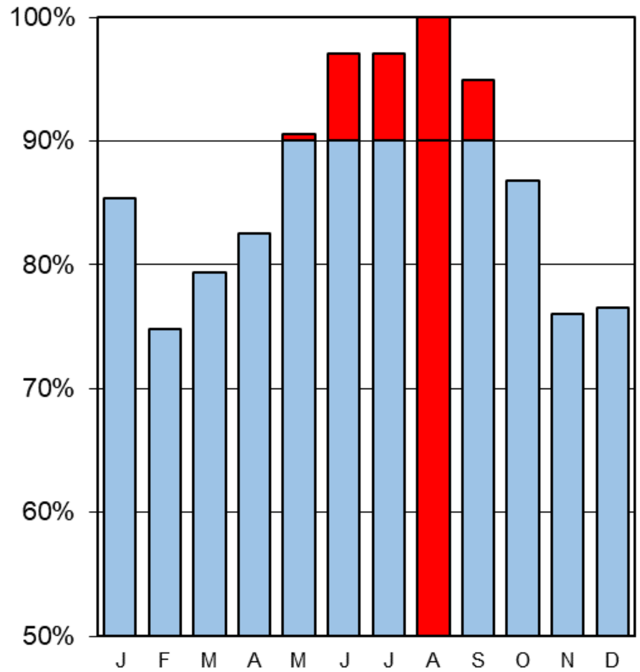
Chart 1
Monthly Peak Demands as a Percent of
The Annual System Peak: 2020-2025



As can be seen, there are substantial differences in TECO's monthly system peak demands. Historically, the demands during the summer months are consistently much closer to the annual system peak than the peak demands in the non-summer months.

Q IS TECO PROJECTING TO REMAIN SUMMER PEAKING?

A No. TECO is currently projecting a winter peak in January 2025 (the test year). Further, TECO is also projecting more peak load growth during the winter months than during the summer months.[13] As a result, TECO is now projecting to become a winter-peaking utility. For this reason, TECO included January in addition to the summer months June through August in applying the 4CP method.

[13] TECO's Ten-Year Site Plan January 2024 – December 2033 at 20.

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Q WHY IS TECO SUPPORTING 4CP?

A Among the reasons cited by TECO is that 4CP reflects cost causation. Specifically, TECO witness, Jordan Williams, states:

> (1) The 4 CP methodology reflects cost causation in relation to Tampa Electric's peak demands. Tampa Electric's peaks are primarily a function of energy consumption associated with weather. There is a strong correlation between weather and residential and small commercial energy consumption. When it is hot, those rate classes tend to consume more energy through cooling, and when it is cold, those rate classes tend to consume more energy through heating. Tampa Electric's large commercial and industrial customers tend to be high load factor customers and are not as strongly correlated with weather, so their energy consumption stays fairly consistent throughout the year. Since the residential and small commercial rate classes are highly correlated with weather, they are the rate classes that cause Tampa Electric's peaks, so they are allocated costs based on cost causation.[14]

Mr. Williams also cites the fact that the Commission approved the 2021 Agreement in which the parties agreed to allocate production and transmission demand-related costs using the 4CP method.[15]

Q DOES THE COMMISSION REQUIRE UTILITIES TO FILE A CLASS COST-OF-SERVICE STUDY USING A METHOD OTHER THAN 4CP?

A Yes. The Commission's minimum filing requirements (MFRs) also require filing of a CCOSS using 12CP+8% AD.

Q WHAT IS THE 12CP+8% AD METHOD?

A The 12CP+8% AD method is a composite of two methodologies: (1) 12CP and (2) Average Demand. The 12CP method allocates cost based on each rate class's

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[14] Prepared Direct Testimony and Exhibit of Jordan Williams at 25. In his May 22nd deposition, Mr. Williams also referenced TECO's Response to Staff's Sixth Data Request, Request No. 4 provided in the 2021 rate case listing the reasons for adopting 4CP over 12CP. A copy of TECO's Response is provided in **Exhibit JP-3**.

[15] *Id.* at 4.

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contribution to each of the 12 monthly peaks during the test year. Average Demand measures each rate class's energy (or kWh) usage throughout the year. Under 12CP+8% AD, 12CP is weighted 92%, while energy usage is weighted 8%.

Q IS THE 12CP METHOD CONSISTENT WITH COST CAUSATION?

A No. 12CP gives approximately equal weighting to the power demands that occur during each of the 12 monthly system peaks. In other words, 12CP assumes that the demands placed on the TECO system occurring in the spring and fall months are as critical to system reliability as the summer and winter peak period demands. Thus, by giving substantial weighting to the non-summer months in allocating production and transmission costs, 12CP ignores the reality that TECO's investment in system capacity is driven by its strong summer peaks with a growing winter peak.

Q DOES THE 12CP METHOD BEST REFLECT COST CAUSATION?

A No. The 12CP method overlooks TECO's primary obligation, which is to have sufficient generation capacity to meet the expected system peak demand to ensure that it can provide reliable service to its firm customers. Once installed, the capacity to meet the expected peak demand is also available to meet system demand throughout the year. Thus, meeting system peak demand is the cost-causer, while serving loads in other periods is the *byproduct* of this obligation. Giving equal weight to non-peak months, such as April, dilutes the impact of demands occurring in peak months, such as January and August. TECO must plan for sufficient capacity to meet the expected summer peak (and secondary winter peak) demands if it is to continue providing reliable service to its firm customers. The 12CP method fails to recognize this reality, as well as TECO's own system planning principles.

To illustrate further, if TECO only had to plan for capacity to meet the average of the 12CPs during the (2025) test year, it would have needed only 4,012 MW, plus reserves. If TECO only had 4,012 MW of capacity plus reserves, it would not be able to meet the 4,566 MW peak demand that it is projecting in January 2025 or the 4,366 to 4,421 MW of projected peak demands in June, July and August 2025.[16] In other words, the lights would go out since TECO would have to curtail service to firm customers because it would have insufficient capacity to meet the firm system peak.

Q ARE THERE OTHER AUTHORITIES THAT SUPPORT YOUR OPINION THAT 12CP IS NOT AN APPROPRIATE METHOD FOR TECO?

A Yes. For example, in its Ten-Year Site Plan, TECO measures resource adequacy based on summer and winter peak conditions. Reliability assessments are not conducted for the spring and fall months.

A further example is the National Association of Regulatory Utility Commissioners' cost allocation manual which states:

> This [the 12CP] method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky.[17]

Clearly, TECO's annual load shape is spiky and its monthly peaks do not lie within a narrow range. This was demonstrated in **Chart 1**. Accordingly, 12CP does not reflect cost causation.

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[16] MFR Schedule E-18.

[17] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 46 (Jan. 1992).

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Q HOW IS 12CP+8% AD DIFFERENT FROM 12CP?

A As previously explained, 12CP+8% AD gives weight to both the average of the 12 monthly coincident peak demands and average demand (or annual energy usage). This approach is often referred to as the Peak and Average method.

Q DOES THE PEAK AND AVERAGE METHOD REFLECT COST CAUSATION?

A No. The Peak and Average method does not reflect cost causation.

First, Peak and Average incorrectly assumes that utilities invest in power plants that are more expensive than a combustion turbine (CT) peaking unit to save fuel costs. This is a false notion because, as previously explained, utilities must provide sufficient generation capacity to meet peak demand, which is the cost-causer, while serving load at other times, which is merely the *byproduct* of having enough resource assets to meet peak demand.

Second, Peak and Average ignores that all of the components of the bulk power (*i.e.,* production and transmission) system are operated in a fully integrated manner. For example, solar projects generate electricity only during daytime hours when the sun is shining, while other resources are used to follow the variations in load and supply power when it is needed and cannot be provided by other resources. In other words, because energy from solar projects is intermittent, they cannot be relied upon to provide either firm capacity or firm energy. Thus, solar energy can *temporarily* displace *energy* that would otherwise have been generated from TECO's dispatchable (*i.e.,* coal and gas) generation, but it cannot replace the need for *firm* dispatchable generation *capacity*. Thus, dispatchable generation provides both the necessary firm capacity and firm energy to keep the lights on.

Q ARE THERE OTHER FLAWS WITH THE PEAK AND AVERAGE METHOD?

A Yes. Peak and Average does not allocate fuel costs in a symmetrical manner to production plant costs (*i.e.,* the "fuel symmetry" problem). It also double-counts average demand (*i.e.,* the Double-Counting" problem).

Q WHAT IS THE FUEL SYMMETRY PROBLEM?

A The fuel symmetry problem occurs when production plant is allocated, in part, on an energy basis, but no change is made in how the corresponding fuel costs are allocated. Allocating plant on an energy basis presumes that generating resources with higher installed capital costs – as measured on a per kW basis – are incurred, in part, to save fuel costs rather than to meet peak demand.

For example, combined cycle gas turbine (CCGT) plants have higher installed costs (in $/kW) than CT peaking plants, but CCGTs also have lower fuel costs (on a $/MWh basis) than CTs. Consistency demands that if higher load factor classes are allocated a larger share of CCGT plant costs (because they purportedly benefit more from the lower CCGT fuel costs), they should also be allocated more of the lower CCGT fuel costs. In other words, there should be symmetry between the allocation of fuel costs and the corresponding allocation of capital costs (*i.e.,* a rate class that is allocated more $/kW of capital costs should pay less $/MWh in fuel costs, and vice versa).

Q HAVE OTHER REGULATORY COMMISSIONS CITED THE FUEL SYMMETRY PROBLEM AS A FATAL FLAW WITH THE PEAK AND AVERAGE METHOD?

A Yes. The fuel symmetry problem was one of the primary reasons cited by the Public Utility Commission of Texas in rejecting every type of energy-based allocation method

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proposed in rate cases throughout the 1980s and 1990s (see, for example, Docket No. 5560; Docket No. 5700; Docket Nos. 7460 and 7172; Docket No. 8032).

For example, in Docket No. 7460, the Commission adopted the Hearing Examiner's Report, which cited the apparent lack of fuel symmetry in rejecting capital substitution, an energy-based allocation method.

> The Examiner's find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal…the high load factor classes, which will bear the higher cost responsibility for base load units, will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units.[18]

Q WOULD THE FUTURE SOLAR PROJECTS TECO IS PROPOSING BE AN EXCEPTION BECAUSE THEY ARE BEING INSTALLED TO LOWER FUEL COSTS?

A No. TECO is partially cost-justifying the Future Solar Projects based on their ability to reduce fuel costs. However, the primary driver to install solar (rather than fossil fuel) plants is clearly public policy – primarily to reduce carbon emissions. As discussed in Mr. Ly's testimony, the cost-effectiveness of TECO's Future Solar Projects is largely a result of the PTCs for which they are eligible. Discounting the impact of these PTCs, the net benefits of these resources would be severely diminished. Therefore, the fuel savings alone would not justify the much higher installed cost.

[18] *Application of El Paso Electric Company for Authority to Change Rates and Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit 2*, Consolidated Docket Nos. 7460 and 7172, Examiner's Report, at 199 (Jun. 16, 1988), adopted in *Order on Rehearing* (May 10, 1988), 14 Tex. P.U.C. Bull. 929.

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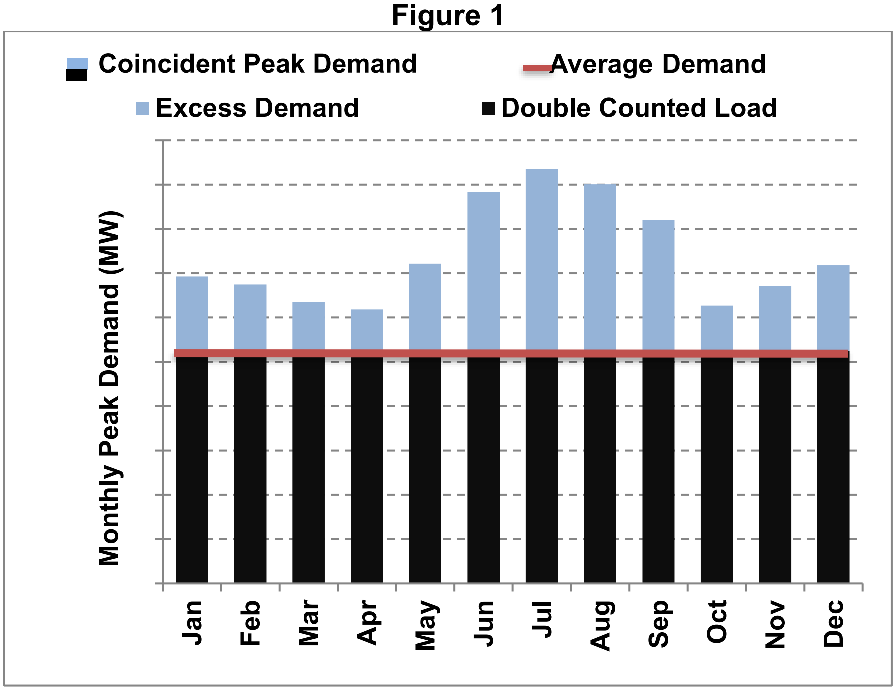
However, notwithstanding the integrated nature of TECO's generation fleet, if the proposed Future Solar Projects are to be allocated using a methodology other than 4CP, the costs should be allocated to the periods the solar plants are expected to produce energy (*i.e.,* daytime hours) and not spread to all hours.

Q WHAT IS THE DOUBLE-COUNTING PROBLEM?

A Double-counting can occur when plant-related costs are properly allocated partially on a coincident peak basis and an average demand (or energy) basis. Average demand is annual energy consumption divided by 8,760 hours. It is also a component of coincident peak demand. This is illustrated in the following Figure 1 for a hypothetical summer peaking utility.

Figure 1



Average demand is equivalent to the black shaded area of the chart. Coincident peak demand is represented by the combined black and blue shaded areas. Double-counting occurs because coincident peak demand incorporates average demand.

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By allocating some plant-related costs relative to average demand and some relative to coincident peak demand, energy usage is counted twice in the allocation process: once by itself and a second time as a subset of coincident peak demand. If you presume that base load units are built to meet average year-round demand, then it follows that the only time load-following (*e.g.*, intermediate and peaking) units would be needed is when system demands exceed the average demand. The proponents of the Peak and Average method would allocate the cost of this additional capacity relative to coincident peak demand (*i.e.*, the entire bar including both the black and blue portions of the bars), rather than just the excess demand (*i.e.*, the blue portion of the bar).

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLOW IN ENERGY-BASED PEAK AND AVERAGE ALLOCATION METHODOLOGIES?

A Yes. For example, the Public Utility Commission of Texas cited the double-counting problem in numerous cases. For example:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50 percent of the intermediate demand, includes within it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and thus "double dipping" is taking place.[19]

[19] *Id.* at 199.

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Q **YOU PREVIOUSLY DISCUSSED HOW TECO'S GENERATION FLEET IS FULLY INTEGRATED. DOES THE INTEGRATED NATURE OF THE GENERATION FLEET SIMILARLY APPLY TO THE INDIVIDUAL COMPONENTS OF TECO'S DISPATCHABLE GENERATING PLANTS?**

A Yes. For example, TECO proposes to classify the cost of the gasifier investment at Polk 1 and the scrubber at Big Bend Unit 4 as energy-related costs. However, this is apportioning parts of a generation plant as if the generation plant can function in pieces. If a generator needs all pieces to deliver firm capacity and energy, then all pieces of the generator should be classified the same. Accordingly, since no generator can provide firm capacity and energy without a reliable fuel source (*i.e.,* the Polk 1 gasifier) or, in the case of Big Bend Unit 4, absent the scrubber, there is no valid reason to classify the Polk 1 gasifier and Big Bend Unit 4 scrubber differently than the remaining investments in these plants.

Q **WHAT DO YOU RECOMMEND?**

A The Commission should, once again, approve the 4CP method to allocate production and transmission plant and related costs. The Commission should reject the 12CP method for retail class allocation because it is contrary to both cost causation and the reality that TECO has had (and is expecting to continue having) well defined seasonal (summer and winter) peaks.

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Minimum Distribution System

Q EARLIER YOU STATED A PREFERENCE FOR TECO'S MDS METHODOLOGY. WHY SHOULD TECO'S MDS BE USED FOR SETTING RATES IN THIS PROCEEDING?

A The MDS classifies a portion of the distribution network as a customer-related cost. This is in stark contrast to the 12CP+8% AD CCOSS in which all distribution network costs are considered demand related. As further discussed below, classifying a portion of the distribution network as a customer-related cost is consistent with the principles of cost causation; that is, it better reflects the factors that cause a utility to incur these costs.

Q WHAT ARE DISTRIBUTION NETWORK COSTS?

A The electric distribution network consists of TECO's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Account Nos. 364, 365, 366, 367 and 368.

Q WHAT FACTORS CAUSE A UTILITY TO INVEST IN AN ELECTRIC DISTRIBUTION NETWORK?

A The purpose of the electric distribution network is to deliver power from the transmission grid to the customer, where it is eventually consumed. Thus, the central roles of the distribution network are to:

- Provide access to a safe, delivery-ready power grid (*i.e.*, a customer-related cost); and
- Meet customers' peak electrical power needs (*i.e.*, a demand-related cost).

Providing access to a safe, delivery-ready power grid requires not only a physical connection that meets all construction and safety standards, but also the voltage

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support and readiness to serve, which is provided by the distribution network infrastructure. Clearly, these costs are related to the existence of the customer. This is why classifying a portion of the distribution network as customer related is consistent with cost causation. In other words, investments that must be made solely to attach a customer to the system are clearly customer-related. These customer-related costs should be allocated based on the number of customers served rather than peak demand.

Q WHY WOULD CLASSIFYING ALL DISTRIBUTION NETWORK COSTS TO DEMAND NOT BE CONSISTENT WITH COST CAUSATION?

A Although the distribution network is sized to meet expected peak demand, it must also provide the direct connection to the customer while providing the necessary voltage support to allow power to flow to the customer. Absent a distribution network and the voltage support it provides, electricity cannot flow to customers. Thus, this investment is essential and unrelated to the amount of power and energy consumed by customers, which is why classifying these costs entirely to demand is not consistent with cost causation.

If TECO were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of distribution lines because they are required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced. Consider the diagram below, which shows the distribution network for a utility with two customer classes, A and B.

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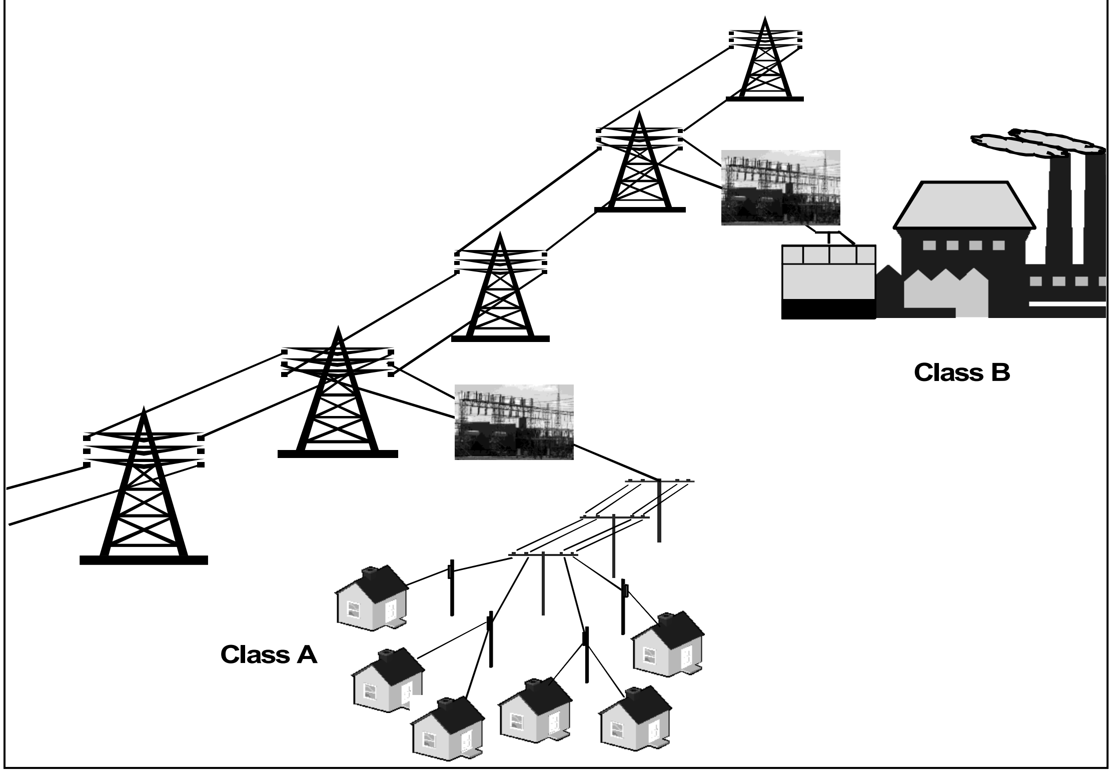
Illustration Showing the Customer Component of Distribution Primary and Secondary Plant



In this example the physical distribution network necessary to attach Class A, a residential subdivision, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

Q IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE ELECTRIC DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A Yes. For example, the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual states:

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> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[20]

Q WHAT DO YOU RECOMMEND?

A The Commission should approve the MDS in setting base rates in this proceeding. The MDS methodology more fairly allocates costs between user groups and recognizes that there are additional customer-related costs to provide distribution service (other than the meter and service drop). Further, it allocates these costs based on the number of customers, which is consistent with cost causation. MDS is an accepted industry practice which the Commission has previously approved for use with Gulf Power and TECO.

Revised CCOSS

Q HAVE YOU REVISED TECO'S 4CP/MDS CCOSS?

A Yes. A revised 4CP/MDS CCOSS is provided in **Exhibit JP-4.** As discussed earlier, TECO allocated the vast majority of the PTCs to rate classes using the 4CP method. PTCs are earned for every MWh generated from TECO's owned solar projects. Thus, allocating PTCs on an energy basis would better reflect cost causation than TECO's proposed 4CP method. Additionally, I have classified the Polk 1 gasifier and Big Bend Unit 4 scrubber as demand-related costs.

[20] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 90 (Jan. 1992).

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4. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

Q HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES TECO SERVES?

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism.

Q WHAT IS THE PRINCIPLE OF GRADUALISM?

A Gradualism is a concept that is applied to avoid rate shock; that is, no class should receive an overly-large or abrupt rate increase. Thus, rates should move gradually to cost rather than all at once because moving rates immediately to cost would result in rate shock to the affected customers.

Q SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?

A Yes. Cost-based rates are fair because each class's rates reflect its cost to serve, no more and no less; they are efficient because, when coupled with a cost-based rate design, customers are provided with the proper incentive to minimize their costs, which

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will, in turn, minimize the costs to the utility; they enhance revenue stability because an increase or decrease in sales and revenues would be offset by an increase or decrease in expenses, thus keeping net income stable; and they encourage conservation because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions.

Q DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal.

Q SHOULD GRADUALISM BE MEASURED RELATIVE TO BASE REVENUES OR TOTAL REVENUE?

A Gradualism should be measured on base revenues. This is because only base revenues are subject to change in this proceeding. Total revenues include base revenues as well as the revenues collected under TECO's five separate cost recovery mechanisms:

- Fuel and Purchased Power;
- Energy Conservation;
- Environmental;
- Storm Protection; and
- Clean Energy Transition Mechanism.

With the exception of the Clean Energy Transition Mechanism, the costs recovered in these cost recovery mechanisms are not subject to change in a base rate case. Further, gradualism is not considered in any of the other cost-recovery mechanisms. Therefore, a general rate case is the only venue in which gradualism can be properly applied.

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Thus, measuring the impact of those proposed increases on ***base*** revenues is the only proper way to determine whether TECO's proposed class revenue allocation results in rate shock.

Q HAVE YOU DEVELOPED A PROPOSED CLASS REVENUE ALLOCATION BASED ON YOUR REVISED CLASS COST-OF-SERVICE STUDIES?

A Yes. **Exhibit JP-5** uses TECO's 4CP/MDS CCOSS with the corrections discussed previously. My recommendation would result in moving all rate classes, except Lighting, to a relative rate of return of 0.98, which is just slightly below parity. Consistent with gradualism, the Lighting class would receive no increase because it is already providing a rate of return that exceeds TECO's proposed system average rate of return, and no class would receive a base revenue increase higher than 1.5 times the 19.8% system average base revenue increase.

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5. RATE DESIGN

Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I address TECO's proposals to eliminate seasonal rates and to implement a Super Off-Peak period that would set very low energy prices during the majority of the daytime hours throughout the year.

Q HOW SHOULD RATES BE DESIGNED?

A Rate design is an extension of the cost allocation process. Also referred to as "intraclass" allocation, rate design determines how the costs allocated to each customer class are recovered from the customers within the class. Thus, rates should be designed consistent with the methodologies used to allocate costs in the CCOSS.

Q WHY IS TECO PROPOSING TO ELIMINATE SEASONAL RATES?

A TECO believes that, although there are seasonal components to its peaks, eliminating seasonal rates would achieve simplicity and understandability, thereby making it easier for customers to set their operations year-round.[21]

Q WOULD ELIMINATING SEASONAL RATES BE CONSISTENT WITH COST CAUSATION?

A No. As previously discussed, TECO supports the 4CP method of allocating production and transmission plant and related expenses. The 4CP method recognizes that TECO experiences its peak demands for electricity (which determine the amount of generation capacity required to maintain reliable service) during the summer months (June, July, and August) while also recognizing a growing winter peak (January).

[21] Prepared Direct Testimony and Exhibit of Jordan Williams at 32.

There is no clear connection or rationale between TECO's CCOSS and a seasonal rate design.

Q SHOULD A DESIRE FOR SIMPLICITY AND TO MAKE IT EASIER FOR CUSTOMERS TO SET THEIR OPERATIONS YEAR-ROUND OVERRIDE A RATE DESIGN THAT IS CLEARLY FOUNDED ON COST CAUSATION?

A No. TECO has had seasonal rates for many years. Not only would eliminating seasonal rates not be consistent with cost causation, it would actually make customers' lives *less* simple. When coupled with the introduction of low Super Off-Peak energy charges during daytime hours, it will force customers to change long-established operating practices. Both rate design changes are far from gradual, and as discussed later, they are premature.

Q WHY IS IT IMPORTANT TO DESIGN RATES THAT REFLECT COST?

A As with class revenue allocation, a cost-based rate design is fair because each customer will pay rates that reflect the customer's cost to serve, as closely as practicable. Similarly, a cost-based rate design is also efficient, will encourage conservation, and provide a more stable revenue stream. This is because a cost-based rate design will send the price signals that incent customers to minimize their costs which will, in turn, minimize TECO's costs.

Q HOW IS TECO PROPOSING TO REDEFINE THE TIME-OF-DAY RATING PERIODS?

A The changes in time-of-day definitions are summarized in Table 2.

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Table 2
Time of Day Periods

Period	Current		Proposed Year-Round
	Apr-Oct	Nov-Mar	
Peak*	Mon-Fri 12 p.m. -9 p.m.	Mon-Fri 6 a.m. -10 a.m. 6 p.m. – 10 p.m.	Mon-Fri 6 a.m. – 10 a.m. 5 p.m. – 9 p.m.
Off-Peak	All else	All else	All else
Super Off-Peak	N/A	N/A	Mon-Sun 10 a.m.- 5 p.m.

* Excluding Holidays
Source: Direct Testimony of Jordan Williams at 29-31

The most significant change would be to establish a new Super Off-Peak period between the hours of 10 a.m. and 5 p.m. daily, including weekends. The base energy charges during Super Off-Peak hours would be lower than the corresponding charges in both Peak and Off-Peak hours. As Table 2 demonstrates, the proposed Super Off-Peak period would largely overlap the current April to October (summer) peak hours, which occur between 12 p.m. and 9 p.m.

The proposed On-Peak hours, by contrast, would include morning hours between 6 a.m. and 10 a.m. year-round. Currently, these hours are On-Peak during the November to March (winter) period. Under TECO's proposal, the evening On-Peak hours during the summer afternoons would not commence until 5 p.m. Thus, the vast majority of the daytime hours that are now considered On-Peak with higher prices than during Off-Peak hours, would become the lowest price Super Off-Peak hours. This is a dramatic change. Further, it will require customers to make drastic operational changes.

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Q WHAT IS THE BASIS FOR TECO'S PROPOSED SUPER OFF-PEAK PRICING?

A TECO states that it used a marginal cost methodology to determine the time-of-use rating periods and rate differentials. Specifically, TECO states that future marginal costs are being impacted by the continued integration and growth in renewable generation. [22]

Q ARE THE MARGINAL ENERGY PRICES CONSISTENTLY LOW DURING THE PROPOSED SUPER OFF-PEAK PERIOD?

A No. **Exhibit JP-6** is a heat map showing the average marginal energy costs by hour by month. The Super Off-Peak hours are highlighted in yellow, and the corresponding marginal energy costs are within the black border. The higher price hours are indicated in red, while the lower price hours are indicated in green. As can be seen, with the exception of April and May, the marginal energy costs are not consistently low during TECO's proposed Super Off-Peak period.

