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FPSC - COMMISSION CLERK

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 8 - PAGES 1559 - 1798

PROCEEDINGS: HEARING

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

DATE: Wednesday, August 28, 2024

TIME: Commenced: 8:00 a.m.
Concluded: 9:15 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
25	As identified in the CEL		1637
146	As identified in the CEL		1637
838	As identified in the CEL		1637
580	As identified in the CEL		1637
511-512	As identified in the CEL		1639
663	As identified in the CEL		1639
766	As identified in the CEL		1639
831	As identified in the CEL		1639
26	As identified in the CEL		1748
147	As identified in the CEL		1748
27	As identified in the CEL		1797

P R O C E E D I N G S

(Transcript follows in sequence from Volume 7.)

CHAIRMAN LA ROSA: All right. We can jump back in if we are ready.

MR. LUEBKEMANN: Yes. Thank you, Mr. Chair.

CHAIRMAN LA ROSA: Sure.

EXAMINATION continued

BY MR. LUEBKEMANN:

Q All right. So, Ms. Cifuentes, do you recognize the document that's pulled up?

A Yes, I do.

Q Okay. And this is a report of the peak demand from 2019?

A Yes.

Q I apologize. Give me one second. Okay. And for context, this is master number F16-89 from Comprehensive Exhibit 831.

Okay. So this report is from 2019. We are going to also go through separate documents that you have for 2020 through 2023. We are going to try to be as efficient as possible in going through these; but for all of these documents, these are work papers from the development of your testimony and MFRs?

A Yes, I believe they are.

Q Okay. Can we scroll down to the section that is retail peak demand? This is going to be row 109. And this section includes the real, actual and forecasted peaks for each month of 2019?

A That's correct.

Q So, for instance, in 2019, January was forecast to have a peak of 4,337 megawatts?

A That's correct.

Q And the actual peak demand for January was 3,091 megawatts?

A That's correct.

Q So looking at the cell below the forecast number, that represents a variance of negative 29 percent?

A That's correct.

Q And so put another way, TECO's forecast was 29 percent higher than the actual for January 2019?

A That's correct. And just to remind you that our winter forecast, we forecast a 31-degree peak at the time -- at the time of the peak, because we need to plan to make sure -- ensure we have the capacity to meet a winter load.

We do have an occasional winter load -- winter load. And in fact, we don't have the 2010 peak report, but if we did, that would show that that peak in 2010, we had 14 consecutive days of cold weather. That peak is actually only 50 megawatts or so off of our 2024, 2025 winter peak. So if we have a winter peak, we are going to have a pretty sharp spike in the demand.

So I just want to explain why we forecast for 31 degrees, and we don't meet that every year. But like I said, when we have a winter, we will meet it and even surpass it.

Q And so if I could draw your attention back to the forecast row. If we look across the row, that row that has 4,337 for January. If you look across that row for the rest of the year, January is actually forecast to be the peak for 2019?

A Say that -- January? Yes.

Q January of 2019 was forecast to be the system -- the retail system peak for the year?

A Yes. Yes.

Q But the actual retail peak for that year was 4,298 megawatts in June?

A That is correct.

Q And if we look at the actual peak demand for January, that 3,091 megawatt number, if we look across the rest of that row, would you agree that the actual peak was higher than the actual peak in January for the months of February, March, April, May, June, July,

August, September, October and November of 2019?
A I would agree.
Q And so putting aside the months of June through August, that's seven months outside of the 4CP months that TECO uses, with higher peaks than January?
A Again, I don't want to speak to 4CP. I am not that familiar with it. That's a question for Jordan -- Jordan Williams.
Q It is your sales forecast data that goes into Mr. Williams' models?
A Yes, they do.
Q And so it is the peaks from those months that drive the cost of service that he uses?
A That, as well as a number of other things.
Q And as we sit here today, it is your understanding that the peaks that are used in the 4CP model are January, June, July and August, is that correct?
A That would be correct.
Q Okay.
A Our June, July and August peaks were dead on.
Q Can we go to the section Net Integrated Retail Firm Peak Data? It should be around line 129 -- or 117, yeah, that's -- that's right.
This section includes, for each month, the

total megawatts available for interruption?
A I am sorry. Where are we looking?
Q So on line 129.
A Okay.
Q That line represents the monthly total available megawatts that could be interrupted?
A That's correct.
Q And the actually -- the total megawatts actually curtail to that month are represented by line 123, which is called Curtailed Megawatts Interruptible?
A Yes. 123 and 128 -- oh, no, 123. You are correct.
Q And subject to check, looking across the row for potentially curtailable, that line 123 ranges from roughly 180 to 260 megawatts, depending on the month?
A That is correct.
Q And those potentially curtailable megawatts are the basis for credits to interruptible customers?
A I am not sure. For these purposes, it is what is -- we reduce to get to firm load, to get, you know, do reserve margin calculations. As far as credits to customers, I don't know if it's the same amount or not.
Q Questions about how retail -- or how about credits are calculated for interruptible customers would be best directed to another witness?

A Yes, it would.

Q But you would agree, if you look across that row, that TECO did not interrupt or curtail any load from those customers at any point over the year?

A At any time of the peak. There could have been another hour that was not our reported monthly peak that there could have been an interruption. This is just one point in time for each month.

Q Sure.

To your knowledge, does TECO interrupt its interruptible or curtailable customers at times other than peak periods?

A I can't answer that. I am not sure, but I would think they could.

Q But you don't have any evidence that they do?

A No. What I will say is if they did interrupt, I mean, that's going to reduce our peak. So it might not show up as our actual monthly peak, if that makes sense.

Q But if they interrupted, it would show up as reducing the firm load, is that not true?

A It would reduce firm load, but I don't know if it would reduce the actual peak load on these reports.

Q Okay. Fair enough.

We will move on now to the same report for

2020. The number there is F16-90. And we did some groundwork on that first one, so I think we can move through this -- the following years a little more quickly.

A Okay.

Q Okay. If we could go back down to the retail peak section, beginning with row 115. Thank you.

For 2020, January was forecast to have a peak of 4,384 megawatts?

A That's correct.

Q And a few rows above that, the actual peak for January was 3,538 -- 3,538?

A That's correct. It was a 37-degree peak versus a 31.

Q And so that forecast was 19 percent higher than the actual?

A Correct.

Q And looking across the rest of the forecast row, January was expected to be the peak for 2020?

A January was, yes.

Q And the actual peak for 2020 was 4,255 megawatts in September.

A That's correct.

Q And September is not one of the 4CP months that we discussed?

A No, it is not.

Q And looking back at the actual peak for January of 3,538 megawatts, actual peak was higher in March, April, May, June, July, August, September and October?

A That's correct.

Q So putting aside the months of June to August, that's five months with higher demand than January outside of TECO's 4CP months?

A That would be right.

Q We go now to the net integrated retail firm peak data, and just looking across line 130. TECO did not interrupt or curtail any load from its interruptible curtailable customers during any of the peaks of the year?