Q EVEN IF MARGINAL ENERGY COSTS WERE CONSISTENTLY LOW DURING SUPER OFF-PEAK HOURS, WOULD IT BE REASONABLE TO PRICE ENERGY LOWER DURING DAYTIME HOURS SOLELY DUE TO HIGHER SOLAR PENETRATION?

A No. The decision to invest in ever increasing amounts of solar will result in a "duck curve." A duck curve occurs when uncontrollable generation like solar decouples cost from load on the grid. In effect, during high load conditions, pricing appears low and it creates a perverse incentive to use more energy during high load conditions. Not only

[22] *Id*. at 31.

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does this contradict many years of encouraging customers to conserve energy during peak periods, the duck curve has also resulted in significant challenges for grid operators. In a recent posting by the U.S. Energy Information Administration:

> The duck curve presents two challenges related to increasing solar energy adoption. The first challenge is grid stress. The extreme swing in demand for electricity from conventional power plants from midday to late evenings, when energy demand is still high but solar generation has dropped off, means that conventional power plants (such as natural gas-fired plants) must quickly ramp up electricity production to meet consumer demand. That rapid ramp up makes it more difficult for grid operators to match grid supply (the power they are generating) with grid demand in real time. In addition, if more solar power is produced than the grid can use, operators might have to curtail solar power to prevent overgeneration. [23]

Q ARE MARGINAL ENERGY COSTS THE ONLY CONSIDERATION IN DETERMINING TIME-OF-USE RATING PERIODS AND PRICING DIFFERENTIALS?

A No. Time-of-use rating periods should also consider other factors besides marginal energy costs. These factors include system loads, loss of load expectation, and the fact that TECO has to maintain dispatchable generation capacity to support the integration of renewable resources to ensure that supply and demand remain in balance from minute-to-minute. As more renewable generation is integrated into the system, resulting in an even steeper duck curve, the more stress will be imposed on TECO's dispatchable generation, resulting in higher (fuel and maintenance) costs and shorter operating lives.

[23] As solar capacity grows, duck curves are getting deeper in California - U.S. Energy Information Administration (EIA).

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Q SHOULD THE COMMISSION APPROVE TECO'S PROPOSED SUPER OFF-PEAK PERIOD?

A No. The proposal would be a very dramatic and drastic change in pricing. It would require customers to significantly change their operations to adapt to the proposed changes.

Second, as previously stated, low energy prices during daytime hours sends the wrong price signals because peak demands occur during daytime hours.

Third, it is premature to premise a major rate structure change on TECO's ever-expanding investment in renewable generating assets. Mr. Ly has determined that the cost-effectiveness analysis supporting the proposed Future Solar Projects is insufficiently robust, and therefore, these projects should only be approved if the Commission Orders a construction cost cap and operating performance guarantees.

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6. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?

A The Commission should make the following findings:

- Adopt a lower ROE that reflects TECO's reduced regulatory lag and financial risk.
- Adopt the 4CP method of allocating production and transmission plant.
- Reject TECO's proposal to classify the Polk 1 gasifier and Big Bend Unit 4 scrubber as energy costs.
- Adopt TECO's Minimum Distribution System methodology in allocating distribution network costs.
- Allocate production tax credits on an energy basis.
- Reject TECO's proposals to eliminate seasonal rates and to establish a Super Off-Peak period during all daytime hours.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

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APPENDIX A

<u>Qualifications of Jeffry Pollock</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

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

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing

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requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AEP TEXAS INC.	Texas Industrial Energy Consumers	56165	Direct	TX	Transmission Operation and Maintenance Expense; Property Insurance Reserve; Class Cost-of-Service Study; Rate Design; Tariff Changes	5/16/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Cross-Rebuttal	TX	Turk Remand Refund	5/10/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Surrebuttal	SC	Class Cost-of-Service Study; Revenue Allocation and Rate Design	4/29/2024
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	55155	Direct	TX	Turk Remand Refund	4/17/2024
DUKE ENERGY CAROLINAS, LLC	South Carolina Energy Users Committee	2023-388-E	Direct	SC	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/8/2024
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	55378	Direct	GA	Deferred Accounting; Additional Sum; Specific Capacity Additions; Distributed Energy Resource and Demand Response Tariffs	2/15/2024
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	23-E-0418 23-G-0419	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Electric Customer Charge	11/21/2023
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY	Industrial Customer Group	2023-154-E	Direct	SC	Integrated Resource Plan	9/22/2023
MIDAMERICAN ENERGY COMPANY	Google, LLC and Microsoft Corporation	RPU-2022-0001	Rehearing Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	9/8/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Cross-Rebuttal	TX	Class Cost-of-Service Study; LGS-T Rate Design; Line Loss Study	8/25/2023
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-633-ER-23	Direct	WY	Retail Class Cost of Service and Rate Spread; Schedule Nos. 33, 46, 48T Rate Design; REC Tariff Proposal	8/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revenue Requirement; Jurisdictional Cost Allocation; Class Cost-of-Service Study; Rate Design	8/4/2023
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Assocation, Inc.	E-7, Sub 1276	Direct	NC	Multi-Year Rate Plan; Class Revenue Allocation; Rate Design	7/19/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00286-UT	Direct	NM	Behind-the-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	4/21/2023

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by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44902	Direct	GA	FCR Rate; IFR Mechanism	4/14/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Stipulation Support	NM	Standby Service Rate Design	4/10/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	53931	Direct	TX	Fuel Reconciliation	3/3/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Cross-Answer	IN	Class Cost-of-Service Study; Class Revenue Allocation	2/16/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Testimony	IA	Application of Advance Ratemaking Principles to Wind Prime	2/13/2023
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	54234	Direct	TX	Interim Fuel Surcharge	1/24/2023
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC	RV Industry User's Group	45772	Direct	IN	Class Cost-of-Service Study; Class Revenue Allocation	1/20/2023
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Surrebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	1/17/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54282	Direct	TX	Interm Net Surcharge for Under-Collected Fuel Costs	1/4/2023
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Surrebuttal	SC	Allocation Method for Production and Transmission Plant and Related Expenses	12/22/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Surrebuttal	MN	Cost Allocation; Sales True-Up	12/6/2022
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2022-254-E	Direct	SC	Treatment of Curtailable Load; Allocation Methodology	12/1/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Rebuttal	NM	Standby Service Rate Design	11/22/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Additional Direct & Rebuttal	IA	Application of Advance Ratemaking Principles to Wind Prime	11/21/2022
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Cross	TX	Retiring Plant Rate Rider	11/16/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Rebuttal	MN	Class Cost-of-Service Study; Distribution System Costs; Transmission System Costs; Class Revenue Allocation; C&I Demand Rate Design; Sales True-Up	11/8/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	53719	Direct	TX	Depreciation Expense; HEB Backup Generators; Winter Storm URI; Class Cost-of-Service Study; Schedule IS; Schedule SMS	10/26/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY	COVID-19 Impact; Distribution Cost Allocation; Class Revenue Allocation; Firm Transportation Rate Design	10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Standby Service Rate Design	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Cross-Rebuttal	TX	Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins	8/5/2022
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2022-0001	Direct	IA	Application of Advance Ratemaking Principles to Wind Prime	7/29/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	53034	Direct	TX	Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri	7/6/2022
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AUSTIN ENERGY	Texas Industrial Energy Consumers	None	Direct	TX	Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/22/2022
DTE ELECTRIC COMPANY	Gerdau MacSteel, Inc.	U-20836	Direct	MI	Interruptible Supply Rider No. 10	5/19/2022
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44160	Direct	GA	CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum	5/6/2022
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Cross-Rebuttal	TX	Rate 38; Class Cost-of-Service Study; Revenue Allocation	11/19/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Responding to Seventh Bench Request Order (Amended testimony filed on 11/15)	11/12/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan, Inc.	52195	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design	10/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Cross-Rebuttal	TX	Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design	9/14/2021
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	43838	Direct	GA	Vogtle Unit 3 Rate Increase	9/9/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	21-00172-UT	Direct	NM	RPS Financial Incentive	9/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design	8/13/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51802	Direct	TX	Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets	8/13/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51997	Direct	TX	Storm Restoration Cost Allocation and Rate Design	8/6/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Class Cost-of-Service Study; Revenue Allocation	8/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Rebuttal	PA	Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs	7/22/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Supplemental	NM	Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement.	7/1/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Class Cost-of-Service Study; Revenue Allocation	6/28/2021

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DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Rebuttal	MI	Allocation of Uncollectible Expense	6/23/2021
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	20210015-EI	Direct	FL	Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits	6/21/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Surrebuttal	AR	Certificate of Environmental Compatibility and Public Need	6/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Rebuttal	NM	Rate Design	6/9/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Class Cost-of-Service Study; Rate Design	6/3/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Supplemental Direct	TX	Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate	5/17/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge	5/17/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-067-U	Direct	AR	Certificate of Environmental Compatibility and Public Need	5/6/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	51625	Direct	TX	Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor	4/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge	3/31/2021
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51215	Direct	TX	Certificate of Convenience and Necessity for the Liberty County Solar Facility	3/5/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Cross Rebuttal	TX	Rate Case Expenses	1/28/2021
PPL ELECTRIC UTILITIES CORPORATION	PPL Industrial Customer Alliance	M-2020-3020824	Supplemental	PA	Energy Efficiency and Conservation Plan	1/27/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Rebuttal	NY	Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study	1/22/2020
MIDAMERICAN ENERGY COMPANY	Tech Customers	EPB-2020-0156	Reply	IA	Emissions Plan	1/21/2021

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	50997	Direct	TX	Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity	1/7/2021
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	20-E-0428 / 20-G-0429	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism	12/22/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Rebuttal	NY	AMI Cost Allocation Framework	12/16/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	51381	Direct	TX	Generation Cost Recovery Rider	12/8/2020
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	20-E-0380 / 20-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation	11/25/2020
LUBBOCK POWER & LIGHT	Texas Industrial Energy Consumers	51100	Direct	TX	Test Year; Wholesale Transmission Cost of Service and Rate Design	11/6/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20889	Direct	MI	Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds	10/30/2020
CHEYENNE LIGHT, FUEL AND POWER COMPANY	HollyFrontier Cheyenne Refining LLC	20003-194-EM-20	Cross-Answer	WY	PCA Tariff	10/16/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00143	Direct	NM	RPS Incentives; Reassignment of non-jurisdictional PPAs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Cross	WY	Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs	9/11/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-578-ER-20	Direct	WY	Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs	8/7/2020
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	50790	Direct	TX	Hardin Facility Acquisition	7/27/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Surrebuttal	PA	Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism	7/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs	7/14/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Rebuttal	PA	Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions	7/13/2020

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PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3019290	Rebuttal	PA	Network Integration Transmission Service Costs	7/9/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit	6/24/2020
PHILADELPHIA GAS WORKS	Philadelphia Industrial and Commercial Gas Users Group	2020-3017206	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	6/15/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Distribution Mains Classification and Allocation	5/5/2020
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	43011	Direct	GA	Fuel Cost Recovery Natural Gas Price Assumptions	5/1/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues	4/14/2020
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	90000-144-XI-19	Direct	WY	Coal Retirement Studies and IRP Scenarios	4/1/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues	3/24/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Cross	TX	Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense	3/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00315-UT	Direct	NM	Time-Differentiated Fuel Factor	3/6/2020
SOUTHERN PIONEER ELECTRIC COMPANY	Western Kansas Industrial Electric Consumers	20-SPEE-169-RTS	Direct	KS	Class Revenue Allocation	3/2/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49831	Direct	TX	Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony)	2/10/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00134-UT	Direct	NM	Renewable Portfolio Standard Rider	2/5/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Settlement	NM	Settlement Support of Rate Design, Cost Allocation and Revenue Requirement	1/20/2020

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SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49737	Direct	TX	Certificate of Convenience and Necessity	1/14/2020
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Rebuttal	NM	Class Cost-of-Service Study; Class Revenue Allocation	12/20/2019
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	32953	Direct	AL	Certificate of Convenience and Necessity	12/4/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	19-00170-UT	Direct	NM	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	11/22/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	49616	Cross	TX	Contest proposed changes in the Fuel Factor Formula	10/17/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design	10/17/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Rebuttal	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design	10/15/2019
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381	Direct	NY	Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation	9/20/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019
AEP TEXAS INC.	Texas Industrial Energy Consumers	49494	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions	7/25/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Cross-Rebuttal	TX	Class Cost-of-Service Study	6/19/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions	6/6/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48973	Direct	TX	Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales	5/21/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage	4/29/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Class Cost-of-Service Study; Transportation Rate Design	4/5/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	49042	Cross-Rebuttal	TX	Transmsision Cost Recovery Factor	3/21/2019

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ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	49057	Direct	TX	Transmsision Cost Recovery Factor	3/18/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense	3/4/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Settlement	AR	Testimony in Support of Settlement	3/1/2019
ENERGY+ INC.	Toyota Motor Manufacturing Canada	EB-2018-0028	Updated Evidence	ON	Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design	2/15/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Surrebuttal	AR	Solar Energy Purchase Option Tariff	2/14/2019
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	48847	Direct	TX	Fuel Factor Formulas	1/11/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	18-037	Direct	AR	Solar Energy Purchase Option Tariff	1/10/2019

To access a downloadable list of Testimony filed from 1976 through the prior year, use this link: **J. Pollock Testimony filed from 1976 through the prior year**

APPENDIX C

Procedures and Key Principles of a CCOSS

Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kWs). This includes production, transmission, and some distribution investment and related fixed O&M expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWhs). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

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Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes several key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (i.e., demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities. Finally, customers who self-serve all or a portion of their power needs from BTMG will have dramatically different load characteristics than customers who purchase all or most of the power from the utility. Thus, they should be costed separately.

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Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- Operate at higher load factors;
- Take service at higher delivery voltages; and
- Use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

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In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than either primary distribution or primary substation customers. More investment is required to serve a primary distribution than a primary substation customer. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis. Efficiency can be measured in terms of load factor. Load factor is the ratio of Average Demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI** **Filed: June 6, 2024**

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 14323 S. Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20240026-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 6th day of June 2024.

KITTY TURNER
Notary Public, Notary Seal
State of Missouri
Lincoln County
Commission # 15390610
My Commission Expires 04-25-2027

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2027.

(Whereupon, Exhibit Nos. 82-87 were received into evidence.)

CHAIRMAN LA ROSA: Any other exhibits?

MR. MARSHALL: Yes, Mr. Chairman, and we would like to enter into the record Exhibits 628 through 631.

CHAIRMAN LA ROSA: Are there objections?

Seeing none, show them entered into the record.

(Whereupon, Exhibit Nos. 628-631 were received into evidence.)

CHAIRMAN LA ROSA: Other exhibits?

Okay. Seeing none, Mr. Pollock, thank you. You are excused.

THE WITNESS: Thank you for your time.

CHAIRMAN LA ROSA: Of course.

THE WITNESS: I appreciate it.

(Witness excused.)

CHAIRMAN LA ROSA: Mr. Moyle, I believe you have another witness.

MR. MOYLE: We do. We would call Jonathan Ly to the stand, please.

CHAIRMAN LA ROSA: Mr. Ly, before you sit down, let's administer the oath --

MR. LY: Yes.

CHAIRMAN LA ROSA: -- when you are ready.
Please raise your right hand.
Whereupon,
JONATHAN LY
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 LA ROSA: Thank you.
EXAMINATION
BY MR. MOYLE:
Q Can you please state your full name for the record?
A Yes. My name is Jonathan Ly.
Q And you are employed with Jeff Pollock, Inc., correct?
A That is correct.
Q And you were just sworn. Did you cause to be filed 15 pages of direct prefiled testimony with attachments and three exhibits?
A Yes.
Q And if asked those questions today by me, would the answers that you provided in your prefiled testimony be the same?
A They would.

MR. MOYLE: Mr. Chair, I would like to go ahead and move the prefiled testimony into the record.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Jonathan Ly was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI** **Filed: June 6, 2024**

CONFIDENTIAL INFORMATION REDACTED

DIRECT TESTIMONY AND EXHIBITS OF JONATHAN LY

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
INCORPORATED

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C28-2876

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI** **Filed: June 6, 2024**

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LIST OF EXHIBITS

Exhibit	Description
JL-1	Summary of TECO's Future Solar Projects Cost-Effectiveness Analysis
JL-2	Comparison of Natural Gas Forecasts
JL-3	Comparison of EIA Reference Case Henry Hub Natural Gas Price Forecasts

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C28-2878

GLOSSARY OF ACRONYMS

Term	Definition
EIA	Energy Information Administration
FIPUG	Florida Industrial Power Users Group
Future Solar Projects	TECO's Proposed Solar Facilities
kW	Kilowatt
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
PTC	Production Tax Credit
TECO	Tampa Electric Company

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Direct Testimony of Jonathan Ly

Introduction and Qualifications

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly, 1314 Welch Street, Unit A, Houston, TX 77006.

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

A I am a regulatory consultant affiliated with J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley and a Master's degree in Energy and Earth Resources from the University of Texas at Austin. Since joining J. Pollock, Incorporated in 2018, I have participated in numerous regulatory proceedings regarding the ratemaking process, resource planning, certificates of convenience and necessity, and assessments of planned new resources in Arkansas, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming. My qualifications are documented in **Appendix A**. A list of my appearances is provided in **Appendix B**.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). A substantial number of FIPUG members purchase electricity from Tampa Electric Company (TECO). They consume significant quantities of electricity, often around-the-clock, and require a reliable, affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and substantial interest in the issues raised in and the outcome of this proceeding.

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Q WHAT ISSUES DO YOU ADDRESS?

A I am addressing the cost-effectiveness of TECO's eight proposed solar projects for which it is seeking cost recovery in this base rate proceeding (hereinafter referred to as the "Future Solar Projects"). In addition, I also discuss the need for customer protections to balance the risk associated with these proposed resources between TECO and its customers.

Q ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP?

A Yes. My colleague, Mr. Pollock, will address TECO's class cost-of-service study, class revenue allocation, and rate design.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibits JL-1** through **JL-3.**

Q DOES THE FACT THAT YOU ARE LIMITING YOUR TESTIMONY TO THE AFOREMENTIONED ISSUES MEAN THAT YOU ARE ENDORSING TECO'S OTHER PROPOSALS IN THIS CASE?

A No. One should not interpret the fact that I do not address every issue raised by TECO as support of its proposals.

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A My findings and recommendations are as follows:

- The purported cost-effectiveness of the Future Solar Projects for which TECO is seeking cost recovery in this base rate proceeding are not supported by robust analysis. Further, TECO has not provided sensitivity analyses supporting the benefits of these projects under a range of capital and fuel cost assumptions.

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- The net present value (NPV) benefits TECO claims would be achieved by the Future Solar Projects are based upon inflated natural gas prices and include the impact of a speculative carbon adder. If future fuel prices are lower than TECO projects and/or a carbon adder is not implemented, these benefits could be diminished or even negated, thereby imposing an incremental cost on TECO's customers.

- Given the significant uncertainties surrounding the cost-effectiveness analysis, if the Commission approves the Future Solar Projects, it should also impose conditions to balance the risks of these resources between TECO and its customers.

- The Commission should implement a cost cap on the Future Solar Projects and establish a minimum capacity factor guarantee based upon TECO's projections.

- The Commission should also ensure that each of the Future Solar Projects entering rate base qualify for the production tax credits anticipated by TECO, which should also be included as an offset to these projects' base revenue requirements when rate recovery is authorized.

Future Solar Projects

Q FOR WHAT PROJECTS IS TECO SEEKING COST RECOVERY OF IN THIS PROCEEDING?

A TECO is seeking cost recovery for eight Future Solar Projects. The characteristics of the eight Future Solar Projects are summarized in Table 1 on the following page.

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Table 1
Summary of Proposed Future Solar Projects

Project	Nameplate Capacity (MW)	Installed Cost ($/kW)	Annual Capacity Factor	In-Service Date
English Creek Solar	23.0	$1,754	26%	December 2024
Bullfrog Creek Solar	74.5	$1,402	26%	December 2024
Duette Solar	74.5	$1,466	26%	December 2025
Cottonmouth Ranch Solar	74.5	$1,410	26%	December 2025
Big Four Solar	74.5	$1,332	26%	May 2026
Farmland Solar	54.4	$1,641	26%	December 2026
Brewster Solar	38.8	$1,411	26%	December 2026
Wimauma 3 Solar	74.5	$1,637	26%	December 2026
Total	488.7	$1,609		

Source: Exhibit KS-1, Document Nos. 2-9.

TECO's estimated total cost to construct the proposed Future Solar Projects is $786.4 million, which translates into a capital cost of $1,609 per kilowatt (kW). The capital cost includes all interconnection and upgrade costs.[1]

Q DOES TECO ASSERT THAT THE FUTURE SOLAR PROJECTS WILL BENEFIT CUSTOMERS?

A Yes. TECO estimates that the NPV benefits of the proposed Future Solar Projects are $322.3 million or approximately 41% of the projected capital costs.[2]

Q DO YOU HAVE ANY CONCERNS WITH THE FUTURE SOLAR PROJECTS?

A Yes. First, the Future Solar Projects represent a $786.4 million addition to rate base. The corresponding benefits are a fraction of the projected upfront capital costs. Any

1 Prepared Direct Testimony and Exhibit of Kris Stryker at 8.

2 Prepared Direct Testimony and Exhibit of Jose Aponte at 31-32.

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material changes in the assumed capital costs, fuel savings, operating performance, and/or the magnitude of the applicable production tax credits (PTCs) could result in the costs exceeding the benefits. Thus, unless the Commission finds TECO's cost-effectiveness analysis to be sufficiently robust (that is, the benefits exceed the costs under a wide range of assumptions), the Future Solar Projects should not be approved.

Second, the PTCs, which apply during the first ten years of commercial operation, comprise a significant portion of the NPV benefits associated with the Future Solar Projects. Thus, as a policy matter, the Commission should guarantee, at a minimum, that the PTCs flow through to customers based on projected performance — even if the Company is unable to monetize them. This PTC guarantee is discussed in more detail later.

Third, the projected benefits include avoided carbon emissions costs. However, these avoided carbon emission costs are the result of imposing a carbon tax or fee on fossil fuel generation that the Future Solar Projects would displace. As discussed later, the avoided carbon emissions comprise $157 million of the cumulative NPV benefits from the Future Solar Projects. Including avoided carbon emissions is problematic since there is no existing or pending federal legislation imposing a carbon tax on fossil fuel emissions. Further, policymakers have consistently used tax credits to encourage the deployment of renewable energy resources. As such, recognizing both tax credits and avoided carbon emissions places an undue disadvantage on fossil fuel generation, which (unlike renewable energy resources) provides essential and dependable dispatchable capacity. In fact, the Florida Legislature recently expressed

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its intent to "maintain, encourage, and ensure adequate and reliable fuel sources for public utilities."[3]

Cost-Effectiveness Analysis

Q WHAT IS A COST-EFFECTIVENESS ANALYSIS?

A A cost-effectiveness analysis estimates the impact of a new generating project (or projects) by comparing system-wide costs and benefits, both with and without any new project (or projects) over its (their) expected life (or lives). The analysis is typically conducted using a production cost simulation model. For example, TECO performed its cost-effectiveness analysis using its Integrated Resource Planning models.[4] The costs associated with a new project are the incremental capital cost (both generation and transmission) and operating costs over the expected life. The benefits attributable to a new project are the capital, fuel, and non-fuel operating costs that the system would not incur because of the new project. Because these new generating resources have expected lives of 35 years, a cost-effectiveness analysis must, by necessity, rely on assumptions about future load growth, inflation, commodity costs, financing costs, labor and materials costs, and operating performance. Given the wide range of required assumptions, it is customary to conduct a base case and several sensitivity studies to determine a range of possible outcomes.

[3] FLA. STAT. § 163.3210(1). HB1645 was approved by the Governor on May 15, 2024 and takes effect on July 1, 2024.

[4] Prepared Direct Testimony and Exhibit of Jose Aponte at 27.

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Q HAS TECO CONDUCTED A COST-EFFECTIVENESS ANALYSIS OF THE FUTURE SOLAR PROJECTS?

A Yes. The results of TECO's cost-effectiveness analysis are summarized in **Exhibit JL-1**.

Q WHAT DO THE RESULTS OF TECO'S COST-EFFECTIVENESS SHOW?

A A significant portion of the benefits associated with the Future Solar Projects are attributable to the PTCs. In other words, absent the speculative savings from carbon emissions, the benefits of the Future Solar Projects would be greatly diminished. Ignoring these savings, the margin of benefit for the Future Solar Projects is only 21% of the projected incremental capital costs. Thus, if the projected fuel savings are 21% lower than TECO is projecting (due to lower commodity prices), the Future Solar Projects would not be beneficial.

Q PLEASE DESCRIBE THE AVOIDED CARBON COSTS THAT TECO HAS INCLUDED IN ITS COST-EFFECTIVENESS ANALYSIS.

A TECO assumed a carbon adder of $[redacted] per ton would be implemented as soon as [redacted] and escalate at an average annual rate of [redacted]% over the forecast period.[5] In total, the avoided carbon emissions comprise approximately $157 million of the NPV benefits of the Future Solar Projects.[6] These savings are entirely speculative and serve only to inflate the purported benefits of these facilities.

[5] TECO Response to FIPUG IRR 1-5 (Confidential).

[6] Prepared Direct Testimony and Exhibit of Jose Aponte, Exhibit JA-1, Document No. 11.

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Q DID TECO PRESENT ANY SENSITIVITY ANALYSIS TO ASSESS THE COST AND BENEFITS FROM THE FUTURE SOLAR PROJECTS IF EITHER FUTURE CAPITAL COSTS WERE HIGHER OR COMMODITY COSTS WERE LOWER THAN PROJECTED?

A No. There does not appear to be any sensitivity analysis of the capital costs of the Future Solar Projects. And although TECO states that it conducted sensitivity analysis considering the impacts of high and low fuel price forecasts, it has neither provided the results of these analyses in its filed testimony nor in discovery.[7] Thus, TECO has not provided sufficient analysis supporting the performance of the Future Solar Projects under a wide range of possible future scenarios — as such, the results of the cost effectiveness analysis are not robustly supported and, therefore, are not competent, substantial evidence in support of these projects.

Q DO YOU HAVE ANY SPECIFIC CONCERNS WITH THE PROJECTED FUEL COST SAVINGS?

A Yes. The projected fuel prices underlying the fuel savings included in TECO's cost-effectiveness analysis are significantly higher than Henry Hub natural gas futures prices from the New York Mercantile Exchange (NYMEX) and projections produced by the Energy Information Administration (EIA), as shown in **Exhibit JL-2** and summarized in Table 2 on the following page. This levelized comparison is provided through 2036, reflecting the availability of Henry Hub natural gas futures data.

[7] *Id*. at 32.

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Table 2 Levelized Natural Gas Price Forecast 2024 Through 2036 ($/MMBtu)	
Description	**Levelized Cost***
TECO Base	$5.42
EIA Reference	$4.08
NYMEX Futures (30-Day Avg)	$3.97
NYMEX Futures (90-Day Avg)	$3.78
EIA High Oil & Gas Supply	$3.47

Sources: TECO Response to FIPUG POD 1-12; EIA 2023 Annual Energy Outlook (Table 13); S&P Global Market Intelligence.
* 7.41% Discount Rate.

Additionally, TECO assumes the proposed Future Solar Projects will generate energy at an average annual capacity factor of 26% in the first 10 operating years of each of these facilities, during which each facility would be eligible for PTCs, as well as over their expected lifetimes for the purposes of determining fuel cost savings. If these facilities fail to operate at such a level, the PTCs and system fuel savings associated with these projects would be diminished.

Q PLEASE DISCUSS THE EIA'S REFERENCE GAS FORECAST THAT IS INCLUDED IN TABLE 2.

A EIA's Reference natural gas price forecast reflects the agency's base case assumptions. Although the levelized amounts included in Table 2 show that the EIA Reference forecast is similar to the NYMEX Futures prices, the EIA has consistently overstated natural gas prices under its Reference forecast. This is documented in **Exhibit JL-3**, which compares the EIA's Reference natural gas price forecasts published in its Annual Energy Outlooks for the years 2017 – 2023 to actual spot gas

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prices over the time span. Further, the EIA has generally lowered its Reference gas forecast in successive editions of its Annual Energy Outlook. Consequently, little weight should be given to EIA's inflated Reference forecast. Because TECO's base natural gas forecast is even higher, it should also be disregarded.

Q WHAT IS THE EIA'S HIGH OIL AND GAS SUPPLY SCENARIO?

A EIA describes its High Oil and Gas Supply scenario as follows:

> In the High Oil and Gas Supply case, we assume the estimated ultimate recovery per well to be 50% higher than in the Reference case for:
>
> - Tight oil, tight gas, and shale gas in the Lower 48 States
> - Undiscovered resources in Alaska
> - Offshore Lower 48 states
>
> Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case. The Liquid Fuels Market Module (LFMM) assumes crude oil pipeline and export capacity increases in the projection period to accommodate higher levels of domestic oil production.[8]

Q HAVE EIA'S HIGH OIL AND GAS SUPPLY SCENARIOS PERFORMED BETTER THAN EIA'S REFERENCE FORECASTS?

A Yes. EIA's High Oil and Gas Supply scenario has consistently projected lower natural gas prices than its Reference forecasts. Therefore, although not perfect, this scenario provides a more accurate forecast. As shown in **Exhibit JL-2**, NYMEX futures prices converge with the EIA's High Oil and Gas Supply forecast in the early to mid-2030s.

Q WHAT ARE NYMEX FUTURE PRICES?

A NYMEX natural gas futures prices (depicted by the orange lines in **Exhibit JL-2**) are based on average closing prices of futures contracts traded through 2036 at the Henry

[8] U.S. Energy Information Administration, *Annual Energy Outlook 2023: Case Descriptions* at 6 (Mar. 2023).

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Hub. The 30-day average reflects the period from April 10 to May 21, 2024, and the 90-day average reflects the period from January 12 to May 21, 2024.

Q DO NYMEX FUTURES CONTRACT PRICES PROVIDE VALUABLE INFORMATION ABOUT FUTURE LONG-TERM ENERGY MARKET FUNDAMENTALS?

A Yes. Futures contracts are highly liquid in the near term, and futures prices are highly visible because they are widely disseminated by the various financial and commodity exchanges. Thus, futures contract prices are an important source of price discovery for sellers and producers.

Thus, futures contract prices are an essential tool for making future production and consumption decisions. Further, they represent actual transactions between buyers and sellers who put real money at risk in their day-to-day operations. The NYMEX futures prices are based on an actual market.

Q PLEASE SUMMARIZE YOUR ASSESSMENT OF TECO'S NATURAL GAS PROJECTION.

A TECO's natural gas forecast is significantly higher than forecasts developed by the EIA and NYMEX futures prices for natural gas reflecting actual market expectations. Therefore, the Commission should be wary of the purported fuel savings attributable to the Future Solar Projects, and consequently, the overall cost-effectiveness of these projects.

Q HOW SHOULD THE COMMISSION ASSESS THE COST-EFFECTIVENESS ANALYSIS OF THE FUTURE SOLAR PROJECTS?

A The Commission should be highly skeptical that customers will benefit from the Future Solar Projects. Even under TECO's analysis, the benefits of the Future Solar Projects

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are heavily reliant upon PTCs. When subjected to more scrutiny, it is clear that the projected benefits may not outweigh the projected costs, particularly if:

- Future commodity costs are lower than TECO has projected;
- Future Solar Project costs are more expensive than projected; and
- Future Solar Projects fail to produce energy at a 26% annual capacity factor over the first 10 years.

Therefore, if the Commission approves the Future Solar Projects, any rate base treatment should be contingent on providing specific and meaningful consumer protections.

<u>Consumer Protections</u>

Q RECOGNIZING YOUR CONCERNS ABOUT THE SENSITIVITIES IN TECO'S COST-EFFECTIVENESS ANALYSIS, IF THE COMMISSION APPROVES THE FUTURE SOLAR PROJECTS, SHOULD THE COMMISSION IMPOSE CONDITIONS TO ESTABLISH A MORE BALANCED RISK APPORTIONMENT BETWEEN TECO AND ITS CUSTOMERS?

A Yes. There are several measures that should be implemented to provide a more balanced risk apportionment, including:

- Imposing a cap on the construction costs;
- Establishing a performance standard for the Future Solar Projects; and
- Obtaining a guarantee or firm commitment that the Future Solar Projects are fully eligible to receive PTCs and that all PTCs (grossed up for income taxes) will be flowed through to customers.

Q WHAT COST CAP FOR THE FUTURE SOLAR PROJECTS DO YOU RECOMMEND?

A I recommend a cost cap of $1,609 per kW, which is TECO's projected capital cost of the proposed Future Solar Projects.

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Q SHOULD ANY ALLOWANCES BE REFLECTED IN THE CONSTRUCTION COST CAPS?

A No. The projected installed cost already includes $54 million of contingency allowances.[9]

Q WHAT PERFORMANCE STANDARDS WOULD HELP REBALANCE THE RISKS ASSOCIATED WITH THE PROPOSED FUTURE SOLAR PLANTS?

A As previously discussed, the amount of energy generated from the proposed Future Solar Projects is critical to determining the amount of PTCs that TECO will receive and whether, and to what extent, it would realize any fuel cost savings. The most logical performance standard would be to require that the Future Solar Projects achieve a minimum annual capacity factor. In the event that the minimum annual capacity factor standard is not met, ratepayers should be held harmless. That is, the Commission should evaluate the difference between the actual energy output of the Future Solar Projects against the energy that would be generated at a defined minimum annual capacity factor. If the actual amount of energy falls below the guaranteed level, the shortfall amount should be multiplied by the value of the grossed-up PTCs to determine the value of PTCs that should be provided to customers to be made whole. Similarly, the shortfall amount should also be multiplied by the locational marginal price settlement point for each of the Future Solar Projects to determine the amount of fuel savings that should be credited to customers through a future fuel proceeding.

[9] Prepared Direct Testimony and Exhibit of Kris Stryker at 8.

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Q WHAT MINIMUM ANNUAL CAPACITY FACTOR WOULD BE REASONABLE?

A Given that TECO's projections assume a 26% average annual net capacity factor, it would be reasonable to hold TECO to those projections.

Q HOW CAN THE COMMISSION ENSURE THAT TECO'S CUSTOMERS BENEFIT FROM THE PRODUCTION TAX CREDITS?

A First, as a prerequisite for recovering any of the investment, the Future Solar Projects should be required to qualify for the PTCs. Any portion of the investment that does not qualify should either be disallowed or not included in rate base. Alternatively, customers should be held harmless. This means that TECO should compensate customers for the value of the lost PTCs for any portion of the Future Solar Projects that do not fully qualify.

Second, the Commission should require that all PTCs (grossed up for income taxes) be included as offsets to TECO's base revenue requirements associated with each Future Solar Project that is placed into commercial operation and for which cost recovery is authorized.

Q WOULD IMPLEMENTING THESE PROTECTIONS ELIMINATE ALL RISKS TO TECO'S CUSTOMERS?

A No. As previously stated, the amount of any fuel savings will also depend on future natural gas prices. If natural gas prices are well below TECO's projections, the projected production cost savings may not fully materialize, even if the Future Solar Projects are built within budget, operate at the projected capacity factors and are fully eligible for PTCs.

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In summary, TECO's customers would continue to face significant risks of higher rates as a result of the Future Solar Projects, even if the recommended protections are implemented. However, the risk apportionment would be more appropriately balanced between customers and the utility.

Conclusion

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?

A Given the significant uncertainty surrounding the cost-effectiveness of the Future Solar Projects, the Commission should make the following findings:

- Implement a cost cap of $1,609 per kW for the Future Solar Projects.
- Establish a minimum annual capacity factor for the Future Solar Projects of 26%. In the event this minimum annual capacity factor is not met, TECO's customers should be held harmless for the capacity factor shortfall.
- Ensure that each portion of the Future Solar Projects that enters rate base fully qualifies for the PTCs projected by TECO.
- Require that all PTCs (grossed up for income taxes) be included as offsets to the base revenue requirements associated with the Future Solar Projects.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

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APPENDIX A
Qualifications of Jonathan Ly

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly. My business mailing address is 1314 Welch Street, Unit A, Houston, TX 77006.

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

A I am a regulatory consultant affiliated with J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I received a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley in 2013 and a Master's degree in Energy and Earth Resources from the University of Texas at Austin in 2017. In addition, I have completed a course in utility accounting and finance.

I joined J. Pollock, Incorporated in 2018 as an energy analyst assisting consultants in the preparation of financial and economic studies of investor-owned, cooperative, and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, integrated resource planning, and certificates of convenience and necessity. I began working as a regulatory consultant affiliated with J. Pollock, Incorporated in 2021 expanding upon my responsibilities and assignments in matters I had previously worked on as an energy analyst. I have been involved in various projects in multiple states including Arkansas, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming.

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Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jonathan Ly

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Association, Inc.	E-7. SUB 1304	Direct	NC	Fuel and Fuel-Related Cost Factors	5/23/2024
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Rebuttal	MI	Uncollectible Expense Allocation; Economic Breakeven Points	5/17/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Stipulation Support	NM	Stipulation Support regarding Long-Term Purchased Power Agreement and Ratemaking Treatment	5/10/2024
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Direct	MI	Class Cost-of-Service Study; Revenue Allocation; Rate Design	4/22/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Direct	NM	Long-Term Purchased Power Agreement; Ratemaking Requests	4/1/2024
LCRA TRANSMISSION SERVICES CORPORATION	Texas Industrial Energy Consumers	55867	Direct	TX	Wholesale Transmsision Rate	3/18/2024
MINNESOTA POWER	Large Power Intervenors	E-015/GR-23-155	Direct	MN	Advanced Metering Infrastructure; Class Revenue Allocation; Rider for Voluntary Renewable Energy	3/18/2024
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	23-G-0627	Direct	NY	Class Revenue Allocation; Rate Design	3/1/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00252-UT	Direct	NM	Certificate of Convenience and Necessity	12/1/2023
EL PASO ELECTRIC COMPANY	Texas Industrial Energy Consumers	54929	Direct	TX	Certificate of Convenience and Necessity	10/24/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revised Class Cost-of-Service Study; Class Revenue Allocation; Energy Assistance Program	8/4/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Surrebuttal	AR	Additional Sum associated with Power Purchase Agreements	7/20/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Direct	AR	Additional Sum associated with Power Purchase Agreements	6/8/2023
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Rebuttal	MI	Uncollectible Expense Allocator	5/8/2023
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Direct	MI	Class Cost-of-Service Study, Allocation of Other Distribution Plant; Average & Peak Versus Average & Excess Methods	4/17/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Surrebuttal	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	8/1/2022
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Direct	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	6/22/2022

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	**DOCKET NO. 20240026-EI** **Filed: June 6, 2024**

AFFIDAVIT OF JONATHAN LY

STATE OF TEXAS)
) SS
COUNTY OF HARRIS)

Jonathan Ly, being first duly sworn, on his oath states:

1. My name is Jonathan Ly. I am a regulatory consultant affiliated with J. Pollock, Incorporated which is located at 14323 S. Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. J. Pollock, Inc. has been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20240026-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jonathan Ly

Subscribed and sworn to before me this 5 day of June 2024.

ELDA YAZMIN MARTINEZ
Notary Public, State of Texas
Comm. Expires 04-02-2028
Notary ID 134833359

Elda Martinez

State of Texas, Notary Public

Commission #: 134833359

My Commission expires on 04-02-2028.

J.POLLOCK
INCORPORATED

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BY MR. MOYLE:

Q Have you prepared a summary of your testimony?

A Yes, I have.

Q Okay. And you also prepared Exhibits 1 to 3 with your testimony, is that right?

A That is correct.

Q Okay. Please provide your summary to the Commission and the parties.

A All right. Thank you.

Good morning, Commissioners. My Testimony addresses TECO's request for cost recovery for eight solar projects, which are collectively referred to as the Future Solar projects.

The Future Solar projects will collectively cost just under $800 million, and provide approximately 500 megawatts of capacity, resulting in a per unit cost of about $1,600 per kilowatt. These projects are expected to operate at an annual average capacity factor of 26 percent.

Although TECO has provided a cost-effectiveness analysis indicating that the benefits of the Future Solar projects would purportedly outweigh its capital costs by $322 million on a present value basis, my testimony demonstrates that there are reasons to view TECO's analysis with considerable skepticism.

Although the construction costs are relatively known, the purported benefits of these projects are based entirely on forecasts of future events. We question whether the claimed benefits will be realized, and given the uncertainty, suggest that key consumer protection measures be put in place.

The concerns expressed are based on a number of factors, specifically in first, the projected fuel prices underlying the fuel savings included in TECO's cost-effectiveness analysis are much higher than Henry Hub Natural Gas futures prices from the New York Mercantile Exchange, and projections produced by the Energy Information Administration. Because TECO's natural gas price assumptions are significantly higher than these data sources, the Commission should be wary of the purported fuel savings attributable to these projects, because they may be overstated if the assumed gas prices do not materialize.

Furthermore, the fuel savings are also sensitive to the level of output of the Future Solar projects. If these projects fail to operate at the projected capacity factor of 26 percent, these benefits would be further diminished.

Second, the production tax credits, or PTCs, generated by these plants comprise a significant portion of the suggested present value benefits of the Future Solar projects. These tax credits are generated for each kilowatt hour generated by the solar projects. Therefore, as was the case for the projected fuel savings, failure to generate at the projected capacity factor would similarly decrease the credits received.

Lastly, TECO's analysis assumes that a speculative carbon tax on fossil fuels would be implemented, and includes avoided carbon emissions in determining the benefits of the Future Solar project. Including these supposed speculative savings serves only to inflate the purported benefits of these facilities.

And given these uncertainties, the projected benefits of the Future Solar projects may not materialize if fuel commodity prices and improbable carbon tax rates are lower than TECO projected if the projects fail to produce energy at the expected level of generation, or if the projects are more expensive than estimated. Therefore, should the Commission approve the Future Solar projects, it should consider implementing three consumer protections.

First, I recommend that the Commission impose a cap on construction costs of approximately $1,600 per kilowatt. This is based on TECO's current estimated construction costs, inclusive of financing costs.

Second, a performance standard should be established for the Future Solar projects, specifically if the projects do not produce electricity at a 26-percent annual capacity factor as projected, TECO should, nonetheless, pass through the PTCs as if the resources had achieved the projected capacity factor.

Third, TECO should guarantee or commit that the Future Solar projects are fully eligible to receive PTCs, and that all PTCs will be flowed through to customers. In the event that TECO does not qualify for all the PTCs, the Commission should, nonetheless, hold customers harmless by requiring TECO to compensate and credit customers for the lost and forgone PTCs.

These three consumer protections will not eliminate all risks to TECO's customers, since they would still be exposed for risk related to natural gas prices, but they will more appropriately balance new solar plant risk between TECO and its customers.

Finally, I would add that this commission would not be alone in imposing consumer protections where the benefits of a planned resource are based on future assumptions. I am familiar with several generating projects in Texas in which similar measures as recommended here have been implemented.

In addition, the Commission last week approved a number of solar project related consumer protections in the Duke rate case settlement --

MR. WAHLEN: I am going to object. We have had a long discussion about how there is not going to be a discussion about the Duke settlement agreement, and now this witness is trying to talk about the Duke settlement agreement. It's not relevant. It's not in his testimony. It could not be in his testimony because the settlement was not approved until last week, and his testimony was prefiled. It is not fair summary. It's inappropriate and should be stricken from the record.

CHAIRMAN LA ROSA: Yeah. So I am going to sustain the objection. I am going to ask FIPUG if you can ask your witness to bifurcate and not discuss the Duke settlement and summarize just what's in the testimony that he has provided.

MR. MOYLE: Yeah, I think -- there has been a lot of discussion on this point, in fairness of the witness --

CHAIRMAN LA ROSA: Sure --

MR. MOYLE: -- and I think he prepared --

CHAIRMAN LA ROSA: -- 100 percent.

MR. MOYLE: -- his remarks beforehand. Didn't know how the ruling was going to go on that, you know, I think it's a fairly debatable issue, but --

BY MR. MOYLE:

Q Why don't you not mention the Duke settlement at this point and wrap up your comments, if you would please, Mr. Ly.

A Yeah. That actually just about took me to the end of the summary.

Thank you for the opportunity to present this summary of my testimony. That's all I have to add.

MR. MOYLE: Okay. Mr. Ly is available for cross.

CHAIRMAN LA ROSA: Sure. Thank you.

Start with OPC.

MR. REHWINKEL: No questions.

CHAIRMAN LA ROSA: Florida Rising.

MS. LOCHAN: Thank you, Mr. Chairman.

EXAMINATION

BY MS. LOCHAN:

Q Hello, Mr. Ly. I do have a few questions. It should go by pretty quickly.

Generally speaking, would you agree that the benefits of solar are largely dependent on the price of fuel avoided, in this case, natural gas?

A Yeah. I would say that that's the largest driver of the projected benefits.

Q Great.

So if natural gas prices are lower than TECO's forecast, cost-effectiveness goes down?

A That is correct.

Q And if natural gas prices are higher than TECO's forecast, the cost-effectiveness goes up?

A That is also correct.

Q And that's because the avoided costs from not having to pay for that fuel has increased, resulting in additional savings.

A Yes.

Q So solar is able to avoid that fuel being burned because of the energy it generates?

A Yes.

Q Thank you. Those are all my questions.

A All right. Thank you.

CHAIRMAN LA ROSA: Thank you.

FEA.

CAPTIAN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: Florida Retail.

MR. LAVIA: No questions. Thanks.

CHAIRMAN LA ROSA: Walmart.

MR. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions.
CHAIRMAN LA ROSA: Staff.
MR. SPARKS: No questions.
CHAIRMAN LA ROSA: Commissioners, questions?
All right. Seeing none, let's send it back to FIPUG for redirect.
MR. MOYLE: We don't have any redirect questions, and we would like to move Mr. Ly's exhibits in. He had three exhibits. They were marked as 1 to 3, and I believe it's 88 to 90 on the Comprehensive Exhibit List.
CHAIRMAN LA ROSA: Is there objections to those?
Seeing none, show them entered into the record.
(Whereupon, Exhibit Nos. 88-90 were received into evidence.)
CHAIRMAN LA ROSA: Are there any other exhibits?
Seeing none, Mr. Ly, thank you. You are excused.
THE WITNESS: All right. Thank you for your time.
CHAIRMAN LA ROSA: Thank you.
MS. HELTON: Mr. Chairman, we are a little bit

confused about whether his testimony was inserted into the record, so maybe just in an abundance of caution --

CHAIRMAN LA ROSA: Yeah. Yeah. Yeah. So I would like to strike the portions of the testimony that he just -- is that what you are referring to?

MS. HELTON: No, sir. I am talking about his prefiled testimony.

CHAIRMAN LA ROSA: Okay. It was, but you want to make that --

MR. MOYLE: We can do it twice. We move --

MS. HELTON: Okay.

MR. MOYLE: -- his testimony in.

CHAIRMAN LA ROSA: All right. Let the record reflect that. Okay.

MR. REHWINKEL: Mr. Chairman.

CHAIRMAN LA ROSA: Yes, sir.

MR. REHWINKEL: Has he been excused?

CHAIRMAN LA ROSA: Well, I started to excuse him, so...

THE WITNESS: I am still not sure if I am excused.

CHAIRMAN LA ROSA: Yeah. Does he need to be excused? Do you have a question relating to him, or --

MR. REHWINKEL: No, I was going to pick up a housekeeping matter if he was excused.

CHAIRMAN LA ROSA: Okay. Let's go ahead and allow the witness to be excused. You are excused, Mr. Ly.

THE WITNESS: All right. Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: All right. Let's --

MR. REHWINKEL: All right.

CHAIRMAN LA ROSA: Go ahead.

MR. REHWINKEL: Dr. Woolridge has completed his deposition that we informed you about, and he is available if you would like to take him up now.

CHAIRMAN LA ROSA: I do.

MR. REHWINKEL: Okay.

CHAIRMAN LA ROSA: Before we do that -- let's get him prepared -- FEA has two witnesses that need to be moved into the record, right, because they have been excused?

CAPTIAN GEORGE: Yes, Mr. Chairman. And if it's possible, can we just do all of ours --

CHAIRMAN LA ROSA: Yep. I am -- yeah.

CAPTIAN GEORGE: -- together with our witness who is here?

CHAIRMAN LA ROSA: Yes. So let's hold on

that, and then let's go back to OPC and allow them to introduce their witness, and then we will --

CAPTIAN GEORGE: Okay. Thank you.

CHAIRMAN LA ROSA: -- come back and do that when you have your last witness.

MS. CHRISTENSEN: Thank you, Mr. Chairman.

CHAIRMAN LA ROSA: Sure. I just need to swear the witness in.

MS. CHRISTENSEN: Yes, please.

CHAIRMAN LA ROSA: Do you mind standing and raising right hand?

Whereupon,

J. RANDALL WOOLRIDGE

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 LA ROSA: Excellent. Thank you.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning.

A Morning.

Q Dr. Woolridge, can you please state your name and business address for the record?

A My name is the initial J. Randall Woolridge, and that's spelled W-O-O-L-R-I-D-G-E. I am a professor of finance at the Pennsylvania State University.

Q And did you cause to be filed prefiled direct testimony consisting of 119 pages with cover sheets?

A I did.

Q Do you have any corrections to your testimony?

A No.

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

A That is correct.

MS. CHRISTENSEN: I would ask that Dr. Woolridge's testimony be entered into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of J. Randall Woolridge was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition rate increase by Tampa Electric Company
_____________________________________/

Docket No. 20240026-EI

Filed: June 6, 2024

DIRECT TESTIMONY

OF

J. RANDALL WOOLRIDGE. PH. D.

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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of the State of Florida

C24-2378

DIRECT TESTIMONY

OF

J. RANDALL WOOLRIDGE, Ph.D.

ON BEHALF OF THE CITIZENS OF

THE STATE OF FLORIDA

Docket No. 20240026-EI

I. IDENTIFICATION OF WITNESS AND PURPOSE OF TESTIMONY

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

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

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

A. I have been asked by the Florida Office of Public Counsel ("OPC") to provide an opinion as to the appropriate return on equity for Tampa Electric Company ("TECO" or "Company") and to evaluate TECO's rate of return testimony in this proceeding.

C24-2379

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review my cost of equity recommendation for TECO, highlight several factors that have changed since the Company's last rate case, and discuss the primary areas of contention between TECO's rate of return position and my position. Second, I provide an assessment of capital costs in today's capital markets. Third, I discuss the selection of a proxy group of electric utility companies for estimating the market cost of equity for TECO. Fourth, I discuss the relationship between a utility's capital structure and the return on equity that should be associated with that capital structure. Fifth, I provide an overview of the concept of the cost of equity capital, and then estimate the equity cost rate for TECO. Finally, I evaluate the Company's rate of return analysis and testimony.

II. OVERVIEW AND SUMMARY OF POSITIONS

A. Overview

Q. WHAT COMPRISES A UTILITY'S "RATE OF RETURN"?

A. A company's overall rate of return consists of three main categories: (1) capital structure (i.e., ratios of short-term debt, long-term debt, preferred stock and common equity); (2) cost rates for short-term debt, long-term debt, and preferred stock; and (3) common equity cost rate, otherwise known as return on equity ("ROE").

Q. WHAT IS A UTILITY'S ROE INTENDED TO REFLECT?

A. A ROE is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products/services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and/or products. For a regulated monopoly, the regulator determines the level of profit available to the utility. The United States Supreme Court established the guiding principles for establishing an appropriate level of profitability for regulated public utilities in two cases: (1) *Bluefield* and (2) *Hope*.[1] In those cases, the Court recognized that the fair rate of ROE should be: (1) comparable to returns investors expect to earn on investments with similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain the company's credit and to attract capital.

Thus, the appropriate ROE for a regulated utility requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of all of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate, using market data of similar-risk firms, the rate of return equity investors require for that risk class of firms in order to set an appropriate ROE for a regulated firm.

[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*") and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

A. Summary of Positions

Q. PLEASE REVIEW THE COMPANY'S PROPOSED RATE OF RETURN.

A. TECO has proposed a capital structure from investor-provided capital of 42.57% long-term debt, 3.90% short-term debt, and 54.00% common equity. The Company has recommended long-term and short-term debt cost rates of 4.53% and 3.90%. TECO Witness Dylan W. D'Ascendis has recommended a common equity cost rate of 11.50% for TECO.

Q. PLEASE SUMMARIZE TECO'S OVERALL PROPOSED RATE OF RETURN.

A. TECO's overall rate of return request is 8.27% from investor-provided capital and is summarized in Table 1.

Table 1
TECO Rate of Return Recommendation from Investor-Provided Capital

Capital Source	Capitalization Amount	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long Term Debt	$ 3,536,333	41.57%	4.53%	1.88%
Short Term Debt	376,625	4.43%	3.90%	0.17%
Common Equity	4,593,473	54.00%	11.50%	6.21%
Totals	$ 8,506,431	100.00%		8.27%

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR TECO?

A. I have reviewed the Company's proposed capital structure and overall cost of capital. TECO's proposed capitalization has more equity and less financial risk than the average current capitalizations of the proxy groups. The Company's proposed capital structure includes a higher common equity ratio (54.00%) than the average of the two proxy groups. Nonetheless, while I am not contesting adopting this capital structure in this testimony, I have selected a ROE that recognizes this high common equity ratio. I am also not contesting the Company's short-term and long-term debt cost rates. To estimate an equity cost rate for the Company, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to two proxy groups: (1) my group of publicly-held electric utility companies ("Electric Proxy Group"); and (2) the group developed by Mr. D'Ascendis ("D'Ascendis Proxy Group"). My analysis indicates a common equity cost rate in the range of 8.85% to 10.00% for TECO in this case. Given that I rely primarily on the DCF model and the results for the Electric Proxy Group, I believe that the appropriate ROE range for the Company is a range of 9.25%-9.75% . I am recommending a ROE of 9.50% providing that: (1) TECO's investment risk is a little below the average of the two groups; and (2) I have employed a capital structure that has more common equity and less financial risk than the average of the two proxy groups, as well as TECO's parent, Emera. Given this ROE and my proposed capital structure and debt cost rates for TECO, I am recommending an overall fair rate of return or cost of capital of 7.19% for TECO. This recommendation is summarized in Table 2 and Exhibit JRW-1.

Table 2
OPC's Rate of Return Recommendation from Investor Capital

Capital Source	Capitalization Amount	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Long Term Debt	$ 3,536,333	41.57%	4.53%	1.88%
Short Term Debt	376,625	4.43%	3.90%	0.17%
Common Equity	4,593,473	54.00%	9.50%	5.13%
Totals	$ 8,506,431	100.00%		7.19%

B. Primary Rate of Return Issues in this Case

Q. PLEASE PROVIDE AN OVERVIEW OF THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. The primary issues related to the Company's rate of return include the following:

1. **<u>TECO's Assessment of Capital Market Conditions</u>**: Mr. D'Ascendis' analyses, ROE results, and recommendations are based on assumptions of higher interest rates and capital costs. However, despite the increase in inflation and interest rates over the past two years, there are several factors suggesting the equity cost rate for utilities have not risen significantly. To support this contention, I show that: (1) despite the higher inflation over the past two years, long-term inflation expectations are about 2.35%; (2) the yield curve is currently inverted – which suggests that investors expect yields to decline and that a recession in the next year is very likely, which would also put downward pressure on interest rates; and (3) while authorized ROEs for utilities hit all-time lows in 2020 and 2021, these ROEs did not decline nearly as much as interest rates during those years. Hence, now that interest rates have increased, authorized ROEs have not increased at the same magnitude as interest rates.

2. **<u>Capital Structure</u>** – As I have just noted, TECO's proposed capital structure has much more equity and less financial risk than the average capital structure of the two proxy groups as well as TECO's parent company, Emera. As a result, while I am not contesting this capital structure, I have also recommended a ROE that reflects TECO's capital structure with a relatively high common equity ratio and low financial risk.

3. **<u>TECO's Investment Risk is a Little Below the Average of the Two Proxy Groups</u>** TECO's issuer credit rating is BBB+ according to S&P and A3 according to Moody's.

The average S&P and Moody's ratings for the two proxy groups are BBB+ and Baa2. As such, TECO's S&P rating is equal to the average of the two proxy groups, and TECO's Moody's rating is two notches above the average of the two proxy groups. This indicates that TECO is a little less risky than the average of the two proxy groups. Mr. D'Ascendis has recognized that TECO is less risky than his proxy group.

4. **<u>DCF Equity Cost Rate</u>** - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. There are two issues with Mr. D'Ascendis' DCF study: first, he gives little weight to his DCF results. His mean DCF result for his proxy group is 9.89%, yet he concludes that TECO's cost of equity is 11.50%. Second, he relies exclusively on the overly optimistic and upwardly biased growth-rate forecasts for earnings per share ("EPS") put forth by Wall Street analysts and *Value Line*.

I also have used a traditional constant-growth DCF model. In developing a growth rate for my DCF model for the proxy group, I have reviewed thirteen growth-rate measures including historic and projected growth-rate measures and have evaluated growth in dividends, book value, and earnings per share. I give primary weight to analysts' projected EPS growth rates.

5. **<u>Risk Premium Approach</u>**: The equity cost rate using the risk-premium model is the sum of the base interest rate yield plus a risk premium. With respect to the market-risk premium, Mr. D'Ascendis has employed six different approaches to estimate the market-risk premium. In three of his methods, he uses historical stock and bond return data. In the other three of his approaches, he bases his market-risk premium on his estimate of projected stock-market returns. As I further explain in my critique of

TECO's rate-of-return analysis later in my testimony, there are a number of empirical issues with using historical stock and bond returns to estimate an expected market risk premium. In addition, Mr. D'Ascendis' projected market returns are based on highly unrealistic assumptions about future earnings and economic growth and the resulting stock returns. First, I have conducted a study that shows Mr. D'Ascendis' estimate of the average expected stock market return of 15.60% is more than double the average annual stock return (6.87%) that investment firms are telling investors to expect over the next ten years. Second, as I demonstrate later in my testimony, the EPS growth-rate projection (14.10%) used for the S&P 500 and the resulting expected market return (15.60%) and market risk premium (11.45%) includes unrealistic assumptions regarding future economic and earnings growth and stock returns. On this point, Mr. D'Ascendis makes the assumption that the companies in the S&P 500 can grow their earnings, on average, at 14.10% annually, which is nearly triple the long-term projected growth rate of the economy as measured by Gross Domestic Product ("GDP").