A That's correct here.

Q All right. We are flying now. Can we go to the report for 2021? The number on that is F16-91. When that's open, we are going to go back to the retail peak demand on row 126. Great.

So if you look on row 131, January 2021 was forecast to have a peak of 4,400 megawatts?

A Yes.

Q And the actual peak demand for January was 2,905 megawatts?

A Yes.

Q So TECO's forecast was 34 percent higher than the actual?

A Yes.

Q And January was forecast to be the annual peak for 2021?

A Yes.

Q But the actual peak for 2021 was 4,393 megawatts in August?

A That's correct.

Q And looking at the actual peak for January 2,905 megawatts. The actual peak was higher in every single other month of the year?

A Yes. That's usually the case in January if we don't have a winter peak. But the June, July and August peaks are typically the higher ones. But like I said, we have to forecast for a cold winter peak. We can't avoid that.

Q But once again, putting aside the months of June through August, that's eight months with higher demand than January outside of the 4CP months?

A Yes.

Q If we go to net integrated retail firm peak data. On line 141, this shows that TECO did not interrupt or curtail any load from interruptible or

curtailable customers during any of the yearly peaks --
A Correct.
Q -- the monthly peaks of the year?
We move on to 2022. It's F16-92. Retail peak demand is at row 131 in this document.
Okay. So a few lines below that, January 2022 was forecast to have a peak of 4,461 megawatts?
A Yes.
Q And the actual peak demand was 3,735 megawatts?
A Yes.
Q And so TECO's forecast was correspondingly 16 percent higher than the actual?
A Correct.
Q If you look across the forecast row, January was expected to be the peak for 2022 annually?
A Yes.
Q And the actual peak for 2022 was 4,381 -- 85 -- sorry, 4,385 megawatts in June?
A Yes.
Q And looking at the actual peak demand for January, the actual peak was higher in May through September?
A Yes.
Q So that's two months with higher peaks in

January outside of the 4CP months?

A Correct.

Q Okay. And at line 146, just confirming that TECO did not interrupt or curtail any customers during any of the monthly peaks of the year?

A That is correct.

Q Okay. Moving on to the last one in this batch. That's F16-93, which will have the 2023 peak demand.

Okay. So January 2023 was forecast to have a peak of 4,461 megawatts?

A Yes.

Q And the actual peak was 3,347 megawatts?

A Yes.

Q Which was a variance 25 percent higher than the actual?

A Yes.

Q And January was expected to be the peak annually --

A Yes.

Q -- for 2023?

A January will always be the peak.

Q And the actual peak was in August?

A Correct.

Q With 4,669 megawatts?

A   Yes.

Q   And so looking back at the actual peak demand for January, the monthly peaks were higher in March through November?

A   Yes.

Q   And so that's six months with higher peaks than January outside of TECO's 4CP months?

A   Yes.

Q   And if we go to line 143, looking across at November, TECO curtailed 109 megawatts of interruptible customers during that monthly peak?

A   In November, yes.

Q   In November?

And that was the only instance of curtail -- of curtailment that we have seen in the five years of annual data that we have available to review here?

A   Within five years, I thought we had reported one more. I don't know when that was. It did not fall, obviously, on any of the peak times.

Q   You might be right. I think that you are right.

And if we could also look in row 130 and 131. And I am looking at November. The peak for the month of November occurred in the hour ending in 5:00 p.m.?

A   In November?

Q I am looking at cells M130 and M131 -- oh, I am sorry. That's the hour ending in 4:00 p.m. --

A 4:00. 4:00.

Q -- you are right.

A Okay.

Q And the ambient temperature at that time was 87 degrees?

A That's correct.

Q Okay. And I actually left one thing out in the 2022 report, so if we could go back to that really quickly. F16-92. Okay. Thank you.

There, if we could go to the same place, looking at the peak for November, the time and the temperature for November of 2022, the peak occurred in the hour ending in 5:00 p.m.?

A I don't have '22 up yet. Sorry. I can't see that.

Q That's fair. Bates stamp -- BS46, the beginning of the document.

A Okay. Thank you. Okay.

Q And I apologize for missing this when we were actually on the document.

A Okay. So what are we looking at again?

Q So looking here at the November peak, and I am -- it's row 133 and 134. The peak for the month of

November occurred at -- in the hour ending at 5:00 p.m.?
A That's correct.
Q And the ambient temperature at that time was 86 degrees?
A Yes, it was.
Q Okay. We are done with these.
A I want to -- I mean, you didn't -- you don't have the 2024 peak demand report, but I wanted to just reiterate. In our January peaks -- and I am not talking 4CP. I am just talking in general now. Our January peaks are always going to be our highest peak, because we have to plan for the 31-degrees, you know, winter peak. We need to make sure we have enough capacity on the ground to serve a winter peak. We don't have one every year, but we still have to plan for that.
And I just want to point out again, our June and July, our last two months, our peaks were within eight megawatts. That's two-tenths of a percent. So our current forecasts -- my point is our current forecasts that are used in this proceeding are very, very accurate.
Q Could we go to number F16-97. This is Exhibit 831 from staff's third. And when that is up, we are going to go to the tab total of retail.
Are you there?

A I am here.

Q Okay. This document, or this tab is showing the historic retail peaks from 1973 through 2023?

A Yes. This is one of our working files.

Q And the bolded blue numbers in this chart represent summer peaks?

A I think that was the intent.

Q Presumably the blue is for cooling, compared to the red for heating for the other bolded numbers?

A Yes. They would be cold peaks versus a hot --

Q Okay.

A -- peak.

Q And generally speaking, cold peaks, hot peaks are interchangeable with summer and winter peaks?

A Yes.

Q I might have flipped those, but that's --

A Yes.

Q -- the idea.

A I get what you are saying.

Q So starting with the blue bolded numbers, one year had -- just looking down the row, and we will look at May. So if we --

A Yeah.

Q Are you on tab Total Retail?

A Okay. Now it is.

Q Okay. So if you go to the column for May, you would agree, scrolling down, that there is one year for which the summer peak fell in May?
A Yes.
Q Okay. And if we look over at September, and count five years that the summer peak fell in September?
A Yes.
Q Okay. Now, looking at the red numbers, going, first, to the column for February. Would you agree that there are 13 years with a winter peak in February? I will give you a second to count.
A How many did you say?
Q 13.
A I counted 15, but --
Q We can take 15.
A Now I counted 12. So I will go with your number.
Q Okay. I genuinely believe that it is 13, but it is --
A Okay.
Q -- entirely possible I have miscounted.
And then looking now at the column for March, there were five winter peaks -- five years with the winter peak occurring in March?
A Yes, I have got five.

Q And then moving to the column for November, there were four with a winter peak in November?
A Yes.
Q And then looking at the column for December, there were three years with a winter peak in December?
A Yes.
Q And you would agree that March, May, September, November and December are all outside of the 4CP months?
A Can you repeat that?
Q March, May, September, November and December are not within the 4CP months that we have been talking about?
A Correct.
Q And so if you will accept my representation on the summing there, that would be 25 years for which at least one seasonal peak, if not both, occurred outside of the 4CP months, subject to check?
A Subject to check your number.
Q So if that count is correct, that would be 25 years out of the 51 years of data shown?
A If your numbers are correct.
Q Okay. So roughly 50 percent?
A Yeah.
Q Okay.

A Yes. So --

Q Sure.

A -- I guess I just want to point out there is -- I am not -- I mean, January, you see all the reds in January? I mean, we have numerous winter peaks. And when we do have one, it's a pretty, pretty high peak. Looking at 2010, I mean, that's been our highest -- one of our highest peaks -- winter peaks ever. I just wanted to point that out, but January is -- when we have a winter, January peaks are very high.

Q Could we scroll down to cell L52. And you will see that there is a -- if you -- if you click on that cell or hover over it, there should be a note that pops up.

A My note does not pop up.

MR. LUEBKEMANN: Mr. Schultz, you might have to enable editing to allow a note to pop up.

THE WITNESS: I just enabled editing and I see it.

BY MR. LUEBKEMANN:

Q Okay. Ms. Cifuentes, are you able to read what that note says?

A Not yet. I am trying to make it bigger. Sorry. Give me one minute.

Q I am in no rush.

A Yeah. I am just trying to make the font bigger. Okay.

Q Can you make out what the note says?

A Yes. I am trying to read it now. Do you want me to read --

Q Sure, you can read it.

A Yes. I understand the note.

Q Okay. And essentially, the note is indicating that the peak for that winter occurred on a hot day, but was still the highest megawatt usage in the November to March season that's counted as winter for the '18 to '19 peak?

A That's correct.

Q Okay. Could we now hover over the cell for D54? It should be a red bold. Yes.

Is that the same idea there, where the peak for the winter of 2019 to 2020 fell on a hot day?

A That's correct.

Q And for the cell directly below that one, there is another note. Does that indicate the same thing?

A Same thing, yes. We tend to mark those, because we need to separate cold and hot peaks.

Q Sure.

And then for the two bolded peaks for 2022 and

2023, there is not a note on those, right? This is -- these would be in column L. So neither of those has a note, right?

A That would be because it was a cold temperature.

Q Could I recall our focus on the November peaks in the 2022 and 2023 demand report? We can go back, but will you --

A Yeah.

Q -- accept my representation that we established that those peaks occurred during an afternoon, and with temperatures in the high upper 80s -- or in the upper 80s?

A Yeah. Actually, yes, I do recall that. So we just didn't put a footnote for those.

Q That's perfectly fine. That's not a trap. I am just trying to confirm that for the -- for four of the five most recent years for which data has been provided, TECO's winter peaks are actually being driven by air conditioning use on hot days, rather than heating on cold days?

A Can you repeat that one more time?

Q Sure. Looking at the three notes that we just looked at, and then the other two notes -- or the other two that did not have notes -- this is actually -- it's

five out of six, then, of the most recent years for which we have data, the winter peak is being driven by air conditioning use?

A It does look like that.

Q Okay. Can we go to C10-612? And this is your Exhibit LC-1. And it's Document 8.

Do you have the document up?

A I am showing -- oh, I have to scroll it. Sorry. And which one are you at?

Q So I am on Document No. 8.

A Okay. I am there.

Q Okay. And so this shows an expected increase -- or, rather, it shows an increase in the expected winter peak beginning in 2024?

A Correct.

Q It also shows a decrease in the summer peak beginning in 2024?

A That's correct.

Q And you have attributed the projected growth in winter peaks to what you characterize as recent mild winters?

A Yes, 14 -- well, you can see 2023 was a mild winter, and it's transitioning to 2024, which is based on 31-degree winter peaks. And the summer 2023 was a very hot summer, so we had a higher kW per customer summer peak number versus '24, we are transitioning back to normal weather. That's why it's lower.

Q Thank you.

Could we go now to number F16-100? We are going to go to tab CP.

A Okay. I am on the CP tab.

Q Great. So this tab shows the actual coincident peak data by class for 2023?

A Yes, I -- yes, this is 2023.

Q Okay. And so for January of 2023, there was a peak of 3,347 megawatts, and the resident coincident peak was 1,845 megawatts?

A That's correct.

Q And subject to check, if you would divide the residential coincident peak into the overall peak, would you agree that that number is roughly 55 percent? Does that sound right -- I have a calculator that I am happy to lend.

A That looks about right.

Q Okay. And so that's the -- that percentage is the amount of the January retail peak that's attributable to the residential customer demand?

A Subject to check, yes.

Q Okay. Would you accept my representation that if you did that same calculation for each row of the

year, that none of the percentages for the residential class is above 60 percent, does that sound --

A I would have to do the math. I don't know.

Q In the interest of moving us along, I am not going to ask --

A Subject to check, I will agree.

Q Okay. So as we sit here today, although residential customers are being given 60 percent of system cost under the 4CP model, being driven primarily by the January peak, the forecast peak, you are not aware of any month for which, in the actual data, that the residential class represented 20 -- or represented 60 percent of the coincident peak?

A Could you repeat that?

Q Sure.

Residential customers are 60-percent responsible for peaks cost-wise under TECO's 4CP cost of service methodology?

A You are starting to get a little out of my area of expertise. Again, I think this should be directed at Witness Williams.

Q Okay. We will move on past this.

If we could go to master number F16-96. And we are going to go to the tab rate class -- rate class forecast. And just let me know when you are there.

A I am there.
Q This shows TECO's forecast for the 2025 energy sales by class and month?
A Yes.
Q And so with the exception of the lighting class, which presumably varies inversely to day length and GSLD, all other classes shown here are projected to peak in September?
A Hold on. I am trying to make it bigger, so I can see better.
Okay. So you said with the exception of?
Q Of lighting and GSLD -- are all the other classes pictured here -- and I am -- yeah. The remaining -- do the residential GS and GSD classes, are they projected to peak in September?
A Well, this is -- we are talking megawatt hours now in energy, not peak demands.
Q That's fair. Are the -- is the peak usage here?
A Yes. And there is reasons for it. School and universities are out part of those summer months, July and August. So September, everybody is back, and that's why we have more energy in those months.
Q And looking at the numbers here, the GSD class usage for 2025 ranges from a low in February of about

half a gigawatt hour, to a high in September of about 0.69 gigawatt hours?

A That's correct.

Q Would you accept my math, that that's roughly a 35-percent increase?

A I will accept your math. Yes.

Q And if we look at the GSLD class, their usage for 2025 projected ranges from a low in February of 0.15 gigawatt hours, to a high in July of 0.18 gigawatt hours?

A Yes.

Q And would you accept my math, that that's about a 15-percent increase?

A Yes, I will accept your math.