6. **<u>CAPM Approach</u>**: The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are two primary issues with Mr. D'Ascendis' CAPM analyses: first, he has used a non-traditional CAPM approach, the empirical CAPM (ECAPM), as an equity-cost-rate approach. Second, and most significantly, his CAPM market-risk premium of 10.02% is developed by the same six approaches he used in his Risk-Premium approach I noted above. The market risk premium of 10.02% is larger than: what is indicated by historic stock and bond return data and what is found in the published studies and surveys of the market risk premium. In addition, I will demonstrate that the 10.02% CAPM market risk premium is based on totally unrealistic assumptions of future economic and earnings growth and stock returns.

As I highlight in my testimony, there are three commonly used procedures for estimating a market risk premium: historic returns, surveys, and expected return models. I have used a market risk premium of 5.25%, which factors in all three approaches—historic returns, surveys, and expected return models—to estimate a market premium and that employs the results of many studies of the market risk premium. As I note, the 5.25% figure reflects the market risk premiums: (1) determined in recent academic studies by leading finance scholars; (2) employed by leading investment banks and management consulting firms; and (3) found in surveys of companies, financial forecasters, financial analysts, and corporate CFOs.

7. **<u>Equity Cost Rate Models Applied to Non-Price Regulated Companies</u>**: Mr. D'Ascendis also estimates an equity cost rate by applying his equity-cost-rate approaches and methodologies to a group of what he refers to as "comparable risk" non-price regulated companies. As I note in the rebuttal section of this testimony, these companies are not truly comparable to TECO and Mr. D'Ascendis' analyses are based on the same flawed approach summarized above.

8. **<u>Other Issues</u>**: Mr. D'Ascendis includes a flotation cost adjustment of 0.10% in his ROE analysis and recommendation. However, there is no evidence that TECO has paid flotation costs. Hence, TECO should not receive higher revenues in the form of a higher ROE for flotation costs that the Company does not incur.

C24-2387

III. CAPITAL MARKET CONDITIONS AND AUTHORIZED ROES

A. Capital Market Conditions

Q. PLEASE PROVIDE A SUMMARY OF THE UTILITY CAPITAL MARKET INDICATORS IN EXHIBIT JRW-2.

A. Page 1 of Exhibit JRW-2 shows the yields on Baa rated public utility bonds. These yields have gradually declined in the past decade from 7.5% to the 3.0% range. These yields bottomed out in the 3.0% range in 2020 and 2021 due to the economic fallout from the COVID-19 pandemic. These yields increased with interest rates in general in 2022, 2023, and 2024 and now are in the 5.75% range in 2024.

Page 2 of Exhibit JRW-2 shows the average dividend yield for electric utilities. These yields declined over the past decade, bottoming out at 3.1% in 2019. They have increased since that time, and the average was 3.9% as of 2023.

Page 3 of Exhibit JRW-2 provides the average earned ROEs and market-to-book ratios for electric utilities. The average earned ROE has been in the 9.0% to 10.0% range over the past five years. The average market-to-book ratio increased over the last 13 years, peaked at 2.0X in 2019, declined to the 1.75X range in 2020-2022, and declined to 1.50X in 2023.

Q. PLEASE REVIEW INTEREST RATE MOVEMENTS IN RECENT YEARS.

A. Figure 1, below, shows 30-year Treasury yields over the past 15 years (2010 to 2024). These yields were in the 3.0% range at the end of 2018. They declined to the 2.25% range in 2019 due primarily to slow economic growth and low inflation. In 2020, with the advent of the COVID-19 pandemic in February of that year, 30-year Treasury yields declined to record low levels, dropping about 100 basis points to settle in the 1.25% range. They began their recovery in the summer of 2020 and increased to the 2.00% - 2.50% range in 2021. They increased significantly in 2022 and 2023 with the improving economy and higher inflation. In 2023, these yields increased from 3.50% to 5.00%. In 2024, these yields have since deceased and currently are in the 4.50% - 4.75% range.

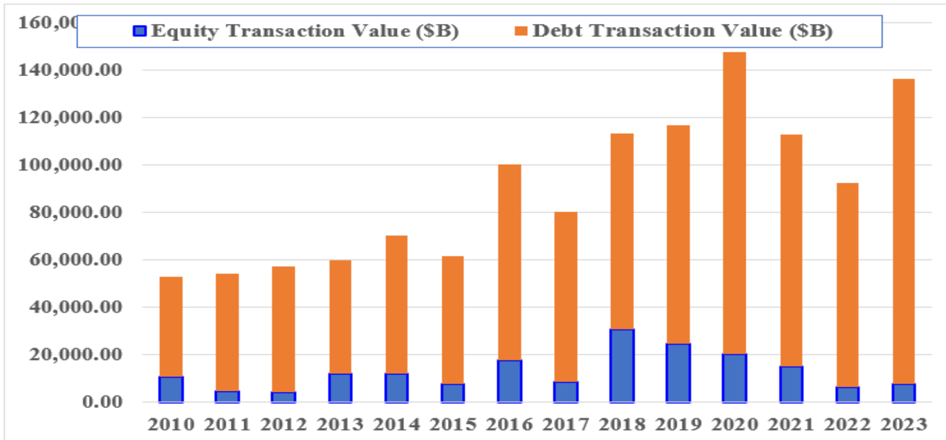
Figure 1
30-Year Treasury Yields

Data source: https://fred.stlouisfed.org/series/DGS30.

Q. DID UTILITIES TAKE ADVANTAGE OF THE RECORD LOWER BOND YIELDS IN 2020 AND 2021 TO RAISE CAPITAL?

A. Yes. Figure 2 shows the annual amounts of debt and equity capital raised by public utility companies over the past 13 years. Electric utility and gas distribution companies have taken advantage of the low interest rate and capital cost environment of recent years and raised record amounts of capital in the markets. In fact, in four of the past five years, public utilities have annually raised more than $100 billion in combined debt and equity capital.

Figure 2
Debt and Equity Capital Raised by Public Utilities
2010–2023



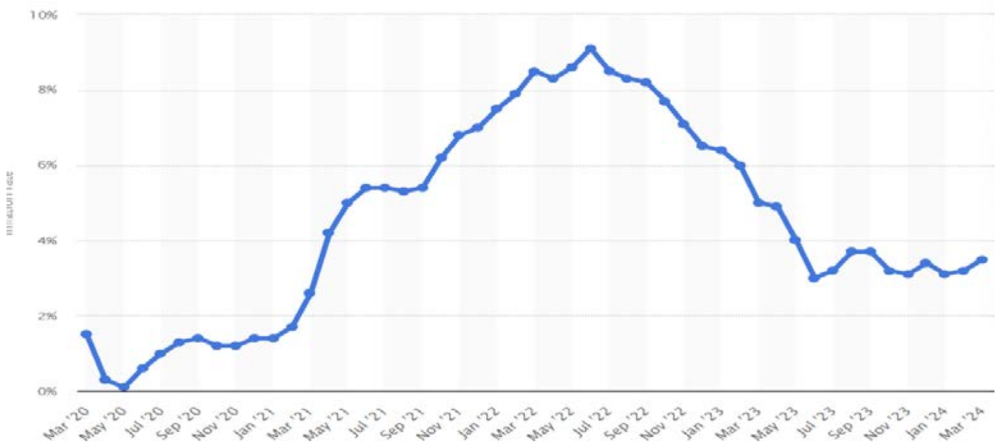
Data Source: S&P Global Market Intelligence, S&P Cap IQ, 2024.

Q. PLEASE DISCUSS THE INCREASE IN INTEREST RATES SINCE THE BEGINNING OF 2022.

A. Several factors led to higher interest rates since 2022. Coming out of the pandemic, real GDP growth has increased 5.95% in 2021, 2.06% in 2022, and 3.25% in 2023, compared to a decline of -3.4% in 2020. This recovery led to greater business activity, higher levels of business and consumer spending, and large increases in housing prices. Unemployment was 6.7% in 2020 and has steadily declined to the 3.5% - 4.0% range in 2024. The recovery in the economy puts upward pressure on interest rates by increasing the demand for capital.

In addition, as reported extensively in the financial press, inflation picked up significantly in 2022, putting additional pressure on interest rates. Reported year-over-year inflation has been as high as 9.20% in 2022. Year-over-year inflation declined since that time, bottoming out at 3.10% in January of 2024 and has since increased to 3.40% in April of 2024. The high inflation reported in the past two years primarily reflects three factors: (1) the recovering and growing U.S. economy; (2) the production shutdowns during the pandemic, which led to supply chain shortages as the global economy has recovered; and (3) the war in Ukraine, which has led to higher energy and gasoline prices worldwide.

Figure 3
Year-Over-Year Inflation Rates
2020-2024



Source: https://www.statista.com/statistics/273418/unadjusted-monthly-inflation-rate-in-the-us/

In response to the higher inflation, the Federal Reserve in 2022 increased the discount rate by 25 basis points in March, 50 basis points in May, 75 basis points in June, July, September, and November, 50 basis points in December, and 25 basis points in February, March, May, and July of 2023. Since the last rate increase, the Federal Reserve has held the discount rate steady while monitoring economic activity, with the expectation that once inflation falls to the target 2.0% range, the Federal Reserve will begin cutting the discount rate.

Investors' inflation expectations can be seen by looking at the difference between yields on ordinary Treasuries and the yields on inflation-protected Treasuries, known as TIPS. Figure 4 shows the expected inflation rate over the next five, ten, and thirty years. One can see that the expected inflation rate has declined since 2022 and is now at an expected inflation rate of 2.35% over the next five years. The expected inflation rates over the next ten and thirty years are also in the 2.35% range. The bottom line is that the expected long-term inflation rate is around 2.35%.

Figure 4
5-Year, 10-Year, and 30-Year Breakeven Inflation Rates

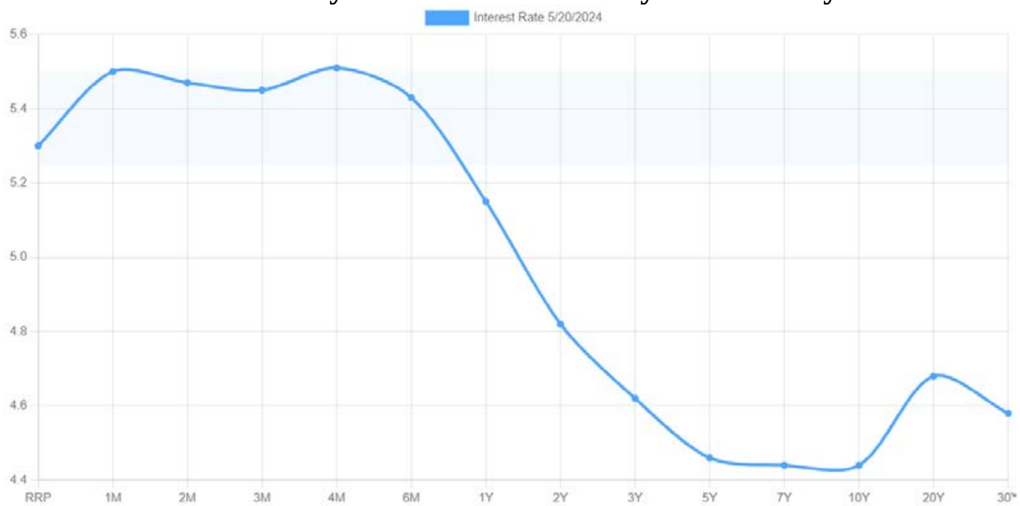
Date source: https://fred.stlouisfed.org/.

Q. DO YOU BELIEVE THAT INTEREST RATES WILL INCREASE IN 2024?

A. No. As discussed above, the current inflationary environment has pushed up interest rates over the past year. Also, as noted above, the Federal Reserve has responded with a series of discount rate increases, intended to slow the economy and cool down inflation, which would lower interest rates. Figure 5 shows the yield curve, which plots the yield-to-maturity and time-to-maturity for Treasury securities. The yield curve is usually upward sloping because investors require higher returns to commit capital for longer periods of time. Currently, the yield curve is said to be "inverted," which means that the yields on shorter-term maturity securities are higher than the yields on longer-term securities. This means that investors do not expect interest rates to remain where they are and expect that they should decline.

C24-2392

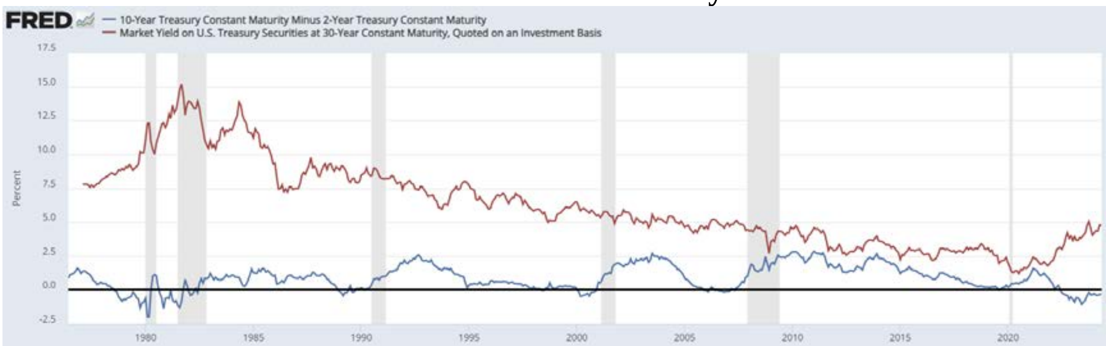
Figure 5
The Yield Curve
The Yield-to-Maturity and Time-to-Maturity for Treasury Securities



Source: https://www.ustreasuryyieldcurve.com/ - 5-20-24.

The financial press has focused on another aspect of an inverted yield curve. An inverted yield curve also is an indicator of a pending recession, which would also put downward pressure on interest rates. An inverted yield curve is usually indicated when the 2-year Treasury yield is above the 10-year Treasury yield. Figure 6 graphs two lines: (1) the 10-year Treasury yield minus the 2-year Treasury yield (blue line); and (2) the 30-year Treasury yield (red line). In Figure 6, the shaded areas are economic recessions, defined as two-straight quarters with negative GDP growth. In Figure 6, one can see that every time the yield curve inverted (2-year > 10-year) in the last 50 years, a recession followed. In addition, one can see that interest rates, as indicated by the 30-year Treasury yield in Figure 6, decline during recessions. Since the yield curve is currently inverted, a recession and lower interest rates are likely to follow.

Figure 6
Treasury 10-Year Minus 2-Year Yields
And the 30-Year Treasury Yield



Source: https://fred.stlouisfed.org/series/T10Y2Y

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE CURRENT CAPITAL MARKET SITUATION.

A. The U.S. economy, as measured by nominal GDP, declined 20% in the first half of 2020, rebounded significantly in 2021, and continued to rebound in 2022 and 2023. This rebound has seen big increases in consumer and business spending, lower unemployment, and higher housing prices. The rebounding economy has put pressure on prices, which has been further exacerbated by the post-COVID-19 supply chain issues and the higher energy prices brought on by the Russia-Ukraine conflict. In recent months, market participants have been focusing on economic growth, the labor market and unemployment, and inflation in anticipation of a cut in the discount rate by the Federal Reserve. Such a discount rate cut would signal that the Federal Reserve believes its target inflation rate of 2.0% is within range.

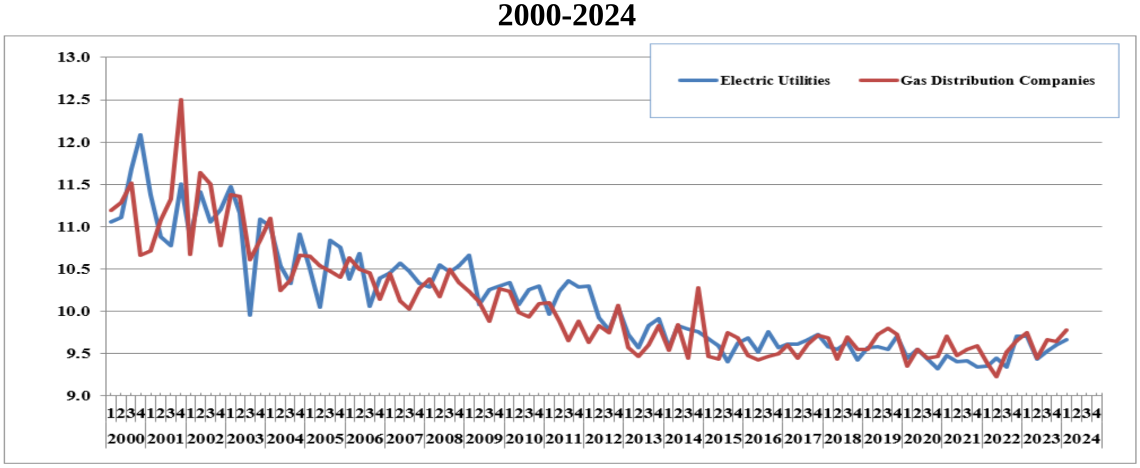
While utilities did take advantage of the low yields in 2020 and 2021 to raise record amounts of capital, the big economic issue has been reported inflation and interest rates. However, while year-over-year inflation has remained above the 2.0% target, the yields on TIPS suggest that longer-term inflationary expectations are still about 2.35%. In addition, as I note above, with an inverted yield curve, the prospect of a recession is likely, which would lead to lower interest rates.

B. Authorized ROEs

Q. PLEASE DISCUSS THE TREND IN AUTHORIZED ROES FOR ELECTRIC AND GAS COMPANIES.

A. In 2020 and 2021, authorized ROEs for utilities hit an all-time low as the low interest rate and capital cost environment put downward pressure on authorized ROEs.[2] Figure 7 reflects the authorized ROEs for electric utility and gas distribution companies from 2000-2023. The authorized ROEs have trended downward with interest rates and capital costs in the past 15 years. The average authorized ROEs fell below 10% for electric utilities in 2012. Table 3 shows the average annual authorized ROEs for electric utility and gas distribution from 2010 to the first quarter of 2024.

Figure 7
Authorized ROEs for Electric Utilities and Gas Distribution Companies
2000-2024



Data Source: S&P Global Market Intelligence, RRA *Regulatory Focus*, 2024.

Table 3
Average Annual Authorized ROEs for Electric Utilities

[2] The data and numbers discussed in this section come from S&P Global Market Intelligence, RRA *Regulatory Focus*, 2024.

and Gas Distribution Companies
2010–2024

	Electric	Gas		Electric	Gas
2010	10.37	10.15	2017	9.74	9.72
2011	10.29	9.92	2018	9.65	9.59
2012	10.17	9.94	2019	9.66	9.72
2013	10.03	9.68	2020	9.44	9.47
2014	9.91	9.78	2021	9.38	9.56
2015	9.78	9.6	2022	9.54	9.53
2016	9.77	9.54	2023	9.60	9.64
			Q1-2024	9.66	9.78

Data Source: S&P Global Market Intelligence, RRA Regulatory Focus, 2024.

Q. PLEASE REVIEW THE AUTHORIZED ROES IN FLORIDA RELATIVE TO AUTHORIZED ROES IN THE U.S.

A. In Table 4, I show the authorized ROEs for electric and gas utilities in Florida over the 2010-2024 time period. I have several observations on these ROEs:

1. Authorized ROEs in Florida have consistently been above the average authorized ROEs for electric utilities in the U.S;
2. Prior to the pandemic (2020-2021), the authorized electric ROEs in Florida were in the 10.25%-10.50% range, about 75 basis points above the national averages;
3. During the pandemic, the authorized electric ROEs in Florida declined to the 9.85%-9.95%; and
4. Since the pandemic, electric ROEs in Florida have increased and have been in the 10.10%-10.80% range.

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Table 4
Florida Authorized ROEs for
Electric Utility and Gas Distribution Companies
2010-24

Company	*Parent*	*Docket*	*Service Type*	*Date*	*Decision Type*	*Rate Increase ($M)*	*ROE (%)*	*Common Equity (%)*
Duke Energy Florida LLC	DUK	D-090079-EI	Electric	3/5/2010	Settled	126.2	10.50	46.74
Florida Power & Light Co.	NEE	D-080677-EI	Electric	3/17/2010	Settled	75.5	10.00	47.00
Duke Energy Florida LLC	DUK	D-120022-EI	Electric	2/22/2012	Settled	150.0	NA	NA
Gulf Power Co.	NEE	D-110138-EI	Electric	2/27/2012	Litigated	68.1	10.25	38.50
Florida Power & Light Co.	NEE	D-120015-EI	Electric	12/13/2012	Settled	350.0	10.50	NA
Tampa Electric Company	EMA	D-130040-EI	Electric	9/11/2013	Settled	70.0	10.25	42.00
Gulf Power Co.	NEE	D-130140-EI	Electric	12/3/2013	Settled	55.0	10.25	NA
Florida Public Utilities Co.	CPK	D-140025-EI	Electric	9/15/2014	Settled	3.8	10.25	NA
Florida Power & Light Co.	NEE	D-160021-EI	Electric	11/29/2016	Settled	811.0	10.55	NA
Gulf Power Co.	NEE	D-160186-EI	Electric	4/4/2017	Settled	62.0	10.25	NA
Duke Energy Florida LLC	DUK	D-20170183-EI	Electric	10/25/2017	Settled	200.0	NA	NA
Tampa Electric Company	EMA	D-20170210-EI	Electric	11/6/2017	Settled	0.0	10.25	NA
Pivotal Utility Holdings	NEE	20170179-GU	Natural Gas	3/26/2018	Settled	15.3	10.19	48.00
Duke Energy Florida LLC	DUK	D-20180084-EI	Electric	7/10/2018	Settled	200.5	NA	NA
Duke Energy Florida LLC	DUK	D-20180149	Electric	4/2/2019	Settled	29.2	10.50	NA
Peoples Gas System	EMA	D-20200051-GU	Natural Gas	11/19/2020	Settled	58.0	9.90	54.70
Duke Energy Florida LLC	DUK	D-20210016-EI	Electric	5/4/2021	Settled	195.4	9.85	44.84
Tampa Electric Company	EMA	D-20210034-EI	Electric	10/21/2021	Settled	302.4	9.95	45.07
Florida Power & Light Co.	NEE	D-20210015-EI	Electric	10/26/2021	Settled	1,252.0	10.60	NA
Tampa Electric Company	EMA	D-20220122-EI	Electric	8/16/2022	Settled	10.0	10.20	NA
Duke Energy Florida LLC	DUK	D-20220143-EI	Electric	10/4/2022	Settled	24.4	10.10	NA
Florida Power & Light Co.	NEE	20210015 - ROE	Electric	10/4/2022	Settled	0.0	10.80	NA
Tampa Electric Company	EMA	D-20220148	Electric	12/6/2022	Settled	91.0	10.20	45.07
Florida Public Utilities Co.	CPK	D-20220067-GU	Natural Gas	1/24/2023	Litigated	17.2	10.25	45.16
Peoples Gas System	EMA	D-20230023-GU	Natural Gas	11/9/2023	Litigated	106.7	10.15	NA

Date Source: S&P Global Market Intelligence, RRA *Regulatory Focus*, 2024

Q. PLEASE REVIEW THE COMMISSION'S COST OF CAPITAL DETERMINATION IN TECO'S MOST RECENT RATE CASE.

A. On December 6, 2022, in Docket No**.** 20220148-EI**,** the Commission approved a settlement between TECO and intervening parties which included a ROE of 10.25%.

Q. DID THE HIGHER INTEREST RATES IN 2022 AND 2023 MEAN THAT AUTHORIZED ROES MUST INCREASE IN LINE WITH INTEREST RATES?

A. Not necessarily. As noted above, authorized ROEs for utilities reached record low levels in 2020 and 2021 due to the record low interest rates and capital costs. However, authorized utility ROEs never declined to the same extent that interest rates declined in these two years. Table 5 shows the average annual 30-year Treasury yields and authorized ROEs for electric utility companies from 2018-2023. In Table 5, I have averaged the 2018-2019 (pre-COVID-19 period) figures and the 2020-2021 (COVID-19 period) figures for the Treasury yields and ROEs, and then compared the pre-COVID-19 and COVID-19 period ROEs and yields to those in 2022 and 2023 (post-COVID-19 period). A key observation from Table 5 is that authorized ROEs for electric utility companies, despite hitting record lows in the COVID-19 period, did not decline as much as interest rates. The daily 30-year Treasury yield averaged 2.85% in the pre-COVID-19 period, versus 1.81% in the COVID-19 period, a decrease of 1.04% or 104 basis points. However, the authorized ROE for electric utility companies averaged 9.63% in the pre-COVID-19 period and declined to an average of 9.41% in the COVID-19 period, a decline of -0.22%. In 2022, the average daily 30-year Treasury yield increased by 105 basis points to 3.11%, while authorized ROEs for electric utility companies increased 0.16% to 9.54%, respectively. Likewise, the average daily 30-year Treasury yield increased by 92 basis points to 4.03% in 2023, while authorized ROEs for electric utility companies only increased by 0.06% to 9.60%.

Table 5
Average Annual 30-Year Treasury Yields and Authorized ROEs for Electric Distribution Companies
2018–2023

	2018 Average	2019 Average	2018-19 Average	2020 Average	2021 Average	2020-21 Average	2020-21 Avg. Minus 2018-19 Avg.	2022 Average	2022 Avg. Minus 2021 Avg.	2023 Average	2023 Avg. Minus 2022 Avg.
30-Year Treasury Yield	3.11%	2.58%	2.85%	1.56%	2.06%	1.81%	-1.04%	3.11%	1.05%	4.03%	0.92%
Average Electric ROE	9.60%	9.66%	9.63%	9.44%	9.38%	9.41%	-0.22%	9.54%	0.16%	9.60%	0.06%

Data Source: S&P Global Market Intelligence, RRA Regulatory Focus, 2024.

Q. DO YOU BELIEVE THAT YOUR ROE RECOMMENDATION MEETS THE *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes. As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

As shown on page 3 of Exhibit JRW-2, electric utility companies have been earning ROEs in the range of 9.0%-10.0% in recent years. With these ROEs, electric utility companies such as those in the proxy group have strong investment-grade credit ratings, their stocks have been selling well over book value, and they have been raising abundant amounts of capital. While my recommendation is slightly below the average authorized ROEs for electric utility companies, the Werner and Jarvis (2022) study, which is discussed below, concluded that, over the past four decades, authorized ROEs have not declined in line with capital costs over time and therefore past authorized ROEs have overstated the actual cost of equity capital.[3] Hence, the Florida Public Service Commission ("Commission") should not be concerned that my recommended ROE is slightly below the average of currently authorized ROEs. Therefore, I believe that my recommendation meets the criteria established in *Hope* and *Bluefield*.

Q. WITH RESPECT TO THIS DISCUSSION, PLEASE DISCUSS THE *WALL STREET JOURNAL* ARTICLE ON UTILITIES' AUTHORIZED ROES IN THE CURRENT ENVIRONMENT.

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[3] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," Working Paper, Energy Institute, University of California at Berkeley, 2022.

A. The *Wall Street Journal* article, entitled "Utilities Have a High-Wire Act Ahead," discussed the issues utilities face today to meet the needs of their primary stakeholders – customers and investors.[4] The article also highlights current utility rate issues in the context of a recent study on rate of return regulation.[5] In the 2022 study, Werner and Jarvis evaluated the authorized ROEs in 3,500 electric and gas rate case decisions in the U.S. from 1980-2021. They compared the allowed rate of return on equity to a number of capital cost benchmarks (government and corporate bonds, CAPM equity cost rate estimates, and U.K. authorized ROEs) and focused on three questions: (1) to what extent are utilities being allowed to earn excess ROEs by their regulators?; (2) how has this ROE affected utilities' capital investment decisions?; and (3) what impact has this had on the costs paid by consumers?[6]

The authors reported the following empirical results:[7]

(1) The real (inflation-adjusted) return that regulators allow equity investors to earn has remained steady over the last 40 years, while the many different cost of capital measures have been declining;

(2) The gap between the authorized ROEs and the benchmarks suggest that regulators have been approving ROEs that are from 0.50% to 5.50% above the cost of equity estimates;

(3) One potential explanation is that utilities have become riskier. However, the authors find that utility credit ratings, on average, have not changed much over the past 40 years;

(4) An extra 1.0% of allowed ROE causes a utility's capital rate base to expand by an extra 5% on average. This supports the Averch-Johnson effect that utilities have the

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4 Jinjoo Lee, "Utilities Have a High-Wire Act Ahead," *Wall Street Journal*, October 9, 2022, p. C1, *See* Attachment A.