Q So you would agree that large industrial and commercial customers are not projected to have flat consumption across the year?

A Well, these are by these rate schedules. There is nonindustrial customers in all of these rate classes. This is just not an industrial rate.

Q Fair enough.

You would agree that the GSD and GSLD classes are typically associated with larger commercial industrial customers?

A The GSLD would be the -- would be larger.

Q And that class does not have flat consumption for each month of the year, but, in fact, has variation?

A No. It's not completely flat. I mean, you have got other things that influence it, like seasonal weather, number of days in the typical billing period, that fluctuates. So you will see differences because of that, not just because of their consumption pattern.

Q Okay. You are aware of the ROE that TECO is seeking in this case?

A I am aware of it.

Q That's 11.5 percent?

A Yes.

Q And you are aware that TECO is justifying this requested 11.5 percent ROE, in part, on the basis that high prices from present and future inflation necessitate higher return?

A I can't speak to that. I think you need to speak with Witness Chronister, one of our other witnesses.

Q Okay. I will refer that question to him.

Could we turn to the confidential exhibit that's been passed out? This is hearing Exhibit 6 -- 766, and it's FLL-306C.

A I have it.

Q Okay. Do you recognize this document?

A Yes, I do.

Q And this was produced from your work papers?

A Yes, it is.

Q And this is a confidential document that shows -- oh, yeah. The parts on this document that are confidential are highlighted in yellow?

A Yes. Those were projections.

Q Okay. So in general terms, this document shows inflation escalation rates for non-production CPI and production HWI?

A Yes.

Q And just to clarify for the record, CPI is the consumer price index.

A That's correct.

Q And HWI is the Hardy Whitman Index?

A Handy Whitman Index. Yes.

Q Excuse me. Handy Whitman.

And so according to this memo, TECO uses the CPI to guide escalation costs of O&M expenses?

A So what I can speak to is that we provide this memo -- we get these projections from Moody's Analytics, and we prepare this memo and distribute it throughout the company for areas of the company that do not have any other indices to project their O&M expenses by. So it is not used -- I don't know who uses it. So, like I said, it's just available for them as a guide if they need value to escalate their expenses by.

Q If I could return you to my question. The CPI is used by TECO to escalate O&M costs as a guide? Would it be helpful to --

A It would not be all O&M cost. I don't know which O&M costs apply the CPI.

Q Okay. If we look at the first page of this memo. Do you see -- under the chart, do you see the heading that's bolded, Consumer Price Index?

A Yes, I do.

Q Could you read the sentence beneath that heading?

A The sentence right below it? Is that what you said?

The CPI, the most widely used measure of inflation, is a guide to use when escalating O&M at Tampa Electric Company.

Q Thank you. And on the second --

A And I just wanted to add, it's a guide. There is many areas of the company that have their own indices that they use to escalate their O&M expenses.

Q Sure. My question was whether it was used as a guide at TECO for escalating those expenses.

Similarly, does TECO use the Handy Whitman

Index to escalate costs for capital projects to guide the escalation of costs for capital projects?

A We provide it. Whether it's used or not, I am not sure. I would assume some areas may use it.

Q Could you read the two sentences on the second page below the heading that reads, Handy Whitman Index?

A The HWI is a widely used utility cost index that tracks costs based on the Commission's uniform system of accounts for electric plants and related plant items. For the purposes of TEC, it is a guide to use when escalating projects associated with our plant assets.

Q Thank you.

A Again, if they have no other indices. I don't know who is using it or not.

Q Fair enough. But this is a guidance issue -- this is a guidance memo that is issued to departments at TECO to use?

A Yes. It's -- we issue this annually.

Q And so if we could go back to the first page. Without verbalizing any of the highlighted numbers, can you confirm that this chart forecasts both the CPI and HWI numbers for the next period? Basically, it begins in '21, '22, '23, and the other -- the highlighted numbers represent the forecasts for '24 through 2030.

A And what was the specific question, again?

Q I am asking if it is a correct characterization that the highlighted confidential values on this page are the projected values for the CPI and HWI over the time period between 2024 and 2030?

A Yeah. Those were the projections at the time that this was prepared, 2023.

Q And without verbalizing confidential information, could you give an indication of the general trend of those forecasts?

MR. LUEBKEMANN: And I am actually -- this is also to counsel. Please let me know if we are getting anywhere we shouldn't be.

MS. PONDER: Understood. Thank you.

THE WITNESS: So for -- I can't -- for 2024, inflation is actually higher than what we have on this memo.

BY MR. LUEBKEMANN:

Q I am just asking what the memo is referring to. What does this memo forecast in terms of inflation? Does it anticipate inflation increasing or decreasing on these -- by these metrics?

A Okay. I see. So, yes. And -- well, we can see in 2022, we had a high, and it has been coming down. And the projection periods for 2024 and 2025, and beyond, we expected 2024 to come down. We expected 2025 inflation to also come down some. And then we expected '26 through '30 to remain at the same level as 2025.

Q Thank you.

A I believe these numbers, inflation has actually been higher in 2024.

Q Are you familiar with any documents that corroborate that on this record that you could point me to?

A Not that I can think of -- not that I can think of.

Q Thank you.

Could we move on to F16-98. And just give me a nod when you are ready.

A I am there.

Q Okay. Do you recognize this document?

A Yes, I do.

Q TECO uses a 20-year historical period for weather to calculate its load forecasts?

A Yes, we do.

Q And that 20-year period is also used as the predictive period for normal weather?

A That's correct.

Q And TECO's normal weather is developed by -- and I want to make sure I have this right -- it's by

averaging the Monte Carlo simulations for the weather in those years, not directly from the 20 years of actual usage -- or rather, of actual weather data?

A So we are not averaging anything from the Monte Carlo simulation. We are using numbers directly from the Monte Carlo simulation. And the -- on the summary tab, the next tab, the 50-percent probability is what we are using to assume as normal. And that is very similar to a -- an average of a -- over the 20 years.

Q Thank you. I appreciate the clarification there.

So let's actually talk about Monte Carlo simulations for a moment. Can you explain, in general terms, how they work and are used to establish TECO's baseline?

A So years back, we just did a simple average, like many utilities do. We started incorporating the Monte Carlo simulations so that we could get a range of possible degree days.

So what the Monte Carlo simulations do, is they run through numerous iterations, and they will give you a chart like this that says, okay, there is a zero probability of having degree days at this level, a five-percent at this level, et cetera, all the way to 100 percent probability.

We use the 50-percent point, because that's basically minimizing the risk of the company, saying that there is a 50-percent chance it's going to be hotter or a 50-percent chance it will be not as hot. So that's how we use the Monte Carlo simulation.

And the reason we use this software versus just a simple average, is because we are asked to do different scenarios, weather scenarios, which I have provided several of those. So what we can do is just say, okay, how -- what kind of risks are we looking at? Do we want a winter scenario that there is only a five-percent probability of its occurrence? And then we have the numbers already. We don't have to figure out a way, like some utilities have to do. You know, okay, oh, no, so what is a five-percent probability? We have that available. So it's just convenient to use the Monte Carlo simulations.

Q Would it be a fair comparison to say it would sort of be like, if you wanted to know the distribution of outcomes for two dice -- rolling two dice 1,000 times to get that distribution curve of the possible outcomes?

A I don't think I would relate it to rolling a dice.

Q Okay. And why not?

A I think it's -- I can't explain exactly why, but I don't agree -- I don't believe that it's the same thing.

Q I am not an expert in forecasting. I am trying to --

A Yeah. That's --

Q -- think of something to compare it to. That's totally fine.

So looking across the tabs for this spreadsheet as a whole, there are runs for each month which are indicated by the number following simulation results?

A That's correct. It's automatically created by the software.

Q And so the months where TECO could experience heating or cooling loads, there is an HDD and a CDD run?

A That is correct.

Q And for the summer months, there is just one run, presumably for CDD?

A That would -- yes.

Q Okay. If we could turn to F3.1-1250, which is Exhibit 511, or FLL-51.

Do you recognize this exhibit? Sorry, when it comes up.

A Yes, I do.

Q The attached table on this exhibit shows that

for 2022, TECO's forecast overstated actual heating degree days by almost 50 percent on average?

A Yes.

Q And it understated cooling degree days by roughly 20 percent on average?

A That's correct.

Q And for January, where TECO expected the annual retail peak demand, heating degree days were roughly 80 percent less than, and cooling degree days were roughly 110 percent higher than TECO's forecast?

A That's correct. We had a -- the weather was very hot in 2022.

Q You anticipated my next question. You attribute this to the record-breaking weather?

A Some of the months, yes.

Q And if we could go to E8268, it's Exhibit 216. Actually, I gave the wrong number. Can we go to E8271? I apologize.

Do you recognize this document?

A Yes.

Q Okay. And so this is exhibit -- this is late-filed Exhibit 4 from your deposition?

A That's correct.

Q And this is comparing the expected energy sales based on degree days for TECO's 20-year normal

versus 10-year normal?

A That is correct.

Q And this chart shows that if weather is in line with the 10-year normal as compared to the 20-year normal, TECO should expect January energy usage to be one percent below what it would be otherwise?

A Can you repeat that?

Q Yeah. There. If the weather for the year is in line with the 10-year normal instead of the 20-year normal, that would be associated with a roughly one-percent decrease in energy usage for January?

A Oh, for January? Yes. I am sorry. I was looking at the total.

Q And for April and May, sales would be about two percent higher than -- given that you use a 20-year normal as the reference -- can I call that the reference?

A Yes. I am following you.

Q So for April and May, it would be about two percent higher than the reference?

A Yes.

Q And for November, it would be about two-and-a-half percent higher?

A Yes.

Q And so cumulatively, the effects of a year of

weather that is more in line with the 10-year normal than the 20-year normal would be associated with an additional 204 gigawatt energy -- gigawatt hours of energy sales, looking at the summary row at the bottom for difference?

A And which month were you referring to?

Q This would basically be row 13, so the total annual difference.

A Oh, okay. Yes.

Q Okay. Thank you.

If we could, if we can just scroll to it. So this is late-filed 4. If we could scroll to late-filed 6, that's on 8268. Oh, sorry. It should be 8275. Excuse me.

A I wanted to point something out before we move on.

Q Okay.

A We talked about the 20 years versus the 10 years, we look at a num -- we look at things other than just, you know, the last 10 years has been hot. I have mentioned earlier today, 20 years is kind of the industry standard. It's the -- it's actually the standard in Florida. And there is no utility using 10 years or anything lower than 20, and there is a reason for that. Sample size is the reason. When you are using 20 years, you have a large sample of degree days. You have 20 years. 10 years we consider a small sample.

And what's important about a large sample is stability. So every year when we update our normals, we -- it's a rolling look. You are dropping off your oldest year and adding your newest year. Those two years that are changing are very different. It's going to impact your new normal degree days.

When you have a sample that's 20 years old, it's a stable transition from year to year, which is very important for the company's long-term planning, which, like I have said before, our forecasts are not just used for revenues. It's used for long-term planning of generation, of transmission distribution, infrastructure. It's also used for state planning at the FRCC level, the Florida Reliability Coordinating Council. So this transition of our normals is important.

When you go to a 10-year sample, regardless of what's been happening with the weather, when you have a 10-year sample, there is more instability. When you drop a year and add your new year, if they are very different, your normal is going to change, might change significantly. And that impacts expansion plans, you know, the company's infrastructure planning.

And you don't -- when you are planning, you want -- you don't want these sudden changes, you know, you don't want to, okay, we need to add a lot of generation. Oh, no, now this year we got to take it away.

So that's why we use 20 years. And that's why I am opposed to moving to a 10-year look, even if it has been hotter. And our normals, over 20 years, are -- the gap is closing between the 20 and the 10, because now we have these 10 hot years in our 20 years. So that gap is closing. Our normals are very, very hot, you know, and warm years of -- I -- if you -- I illustrate that, I have already said that, in my late-filed Exhibit No. 6. I believe it's in the CEL Exhibit 216.

These last nine years, not just that they are a small sample, they are also very anomalous compared to the 40 or 50 years prior. So I just want to make that point, you know, yes, it's been hot these past 10 years, but it's just not good forecasting practice to just look at that period in time.

Q All right. And it's your testimony that the last nine years are anomalous?

A Compared to what we have seen historically, they are.

Q And so you would anticipate a return to lower

temperature baseline?

A I don't think anybody knows that, but because there have been some -- a number of anomalies during that period of time, I just don't believe that it's a good period of time to use as normals and to plan the company's future with. A lot of uncertainty there. And there is not any utilities in Florida that are willing to do that either.

Q Sure. But if I could redirect you to my question. You would agree that the -- I will withdraw the question. We will move on.

If we could look at the document that we pulled up next. So this is E8275. This document shows the cooling degree days, heating degree days and total degree days from 1990 through 2023. I apologize. I think it should be 1970 through 2023.

A Yes.

Q And looking at the heating degree day chart, which should be second -- yes -- the average for the Monte Carlo simu -- or is it fair to say it's the average, or is it the 20-year normal for the Monte Carlo simulation?

A It's the 50-percent probability.

Q Okay. So the 50-percent probability, which we will call the 20-year normal, that number is 431 heating

degree hours -- or heating degree days?

A Heating degree days, yes.

Q And so if we look at this chart, it shows that the heating degree days have gone down dramatically over time, and not just in the last nine years?

A They have gone down. If you -- if we scroll a few more, it's, like, illustrated, and it's much easier to see.

Q We will get there.

A Okay.

Q Would you accept, subject to check, that for the 54 years of data that are shown here, there are 23 years for which the total heating degree days were fewer than TECO's 20-year normal?