5 *Id.*

6 Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," Working Paper, Energy Institute, University of California at Berkeley, 2022.

7 *Id.* These observations are summarized on pages 34-7 of the study.

incentive to overinvest in capital projects if they are earning an outsized return on those investments;[8]

(5) Both the ROE requested by utilities and the return granted by regulators respond more quickly to rises in market measures of capital cost than to declines. The time adjustment for decreases is twice as long as for increases;

(6) Authorized ROEs tend to be approved at round numbers (1.0, 0.5, 0.25), with 10.0% being the most common authorized ROE;

(7) Overall, based on the gap, consumers may be paying $2-20 billion per year more than if authorized ROEs had fallen in line with other capital market indicators; and

(8) The authors also indicated that their results are similar to those found in a previous study by David Rode and Paul Fischback (2019).[9]

In summary, these results indicate that over the past four decades authorized ROEs have not declined in line with capital costs, so past authorized ROEs have overstated the actual cost of equity capital. Hence, the Commission should not be concerned that my recommended ROE is below other authorized ROEs.

IV. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR TECO.

A. To develop a fair rate-of-return recommendation for the Company, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held utility companies.

Q. WHAT PROXY GROUPS HAVE YOU USED?

A. I have used my Electric Proxy Group and Mr. D'Ascendis' proxy group.

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8 https://en.wikipedia.org/wiki/Averch%E2%80%93Johnson_effect

9 David C. Rode and Paul S. Fischbeck, "Regulated Equity Returns: A Puzzle." *Energy Policy*, October, 2019.

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF ELECTRIC COMPANIES.

A. The selection criteria for the Electric Proxy Group include the following:

1. At least 50% of revenues from regulated electric operations as reported by *AUS Utilities Report*;
2. Listed as an U.S.-based Electric Utility by *Value Line Investment Survey;*
3. An investment-grade corporate credit rating from S&P and Moody's;
4. Has paid a cash dividend in the past six months, with no cuts or omissions;
5. Not involved in an acquisition of another utility, the target of an acquisition, or in the sale or spin-off of utility assets, in the past six months; and
6. Analysts' long-term earnings per share ("EPS") growth rate forecasts available from Yahoo, S&P Cap IQ, and/or Zacks.

Q. PLEASE DISCUSS THE ELECTRIC PROXY GROUP.

A. The Electric Proxy Group includes 24 companies. Page 1 of Exhibit JRW3 provides a summary of financial statistics for the proxy group, showing mean operating revenues and net plant among members of the Electric Proxy Group of $10.78 billion and $41.55 billion, respectively. The group on average receives 85% of its revenues from regulated electric operations; has a BBB+ bond rating from S&P and a Baa2 rating from Moody's; has a current average common equity ratio of 40.9%; and has an average earned ROE of 9.36%.

Q. PLEASE DESCRIBE MR. D'ASCENDIS' PROXY GROUP OF ELECTRIC UTILITY COMPANIES.

A. The D'Ascendis Proxy Group consists of fourteen electric utility companies. Summary financial statistics for the proxy group are listed on Panel B of page 1 of Exhibit JRW-3. The mean operating revenues and net plant among members of the D'Ascendis Proxy Group are \$10.29 billion and \$40.90 billion, respectively. On average the group receives 90% of revenues from regulated electric operations; has an average BBB+ issuer credit rating from S&P and an average Baa2 long-term rating from Moody's; has a current common equity ratio of 40.1%; and has an earned return on common equity of 9.48%.

Q. HOW DOES THE INVESTMENT RISK OF TECO COMPARE TO THAT OF THE PROXY GROUPS?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. Page 1 of Exhibit JRW-3 also shows S&P and Moody's issuer credit ratings for the companies in the two groups. The average S&P and Moody's ratings for the two groups are BBB+ and Baa2. TECO's issuer credit rating is BBB+ according to S&P and A3 according to Moody's. As such, TECO's S&P issuer credit rating is equal to the average of the two proxy groups (BBB+ vs. BBB+), and TECO's Moody's rating is two notches above the average of the two proxy groups (A3 vs. Baa2). In my opinion, this indicates that TECO is a little less risky than the average of the two proxy groups.

Q. HOW DOES THE INVESTMENT RISK OF THE TWO GROUPS COMPARE BASED ON THE VARIOUS RISK METRICS PUBLISHED BY *VALUE LINE*?

A. On page 2 of Exhibit JRW-3, I have assessed the riskiness of the two proxy groups using five different accepted risk measures. These measures include Beta, Financial

Strength, Safety, Earnings Predictability, and Stock Price Stability. These risk measures suggest that the two proxy groups are similar in risk. The comparisons of the risk measures include beta (0.92 vs. 0.92), Financial Strength (A vs. A/B++), Safety (2.0 vs. 2.1), Earnings Predictability (89 vs. 89), and Stock Price Stability (88 vs. 91). On balance, these measures suggest that these two proxy groups are very low risk relative to the overall stock market and are similar in risk to each other.

V. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DESCRIBE TECO'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. TECO has proposed a capital structure from investor-provided capital of 42.57% long-term debt, 3.90% short-term debt, and 54.00% common equity and long-term and short-term debt cost rates of 4.53% and 3.90%.

Q. WHAT ARE THE COMMON EQUITY RATIOS IN THE CAPITALIZATIONS OF THE TWO PROXY GROUPS?

A. As shown in Exhibit JRW-3, the average common equity ratios of the Electric and D'Ascendis Proxy Groups are 40.9% and 40.1%, respectively. As such, TECO's proposed capitalization from investor-provided capital and as proposed for rate setting purposes has much more equity and much less financial risk than the average current capitalizations of the electric utility companies in the proxy groups.

Q. WHAT IS THE COMMON EQUITY RATIO OF TECO'S PARENT, EMERA?

A. According to *Value Line*, the common equity ratio as of December 31, 2023, for Emera is 41.4%. Hence, TECO's proposed capitalization also has more equity and less financial risk than the average current capitalizations of the electric utility companies in the two proxy groups.

Q. IS IT APPROPRIATE TO USE THE COMMON EQUITY RATIOS OF THE PARENT HOLDING COMPANIES OR SUBSIDIARY OPERATING UTILITIES FOR COMPARISON PURPOSES WITH TECO'S PROPOSED CAPITALIZATION?

A. Yes. It is appropriate to use the common equity ratios of the utility holding companies because the *holding companies* are publicly-traded and their stocks are used in the cost-of-equity capital studies. The equities of the *operating utilities* are not publicly-traded and hence their stocks cannot be used to compute the cost-of-equity capital for TECO.

Q. IS IT APPROPRIATE TO INCLUDE SHORT-TERM DEBT IN THE CAPITALIZATION IN COMPARING THE COMMON EQUITY RATIOS OF THE HOLDING COMPANIES WITH TECO'S PROPOSED CAPITALIZATION?

A. Yes. Short-term debt, like long-term debt, has a higher claim on the assets and earnings of the company and requires timely payment of interest and repayment of principal. Thus, in comparing the common-equity ratios of the holding companies with TECO's recommendation, it is appropriate to include short-term debt when computing the holding company common-equity ratios. Additionally, the financial risk of a company is based on total debt, which includes both short-term and long-term debt.

Q. PLEASE DISCUSS THE ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS EMERA USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS TECO.

A. Moody's published an article on the use of low-cost debt financing by public utility holding companies to increase their ROEs. The summary observations included the following about how these holding companies use "leverage" and how an increase in leverage at the parent holding company can "hurt the credit profiles of its regulated subsidiaries":

> U.S. utilities use leverage at the holding-company level to invest in other businesses, make acquisitions and earn higher returns on equity. In some cases, an increase in leverage at the parent can hurt the credit profiles of its regulated subsidiaries.[10]

This financial strategy has traditionally been known as "double leverage." Noting that double leverage results in "a consolidated debt-to-capitalization ratio that is higher at the parent than at the subsidiary because of the additional debt at the parent," Moody's defined double leverage as follows:

> Double leverage is a financial strategy whereby the parent raises debt but downstreams the proceeds to its operating subsidiary, likely in the form of an equity investment. Therefore, the subsidiary's operations are financed by debt raised at the subsidiary level and by debt financed at the holding-company level. In this way, the subsidiary's equity is leveraged twice, once with the subsidiary debt and once with the holding-company debt. In a simple operating-company / holding-company structure, this practice results in a

[10] Moody's Investors' Service, "High Leverage at the Parent Often Hurts the Whole Family," May 11, 2015, p. 1.

> consolidated debt-to-capitalization ratio that is higher at the parent than at the subsidiary because of the additional debt at the parent.[11]

Moody's goes on to discuss the potential risk "down the road" to utilities of this financing corporate strategy if regulators were to ascribe the debt at the parent level to the subsidiaries or adjust the authorized return on capital:

> **"Double leverage" drives returns for some utilities but could pose risks down the road.** The use of double leverage, a long-standing practice whereby a holding company takes on debt and downstreams the proceeds to an operating subsidiary as equity, could pose risks down the road if regulators were to ascribe the debt at the parent level to the subsidiaries or adjust the authorized return on capital.[12]

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN A UTILITY'S CAPITAL STRUCTURE.

A. A utility's decision as to the amount of equity capital it will incorporate into its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital for a given commitment of dollars than it could raise with just equity. Debt is, therefore, a means of "leveraging" capital dollars. However, as the amount of debt in

[11] *Id.* at p. 5.

[12] *Id.* at p. 1.

the capital structure increases, financial risk increases and the risk of the utility, as perceived by equity investors, also increases. Significantly, for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. CAN THE IMPACT OF A UTILTY'S AWARDED ROE BE DETERMINED WITHOUT REFERENCE TO THAT UTILITY'S CAPITAL STRUCTURE?

A. No. A high equity component can amplify the overall impact of a relatively low ROE while a low equity component can mitigate the overall impact of a relatively high ROE. For example, suppose an electric utility has an authorized ROE and common equity ratio of 10.0% and 50.0%. Financially, the same utility would be at about the same point with authorized ROE of 9.0% but with a common equity ratio of 55.0%.

Q. IS THERE ALSO A DIRECT CORRELATION BETWEEN THE AMOUNT OF EQUITY IN A COMPANY'S CAPITAL STRUCTURE AND THE REVENUE REQUIREMENTS THAT CUSTOMERS ARE CALLED ON TO BEAR?

A. Yes. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements that customers are called on to bear. As the equity ratio increases, the utility's revenue requirement increases and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management should pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. CAN A REGULATED UTILITY SAFELY TAKE ON MORE DEBT THAN A NON-REGULATED COMPANY?

A. Yes. Due to regulation and the essential nature of its output, a regulated utility is exposed to less business risk than other companies that are not regulated. This means that a utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. Thus, a utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements.

Q. GIVEN THAT TECO HAS PROPOSED AN EQUITY RATIO THAT IS MUCH HIGHER THAN THE AVERAGE COMMON EQUITY RATIO OF OTHER ELECTRIC UTILITY COMPANIES AND THE COMMON EQUITY RATIO OF ITS PARENT COMPANY, EMERA, WHAT SHOULD THE COMMISSION DO IN THIS RATEMAKING PROCEEDING?

A. When a regulated utility's actual capital structure contains a high equity ratio, the Commission has two options. The first option is to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements. Otherwise, the Commission's second option is to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity-cost rate lower than that of the proxy group.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility should not be permitted to "have it both ways." Specifically, a utility cannot propose to maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between lower risk and the appropriate authorized return should not be ignored.

Q. PLEASE COMMENT ON MR. D'ASCENDIS'S CAPITAL STRUCTURE STUDY FOUND IN DOCUMENT NO. 3.

A. To support the Company's proposed capital structure with a common equity ratio of 54.0%, Mr. D'Ascendis erroneously reports on the ranges of the average five-year mean common equity ratio for the proxy companies and their operating subsidiaries. Mr. D'Ascendis is in error because he reports the ranges and not the mean common equity ratios. The fact is that the mean average five-year common equity ratios for the proxy companies and their operating subsidiaries are 43.25% and 49.05%.[13] These averages clearly do not support the Company's proposed common equity ratio. In addition, I show on page 1 of Exhibit JRW-3 that the average common equity ratios for the parent holding companies in the two proxy groups as of December 31, 2023, were 40.9% (Electric) and 40.1% (D'Ascendis). Hence, Mr. D'Ascendis' study does not

[13] See pages 2 and 5 of Mr. D'Ascendis' Document No. 3.

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support the Company's proposed capital structure.

Q. HOW DO YOU PLAN TO ACCOUNT FOR THE DIFFERENCE IN THE CAPITAL STRUCTURE?

A. I am not contesting the Company's proposed capital structure in this testimony, with a common equity ratio of 54.0%, and the proposed senior debt cost rates for two reasons: (1) a capitalization (with the 54.0% common equity ratio) adopted in a settlement in the Company's last rate case; and (2) as shown on page 1 of Mr. D'Ascendis' Document No. 3, a capital structure with a common equity ratio of 54.0% is consistent with how the Company has financed itself over the past three years. While I am not contesting the proposed capital structure, I have accounted for the high common equity ratio and lower financial risk of the capital structure in adopting an ROE in this case.

V. <u>THE COST OF COMMON EQUITY CAPITAL</u>

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services and the construction of utility-infrastructure facilities, most public utilities are monopolies. Because of the lack of competition and

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the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices.

Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility (*i.e.*, provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common-equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between a firm's performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition - where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production - firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where the price of the firm equals the average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In a competitive market, firms can achieve competitive advantage due to product-market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are more than those required by investors, or when a firm earns a ROE in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, Inc., described this essential relationship between the ROE, the cost of equity, and the market-to-book ratio in the following manner:

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business

> earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value. [14]

As such, the relationship between a firm's ROE, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a ROE above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a ROE below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN ROE AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity [(K)] should sell for less than book value. [15]

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book< 1*

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios of the Electric Proxy Group companies. The results are presented in Figure 8. The average R-square is 0.61.[16] This demonstrates the strong positive relationship between ROEs and market-to-book ratios

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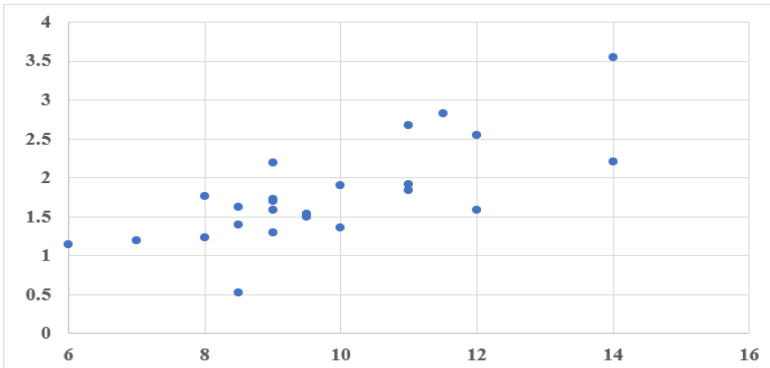
[14] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p. 3.

[15] Benjamin C. Esty, *Note on Value Drivers*, HARVARD BUSINESS SCHOOL BACKGROUND NOTE 297-082, April 1997.

[16] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between 0 and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

for public utilities. Given that the market-to-book ratios have been above 1.0 for a number of years, this also demonstrates that utilities have been earning ROEs above the cost of equity capital for many years.

Figure 8
The Relationship Between Expected ROE and Market-to-Book Ratios
***Value Line* Electric Utilities**



Data: *Value Line Investment Survey*, 2024
R-Square – 0.61, n=31.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money, as indicated by the level of interest rates in the economy. Common-stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business risk and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Table 6 provides an assessment of investment risk for 91 industries as measured by beta, which, according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey*. The study shows that the investment risk of utilities is low compared to other industries.[17] The average betas for electric, gas, and water utility companies are 0.89, 0.88, and 0.82, respectively.[18] As such, the cost of equity for utilities is the lowest of all industries in the U.S., based on modern capital market theory.

[17] As I discuss in more detail below, a stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below-average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0.

[18] The beta for the *Value Line* electric utilities is the simple average of *Value Line*'s Electric East (0.90), Central (0.88), and West (0.91) group betas.

Table 6
Industry Average Betas*
Value Line* Investment Survey Betas*

Industry Average Betas*
Value Line Investment Survey Betas**
13-Jan-24

Rank	Industry	Beta	Rank	Industry	Beta	Rank	Industry	Beta
1	Hotel/Gaming	1.52	33	Bank	1.18	65	Railroad	1.07
2	Oilfield Svcs/Equip.	1.44	34	Heavy Truck & Equip	1.18	66	IT Services	1.05
3	Apparel	1.41	35	R.E.I.T.	1.18	67	Cable TV	1.05
4	Insurance (Life)	1.40	36	Pipeline MLPs	1.18	68	Thrift	1.04
5	Air Transport	1.39	37	Electrical Equipment	1.17	69	Information Services	1.03
6	Petroleum (Producing)	1.37	38	Med Supp Invasive	1.16	70	Retail Store	1.03
7	Petroleum (Integrated)	1.36	39	Computers/Peripherals	1.16	71	Packaging & Container	1.01
8	Office Equip/Supplies	1.36	40	Entertainment	1.16	72	Human Resources	1.00
9	Advertising	1.36	41	Computer Software	1.16	73	Investment Co.	0.99
10	Shoe	1.33	42	Chemical (Specialty)	1.15	74	Retail Building Supply	0.99
11	Metals & Mining (Div.)	1.33	43	Healthcare Information	1.15	75	Med Supp Non-Invasive	0.99
12	Public/Private Equity	1.33	44	Engineering & Const	1.15	76	Environmental	0.98
13	Homebuilding	1.30	45	Maritime	1.15	77	Educational Services	0.97
14	Building Materials	1.30	46	Automotive	1.15	78	Drug	0.94
15	Auto Parts	1.30	47	Wireless Networking	1.15	79	Telecom. Services	0.92
16	Metal Fabricating	1.28	48	Semiconductor	1.15	80	Electric Utility (West)	0.91
17	Recreation	1.28	49	Medical Services	1.14	81	Beverage	0.91
18	Steel	1.28	50	Diversified Co.	1.14	82	Trucking	0.90
19	Retail (Hardlines)	1.27	51	Chemical (Basic)	1.13	83	Electric Utility (East)	0.90
20	Natural Gas (Div.)	1.27	52	Machinery	1.13	84	Tobacco	0.89
21	Retail (Softlines)	1.26	53	E-Commerce	1.13	85	Electric Util. (Central)	0.88
22	Restaurant	1.25	54	Power	1.13	86	Natural Gas Utility	0.88
23	Furn/Home Furnishings	1.23	55	Electronics	1.12	87	Biotechnology	0.83
24	Retail Automotive	1.22	56	Toiletries/Cosmetics	1.11	88	Household Products	0.82
25	Semiconductor Equip	1.21	57	Industrial Services	1.10	89	Retail/Wholesale Food	0.82
26	Chemical (Diversified)	1.21	58	Publishing	1.09	90	Water Utility	0.82
27	Financial Svcs. (Div.)	1.20	59	Investment Co.(Foreign)	1.09	91	Food Processing	0.77
28	Internet	1.20	60	Entertainment Tech	1.08			
29	Aerospace/Defense	1.20	61	Reinsurance	1.07			
30	Oil/Gas Distribution	1.19	62	Insurance (Prop/Cas.)	1.07			
31	Paper/Forest Products	1.19	63	Telecom. Equipment	1.07			
32	Bank (Midwest)	1.18	64	Precision Instrument	1.07		Mean	1.13

* Industry averages for 92 industries using *Value Line*'s database of 1,700 companies - Updated 1-13-24.
** *Value Line* computes betas using monthly returns regressed against the New York Stock Exchange Index for five years. These betas are then adjusted as follows: *VL* Beta = [{(2/3) * Regressed Beta} + {(1/3) * (1.0)}] to account to tendency for Betas to regress toward average of 1.0. See M. Blume, "On the Assessment of Risk," *Journal of Finance*, March 1971.

Q. WHAT IS THE COST OF COMMON EQUITY CAPITAL?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return requirement of the stockholder should be commensurate with the return requirement on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DID YOU ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. Primarily, I rely on the DCF model to estimate the cost-of-equity capital. Given the investment-valuation process and the relative stability of the utility business, the DCF model provides the best measure of equity-cost rates for public utilities. I have also performed an analysis using the CAPM; however, I give these results less weight because I believe that risk-premium studies, of which the CAPM is one form, provide a less reliable indication of equity-cost rates for public utilities.

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Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT THE CAPM PROVIDES A LESS RELIABLE INDICATOR OF EQUITY COST RATES.

A. I believe that the CAPM provides a less reliable measure of a utility's equity-cost rate because it requires an estimate of the market-risk premium. As discussed below, there is a wide variation in estimates of the market-risk premium found in studies by academics and investment firms as well as in surveys of market professionals.

B. DCF Approach

Q. PLEASE DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

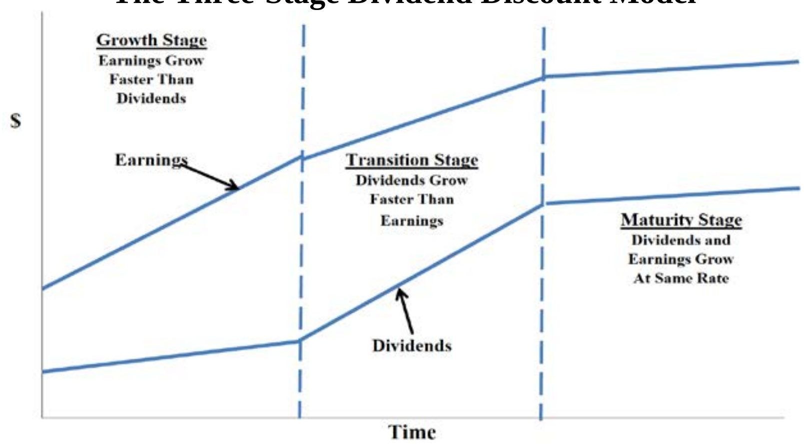
$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_1, D_2, D_n are the dividends in (respectively) year 1, 2, and in the future years n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are shown in Figure 9. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is a function of the life cycle of the product or service.

Figure 9
The Three-Stage Dividend Discount Model



1. **Growth stage**: This stage is characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. **Transition stage**: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. **Maturity (steady-state) stage**: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly more attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. As I will explain below, the constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using the 3-stage model to estimate a firm's cost-of-equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity-cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF "PRESENT VALUE."

A. Present value is the concept that an amount of money today is worth more than that same amount in the future. In other words, money received in the future is not worth as much as an equal amount received today. Present value tells an investor how much he or she would need in today's dollars to earn a specific amount in the future.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where P is the current stock price, D_1 represents the expected dividend over the coming year, k is investor's required ROE, and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for "k" in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF model. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity-cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS HAVE YOU REVIEWED?

A. I have calculated the dividend yields for the companies in the proxy groups using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. The dividend yields for the Electric Proxy Group are provided in Panel A of page 2 of Exhibit JRW-5. For the group, the mean and median dividend yields using the 30-day, 90-day, and 180-day average stock prices range from 4.00% to 4.20%. Hence, I will use 4.10% as the dividend yield for the Electric Proxy Group. The dividend yields for the D'Ascendis Proxy Group are provided in Panel B of page 2 of Exhibit JRW-5. For the group, the mean and median dividend yields using the 30-day, 90-day, and 180-day average stock prices range from 4.20% to 4.40%. Hence, I will use 4.30% as the dividend yield for the D'Ascendis Group.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates the dividend paid over the coming period to the current stock price. As indicated by Professor

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Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by multiplying the expected dividend over the coming quarter by 4, and then dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[19]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR DO YOU USE FOR YOUR DIVIDEND YIELD?

A. I adjust the dividend yield by one-half (1/2) of the expected growth to reflect growth over the coming year. The DCF equity-cost rate ("K") is computed as:

$$K = \left[\left(\frac{D}{P}\right) \times (1 + 0.5g)\right] + g$$

[19] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectations of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth-rate estimates for EPS, dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth-rate forecasts of Wall Street analysts as provided by Yahoo, Zacks, and S&P Cap IQ. These services solicit five-year earnings growth-rate projections from securities analysts and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS, AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth-rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth-rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (*i.e.*, business cycles). Thus, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common-equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Q. PLEASE DEFINE AND EXPLAIN THE RELEVANCE OF INTERNAL GROWTH.

A. A company's internal (or "organic") growth occurs when a business expands its own operations rather than relying on takeovers and mergers. It can come about through various means (e.g., increasing existing production capacity through investment in new capital and technology, or development and launch of new products).

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (i.e., the ROE). The internal growth rate is computed as the retention rate times the ROE. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVIDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by several different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, S&P Cap IQ, Zacks, First Call, and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, S&P Cap IQ, and Zacks each publish their own set of analysts' EPS forecasts for companies. These services do not reveal: (1) the analysts who are solicited for forecasts; or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services.

I/B/E/S, Bloomberg, FactSet, S&P Cap IQ, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts.

In contrast, Thomson Reuters and Zacks provide limited EPS forecast data free-of-charge on the Internet. Yahoo Finance (http://finance.yahoo.com) lists Thomson Reuters as the source of its summary EPS forecasts. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks' estimates are also available on other websites, such as MSN.money (http://money.msn.com).

Q. ARE YOU RELYING EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. No. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth.

Second, a study by Michael Lacina, Biran Lee, and Randall Zhaohui Xu (2011) has shown that analysts' three-to-five year EPS growth-rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[20] Employing data over a 20-year period, these authors demonstrate that using the most recent year's actual EPS figure to forecast EPS in the next three to five years proved to be just as accurate as using the EPS estimates from analysts' three-to-five year EPS growth-rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth-rate forecasts should be used with caution as inputs for valuation and cost-of-capital purposes.

Finally, and most significantly, it is well known that the long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly

[20] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp. 77-101. According to random walk theory in this context, annual changes in earnings are normally distributed and are independent of each other. Therefore, the theory presumes the past movement or trend of earnings cannot be used to predict its future earnings.

biased. This has been demonstrated in a number of academic studies over the years.[21] Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Peter Easton and Gregory Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[22]

Q. ARE ANALYSTS' PROJECTED EPS GROWTH RATES FOR ELECTRIC UTILITIES LIKEWISE OVERLY OPTIMISTIC AND UPWARDLY BIASED?

A. Yes. I have completed a study of the accuracy of analysts' EPS growth rates for electric utilities and gas distribution companies over the 1985 to 2022 time period. In the study, I used the utilities listed in the electric utilities and gas distribution companies covered by *Value Line*.

I collected the three-to-five-year projected EPS growth rate from I/B/E/S for each utility and compared that growth rate to the utility's actual subsequent three-to-five-year EPS growth rate. As shown in Figure 10, the mean forecasted EPS growth rate (depicted in the red line in Figure 10) is consistently greater than the achieved actual EPS growth rate over the time period, with the exception of short periods in

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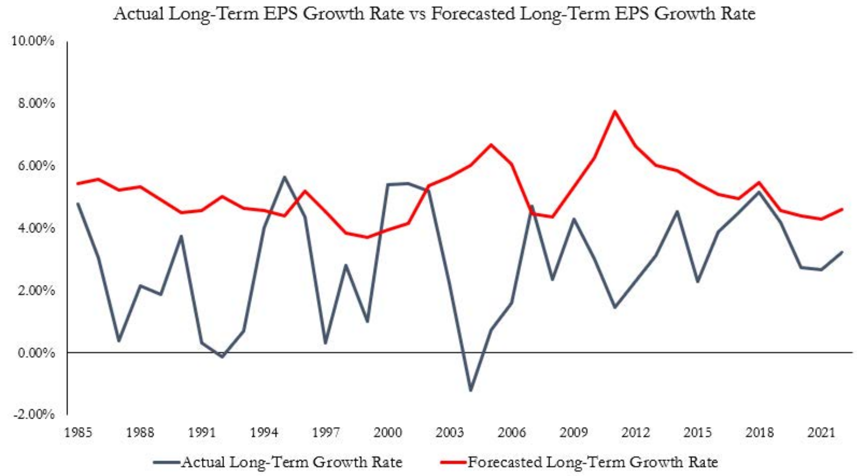
21 The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance*, pp. 643−684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

22 Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

1996, 2001, and 2007. Over the entire period, the mean forecasted EPS growth rate is over 200 basis points above the actual EPS growth rate. As such, the projected EPS growth rates for electric utilities are overly optimistic and upwardly based.

Figure 10
Mean Forecasted vs. Actual Long-Term EPS Growth Rates
Electric Utilities and Gas Distribution Companies
1985–2022



Data Source: S&P Global Market Intelligence, Capital IQ, I/B/E/S, 2023.

Q. ARE THE PROJECTED EPS GROWTH RATES OF *VALUE LINE* ALSO OVERLY OPTIMISTIC AND UPWARDLY BIASED?

A. Yes. A study by Andrew Szakmary, Mitchell Conover, and Carol Lancaster ("SCL") evaluated the accuracy of *Value Line*'s three-to-five-year EPS growth rate forecasts using companies in the Dow Jones Industrial Average over a 30-year time period and found these forecasted EPS growth rates to be significantly higher than the EPS growth rates that these companies subsequently achieved.[23]

SCL studied the predicted versus the projected stock returns, sales, profit margins, and earnings per share made by *Value Line* over the 1969 to 2001 time period.