A Subject to check, yes.

Q And subject to check, there were 10 years with fewer heating degree days lower than the -- fewer than the current 20-year normal in the 34 years between 1970 and 2003?

A Subject to check.

Q And so 10 out of 34 is roughly a third?

A Yes.

Q And subject to check, this chart shows that there were 13 years with fewer heating degree days than the current 20-year normal between 2004 and 2023?

A Yes.

Q And would you accept my math, that 13 out of 20 is roughly two-thirds?

A Yes.

Q And this one I don't think we necessarily have to subject to check, because there is few of them. Nine of the last 10 years had fewer heating degree days than the 20-year normal?

A Subject to check, yes.

Q And that would be a rate of 90 percent?

A Subject to check your math, yes.

Q Looking at the next sheet, cooling degree days, briefly go through the same exercise.

So again, there is 54 years of data shown on this chart?

A Correct.

Q And by my count, there are 16 years for which the total cooling degree days were higher than TECO's 20-year normal, would you accept --

A I would agree.

Q -- subject to check, you would accept that?

A I would agree.

Q Would you accept that there are just six years with more cooling degree days than the 20 -- than the current 20-year normal in the 34 years between 1970 and

2003?

A Yes.

Q And six of -- six out of 34 is roughly one-sixth of those years?

A Yes.

Q And if we look at the years between 2004 and 2023, subject to check, there were 10 years with cooling degree days that were more than the current 20-year normal?

A How many days -- how many years did you say?

Q 10.

A Yes.

Q And so that's half?

A Yes.

Q And again, nine of the last 10 years had higher cooling degree days than the 20-year normal?

A Yes.

Q So again, 90 percent?

A Correct.

Q And this chart also produces a 10-year normal, correct?

A Yes.

Q And understanding that it's your testimony that that's not the right normal to use, it is on this chart?

A That is correct.

Q And are you aware that of the 54 years on this chart, there are just eight that surpass the 10-year normal?

A I will accept your math.

Q And all eight of those years occurred not just in the last 20, but in the last 10 years?

A I would agree.

Q In fact, we could go through those. Those would be 2015, 2016, 2017, '18, '19, '20, '21, '22 and '23?

A Really -- yes.

Q So despite being normal for the 10-year period, this actual exceeded it 80 percent of the time?

A I am sorry, can you say that again?

Q Would you agree that the actual cooling degree days exceeded the 10-year normal cooling degree days 80 percent of the last decade?

A Yes. It was -- are we going to scroll to the next page?

Q You are actually going to go to --

A Can I scroll -- can we scroll, just so I can --

Q Sure.

A -- make a point? Because, I mean, you have been saying a bunch of numbers, but I want to illustrate it.

Q Sure.

A So these are all the numbers that we have just talked about. The top left is the heating degree days. And you can see what I have graphed here is -- the solid red line is our 20-year normal. The dotted line is the 10-year normal. And degree days have been going down. And the graph next to it is cooling degree days, and it has -- you can see it has been higher in the last 10 years.

But the point I want to make is customers are using more energy in the heating degree day -- when it's a heating degree day than when it's a cooling degree day. And in other words, 10 heating degree days, customers are going to use a lot more than 10 cooling degree days. Your heating appliances just use more electricity than your cooling appliances. So we would be losing some load on the heating side. We are making it up on the cooling side. But if you look at it together, which is important -- and those are the bottom two graphs.

So if you could -- the bottom -- the bottom left to start with, you can see the solid red line, which is my 20-year normals, it's way above those historical values all the way back to 1970.

We are hovering over the highest, hottest years during that period. Yes, we are below the past nine, which I say are anomalous, which leads me to the second graph, the bottom graph on the right, that has them boxed in. So you see -- and I have kind of put a box between 1970 and 2014. That looks pretty stable.

If you were to draw a trend line through that, it would be relatively flat, and maybe tick up a little bit, because one of those years in there, 2010, which was a cold winter, not even a hot year. It was a cold winter, which made those total degree days spike. So that's relatively stable. To me, that's a stable trend.

Now, I have boxed in the past nine years that we keep talking about. And to me, anomalous means different than what you expect, different than what you have seen in the past. So that's why I am saying, those 10 years are anomalous to me.

They are been extremely hot. I agree. And it's nothing like what we have seen. So to say that those nine years there are going to be our new normal, no utility is ready to say that. And this is, to me, is an important illustration.

So our 20 years is somewhere -- you know, we have got those nine years in that boxed in area, and then we have got the 10 years prior to it. So our normals are right in between there. And our normals are getting hotter and hotter. And I believe that's just the best representation for future weather for load forecasting.

Q So looking at these illustrations, as you know, you have got your 10-year -- or you have got your 20-year normal and your 10-year normal as flat lines across the bottom. You would agree that those are not best fit lines for the data on this chart -- on any of these charts?

A It's a -- it's our 20-year -- Monte Carlo 20-year average and our Monte Carlo 10-year average.

Q Sure. But those -- but the actual data points on this chart are not Monte Carlo -- they are not Monte Carlo numbers, they are actuals, correct?

A Correct, those are actuals.

Q And you would agree that the 10- and 20-year Monte Carlo lines are not best fit lines for the data that is shown in all of these charts?

A Well, they are only best fit for the 20-year period, not for this entire period.

Q But they are not -- even for the 20-year period, they are, if I understand correctly --

A It's an average.

Q -- the calculation --

A It's an average.

Q The 50-percent simulation?

A (Witness nods head in the affirmative.)

Q And so even to your point, if you draw a neat little box around the last nine years and segregate that, you would agree, if you have one year that's an outlier, perhaps it's not worth changing how the system operates; is that fair to say?

A That's fair to say.

Q This is nine years in a row that don't fit in your chart, is that fair to characterize it as?

A That's correct. But it still is anomalous. We have -- and again, we have had a lot of winter weather events, such as La Niñas, El Niños, you know, a number of those during that period that we didn't have in the period before it.

So I am just not -- I just don't believe those 10 years should represent our future. If we did -- you know, obviously, yes, our retail energy sales would go up and our revenues would go up. It doesn't necessarily mean net income will go up, because now we would be probably having to add additional capacity, additional infrastructure. That costs money. So, you know, there is two sides that you have got to look at not just, you know, the story on the energy sales.

Q So recognizing that we have been talking about a period that ends in 2023 and we are now in 2024, has 2024 been a return towards normal for TECO's system?

A Yes. Actually, through June, we were below our normal degree days through June.

Q I think we have got a good document to illustrate this. Could we go to your late-filed No. 5? This will be E8274. And do you, by any chance, have a copy of your late-filed that you could also look at? It -- I think it would be helpful to be able to go back and forth between the heating and cooling degree days on the --

A I probably do. Let me -- give me a second to find it. And this was my late-filed exhibit?

Q Yes.

A Which number was it?

Q It's from late-filed 6. Basically going back and forth between late-filed 5 and 6.

A Okay.

Q And if we could zoom in for late-filed 6. Thank you.

All right. So looking at your late-filed No. 5, this shows the cooling degree days by month from January '24 through June '24?

A Yes.

Q Well, the most recent degree days for which TECO had data at the time?

A That is correct.

Q Okay. And so for -- looking at heating first, the actual heating degree days for January of this year were 124?

A Correct.

Q And that's below the 20-year normal?

A Yes, it is.

Q And for February, it was 122?

A Correct.

Q And that's below the 20-year normal?

A That's correct.

Q And it's just four heating degree days above the 10-year normal?

A That's correct.

Q And for March, it's 40 heating degree days?

A Yes.

Q And that's fewer heating degree days than both the 10-year and 20-year normal?

A I am sorry. What was the last thing you said?

Q 40 heating degree days would be below both the 20-year and 10 year normals?

A Okay. You are on March?

Q For March.
A Okay. Sorry. Yes.
Q And then looking at April, there were three heating degree days in April of 2024?
A That's correct.
Q And that's below the 20-year normal and the 10-year normal?
A Yes.
Q And then, of course, we don't expect heating degree days in May and June?
A That's correct.
Q So if we could go to the cooling degree days. There were 43 cooling degree days in January of 2024?
A That's correct. That's below the 20 and the 10-year normal.
Q Yes. There were 46 cooling degree days in February?
A That's correct, again, below the 10 and the 20-year normal.
Q And then in March, there were 122 cooling degree days?
A That's correct.
Q And that's above the 20-year normal?
A That is.
Q And for April, there was 212 cooling degree

days?

A   And I believe that is normal.

Q   And that's exactly the 20-year normal?

A   Yes.

Q   And then for May, there were 382 cooling degree days?

A   Yes.

Q   Which is above both the 20 and 10-year normals?

A   That's correct.

Q   And now for June, the most recent month for which you have degree data at the time that this was produced, there were 578 cooling degree days?

A   That's correct.

Q   And that's above the 20-year normal?

A   Yes.

Q   And the 10-year normal?

A   That's correct.

Q   And if we take a moment to scroll up through that column --

A   I can tell you the total, or even the 1,383, that's the lowest we have seen in 10 years.

Q   The 1,383? Oh, no, I am sorry. I am sorry. I am on cooling degree days for June --

A   Yes.

Q -- and I am comparing --

A Oh, okay.

Q -- that to your late-filed.

If we look up through June, for 55 years, now that we have got the '24, is 578 degree -- is 578 cooling degree days the highest cooling degree days that TECO has ever experienced for the month of June?

A Let me just look real close. It looks like it might be, 500 and what, 78?

Q 578.

A From what I am seeing, yes.

Q Okay.

A But in total, which is important -- I mean, we can have some hot months and we can have some wild -- mild months, we are planning for the whole year. That is -- 1,383 is the lowest cooling degree days we have seen in 10 years.

Q But a 10-year period which you term by -- it's a 10-year period which you characterize as anomalous, right?

A Yeah. I am saying we are --

Q So it's the lowest in the 10-year period that you characterize as --

A This is lower.

Q -- highly elevated?

A This is lower than that anomalous period. We are moving -- so I am just saying it's lower than what we have seen in the past nine years -- past 10 years. Sorry.

Q Give me a moment. I am trying to see if I can cut a few questions.

If we could go to your late-filed 7, which should be just a few pages -- actually, that's not included in the staff exhibit. So that's going to be 3 -- F3.1-1252. It's Comprehensive Exhibit 512. Yeah. Thank you.

If we could go to page 10 of this document. Oh, I believe it's consistent with your earlier testimony, but I want to confirm that TECO does still plan on cold driven January peaks?

A We do.

Q Even though for many of the more recent years, they are actually being driven by cooling and not heating?

A That's correct. Like I said, we need to plan for our winter peak for capacity planning.

Q We are getting very close.

Okay. I would like to follow up on something that I asked you in our conversation during your deposition.

As we sit here today, are you aware if Emera has taken a position on climate change?

A I am not aware.

Q Okay. And the same question for TECO?

A Yeah. I don't know.

Q In directing the activities of load research and forecasting for Tampa Electric Company, do you and your team acknowledge that climate change is consistently increasing the average temperature in TECO's surface territory?

A Whether it's climate change or not, I don't know. But I would agree that it has been hotter, as we have just discussed. To me, climate change is a gradual change. You know, I have seen sudden changes as far as I am concerned.

Q And as temperature increases, demand for air conditioning increases?

A Say that one more time.

Q As the average temperature increases, it's fair to say that the demand for air conditioning also increases?

A The demand will increase. In the winter months, it could actually decrease.

Q That's fair.

So I guess, let's say, given the data that we

looked at for the last number of years for which it was available, we were seeing peaks in the summer, right?

A Yes.

Q And so as the temperatures in the summer increase, you would expect to see higher air conditioning usage during those months?

A Yes, just based on that. But consumers do change their behavior and do conserve at times, so -- but in general, yes.

Q Because your -- I will put it this way: We spoke earlier about that breakpoint, that 65-degree breakpoint. That's embedded in TECO's forecasting models, right?

A That is correct.

Q And so that does not assume that customers will change their behavior?

A The 65 degrees does not.

Q I recognize that you make out-of-model adjustments for energy efficiency and other behavioral changes, but --

A Correct.

Q -- looking at just the model itself, you would agree that if the ambient temperature is increasing further away from 65 degrees, there would be more load associated with returning climate controlled spaces to

65 degrees?

A Well, I would say our -- because our normal heating degree days are increasing, then I would say even if the 65-degree point doesn't change that we use for calculating our heating and cooling degree days on a historical basis, the future normal has changed.

Q Just to clarify something. I might have misheard, but I think you just said heating degree days increasing --

A No, I mean --

Q -- you mean cooling degree days?

A I meant cooling probably. Yeah. Sorry.

Q I just wanted to make sure that I am not cracking up.

So recalling our earlier discussion on the accuracy of load forecasting and its potential impacts for revenue, could ignoring the change in weather baseline in TECO's service territory benefit by -- benefit TECO by allowing for higher revenue recovery than what is forecast for the year to the Commission?

A You have to -- can you repeat that again?

Q Sure.

If TECO's forecasts do not take into account the new, potentially new normal -- or put it this way: You acknowledge that temperatures, at least in the last

10 years, have been elevated for what you would consider to be baseline. If TECO's forecast, forward-looking forecast treats those years as anomalous and continues to expect lower load than is actual, then could TECO be benefiting by recovering more energy sales than it has forecast to the Commission as part of this rate case?

A Say that last part of the question. I got the beginning. Does TECO --

Q TECO is making a forecast to this commission --

A Yes.

Q -- about the amount of energy that it expects to sell to customers?

A Correct.

Q And that forecast, as we discussed, is part of the predicate from which the ultimate tariff sheets are derived to make sure the company can recover its revenue requirement?