[23] Szakmary, A., Conover, C., & Lancaster, C., *An Examination of* Value Line*'s Long-Term Projections*, J. BANKING & FIN., May 2008, at 820–33.

Value Line projects variables from a three-year base period (e.g., 2012 to 2014) to a future three-year projected period (e.g., 2016 to 2018). SCL used the 65 stocks included in the Dow Jones Indexes (30 Industrials, 20 Transports, and 15 Utilities). SCL found that the projected annual stock returns for the Dow Jones stocks were "incredibly over optimistic" and of no predictive value. The mean annual stock return of 20% for the Dow Jones stocks' *Value Line*'s forecasts was nearly double the realized annual stock return.

The authors also found that *Value Line*'s forecasts of earnings per share and profit margins were "strikingly over optimistic." *Value Line*'s forecasts of annual sales were higher than achieved levels, but not statistically significant. SCL concluded that the overly optimistic projected annual stock returns were attributable to *Value Line*'s upwardly biased forecasts of earnings per share and profit margins.

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes. I believe that investors are well aware of the bias in analysts' EPS growth-rate forecasts, and therefore stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Because I believe that investors are aware of the upward bias in analysts' long-term EPS growth-rate forecasts, stock prices reflect the bias. But the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias in the DCF model.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS, AS PROVIDED BY *VALUE LINE.*

A. Panel A of page 3 of Exhibit JRW-5 provides the 5- and 10-year historical growth rates for EPS, DPS, and BVPS for the companies in the Electric Proxy Group, as published in the *Value Line Investment Survey*. The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group range from 3.5% to 5.0%, with an average of the medians of 4.3%. Panel B of page 3 of Exhibit JRW-5 provides the *Value Line* 5- and 10-year historical growth rates for EPS, DPS, and BVPS for the companies in the D'Ascendis Proxy Group. The median historical growth measures for EPS, DPS, and BVPS for the D'Ascendis Proxy Group range from 3.5% to 5.0%, with an average of the medians of 4.1%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUP.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-5. Due to the presence of outliers, I relied on the medians in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-5, the medians range from 4.0% to 6.0%, with an average of the medians of 5.0%.[24] For the D'Ascendis Proxy Group, as shown in Panel B of

[24] It should be noted that *Value Line* uses a different approach in estimating projected growth. *Value Line* does not project growth from today, but *Value Line* projects growth from a three-year base period – 2020-2022 –

page 4 of Exhibit JRW-5, the medians range from 4.3% to 6.3%, with an average of the medians of 5.3%.

Also provided on page 4 of Exhibit JRW-5 are the prospective sustainable growth rates for the companies in the proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Electric and D'Ascendis Proxy Groups, the median prospective sustainable growth rates are 4.1% and 3.9%, respectively.

Q. PLEASE ASSESS THE GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and S&P Cap IQ collect, summarize, and publish Wall Street analysts' long-term EPS growth rate forecasts for the companies in the proxy group. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-5. I have reported both the mean and median growth rates for the group. Since there is considerable overlap in analyst coverage between the two services, and not all the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the two services for each company to arrive at an expected EPS growth rate for each company. As shown in Panel A of page 5 of Exhibit JRW-5, the mean/median of analysts' projected EPS growth rates for the Electric Proxy Group

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to a projected three-year period for the period 2026-2028. Using this approach, the three-year base period can have a significant impact on the *Value L*ine growth rate if this base period includes years with abnormally high or low earnings. Therefore, I evaluate these growth rates separately from analysts EPS growth rates.

are 5.9%/6.0%. The mean/median of analysts' projected EPS growth rates for the D'Ascendis Proxy Group, as shown in Panel B of page 5 of Exhibit JRW-5, are 6.0/6.2%.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUP.

A. Page 6 of Exhibit JRW-5 shows the summary DCF growth rate indicators for the proxy group.

The historical growth rate indicators for the Electric Proxy Group imply a baseline growth rate of 4.3%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.0%, and *Value Line*'s projected sustainable growth rate is 4.1%. The mean/median projected EPS growth rates of Wall Street analysts for the Electric Proxy Group are 5.9%/6.0% (average = 5.95%) as measured by the mean and median growth rates. The overall range for the projected growth-rate indicators (ignoring historical growth) is 4.10% to 5.95%, and the average of the three projected growth rates is 5.00% (4.1%, 5.0%, and 5.95%). Giving more weight to the projected growth rates of Wall Street analysts and *Value Line*, but recognizing the upward bias nature of these forecasts, I believe that the appropriate projected growth rate is in the range of 5.00% to 5.95%. Given this range, I will use 5.50%, which is the midpoint of the range, for my DCF growth rate for the Electric Proxy Group. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

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For the D'Ascendis Proxy Group, the historical growth rate indicators suggest a growth rate of 4.10%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.3%, and *Value Line*'s projected sustainable growth rate is 3.9%. The projected EPS growth rates of Wall Street analysts are 6.0% and 6.2% (average = 6.1%) as measured by the mean and median growth rates. The overall range for the projected growth-rate indicators (ignoring historical growth) is 3.90% to 6.10%, and the average of the three projected growth rates is 5.10% (5.3%, 3.9%, and 6.1%). Again, giving more weight to the projected EPS growth rate of Wall Street analysts but recognizing the upward bias nature of these forecasts, I believe that the appropriate DCF growth rate range is 5.10% to 6.10%. Given these figures, I will use the midpoint of this range, 5.60%, as the DCF growth rate for the D'Ascendis Proxy Group. As with the Electric Proxy Group, this growth rate figure is in the upper end of the range of historic and projected growth rates for the D'Ascendis Proxy Group.

Q. WHAT ARE THE RESULTS FROM YOUR APPLICATION OF THE DCF MODEL?

A. My DCF-derived equity cost rate for the group is summarized on page 1 of Exhibit JRW-5 and in Table 7.

Table 7
DCF-derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**4.10%**	**1.02725**	**5.50%**	**9.70%**
D'Ascendis Proxy Group	**4.30%**	**1.02800**	**5.60%**	**10.00%**

The result for the Electric Proxy Group is the 4.10% dividend yield, times the 1 + ½ growth adjustment of 1.02725, plus the DCF growth rate of 5.45%, which results in an equity cost rate of 9.70%. The result for the D'Ascendis Proxy Group is the 4.30% dividend yield, times the 1 + ½ growth adjustment of 1.02800, plus the DCF growth rate of 5.60%, which results in an equity cost rate of 10.00%.

C. Capital Asset Pricing Model ("CAPM")

Q. PLEASE DISCUSS THE CAPM.

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. RPs are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to the following:

$$K = (R_f) + \beta \times [E(R_m) - (R_f)]$$

Where:

K represents the estimated rate of return on the stock;

$E(R_m)$ represents the expected return on the overall stock market (frequently, the 'market' refers to the S&P 500);

(R_f) represents the risk-free rate of interest;

$[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and

Beta—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium ($E(R_m) - (R_f)$). I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-6.

A. Exhibit JRW-6 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-6, the yield on 30-year U.S. Treasury bonds has been in the 1.3% to 5.00% range over the 2010–2024 time period. The current 30-year Treasury yield is above the average of this range. Kroll, a division of the investment firm Duff & Phelps, recommends using a normalized risk-free interest rate.[25] Currently, Kroll is recommending a normalized risk-free interest rate of 3.50%, or, if the spot 20-year Treasury yield is above 3.50%, Kroll recommends using the spot 20-year Treasury yield.

However, it has also noted these yields are distorted currently: "We are aware of lack of liquidity issues in the U.S. Treasury market for the 20-year maturity, which is causing some distortion in the 20-year yield relative to that observed for 10- and 30-year maturities."[26] The illiquidity and resulting yield distortion has also been highlighted in the financial press.[27] As shown in Figure 5 (page 16), the yield curve is currently inverted with a yield "hump" at the 20-year mark. The current 30-year Treasury yield is in the 4.50% - 4.75% range. Given the recent range of yields, I am using 4.65% as the risk-free rate, or R_f, in my CAPM.

Q. DOES THE 4.65% RISK-FREE INTEREST RATE TAKE INTO CONSIDERATION FORECASTS OF HIGHER INTEREST RATES?

[25] Kroll, *Cost of Capital Resource Center* (2023). https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

[26] *Id.*

[27] For example, see Duguid and Smith, "The market is just dead - Investors steer clear of 20-year Treasuries," *Financial Times*, July 22, 2022.

A. No. The 4.65% risk-free interest rate takes into account the range of interest rates in the past and effectively synchronizes the risk-free rate with the market risk premium. The risk-free rate and the market risk premium are interrelated in that the market risk premium is developed in relation to the risk-free rate. As discussed below, my market risk premium is based on the results of many studies and surveys that have been published over time.

Q. PLEASE DISCUSS BETAS IN THE CAPM.

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-6, the slope of the regression line is the stock's beta. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher beta and greater-than-average market risk. A less steep line indicates a lower beta and less market risk. Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which beta is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time.

Q. PLEASE DISCUSS THE 2020 CHANGE IN BETAS.

A. I have traditionally used the betas as provided in the *Value Line Investment Survey*. As discussed above, the betas for utilities recently increased significantly as a result of the volatility of utility stocks during the stock market meltdown associated with the novel coronavirus in March 2020. Utility betas as measured by *Value Line* have been in the 0.55 to 0.70 range for the past 10 years. But utility stocks were much more volatile relative to the market in March and April of 2020, and this resulted in an increase of above 0.30 to the average utility beta.

Value Line defines their computation of beta in the following manner:[28]

> Beta - A relative measure of the historical sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00.

However, there are several issues with *Value Line* betas:

1. *Value Line* betas are computed using weekly returns, and the volatility of utility stocks during March 2020 was impacted by using weekly and not monthly returns.

[28] https://www.valueline.com/investment-education/glossary/b.

Yahoo Finance uses five years of monthly returns to compute betas, and Yahoo Finance's betas for utilities are lower than *Value Line*'s.

2. *Value Line* betas are computed using the New York Stock Exchange Index as the market. While about 3,000 stocks trade on the NYSE, most technology stocks are traded on the NASDAQ or the over-the-counter market and not the NYSE. Technology stocks, which make up about 25% of the S&P 500, tend to be more volatile. If they were traded on the NYSE, they would increase the volatility of the measure of the market and thereby lower utility betas.

3. Major vendors of CAPM betas such as Merrill Lynch, *Value Line*, and Bloomberg publish adjusted betas. The so-called Blume adjustment cited by *Value Line* adjusts betas calculated using historical returns data to reflect the tendency of stock betas to regress toward 1.0 over time, which means that the betas of typical low beta stocks tend to increase toward 1.0, and the betas of typical high beta stocks tend to decrease toward 1.0.[29]

The Blume adjustment procedure is:

$$\text{Regressed Beta} = .67 * (\text{Observed Beta}) + 0.33$$

For example, suppose a company has an observed past beta of 0.50. The regressed (Blume-adjusted) beta would be:

$$\text{Regressed Beta} = .67 * (0.50) + 0.33 = 0.67$$

Blume offered two reasons for betas to regress toward 1.0. First, he suggested it may be a by-product of management's efforts to keep the level of firm's systematic risk

[29] M. Blume, *On the Assessment of Risk*, J. OF FIN. (Mar. 1971).

close to that of the market. He also speculated that it results from management's efforts to diversify through investment projects.

Q. GIVEN THIS DISCUSSION, WHAT BETAS ARE YOU USING IN YOUR CAPM?

A. In the past, I have used *Value Line* betas exclusively. However, given the discussion above, I am also using betas published by S&P Capital IQ. S&P Capital IQ computes betas over a five-year period using monthly returns and the S&P 500 as the market return. S&P Capital IQ does not use the Blume adjustment, but I have included that adjustment in my analysis. As shown on page 3 of Exhibit JRW-6, I have averaged the *Value Line* betas and my adjusted S&P Capital IQ for the proxy groups. The median betas for the Electric and D'Ascendis Proxy Groups are 0.80 and 0.80, respectively.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM.

A. The market risk premium is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The market risk premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the market risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market—$E(R_m)$. As I discuss below, there are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for $E(R_m)$. As Merton

Miller, the 1990 Nobel Prize winner in economics, indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[30]

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE MARKET RISK PREMIUM.

A. Page 4 of Exhibit JRW-6 highlights the primary approaches to, and issues in, estimating the expected market risk premium. The traditional way to measure the market risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called *ex post* returns, were used as the measures of the market's expected return (known as the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. However, this historical evaluation of returns can be a problem because: (1) *ex post* returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that *ex post* historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies, which I discuss later. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the

[30] Merton Miller, *The History of Finance: An Eyewitness Account*, J. APPLIED CORP. FIN., 3 (2000).

category "*ex ante* models and market data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "puzzle research" after the famous study by Rajnish Mehra and Edward Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[31]

In addition, there are a number of surveys of financial professionals regarding the market risk premium, as well as several published surveys of academics on the equity risk premium. Duke University has published a CFO Survey on a quarterly basis for over 10 years.[32] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of Professional Forecasters*.[33] This survey of professional economists has been published for almost 50 years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums used in their investment and financial decision making.[34]

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[31] Rajnish Mehra & Edward C. Prescott, *The Equity Premium: A Puzzle*, J. MONETARY ECON. 145 (1985).

[32] *The CFO Survey*, DUKE UNIVERSITY, https://www.richmondfed.org/cfosurvey.

[33] *Survey of Professional Forecasters*, FEDERAL RESERVE BANK OF PHILADELPHIA (Feb. 10, 2023), https://www.philadelphiafed.org/-/media/frbp/assets/surveys-and-data/survey-of-professional-forecasters/2020/spfq120.pdf?la=en. The Survey of Professional Forecasters was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[34] Pablo Fernandez, Teresa Garcia, and Pablo Acín, SURVEY: MARKET RISK PREMIUM AND RISK-FREE RATE USED FOR 80 COUNTRIES IN 2023, IESE BUSINESS SCHOOL WORKING PAPER (April 4, 2023).

Q. PLEASE HIGHLIGHT THE RESULTS OF THE ACADEMIC AND PROFESSIONAL STUDIES DISCUSSING THE MARKET RISK PREMIUM.

A. Richard Derrig and Elisha Orr, Pablo Fernandez, and Zhiyi Song completed the most comprehensive reviews of the research on the market risk premium.[35] Derrig and Orr's study evaluated the various approaches to estimating market risk premiums, discussed the issues with the alternative approaches, and summarized the findings of the published research on the market risk premium. Fernandez examined four alternative measures of the market risk premium – historical, expected, required, and implied. He also reviewed the major studies of the market risk premium and presented the summary market risk premium results. Song provided an annotated bibliography and highlighted the alternative approaches to estimating the market risk premium.

Page 5 of Exhibit JRW-6 provides a summary of the results of the market risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium: (2) *ex ante* market risk premium studies; (3) market risk premium surveys of CFOs, financial forecasters, analysts, companies, and academics; and (4) the building blocks approach to the market risk premium. There are results reported for over 30 studies, and the median market risk premium of these studies is 4.64%.

[35] *See* Richard Derrig & Elisha Orr, *Equity Risk Premium: Expectations Great and Small (Version 3.0)*, Aug. 28, 2003); Pablo Fernandez, EQUITY PREMIUM: HISTORICAL, EXPECTED, REQUIRED, AND IMPLIED, IESE BUSINESS SCHOOL WORKING PAPER (2007); ZHIYI SONG, THE EQUITY RISK PREMIUM: AN ANNOTATED BIBLIOGRAPHY (The CFA Institute Research (2007).

Q. PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS.

A. The studies cited on page 5 of Exhibit JRW-6 include every market risk premium study and survey I could identify that was published over the past 20 years and that provided a market risk premium estimate. Many of these studies were published prior to the financial crisis that began in 2008. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as 50 years of data) and so were not estimating a market risk premium as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the market risk premium, I have reconstructed page 5 of Exhibit JRW-6 on page 6 of Exhibit JRW-6; however, I have eliminated all studies dated before January 2, 2010. The median market risk premium estimate for this subset of studies is 5.23%.

Q. PLEASE SUMMARIZE THE MARKET RISK PREMIUM STUDIES AND SURVEYS.

A. As noted above, there are three approaches to estimating the market risk premium: (1) historic stock and bond returns; (2) *ex ante* or expected returns models; and (3) surveys. The studies on page 6 of Exhibit JRW-6 can be summarized in the following manner:

Historic Stock and Bond Returns: Historic stock and bond returns suggest a market risk premium in the 4.40% to 6.80% range, depending on whether one uses arithmetic or geometric mean returns.

***Ex Ante* Models**: Market risk-premium studies that use expected or *ex ante* return models indicate a market risk premium in the range of 2.61% to 6.00%.

Surveys: Market risk premiums developed from surveys of analysts, companies, financial professionals, and academics are lower, with a range from 3.40% to 5.70%.

Building Block: The mean reported market risk premiums reported in studies using the building blocks approach range from 3.00% to 5.21%.

Q. PLEASE HIGHLIGHT THE *EX ANTE* MARKET RISK PREMIUM STUDIES AND SURVEYS THAT YOU BELIEVE ARE MOST TIMELY AND RELEVANT.

A. I will highlight several studies and surveys.

First, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums used in their investment and financial decision-making.[36] His survey results are included on pages 5 and 6 of Exhibits JRW-6. The results of his 2024 survey of academics, financial analysts, and companies, which included 4,000 responses, indicated a mean market risk premium employed by U.S. analysts and companies of 5.5%.[37] His estimated market risk premium for the U.S. has been in the 5.00% to 5.70% range in recent years.

Second, Professor Aswath Damodaran of New York University, a leading expert on valuation and the market risk premium, provides a monthly updated market risk premium based on projected S&P 500 EPS and stock-price level and long-term interest rates.[38] His estimated market risk premium has been in the range of 4.0% to 6.0% since 2010. As shown in Figure 11 as of May 1, 2024, Damodaran's estimate of the equity risk premium was 4.15%.[39]

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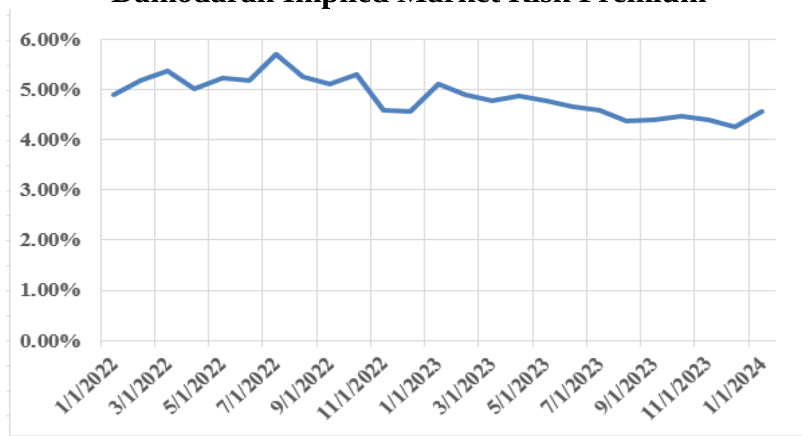
[36] Pablo Fernandez, Teresa Garcia, & Pablo Acín, *Survey: Market Risk Premium and Risk-Free Rate Used for 80 Countries in 2024, IESE Business School Working Paper* (March 2024).

[37] *Id.* at 3.

[38] Aswath Damodaran, *Damodaran Online*, N.Y. Univ https://pages.stern.nyu.edu/~adamodar/

[39] *Id.* On August 12, 2023, Professor Damodaran appeared on CNBC to discuss the equity risk premium. *See* CNBC Television, *Equity Risk Premium is Core to Understanding Long-Term Market Returns, says NYU Aswath Damodaran*, YouTube https://www.youtube.com/watch?v=VPkQ7_3Sf1E (last visited Apr. 24,

Figure 11
Damodaran Implied Market Risk Premium



Source: http://pages.stern.nyu.edu/~adamodar/.

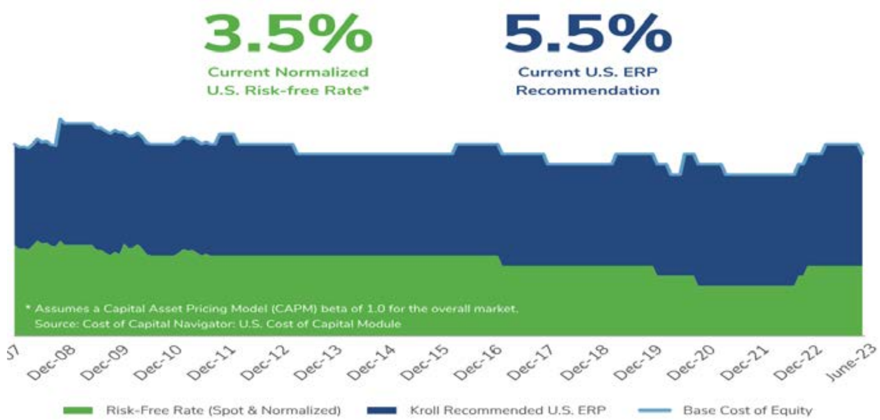
Next, as explained previously, Kroll provides recommendations for the normalized risk-free interest rate and market risk premiums to be used in calculating the cost-of-capital data. Its recommendations over the 2008 to 2023 period are shown on page 7 of Exhibit JRW-6 and are also depicted graphically in Figure 12 below. Over the past decade, Kroll's recommended normalized risk-free interest rates have been in the 2.50% to 4.50% range, and market risk premiums have been in the 5.0% to 6.0% range. In early 2020, in the wake of the emergence of COVID-19, Kroll decreased its recommended normalized risk-free interest rate from 3.0% to 2.50% and increased its market risk premium from 5.00% to 6.00%.[40] Subsequently, on December 9, 2020, Kroll reduced its recommended market risk premium to 5.50%, and on October 18, 2022, Kroll increased its market risk premium to 6.00%. Most recently, on June 8,

2024)).

[40] The following summary may be found at:https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

2023, Kroll again reduced its market risk premium to 5.50%. This recommendation was reaffirmed on February 8, 2024.[41]

Figure 12
Kroll
Normalized Risk-Free Rate and Market Risk Premium Recommendations
2007–2024



Source:https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

Fourth, Dr. David Kelly, the Chief Global Strategist at *J.P. Morgan Asset Management*, is one of the best-known market strategists on Wall Street. His annual publication and their monthly updates, the *JP Morgan Guide to the Markets*, is a must-read guide for stockbrokers and financial professionals.[42] In presenting their annual expectations for the markets, JP Morgan provides details about inputs and assumptions of expected market returns. In its 2023 update, JP Morgan details the 2023 expected long-term stock market return of 7.90%, bond yield of 3.50%, and resulting market risk premium of 4.40%.[43]

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[41] *Id.*

[42] JP Morgan, *2023 Long-Term Capital Market Assumptions*, 70 (2023). (Provided in Dr. Woolridge's work papers.

[43] *Id.*

Finally, KPMG, the international accounting firm, regularly publishes an update to their market risk premium to be used in their valuation practice. KPMG's market risk premium is shown in Figure 13, which was as high as 6.75% in 2020, and was lowered to as low as 5.00% on September 30, 2021. KPMG increased its market risk premium to 6.00% on June 30, 2022, but lowered it to 5.75% on December 31, 2022, to 5.50% on March 31, 2023, to 5.25% on June 30, 2023, and to 5.00% on September 30, 2023.[44]

Figure 13
KPMG
Market Risk Premium Recommendations
2020–2023

https://indialogue.io/clients/reports/public/5d9da61986db2894649a7ef2/5d9da63386db2894649a7ef5

Q. GIVEN THESE RESULTS, WHAT MARKET RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. The studies on page 6 of Exhibit JRW-6 and, more importantly, the more timely and relevant studies cited in the previous section, suggest that the appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range. In the last year, as interest rates have

44 *KPMG Corporate Finance & Valuations NL Recommends A MRP of 5.0% as per March 31, 2024*, KMPG (Mar. 31, 2024). https://indialogue.io/clients/reports/public/5d9da61986db2894649a7ef2/5d9da63386db2894649a7ef5.

increased, estimates of the market risk premium have declined. I give most weight to the market risk-premium estimates of Kroll, KPMG, JP Morgan, Damodaran, and the Fernandez and Duke-CFO surveys. Given the recent estimates, I believe a market risk premium in the 5.00% to 5.50% range is appropriate. I use the midpoint of this range, 5.25%, as the market risk premium in my CAPM study.

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-6 and in Table 8.

Table 8

CAPM-derived Equity Cost Rate/ROE

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	**4.65%**	**0.80**	**5.25%**	**8.85%**
D'Ascendis Proxy Group	**4.65%**	**0.80**	**5.25%**	**8.85%**

For the Proxy Group, the risk-free rate of 4.65% plus the product of the beta of 0.80 times the equity risk premium of 5.25% results in an 8.85% equity cost rate. For the D'Ascendis Proxy Group, the risk-free rate of 4.65% plus the product of the beta of 0.80 times the equity risk premium of 5.25% results in an 8.85% equity cost rate.

D. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY COST RATE STUDIES.

A. Table 9 provides my DCF and CAPM analyses for the proxy groups.

Table 9
ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Electric Proxy Group	**9.70%**	**8.85%**
D'Ascendis Proxy Group	**10.00%**	**8.85%**

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. My analysis indicates an equity cost rate in the range of 8.85% to 10.00% is appropriate for the Company. Given that I rely primarily on the DCF model and the results for the Electric Proxy Group, I believe that the appropriate ROE range for the Company is in the 9.25%-9.75% range. Given further that TECO's investment risk is a little below the average of the two groups, and I have employed a capital structure that has much more common equity and less financial risk than the average of the two proxy groups as well as TECO's parent, Emera, I am recommending a ROE of 9.50% for the Company.

Q. PLEASE INDICATE WHY AN EQUITY COST RATE OF 9.50% IS APPROPRIATE FOR TECO.

A. There are a few reasons why an equity cost rate of 9.50% is appropriate and fair for the Company in this case:

1. As shown in Table 6, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta. As such, the cost of equity capital for this industry is amongst the lowest in the U.S., according to the CAPM.

2. The investment risk of TECO, as indicated by the Company's S&P credit ratings, is slightly below the average of the two proxy groups.

3. The authorized ROEs for electric utility companies were 9.44% in 2020, 9.38% in 2021, 9.54% in 2022, 9.60% in 2023, and 9.66% in the first quarter of 2024.[45] While interest rates have increased coming out of the pandemic, which led to record low authorized ROEs for utilities, I show that authorized ROEs for utilities never declined as much as interest rates in 2020 and 2021. In addition, as discussed on pages 21-3, the Werner and Jarvis study concluded that, over the past four decades, authorized ROEs have not declined in line with capital costs over time, so past authorized ROEs have overstated the actual cost of equity capital. Hence, the Commission should not be concerned that my recommended ROE is below other authorized ROEs.

Q. DO YOU BELIEVE THAT YOUR 9.50% ROE RECOMMENDATION MEET THE *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes, I do. As I previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital. As page 3 of Exhibit JRW-2 shows, electric utility and gas distribution companies have been earning in the 8.0% to 10.0% range in recent years. While my recommendation is slightly below the average authorized ROEs for electric distribution companies, it reflects the downward trend in authorized and earned ROEs of utilities. In addition, as discussed above, the Werner and Jarvis study demonstrated that authorized ROEs over the past four decades have not declined in line with capital costs,

[45] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2024.

so past authorized ROEs have overstated the actual cost of equity capital. Therefore, I believe that my ROE recommendation meets the criteria *Hope* and *Bluefield* established.

VI. CRITIQUE OF TECO'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED RATE OF RETURN RECOMMENDATION.

A. The Company's rate-of-return recommendation is summarized on page 1 of Exhibit JRW-7. TECO has proposed a capital structure from investor-provided capital of 42.57% long-term debt, 3.90% short-term debt, and 54.00% common equity and long-term and short-term debt cost rates of 4.53% and 3.90%. TECO witness Mr. D'Ascendis has recommended a common equity cost rate of 11.50% for TECO.

Q. PLEASE REVIEW MR. D'ASCENDIS' EQUITY COST RATE APPROACHES AND RESULTS.

A. Mr. D'Ascendis has developed a proxy group of electric utility companies and employs DCF, risk premium, and CAPM models. He also applies these models to a group of non-price regulated companies. Mr. D'Ascendis' equity-cost-rate estimates for TECO are summarized on page 2 of Exhibit JRW-7. Based on these figures, he concludes that the appropriate equity-cost rate is 11.50% for TECO's electric utility operations.

Q. WHAT ARE THE AREAS OF DISAGREEMENT IN ESTIMATING THE RATE OF RETURN OR COST OF CAPITAL IN THIS PROCEEDING?

A. As I discuss above, the primary issues related to the Company's rate of return include the following: (1) capital market conditions; (2) the capital structure; (3) DCF Approach; (4) CAPM Approach; (5) risk premium approach; (6) equity cost models applied to non-price regulated companies; and (7) other factors notably a flotation cost adjustment.

The capital market conditions, capital structure, and other factors were previously discussed. I address the remaining items below.

A. DCF Approach

Q. PLEASE SUMMARIZE MR. D'ASCENDIS' DCF ESTIMATES.

A. On pages 28-31 of his testimony and in Document No. 4, Mr. D'Ascendis develops an equity cost rate by applying the DCF model to his electric group. Mr. D'Ascendis' DCF results are summarized on page 2 of Exhibit JRW-7. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. Mr. D'Ascendis computes his dividend yield using the 60-day average stock price for the proxy companies. For the DCF growth rate, Mr. D'Ascendis uses three measures of projected EPS growth: the projected EPS growth of Wall Street analysts as compiled by Yahoo Finance, Zack's, *Value Line*. He reports a DCF equity cost rate of 9.89% for his electric group.

Q. WHAT ARE THE ERRORS IN MR. D'ASCENDIS' DCF ANALYSES?

A. There are several issues with Mr. D'Ascendis' DCF study. First and foremost, he gives very little weight to his DCF results in his final analysis and recommendation. Secondly, he relies exclusively on the overly-optimistic and upwardly-biased earnings per share ("EPS") growth-rate forecasts of Wall Street analysts and *Value Line*.

1. The Low Weight Given the DCF Results and the Reported DCF Results

Q. HOW MUCH WEIGHT HAS MR. D'ASCENDIS GIVEN HIS DCF RESULTS IN ARRIVING AT AN EQUITY COST RATE FOR THE COMPANY?

A. Apparently, very little, if any. The average of his mean constant-growth DCF equity cost rates is only 9.89% for his electric group. Had he given his DCF results more weight, he would have arrived at a significantly lower recommendation for his estimated cost of equity.

2. Exclusive Reliance on Analysts' EPS Growth-Rate Forecasts

Q. PLEASE REVIEW MR. D'ASCENDIS' DCF GROWTH RATE.

A. In his constant-growth DCF model, Mr. D'Ascendis' DCF growth rate is the average of the projected EPS growth-rate forecasts of Wall Street analysts as compiled by Yahoo Finance, Zack's, and *Value Line*.

Q. WHAT IS THE EFFECT OF MR. D'ASCENDIS' EXCLUSIVE RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE*?

A. Mr. D'Ascendis' exclusive reliance on the projected growth rates published by Wall Street analysts and *Value Line* inflates his estimates of growth rates. It seems highly unlikely that investors today would rely exclusively on the EPS growth-rate forecasts of Wall Street analysts and *Value Line* and ignore other growth-rate measures in arriving at their expected growth rates for equity investments.

As I previously stated, the appropriate growth rate in the DCF model is the dividend growth rate rather than the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth. Due to the inaccuracy of analysts' long-term-earnings growth-rate forecasts, the weight given to analysts' projected EPS growth rates should be limited.

Finally, not only are those forecasts inaccurate but they also are overly optimistic and upwardly biased. I have provided a discussion of this issue on pages 48 to 52 of this testimony and report on a study I conducted in Figure 10. Using the electric utilities and gas distribution companies covered by *Value Line*, this study demonstrates that *Value Line's* mean forecasted EPS growth rates are consistently greater than the achieved actual EPS growth rates over the 1985-2022 time period. Over the entire period, the mean forecasted EPS growth rate is over 200 basis points above the actual EPS growth rate. As such, the projected EPS growth rates for utilities are overly optimistic and upwardly based. Hence, exclusively using these growth rates as a measure of the DCF growth rate produces an overstated equity-cost rate. I also highlighted a study by Szakmary, Conover, and Lancaster (2008) who evaluated the accuracy of *Value Line*'s three-to-five-year EPS growth rate forecasts using companies

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in the Dow Jones Industrial Average over a thirty-year time period and found these forecasted EPS growth rates to be significantly higher than the EPS growth rates that these companies subsequently achieved.[46]

Q. HAVE CHANGES IN REGULATIONS IMPACTING WALL STREET ANALYSTS AND THEIR RESEARCH IMPACTED THE UPWARD BIAS IN THEIR PROJECTED EPS GROWTH RATES?

A. No. A number of studies I cite above demonstrate the upward bias has continued despite changes in regulations and reporting requirements over the past two decades. This observation is supported further by a 2010 McKinsey study entitled "Equity Analysts: Still Too Bullish," which involved a study of the accuracy of analysts' long-term EPS growth rate forecasts. The authors conclude that, after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation:[47]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. *Moreover, analysts have been persistently overoptimistic for the*

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[46] Szakmary, A., Conover, C., & Lancaster, C., *An Examination of* Value Line*'s Long-Term Projections*, J. BANKING & FIN., May 2008, at 820–33.

[47] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, *Equity Analysts, Still Too Bullish*, McKinsey on Fin., 14–17, (Spring 2010) (emphasis added).

> *past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.*

This is the same observation made in a *Bloomberg Businessweek* article.[48] The author concluded:

> **The bottom line:** Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.

B. Risk-Premium Approach

Q. PLEASE DISCUSS MR. D'ASCENDIS' RISK-PREMIUM ("RPM") APPROACH.

A. On pages 31-51 of his testimony and in Document No. 5, Mr. D'Ascendis develops an equity cost rate by using the RPM model. Mr. D'Ascendis reports an RPM equity cost rate of 11.47% for his electric group. For the electric group, the 11.47% RPM estimate is based on an RPM ROE of 11.48% using his own Predictive Risk Premium Model ("PRPM") and an RPM ROE of 11.47% using his Risk Premium Using an Adjusted Total Market Approach ("RPATM"). For the electric group, the PRPM uses a prospective A2 utility bond yield of 5.63% plus a PRPM risk premium of 5.67%. The RPATM approach uses an adjusted utility bond yield of 5.63% plus a risk premium of 5.66%.

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[48] Roben Farzad, *For Analysts, Things Are Always Looking Up*, Bloomberg Businessweek, June 10, 2010, https://www.bloomberg.com/news/articles/2010-06-10/for-analysts-things-are-always-looking-up.

Q. WHAT IS THE PRIMARY ERROR IN MR. D'ASCENDIS' RPM ANALYSIS?

A. The primary error is the excessive magnitude of the risk premiums used by Mr. D'Ascendis which is caused by his use of historical and projected stock and bond-market returns.

Q. PLEASE DISCUSS THE VARIOUS RISK PREMIUMS DEVELOPED BY MR. D'ASCENDIS.

A. Table 10 provides a summary of the six risk premiums developed by Mr. D'Ascendis. The first three approaches use historic stock and bond returns to develop a risk premium and the second three approaches use projected stock returns and risk premiums.

Q. PLEASE INITIALLY IDENTIFY THE OTHER ERRORS IN THE RISK PREMIUMS IN MR. D'ASCENDIS' PRPM ANALYSIS AS WELL AS THE OTHER SIX RISK-PREMIUM STUDIES THAT HE CONDUCTS.

A. There are two primary errors with Mr. D'Ascendis' PRPM and his six other risk-premium studies:

(A) the PRPM and risk-premium studies (1) – (3) listed below in Table 10 are based on historic stock and bond returns/yields, and as discussed below, there are numerous well-known empirical issues with using historical returns to estimate a projected risk premium; and

(B) risk-premium studies (4) – (6) listed below in Table 10 develop risk premiums using projected stock-market returns.

The primary issue with these latter three approaches is that the expected market returns are totally unrealistic and are based on excessive corporate earnings and economic growth rates.

Table 10
D'Ascendis Equity Risk Premium Studies

Equity Risk Premium Measure	Proxy Group of Fourteen Electric Utilities
Kroll Equity Risk Premium (1)	5.82 %
Regression on Kroll Risk Premium Data (2)	7.27
Kroll Equity Risk Premium based on PRPM (3)	9.35
Equity Risk Premium Based on Value Line Summary and Index (4)	10.25
Equity Risk Premium Based on Value Line S&P 500 Companies (5)	9.24
Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	12.62
Conclusion of Equity Risk Premium	9.09 %
Adjusted Beta (7)	0.81
Forecasted Equity Risk Premium	7.36 %

Source" D'Ascendis Direct Testimony, at 129.

Q. PLEASE EXPLAIN YOUR CRITIQUE MR. D'ASCENDIS' PRPM.

A. Based on his PRPM approach, Mr. D'Ascendis estimates a risk premium based on historic stock and bond returns and his prediction of volatility. The inputs to the model are the historical returns on the common shares of each company in the proxy group minus the historical monthly yield on long-term U.S. Treasury securities for some undefined period. Using a generalized form of ARCH, known as GARCH, each electric company's projected equity risk premium was determined using statistical software.[49]

Q. PLEASE ADDRESS THE PROBLEMS WITH MR. D'ASCENDIS' PRPM.

A. There are two primary issues with Mr. D'Ascendis' PRPM. First, it is based on the historical relationship between stock and bond returns. The errors associated with computing an expected equity risk premium using historical stock and bond returns are addressed in detail below. In short, there are a myriad of empirical problems, which result in historical market returns producing inflated estimates of expected risk premiums.

Second, I have seen the PRPM approach used by Mr. D'Ascendis and other witness from his firm for over ten years, and I have never seen the approach adopted by any regulatory commission. The approach is effectively a black box approach, as it cannot be duplicated without access to Mr. D'Ascendis' proprietary software. I believe that this is an issue in having this approach approved by a commission, as well as the fact that the PRPM ROE numbers are always high and variable. Finally, as indicated above, there are numerous empirical issues with using historical stock and bond return data to estimate an equity risk premium.

[49] ARCH stands for autoregressive, conditional, heteroskedasticity. It is a statistical approach to modelling the relationship between variables when volatility of the underlying data changes over time.

Q. PLEASE ADDRESS THE ISSUES INVOLVED IN USING HISTORICAL STOCK AND BOND RETURNS/YIELDS TO COMPUTE A FORWARD-LOOKING OR *EX ANTE* RISK PREMIUM.

A. As indicated, the PRPM and risk-premium studies (1), (2), and (3) are based on historical stock and bond returns/yields. It is well-known and well-studied that using historical returns to measure an *ex ante* equity risk premium is erroneous and overstates the true market or equity risk premium.[50] This approach can produce differing results depending on several factors, including the measure of central tendency used, the time period evaluated, and the stock-market index employed.

In addition, there are a myriad of empirical problems in the approach, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the "Peso Problem"); the company survivorship bias (only successful companies survive – poor companies do not survive); the measurement of central tendency (the arithmetic versus geometric mean, where geometric means tend to better capture negative returns and thus investor loss); the historical time horizon used; the change in risk and required return over time; the downward bias in bond historical returns; and unattainable return bias (the return computation procedure presumes monthly portfolio rebalancing).

The bottom line is that there are a number of empirical problems in using historical stock and bond returns to measure an expected equity risk premium.

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[50] These issues are addressed in a number of studies, including: Aswath. Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2017 Edition" NYU Working Paper, 2017, pp. 30-44; See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-86, (1983); Jay Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research* (Summer 2002); Bradford Cornell, *The Equity Risk Premium* (New York, John Wiley & Sons),1999, pp. 36-78; and J. P. Morgan, "The Most Important Number in Finance," p. 6.

Q. WHAT SOURCE DID MR. D'ASCENDIS USE FOR HISTORICAL RETURNS IN HIS RISK-PREMIUM APPROACHES (1), (2), AND (3)?

A. Approaches (1), (2), and (3) use historical stock and bond return series that are compiled and published by Kroll, a subsidiary of the investment advisory firm Duff & Phelps.[51]

Q. IS KROLL A RESPECTED FINANCIAL FIRM?

A. Yes. Kroll is a global investments advisory firm with offices in twenty-eight countries and 3,500 employees.

Q. WHAT IS KROLL'S OPINION REGARDING THE USE OF HISTORICAL STOCK MARKET RETURNS TO ESTIMATE AN EQUITY RISK PREMIUM?

A. In its Client Update on the equity risk premium, dated March 16, 2016, Kroll (Duff & Phelps) made the following statements regarding using historical returns to compute an equity risk premium ("ERP"):

> In estimating the conditional ERP, valuation analysts cannot simply use the long-term historical ERP, without further analysis. A better alternative would be to examine approaches that are sensitive to the current economic conditions. As previously discussed, Duff & Phelps employs a multi-faceted analysis to estimate the conditional ERP that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.[52]

[51] The investment firm Duff & Phelps acquired Kroll in 2018 and rebranded itself as Kroll in 2022.
[52] Duff & Phelps, Client Alert, March 16, 2016, p. 37 (emphasis supplied).

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Q. DOES KROLL USE A HISTORIC STOCK MARKET RETURN FIGURE AS ITS RECOMMENDED EQUITY OR MARKET RISK PREMIUM?

A. No.

Q. WHAT DOES KROLL SAY ABOUT THE EXPECTED ERP AND HISTORICAL RETURNS?

A. Kroll provides details about its perspective on historical returns versus its estimation of the ERP:

> ERP is a forward-looking concept. It is an expectation as of the valuation date for which no market quotes are directly observable. <u>While an analyst can observe premiums realized over time by referring to historical data (i.e., realized return approach or ex post approach), such realized premium data do not represent the ERP expected in prior periods, nor do they represent the current ERP estimate.</u> Rather, realized premiums represent, at best, only a sample from prior periods of what may have then been the expected ERP. To the extent that realized premiums on the average equate to expected premiums in prior periods, such samples may be representative of current expectations. But to the extent that prior events that are not expected to recur caused realized returns to differ from prior expectations, such samples should be adjusted to remove the effects of these nonrecurring events. Such adjustments are needed to improve the predictive power of the sample.[53]

Q. DOES KROLL PUBLISH ITS RECOMMENDED EQUITY OR MARKET RISK PREMIUM?

A. Yes. In fact, on the same site that Kroll sells their annual valuation handbook used by Mr. D'Ascendis, Kroll publishes its recommended estimate of the equity- or market-

[53] *Id.*, p. 35 (emphasis supplied).

risk premium.[54] Page 7 of Exhibit JRW-6 of my testimony shows Kroll's equity risk premium recommendations.

As noted above, Kroll is currently recommending an equity of market risk premium of 5.50%. This is much below Mr. D'Ascendis' risk premiums using historic data, and especially much lower than his risk premium using his PRPM approach. I find it puzzling that Mr. D'Ascendis would use the historical average annual stock return from the Kroll book and then ignore Kroll's recommendation as to the appropriate equity or market risk premium.

Q. DO YOU AGREE THAT THE U.S. EQUITY RISK PREMIUM OF 5.50% IS A REASONABLE AND WELL-SUPPORTED NUMBER IN THE CURRENT CAPITALIZATION CLIMATE?

A. Yes.

Q. PLEASE ASSESS MR. D'ASCENDIS' MARKET RISK PREMIUMS DERIVED FROM USING (1) *VALUE LINE*'S PROJECTED STOCK MARKET RETURN AND (2) BY APPLYING THE DCF MODEL TO THE S&P 500 AND USING *VALUE LINE* AND BLOOMBERG PROJECTED EPS GROWTH RATES.

A. Mr. D'Ascendis develops three risk premiums using projected stock-market returns. In approach (4), he uses *Value Line*'s projected stock-market return over the next five years. In approaches (5) and (6), he calculates an expected market return by applying

[54] https://www.kroll.com/en/insights/publications/cost-of-capital

the DCF model to the S&P 500 using projected EPS growth rates from Bloomberg and from *Value Line.*

As shown in Table 11, Mr. D'Ascendis uses expected stock-market returns of 15.15%, 14.14%, and 17.52% (average = 15.60%) for the three approaches (*Value Line* Expected Return, *Value Line* DCF Expected Return, and Bloomberg DCF Expected Return) and, using his projected risk-free rate of 4.15%, the resulting risk premiums are 11.00%, 9.99%, and 13.37%. The average market risk premium is 11.45%. With a current adjusted dividend yield of 1.50% for the S&P 500 in 2024, the implied projected EPS growth rates for the three approaches are 13.65%, 12.64%, and 16.02%. The average projected EPS growth rate is 11.45%.

Table 11
D'Ascendis' CAPM Market Risk Premium
Risk Premiums Derived from Expected Market Returns
Using *Value Line* and Bloomberg Projected EPS Growth Rate

	VL Exp. Ret.	VL DCF Exp. Ret.	BL DCF Exp. Ret.	Average
Dividend Yield	1.50%	1.50%	1.50%	2.00%
+ Expected EPS Growth	13.65%	12.64%	16.02%	14.10%
= Expected Market Return	15.15%	14.14%	17.52%	15.60%
+ Risk-Free Rate	4.15%	4.15%	4.15%	4.15%
= Market Risk Premium	11.00%	9.99%	13.37%	11.45%

Q. ARE MR. D'ASCENDIS' RISK PREMIUMS REFLECTIVE OF THE MARKET RISK PREMIUMS?

A. No. Mr. D'Ascendis' average market risk premium, as shown in Table 11, is computed using an average expected market stock return of 15.60%, minus the risk-free interest rate of 4.15%, which produce an average market-risk premium for the three approaches of 11.45%. This figure is well in excess of market risk premiums: (1) found in studies of the market risk premiums by leading academic scholars; (2) produced by analyses of historic stock and bond returns; and (3) found in surveys of financial professionals.

Page 6 of Exhibit JRW-6 provides the results of over fifteen market risk-premiums studies from the past fifteen years. Historic stock and bond returns suggest a market-risk premium in the 4.40% to 6.80% range, depending on whether one uses arithmetic or geometric mean returns. There have been many studies using *ex ante* models, and their market-risk premiums results vary from as low as 2.61% to as high as 6.00%. Finally, the market-risk premiums developed from surveys of analysts, companies, financial professionals, and academics suggest lower market-risk premiums, in a range of 3.40% to 5.70%. The bottom line is that there is no support in historic return data, surveys, academic studies, or reports from investment firms for Mr. D'Ascendis' average projected market-risk premium of 11.45%. As discussed below, the reason is that they are based on unrealistic long-term, earnings-per-share growth rates.

Q. INITIALLY, PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE EXPECTED STOCK MARKET RETURN OF 15.60%.

A. Simply put, the assumption of a 15.60% expected stock market return is excessive and unrealistic. The compounded annual return in the U.S. stock market is about 10% (9.80% according to Damodaran between 1928–2023).[55] Mr. D'Ascendis' CAPM results assume that return on the U.S. stock market will be more than 5*0 percent higher* in the future than it has been in the past. The extremely high expected stock market

[55] Aswath Damodaran, *Damodaran Online*, N.Y. Univ., https://pages.stern.nyu.edu/~adamodar/.

return, and the resulting market risk premium and equity cost rate results, is directly related to computing the expected stock market return as the sum of the adjusted dividend yield plus the expected EPS growth rate of 14.10%.

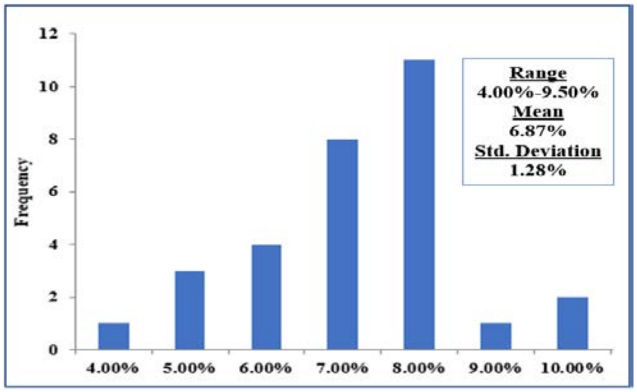
Q. IS MR. D'ASCENDIS' EXPECTED AVERAGE STOCK MARKET RETURN OF 15.60% REFLECTIVE OF THE STOCK MARKET RETURNS THAT INVESTMENT FIRMS TELL INVESTORS TO EXPECT?

A. No. And it is not even close! Many investment firms provide investors with their estimates of the annual stock returns that they should expect in the future. Most publish these expected returns in documents entitled "Capital Market Assumptions" and are available online at their websites. If you do an internet search for "Capital Market Assumptions," you get a long list of investment firms and their base case expected annual return assumptions for stocks, bonds, and other financial assets. In my search, I found thirty-one investment firms that published their capital market assumptions. These are listed in Exhibit JRW-8, and include many of the largest, best-known investment firms, including J.P. Morgan, BlackRock, BNY Mellon, Fidelity, Northern Trust, Vanguard, and State Street. Combined, these thirty firms manage over $50 trillion in assets under management.

Figure 14 provides a histogram of the expected returns listed in Exhibit JRW-8. The average duration of the long-term forecasts is 10 years. The range of the forecasted U.S. annual large cap equity returns is 4.00% to 9.50%. The mean and standard deviation of these expected returns are 6.87% and 1.28%.

Figure 14

Histogram of Investment Firm Expected Large Cap Equity Annual Returns 2023



Date Source: Exhibit JRW-8.

Q. WHAT ARE YOUR OBSERVATIONS ON THE STOCK MARKET RETURNS THAT INVESTMENT FIRMS TELL INVESTORS TO EXPECT?

A. I have three comments: (1) These returns are below the historical average compounded annual stock market return of 9.64% cited above (more on this below); (2) the standard deviation of 1.28% is very low, which indicates that the expected returns provided by these firms are quite similar; and (3) these expected returns indicate Mr. D'Ascendis' expected stock market return of 15.60%, which he calculates with his own study applying the DCF model to the S&P 500 and using analysts projected EPS growth rates, is more than double the returns investment firms tell investors they should expect.

Q. WHY DO YOU THINK THE STOCK MARKET RETURNS THAT INVESTMENT FIRMS TELL INVESTORS TO EXPECT ARE LOWER THAN HISTORICAL STOCK RETURNS?

A. The biggest factor is that the valuation of the overall stock market is high relative to historical standards. When stock prices are high, investors have to pay higher prices to

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buy in, which lowers their future expected returns. Figure 16 provides Schiller's cyclically-adjusted PE ratio (CAPE) over the last 100+ years. Stocks prices have remained above the mean historical CAPE level of 17.02% since 2009, with a current level of 28.80. Hence, the higher valuation of the stock market leads to lower expected returns.

Figure 15
Schiller S&P 500 CAPE Ratio
2023

The Schiller S&P 500 CAPE ratio is based on average inflation-adjusted earnings from the previous 10 years.
Date Source: https://www.multpl.com/shiller-pe

Q. PLEASE DIRECTLY ADDRESS MR. D'ASCENDIS' MARKET RISK PREMIUM DERIVED FROM USING *VALUE LINE*'S PROJECTED STOCK-MARKET RETURN.

A. In approach (4), Mr. D'Ascendis develops a market-risk premium using *Value Line's* projected stock-market return over the next three-to-five-years. In the previously cited study by Szakmary, Conover, and Lancaster (2008), the authors also evaluated the accuracy of *Value Line*'s three-to-five-year predicted annual stock return for the stock market over a thirty-year time period and found these predicted stock-market returns to be "extremely overoptimistic," well in excess of historic market returns, and were not significantly related to future realized returns.[56]

Q. IN APPROACHES (5) AND (6), MR. D'ASCENDIS USES ANALYSTS' EPS GROWTH-RATE FORECASTS IN APPLYING THE DCF MODEL TO THE S&P 500 USING DATA FROM *VALUE LINE* AND BLOOMBERG. PLEASE, ONCE AGAIN, ADDRESS THE ISSUES WITH ANALYSTS' EPS GROWTH-RATE FORECASTS.

A. The key point is that Mr. D'Ascendis' market-risk-premium approaches (5) and (6) are based on the concept that analysts' projections of companies' three-to-five EPS growth rates reflect investors' expected *long-term* EPS growth for those companies. However, this is erroneous given the research on these projections. Numerous studies have shown that the long-term, EPS-growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[57] Moreover, a 2011 study showed that analysts' forecasts of EPS growth over the next three-to-five years' earnings are no more accurate than their forecasts of the next single year's EPS growth.[58] The

[56] Szakmary, A., Conover, C., & Lancaster, C. (2008). An Examination of *Value Line*'s Long-Term projections. *Journal of Banking & Finance*, May 2008, pp. 820-833.

[57] Such studies include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance*, pp. 643−684, (2003); M. Lacina, B. Lee, and Z. Xu, (2011), *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp. 77-101.

[58] M. Lacina, B. Lee, & Z. Xu, (2011), *Advances in Business and Management Forecasting*, Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp. 77-101.

inaccuracy of analysts' growth-rate forecasts leads to an upward bias in equity cost estimates of approximately 300 basis points.[59]

I have also completed studies on the accuracy of analysts' projected EPS growth rates. In Figure 10 (page 51), I demonstrated that the EPS growth rate forecasts of Wall Street analysts are upwardly biased for electric utilities and gas distribution companies. In Figure 16, I provide the results of a study I performed using all companies followed by I/B/E/S who have three-to-five-year EPS growth rate forecasts over the 1985 to 2022 time period.

In this study, for each company with a three-to-five-year forecast, I compared the average three-to-five-year average EPG growth rate forecasts to the actual EPS growth rates achieved over the three-to-five-year time period. In Figure 16, the mean of the projected EPS growth rates is the red line and the mean of the actual EPS growth rates is the blue line. Over the thirty-five years of the study, the mean projected three-to-five-year EPS growth rate was 12.50%, while the average actual achieved three-to-five-year EPS growth rate was 6.50%. This study demonstrates that the projected three-to-five-year EPS growth rate forecasts are upwardly biased and overly optimistic.

[59] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45, *Journal of Accounting Research*, pp. 983–1015 (2007).

Figure 16
Mean Forecasted vs. Actual Long-Term EPS Growth Rates
All Companies Covered by I/B/E/S
1985–2022

Data Source: I/B/E/S, 2023.

Q. HAVE CHANGES IN REGULATIONS IMPACTING WALL STREET ANALYSTS AND THEIR RESEARCH IMPACTED THE UPWARD BIAS IN THEIR THREE-TO-FIVE YEAR EPS GROWTH-RATE FORECASTS?

A. No. A number of the studies I have cited here demonstrate that the upward bias has continued despite changes in regulations and reporting requirements over the past two decades. This observation is highlighted by a 2010 McKinsey study entitled "Equity Analysts: Still Too Bullish," which involved a study of the accuracy of analysts' long-term, EPS-growth-rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation:

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag

> behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. *Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.*[60]

This is the same observation made in a *Bloomberg Businessweek* article.[61] The author concluded:

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Q. IS THERE OTHER EVIDENCE THAT INDICATES THAT MR. D'ASCENDIS' RISK PREMIUMS COMPUTED BY USING *VALUE LINE*'S PROJECTED STOCK-MARKET RETURN AND BY APPLYING THE DCF MODEL TO THE S&P 500 AND USING *VALUE LINE* AND BLOOMBERG PROJECTED EPS GROWTH RATES ARE EXCESSIVE?

A. Beyond my previous discussion of the upwardly biased nature of analysts' projected EPS growth rates, the fact is that long-term EPS-growth rates of 13.45%, 11.50%, and 10.99% (average = 14.10%) are inconsistent with both historic and projected economic and earnings growth in the U.S for several reasons: (1) long-term EPS and economic growth is about one-half of Mr. D'Ascendis' average projected EPS growth rate of

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[60] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010) (emphasis added).

[61] Roben Farzad, "For Analysts, Things Are Always Looking Up," *Bloomberg Businessweek* (June 10, 2010), https://www.bloomberg.com/news/articles/2010-06-10/for-analysts-things-are-always-looking-up.

14.10%; (2) as discussed below, long-term EPS and GDP growth are directly linked; and (3) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future.

Long-Term Historic S&P EPS and GDP Growth rates have been in the 6%-7% Range - I performed a study of the growth in nominal GDP, S&P 500 stock-price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-9, and a summary is shown in Table 12.

Table 12
GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.40%**
S&P 500 Stock Price	**6.99%**
S&P 500 EPS	**7.11%**
S&P 500 DPS	**5.88%**
Average	**6.60%**

The results show that the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 6% to 7% range. By comparison, the average EPS growth rate used by Mr. D'Ascendis, 14.10%, is at best, an outlier. His estimates suggest that companies in the U.S. would be expected to increase their growth rate of EPS in the future by almost 100% and maintain that growth indefinitely in an economy that is expected to grow at about one-third of Mr. D'Ascendis' projected growth rates.

There is a Direct Link Between Long-Term EPS and GDP Growth - The results in Exhibit JRW-9 and Table 12 show that historically there has been a close link between long-term EPS and GDP growth rates. Brad Cornell of the California Institute of Technology published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related to GDP growth, with

GDP growth providing an upward limit on EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth and that "real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world":

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.[62]

<u>The Trend Indicates Slower GDP Growth in the Future</u> - The components of nominal GDP growth are real GDP growth and inflation. Annual Growth rates in nominal GDP are shown on page 2 of Exhibit JRW-9. Nominal GDP growth was in the four percent range over the past decade until the COVID-19 Pandemic hit in 2020. Nominal GDP fell by 2.2% in 2020, before rebounding and growing by over 10.0% in 2021 and in 2022. Page 3 of Exhibit JRW-9 shows the annual real GDP growth rate between 1961 and 2022. Real GDP growth has gradually declined from the 5.0% to 6.0% range in the 1960s to the 2.0% to 3.0% range during the 2015–2019 period. Real GDP fell by 3.5% in 2020, but rebounded and grew by 5.7% in 2021 and 2.1% in 2022.

The second component of nominal GDP growth is inflation. Page 4 of Exhibit JRW-9 shows inflation as measured by the annual growth rate in the Consumer Price Index (CPI) from 1961 to 2022. The large increase in prices from the late 1960s to the early 1980s is readily evident. Equally evident is the rapid decline in inflation during

[62] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February 2010), p. 63.

the 1980s as inflation declined from above ten percent to about four percent. Since that time, inflation has gradually declined and was in the 2.0% range or below from 2015 to 2020. Prices increased in 2021 and 2022 with the rebounding economy, and increased by 4.7% in 2021 and 8.0% in 2022. Year-over-year inflation in 2022 jumped to 40-year highs in 2022 due to supply chain issues and the Russia-Ukraine conflict, but longer-term inflation is expected to be in the 2.0%–3.0% range.

The graphs on pages 2, 3, and 4 of Exhibit JRW-9 provide clear evidence of the decline, in recent decades, in nominal GDP as well as its components, real GDP, and inflation. To gauge the magnitude of the decline in nominal GDP growth, Table 13 provides the compounded GDP growth rates for 10-, 20-, 30-, 40- and 50- years. Whereas the 50-year compounded GDP growth rate is 6.40%, there has been a significant decline in nominal GDP growth over subsequent 10-year intervals. These figures strongly suggest that nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy.

Table 13
Historical Nominal GDP Growth Rates

10-Year Average	4.59%
20-Year Average	4.32%
30-Year Average	4.65%
40-Year Average	5.21%
50-Year Average	6.16%

<u>Long-Term GDP Projections also Indicate Slower GDP Growth in the Future</u>: A lower range is also consistent with long-term GDP forecasts. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of on page 5 of Exhibit JRW-9.

The mean 10-year nominal GDP growth forecast (as of February 2023) by economists in the recent *Survey of Financial Forecasters* is 4.40%.[63] The Energy Information Administration (EIA), in its projections used in preparing *Annual Energy Outlook*, forecasts long-term GDP growth of 4.3% for the period 2023 to 2053.[64] The Congressional Budget Office (CBO), in its forecasts for the period 2023 to 2053, projects a nominal GDP growth rate of 3.8%.[65] Finally, the Social Security Administration (SSA), in its Annual OASDI Report, provides a projection of nominal GDP from 2023 to 2100.[66] SSA's projected growth GDP growth rate over this period is 4.1%. The average projected GDP growth rate for these four forecasts is 4.15%.

The bottom line is that the trends and projections suggest a long-term GDP growth rate in the 4.0% to 4.5% range. As such, Mr. D'Ascendis' average projected EPS growth rate of 14.10% is almost three times the projected GDP growth.

Q. WHAT ARE THE FUNDAMENTAL FACTORS THAT HAVE LED TO THE DECLINE IN PROSPECTIVE GDP GROWTH?

A. As addressed in a study by the consulting firm McKinsey & Co., two factors drive real GDP growth over time: (1) the number of workers in the economy (employment); and

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[63] Ten-year median projected real GDP growth of 2.00% and CPI inflation of 2.37%. *Survey of Professional Forecasters*, Fed. Reserve Bank of Philadelphia, https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/.

[64] *Annual Energy Outlook 2023*, U.S. ENERGY INFORMATION ADMINISTRATION, Table: Macroeconomic Indicators.

[65] *The 2023 Long-Term Budget Outlook*, CONGRESSIONAL BUDGET OFFICE, July 15, 2023.

[66] Social Security Administration, *2023 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program*, Table VI.G4, (July 1, 2023). The 4.1% growth rate is the growth in projected GDP from 2023 to 2100.

(2) the productivity of those workers (usually defined as output per hour).[67] According to McKinsey, real GDP growth over the past 50 years was driven by population and productivity growth which grew at compound annual rates of 1.7% and 1.8%, respectively.

However, global economic growth is projected to slow significantly in the years to come. The primary factor leading to the decline is slow growth in employment (working-age population), which results from slower population growth and longer life expectancy. McKinsey estimates that employment growth will slow to 0.3% over the next fifty years. They conclude that even if productivity remains at the rapid rate of the past fifty years of 1.8%, real GDP growth will fall by 40 percent to 2.1%.

Q. OVER THE MEDIUM TO LONG RUN, IS S&P 500 EPS GROWTH LIKELY TO OUTPACE GDP GROWTH?

A. No. Figure 17 shows the average annual growth rates for GDP and the S&P 500 EPS since 1960. The one very apparent difference between the two is that the S&P 500 EPS growth rates are much more volatile than the GDP growth rates, when compared using the relatively short, and somewhat arbitrary, annual conventions used in these data.[68] Volatility aside, however, it is clear that over the medium to long run, S&P 500 EPS growth does not outpace GDP growth.

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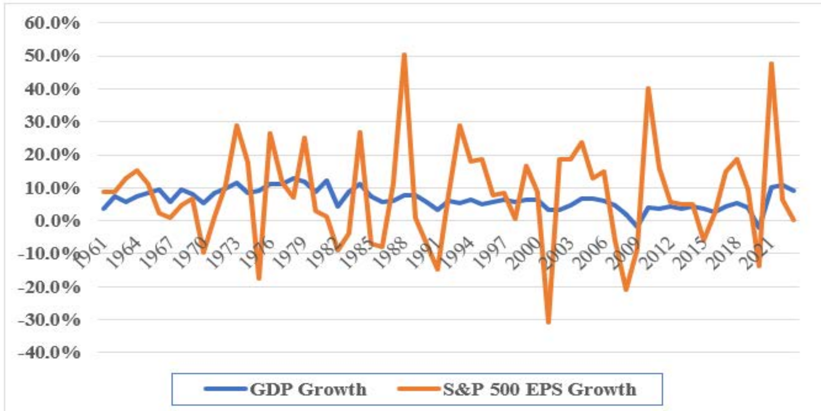
[67] McKinsey & Co., "Can Long-Term Growth be Saved?", McKinsey Global Institute, (Jan. 2015).

[68] Timing conventions such as years and quarters are needed for measurement and benchmarking but are somewhat arbitrary. In reality, economic growth and profit accrual occur on continuous bases. A 2014 study evaluated the timing relationship between corporate profits and nominal GDP growth. The authors found that aggregate accounting earnings growth is a leading indicator of the GDP growth with a quarter-ahead forecast horizon. *See* Yaniv Konchitchki and Panos N. Patatoukas, "Accounting Earnings and Gross Domestic Product," *Journal of Accounting and Economics* 57 (2014), pp. 76–88.

Figure 17
Average Annual Growth Rates
GDP and S&P 500 EPS - 1960-2023



Data Sources: GDPA - http://research.stlouisfed.org/fred2/series/GDPA/downloaddata.
S&P EPS - http://pages.stern.nyu.edu/~adamodar/

A deeper understanding of the relationship between GDP and S&P 500 EPS growth requires consideration of at least three factors, as follows.

<u>Corporate Profits are Constrained by GDP</u> – In a *Fortune* magazine article, Milton Friedman, the winner of the 1976 Nobel Prize in Economic Sciences, warned investors and others not to expect corporate-profit growth to sustainably exceed GDP growth, stating, "Beware of predictions that earnings can grow faster than the economy for long periods. When earnings are exceptionally high, they don't just keep booming."[69] In that same article, Friedman also noted that profits must move back down to their traditional share of GDP. In Table 14, I show that the aggregate net income levels for the S&P 500 companies, using 2022 figures, represent 6.11% of nominal GDP.

[69] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," Fortune, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

Table 14
S&P 500 Aggregate Net Income as a Percent of GDP

	2022 Value ($B)
Aggregate Net Income for S&P 500	$1,555.98
2021 Nominal U.S. GDP	25,461.34
Net Income/GDP (%)	6.11%

Data Sources: 2022 Net Income for S&P 500 companies
https://www.gurufocus.com/economic_indicators/5749/sp-500-net-income-ttm.
2022 Nominal GDP – https://pages.stern.nyu.edu/~adamodar/.

<u>Short-Term Factors Impact S&P 500 EPS</u> – The growth rates in the S&P 500 EPS and GDP can diverge on a year-to-year basis due to short-term factors that impact S&P 500 EPS in a much greater way than GDP. As shown above, S&P EPS growth rates are much more volatile than GDP growth rates. The EPS growth for the S&P 500 companies has been influenced by low labor costs and interest rates, commodity prices, the recovery of different sectors such as the energy and financial sectors, the cut in corporate tax rates, etc. These short-term factors can make it appear that there is a disconnect between the economy and corporate profits.

<u>The Differences Between the S&P 500 EPS and GDP</u> – In the last two years, as the EPS for the S&P 500 has grown at a faster rate than U.S. nominal GDP, some have pointed to the differences between the S&P 500 and GDP.[70] These differences include: (a) corporate profits are about 2/3 manufacturing driven, while GDP is 2/3 services driven; (b) consumer discretionary spending accounts for a smaller share of S&P 500 profits (15%) than of GDP (23%); (c) corporate profits are more international-

[70] *See* the following studies: Burt White and Jeff Buchbinder, "The S&P and GDP are not the Same Thing," LPL Financial, (Nov. 4, 2014), https://www.businessinsider.com/sp-is-not-gdp-2014-11; Matt Comer, "How Do We Have 18.4% Earnings Growth In A 2.58% GDP Economy?," Seeking Alpha, (Apr. 2018), https://seekingalpha.com/article/4164052-18_4-percent-earnings-growth-2_58-percent-gdp-economy; Shaun Tully, "How on Earth Can Profits Grow at 10% in a 2% Economy?," Fortune, (July 27, 2017), http://fortune.com/2017/07/27/profits-economic-growth/.

trade driven, while exports minus imports tend to drag on GDP; and (d) S&P 500 EPS is affected not just by corporate profits but also by share buybacks on the positive side (fewer shares boost EPS), and by share dilution on the negative side (new shares dilute EPS). While these differences may seem significant, it must be remembered that the Income Approach to measure GDP includes corporate profits (in addition to employee compensation and taxes on production and imports) and therefore effectively accounts for the first three factors.[71]

The bottom line is that despite the intertemporal, short-term differences between S&P 500 EPS and nominal GDP growth, the long-term link between corporate profits and GDP is inevitable.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE UNREASONABLENESS OF MR. D'ASCENDIS' 14.10% AVERAGE PROJECTED S&P EPS GROWTH RATE IN LIGHT OF PROJECTED GDP GROWTH.

A. Beyond my previous discussion, I have performed the following analysis of S&P 500 EPS and GDP growth in Table 15. Specifically, I started with the 2022 aggregate net income for the S&P 500 companies and 2022 nominal GDP for the U.S. As shown in Table 14, the aggregate profit for the S&P 500 companies represented 6.11% of nominal GDP in 2022.

[71] The Income Approach to measuring GDP includes wages, salaries, and supplementary labor income, corporate profits, interest and miscellaneous investment income, farmers' incomes, and income from non-farm unincorporated businesses.

In Table 15, I projected the aggregate net income level for the S&P 500 companies and GDP as of the year 2050. For the growth rate for the S&P 500 companies, I used Mr. D'Ascendis' average projected S&P 500 EPS growth rate of 14.10%. As a growth rate for nominal GDP, I used the average of the long-term projected GDP growth rates from CBO, SFF, SSA, and EIA (3.8%, 4.4%, 4.1%, and 4.3%, respectively), which is 4.15%. The projected 2050 level for the aggregate net income level for the S&P 500 companies is $62.52 trillion. Over the same period GDP is expected to grow to $79.5 trillion. As such, if the aggregate net income for the S&P 500 grows in accordance with the growth rate used by Mr. D'Ascendis, and if nominal GDP grows at rates projected by major government agencies, the net income of the S&P 500 companies will represent growth from 6.11% of GDP in 2022 to 78.64% of GDP in 2050. It is totally unrealistic for the net income of the S&P 500 to become such a large component of GDP.

Table 15
Projected S&P 500 Earnings and Nominal GDP
2022-2050
S&P 500 Aggregate Net Income as a Percent of GDP

	2022 Value ($B)	Growth Rate	No. of Years	2050 Value ($B)
Aggregate Net Income for S&P 500	$1,555.98	14.10%	28	$ 62,517.61
2022 Nominal U.S. GDP	$25,461.34	4.15%	28	$ 79,495.21
Net Income/GDP (%)	6.11%			78.64%

Data Sources: 2022 Net Income for S&P 500 companies
https://www.gurufocus.com/economic_indicators/5749/sp-500-net-income-ttm.
S&P 500 EPS Growth Rate - Mr. D'Ascendis' average projected S&P 500 EPS growth rate of 14.10%.
Nominal GDP Growth Rate – The average of the long-term projected GDP growth rates from CBO, SFF, SSA, and EIA (3.8%, 4.4%, 4.1%, and 4.3% = 4.15%).

Q. PLEASE PROVIDE A SUMMARY ANALYSIS ON GDP AND S&P 500 EPS GROWTH RATES.

A. The long-term link between corporate profits and GDP is inevitable. The short-term differences in growth between the two indicate that corporate profits as a share of GDP tend to go far higher after periods where they are depressed, and then drop sharply after they have been hovering at historically high levels. In a famous 1999 *Fortune* article, Mr. Buffet made the following observation:

> You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems. In my opinion, you have to be wildly optimistic to believe that corporate profits as a percent of GDP can, for any sustained period, hold much above 6%.[72]

In sum, Mr. D'Ascendis' average long-term S&P 500 EPS growth rate of 14.10% is grossly overstated and has little (if any) basis in economic reality. In the end, the big question remains whether corporate profits can grow faster than GDP. Jeremy Siegel, the renowned finance professor at the Wharton School of the University of Pennsylvania, believes that going forward, earnings per share can grow about half a point faster than nominal GDP, or about 5.0%, due to the big gains in the technology sector. But he also believes that sustained EPS growth matching analysts' near-term projections is absurd: "The idea of 8% or 10% or 12% growth is ridiculous. It will not happen."[73]

[72] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, (Nov. 22, 1999), https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

[73] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," *Fortune*, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

C. CAPM Approach

Q. PLEASE DISCUSS MR. D'ASCENDIS' CAPM.

A. On pages 31-51 of his testimony and in Document No. 6, Mr. D'Ascendis develops an equity cost rate by using the CAPM. Mr. D'Ascendis uses both the CAPM and the so-called empirical CAPM approaches ("ECAPM"). Mr. D'Ascendis' reports CAPM and ECAPM results of 12.48% for his electric group. Mr. D'Ascendis uses a projected rate of 4.15% for the long-term Treasury bond, betas from *Value Line* and Bloomberg, and a market-risk premium of 10.02%. The market risk premium is the average of three *Value Line* and Bloomberg projected market-risk premiums which were reviewed above.[74]

Q. WHAT ARE THE ERRORS IN MR. D'ASCENDIS' CAPM ANALYSIS?

A. There are two primary flaws with Mr. D'Ascendis' CAPM analyses: (1) the use of the so-called ECAPM; and (2) the market-risk premium of 10.02%. The highly overstated market-risk premium was discussed extensively above.

1. <u>The Validity of the ECAPM</u>

Q. WHAT ISSUES DO YOU HAVE WITH MR. D'ASCENDIS' ECAPM?

A. Mr. D'Ascendis has employed a variation of the CAPM which he calls the 'ECAPM.' The ECAPM attempts to model the well-known finding of tests of the CAPM that have indicated the Security Market Line ("SML") is not as steep as predicted by the CAPM.

[74] These include: (1) *Value Line*'s projected stock market return over the next five years minus the yield on Aaa corporate bond yields; (2) applying the DCF model to the S&P 500 companies using Value Line projected EPS growth rates and subtracting the risk-free interest rate; and (3) applying the DCF model to the S&P 500 companies using Bloomberg projected EPS growth rates and subtracting the risk-free interest rate.

The ECAPM is nothing more than an *ad hoc* version of the CAPM and has not been theoretically or empirically validated in refereed journals. The ECAPM provides for weights which are used to adjust the risk-free rate and market-risk premium in applying the ECAPM. Mr. D'Ascendis uses 0.25 and 0.75 factors to boost the equity risk premium measure, but provides no empirical justification for those figures.

Beyond the lack of any theoretical or empirical validation of the ECAPM, there is another error in Mr. D'Ascendis' ECAPM. I am not aware of any tests of the CAPM that use adjusted betas such as those used by Mr. D'Ascendis. Adjusted betas address the empirical issues with the CAPM by increasing the expected returns for low beta stocks and decreasing the returns for high beta stocks.

2. <u>Inflated Market Risk Premium</u>

Q. PLEASE DISCUSS THE ISSUES WITH MR. D'ASCENDIS' CAPM MARKET RISK PREMIUM?

A. Mr. D'Ascendis develops his CAPM market risk premium of 10.02% using the same six approaches employed in his Risk-Premium approach. As discussed extensively on pages 63-71 of this testimony, the 10.02% market-risk premium is much higher than published market-risk premiums, and is developed using highly unrealistic assumptions of future earnings growth and stock-market returns.

D. Equity Cost Rate Models Applied to Non-Price Regulated Proxy Group

Q. PLEASE DISCUSS MR. D'ASCENDIS' NON-PRICE REGULATED PROXY GROUP.

A. Mr. D'Ascendis has applied his equity cost rate approaches to his utility proxy and a proxy group of non-price regulated companies. Mr. D'Ascendis' equity cost rate results are reported on page 2 of Exhibit JRW-7. He reports ROE results of 12.95% for unregulated companies "comparable" to his electric group. The non-price regulated group includes forty-five that Mr. D'Ascendis claims are similar in risk to his electric group.

Q. PLEASE DISCUSS THE PROBLEM WITH MR. D'ASCENDIS' NON-PRICE REGULATED PROXY GROUP.

A. These companies are listed in page 3 of Document No. 7 of his testimonies. This group includes such companies as Abbott Labs, Air Products, Cisco, IBM, Lockheed, Pfizer, Sherwin-Williams, and Texas Instruments. While many of these companies are large and successful, their lines of business are vastly different from the electric and gas distribution businesses, and they do not operate in a highly regulated environment, and certainly none of these companies' product prices or profit margins are regulated. However, most significantly, the upward bias in the EPS growth rate forecasts of Wall Street analysts is particularly severe for non-price regulated companies.

Q. IS THIS BIAS REFLECTED IN MR. D'ASCENDIS' DCF ANALYSIS FOR THE NON-PRICE REGULATED GROUP?

A. Yes. Figure 16 (page 92) shows that the mean analyst projected EPS growth rate for companies covered by I/B/E/S of 12.50%, was almost double the average actual achieved EPS growth rate of 6.50%. Hence, DCF estimates for non-price regulated companies using analysts' projected EPS growth rates, such as those in this group, are particularly overstated.

E. Other Factors

Q. WHAT OTHER FACTORS DID MR. D'ASCENDIS CONSIDER IN HIS 10.50% ROE RECOMMENDATION?

A. Mr. D'Ascendis includes a flotation cost adjustment of 0.10% in his ROE analysis and recommendation. However, there is no evidence that TECO has paid flotation costs. Hence, TECO should not receive higher revenues in the form of a higher ROE for flotation costs that the Company does not incur.

1. <u>Flotation Costs</u>

Q. DO YOU AGREE THAT AN ADJUSTMENT FOR FLOTATION COSTS IS JUSTIFIED IN THIS CASE?

A. No. First, Mr. D'Ascendis did not provide evidence that TECO has paid flotation costs. As such, there is no need to consider flotation costs in arriving at an equity cost rate for the Company. The Company should not be rewarded with higher revenues (through a higher ROE) for expenses which it does not incur.

In addition, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. In this case, a flotation cost adjustment is justified by reference to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.5 times actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment should be downward.

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at or below its book value. As noted above, electric utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease.

(3) Flotation costs consist primarily of the underwriting spread or fee, and not out-of-pocket expenses. On a per-share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. These are thus not

expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price that they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. The company is therefore not entitled to an adjustment to the allowed return to account for those costs.

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transaction costs, they have not accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in their DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

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VII. SUMMARY AND CONCLUSIONS

Q. DR. WOOLRIDGE, PLEASE SUMMARIZE YOUR TESTIMONY ON THE APPROPRIATE COST OF CAPITAL FOR TECO.

A. I have reviewed the Company's proposed capital structure and overall cost of capital. TECO's proposed capitalization has more equity and less financial risk than the average current capitalizations of the proxy groups. The Company's proposed capital structure includes a common equity ratio of 54.00% versus 41.7% and 41.1% for the averages of the two proxy groups. Nonetheless, while I am not contesting this capital structure, but I have also selected a ROE which recognizes this high common equity ratio. I have also adopted the Company's short-term and long-term debt cost rates. To estimate an equity cost rate for the Company, I have applied the DCF and CAPM approaches to two proxy groups: (1) my group of publicly-held electric utility companies ("Electric Proxy Group"); and (2) the group developed by Mr. D'Ascendis ("D'Ascendis Proxy Group"). My analysis indicates a common equity cost rate in the range of 8.85% to 10.00% for TECO in this case. Given that I rely primarily on the DCF model and the results for the Electric Proxy Group, I believe that the appropriate ROE range for the Company is in the 9.25%-9.75% range. Given that: (1) TECO's investment risk is a little below the average of the two groups; and (2) I have employed a capital structure that has more common equity and less financial risk than the average of the two proxy groups as well as TECO's parent, Emera, I am recommending a ROE of 9.50%. Given this ROE and my proposed capital structure and senior capital cost rates for TECO, I am recommending an overall fair rate of return or cost of capital of 7.19% for TECO. This recommendation is summarized in Table 2 and Exhibit JRW-1.

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Q. **DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?**

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's petition. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

C24-2493

BY MS. CHRISTENSEN:

Q Dr. Woolridge, did you also have 10 exhibits, including your appendix, attached to your prefiled testimony?

A Yes, I did.

Q Did you have any corrections to those exhibits?

A No.

Q I would ask at this time, Dr. Woolridge, that give your summary of your testimony.

A Okay. The company has proposed a capital structure with a higher common equity ratio of 54 percent than the average of the two proxy groups. Nonetheless, I am adopting the proposed capital restructuring testimony, and I have selected a return on equity recognized as the high common equity ratio. The estimated cost of equity for the company I have applied the discounted cash flow and Capital Asset Pricing Models to the two proxy groups of electric utilities.

My analysis indicates a common equity cost rate in the range of 8.85 percent to 10 percent for TECO, in this case. Given that I rely primarily on the DCF model and the results for the electric proxy group, I believe that appropriate ROE range for the company is 9.25 percent to 9.75 percent. I am recommending an ROE of 9.50 percent, and emphasizing that, first of all, TECO is a little less risky than the average of the groups. And two, I have applied a common equity ratio -- capital structure with a high common equity ratio of 54 percent.

In my testimony, I also provide an overview of capital market conditions. I note that the increase in inflation and interest rates within the last two years, which is tied to a rebounding economy, have to -- have subsided. The Treasury -- the 30-year Treasury yield, we peaked at five percent earlier this year, is now about 75 basis points below that. And the yield curve is still inverted, which tells you that interest rates are going to go lower.

Mr. D'Ascendis has developed a proxy group and employed discount cash flow risk premium CAPM, and he also applies these models to a proxy group of nonutility companies. Based on these figures, he comes to the appropriate ROE for the company of 11.5 percent.

Now, Mr. D'Ascendis' results are -- suffer from two errors. First of all, his DCF results are more than 200 basis points below his CAPM risk premium market models approaches. Clearly he gave little, if no, weight to the most basic concept in cost of capital, which is the DCF approach.

Second of all, if you look at his ROE results, they clearly are driven by one factor, and that is the risk premium in his CAPM, his risk premium and market models approaches.

In my testimony, I provide about 30 pages of testimony talking about the empirical errors and erroneous assumptions used and that lead to his high market risk premiums and ROE recommendations. These are detailed in my testimony. The primary area of this risk premium is based on an overstated stock market return, which is based on inflated projected earnings and GDP growth rates.

The bottom line is, his market risk premium is bigger than the market risk premiums discovered in studies of -- by finance scholars, used by elite investment banks like JP Morgan, and also found in surveys of companies and CEOs. I have used a market risk premium of 5.25 percent, which is based on 30 studies and surveys done in the market literature.

Now my ROE of 9.5 percent is very consid -- reasonable considering the following, TECO is less risky than the groups. I have adopted the high equity ratio of the capital structure. In the authorized ROEs for electric utility, the average authorized ROE last year was 9.60 percent. That means that TECO's recommended

ROE at 11.5 percent is about 250 basis points above the average. And mine is very much in line with the average ROE granted electric utilities last year.

I had also mentioned in my testimony that clearly my number meets Hope and Bluefield standards. Electric utilities have been earning eight percent -- eight to percent -- eight to 10 percent ROEs. They have very good bond ratings, investment grade. Their market to book ratios were above one, and they are raising an abundance amount of the capital.

One other issue I want to say, on pages 19 and 20 of my testimony, I demonstrate that authorized ROEs for electric utilities, while they hit all time lows in '20 and '21, they never fell nearly as much as interest rates fell during those time periods. So now that interest rates have gone up, authorized ROEs are not going up by nearly as much.

In 2020 and 2023, the average 30-year Treasury yield increased 100 basis points. The average authorized ROE for electric utilities increased only by 10 to 20 basis points. So the bottom line is interest rates and authorized ROEs haven't been -- don't move in lockstep fashion.

That's my summary.

Q Thank you, Dr. Woolridge.

MS. CHRISTENSEN: We would tender Dr. Woolridge for cross.

CHAIRMAN LA ROSA: Great. Thank you.

Florida Rising/LULAC.

MR. MARSHALL: No questions.

CHAIRMAN LA ROSA: FIPUG.

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FEA.

CAPTIAN GEORGE: No questions.

CHAIRMAN LA ROSA: FRF.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. MEANS: No questions.

CHAIRMAN LA ROSA: Staff.

MR. MARQUEZ: No questions.

CHAIRMAN LA ROSA: Commissioners?

All right. I send it back to redirect -- oh, I am sorry. Sorry, commissioner Passidomo, so hard to see over there to my left.

COMMISSIONER PASSIDOMO: I didn't -- this is quick. I just am curious, and since everybody else flew through, I thought I would take just a brief moment.

When you mention that TECO is less risky than its proxy groups, can you just kind of walk me through why you think that?

THE WITNESS: Yeah. I use credit ratings to assess -- I mean, there is different measures of risk, and I don't think there is one perfect measure of risk. I use credit ratings, because they are independent, and the credit ratings of TECO are slightly better. Their Moody's ratings are BBAA1. The average of the other groups is BAA2. Other than that, they have an S&P rating of BBB+, which is the same as the proxy. So I conclude, based on credit ratings, they are just slightly less risky than the average of the proxy groups.

COMMISSIONER PASSIDOMO: And -- but is there any sort of geographical risk associated with TECO that got factored in there?

THE WITNESS: No -- well, it is in the sense that the credit rating agencies very much look at geography and risk to exposures, and that sort of thing, so, yeah. And their S&P and Moody's credit rating very much reflects various risks that TECO faces.

COMMISSIONER PASSIDOMO: Okay. Thank you.

CHAIRMAN LA ROSA: Thank you.

I will send it back to TECO for -- sorry, for OPC for redirect.

MS. CHRISTENSEN: I have no redirect.

I would ask, if I have not already, to have Dr. Woolridge's testimony entered into the record as though read.

CHAIRMAN LA ROSA: Okay.

MS. CHRISTENSEN: And I also request that we move his exhibits, JRW-1 through JRW-9, plus the appendix, which have been prelisted as Exhibits 63 through 71, into the record.

CHAIRMAN LA ROSA: Is there objection?

MR. MEANS: No objection.

CHAIRMAN LA ROSA: Seeing no objections --

MR. MARQUEZ: Could I just get some clarification from OPC? Which exhibit number was the appendix, Ms. Christensen, or do we need to assign it a new one?

MS. CHRISTENSEN: We may need to assign that a number. It was filed -- I think it may not have gotten a number in your Comprehensive Exhibit List. So in the abundance of caution, if we could ask that that be assigned a separate number and moved in. That would be --

MR. MARQUEZ: 842.

MS. CHRISTENSEN: Thank you.

(Whereupon, Exhibit No. 842 was marked for identification.)

CHAIRMAN LA ROSA: All right. So I think we are cleaned up there. Are there -- is there objections?

MR. MEANS: No objection.

CHAIRMAN LA ROSA: Okay. All right. Seeing no objections, show that entered into the record.

(Whereupon, Exhibit Nos. 63-71 & 842 were received into evidence.)

CHAIRMAN LA ROSA: Are there any other exhibits? Seeing none other, I believe we are good.

Dr. Woolridge, thank you.

THE WITNESS: Thank you very much. Thank you for --

CHAIRMAN LA ROSA: You are excused. Of course.

(Witness excused.)

(Transcript continues in sequence in Volume 13.)

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 videotaped 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 5th day of October, 2024.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028