A Yes.

Q And that's based on an expected percentage of sales?

A Yes.

Q Or, I'm sorry, rather an expected total sales?

A Correct.

Q And so if TECO's actual sales are above that

number, it could over-recover?

A Well, again, I have said this before, you are looking at just one part of the equation. You need to look at the expense side too. If energy sales are going to increase, there is going to be increases on the expense side. So I don't know what that net impact is.

Q And when you say increases on the expense side, what do you mean?

A Well, if energy sales are higher, there could be additional O&M expenses, maintenance, you know, for operational purposes, things like that. We are not looking at that. And if you are talking long-term, there could be additional capital, you know, infrastructure expenses.

So you can't just look at the impact on energy sales and revenues. You have got to look at the big picture to determine, you know, what the impact would be on the revenue requirements.

Q Sure. But for the three-year rate period that is at issue in this case, you would agree that that's -- we are not talking about long-term impacts there. We would be talking about the things that are forecast for the next three years?

A Well, it was either in my late-filed exhibit or in my rebuttal testimony where I actually did a scenario of 10 years. And, yes, revenues went up eight-tenths of a percent. Energy went up. Peak demands went up by 100 and maybe -- close to 170 megawatts in the test year 2025. I would think that there would be some additional cost associated with that.

Q Do you recall when we looked at the peak demand charts, the general range that we saw for the interruptible and curtailable customers?

A Yes.

Q Subject to check, it was between the mid 150 -- or, you know, 160 to 250-ish, 280-ish. I forget exactly what it was, but it's that fair to say that there is probably about 200 megawatts that TECO could call on for curtailment?

A Yes.

Q Okay. And to the other -- just briefly. You mentioned that increased energy sales could be associated with increased O&M expense?

A I would believe it has an impact. Yes.

Q Okay. But that's not recovered as part of base rates?

A I -- that's, again, getting out of my area of expertise.

Q That's fair.

A But I will say, our current 2024 peak demand forecast, like I said earlier, our past two months, we have been eight megawatts actuals, or eight megawatts lower than our forecast. That's two-tenths of a percent. So our forecast, based on these 20-year type forecasts, are very much in line.

Q Based on weather normalization?

A No. That's demands -- we don't really weather normalize the demand. It's a little more diff -- a little more complicated. So on an actual basis, peak demands the past two months, we have been -- have -- actuals have been eight megawatts lower, two-tenths of a percent. So our forecast -- demand forecasts are in line, as well as our energy forecast for this proceeding.

Q All right. I have got just one more thing for you. Can we please go to F16-99? And we are going to go to tab MA Price.

MR. LUEBKEMANN: And, Mr. Schultz, if you see the box in the upper left corner, where you can select tab, I think the fastest way to get where we are going would be to type in Z818. Yes. You might have to enable editing. Z818, I believe. Perfect. And if we could scroll up just a bit from there. That's just a way to locate this. That's the graph we are looking for.

And then one more edit from you. If you could click -- inside that graph, you can see that there is a -- the next bubble over to the right, if you could just move that up a little bit. It's partially obscuring the blue line that I would like to ask about.

Thank you very much.

THE WITNESS: Okay. Can we get to that on my screen? What tab was it?

BY MR. LUEBKEMANN:

Q MA Price. And that will just get you close. We are really looking for the graph that's near there.

A Oh, here.

UNIDENTIFIED SPEAKER: Yeah. You have to enable --

THE WITNESS: I can try to scroll to it.

UNIDENTIFIED SPEAKER: Yeah. Let's try to scroll. It's not letting us type into it even when I try to click on enable content.

BY MR. LUEBKEMANN:

Q I figured out the cell hoping that I could save us some time from scrolling, so I apologize.

A I see -- I just don't see that on this tab. Are you on the MA, Moving Average Price --

Q Yeah.
A -- MA price?
Q Tab MA Price. And it should be row in the late 700s, and then you will need to pan over to the right.
A Okay. We are getting there slowly. Got it.
Q All right. Are you there?
A Okay. I am there.
Q Thank you.
This is one of your work papers?
A This was done under my guidance, yes.
Q Okay.
A I didn't prepare it myself.
Q And so this tab that we are looking at tracks the moving average price of electricity by customer class?
A Yes.
Q And so looking at this -- and real quick about that. When we talk about MA, does real price mean that it has been adjusted for inflation?
A Correct. And this is the total price of electricity, not the base rate portion.
Q I know you weren't here during Mr. Collins' testimony, and so you might not know the answer to this. I don't know if you were able to listen in. But Mr.

Collins testified earlier this week that, when adjusted for inflation, TECO's rates have not increased in the last 10 years. Would you agree with that representation?

A Look -- so do you know what year he was talking about? 2020?

Q He sat in this Commission, and he said they have not increased in the last 10 years. So I assume he is talking about from --

A '23?

Q No, from today, 10 years ago.

A So the 2023, if I put my cursor on the residential, the red line, or the aqua colored line and it --

Q I am assuming he was --

A Yeah. I would not --

Q -- referring to 2024.

A Yeah. I don't know if this is the appropriate comparison. I mean, this is done to come up with a price of electricity trend to put into our consumption models. It might not really be what Mr. Collins was using --

Q Okay.

A -- so...

Q Well, let's talk about that trend for a

second.

So the aqua line there, that's the residential class?

A And I will say again also that this is a 12-month moving average. So the peak that we had because of the fuel would be pushed, you know, out -- would also be seen out into the future a year or so. So that's why I am saying it's not a good comparison.

Q And, in fact, as a 12-month moving average, this chart would actually flatten some of the highest peaks that you might see on a month-to-month basis?

A It would -- it would -- yeah. It would smooth out the month-to-month variations.

Q So looking again at that blue line, you would agree that residential prices on this chart are shown to be the highest they have been in about 15 years, the moving average price for residential customers?

A Yeah. But again, I would have to recall, like how -- you know, what -- how we came up with all these numbers.

Q Sure. But looking at the document that you have provided us, that's what it shows?

A That's what it looks like, but that might not be reality.

Q And that's because of the big spike starting

in 2022?

A With -- possibly with the fuel increases that we saw.

Q There is a note, the one that we had to move so we could see the blue line.

A Yes.

Q That note indicates that the spike is due to the rate increases following the 2021 Settlement Agreement?

A I would assume that it says that that does include the 2022 rate increase.

Q The note itself says: Can see spike due to 2022 rate case increases?

A Yes.

Q Okay. And it does not mention fuel prices?

A No.

Q Okay. And --

A It could be including fuel prices. We just don't specify. I mean, these are just little comments for our own use.

Q And you would agree that that aqua blue line is always higher than the lines for the commercial and industrial customers, which are represented by the purple and dark blue?

A Yes.

Q And you would agree that following the rate cases -- or the rate case in 2021, that the RS line, the residential line, increased proportionately higher and more sharply than the lines for the CNI classes?

A That's what it looks like, unless it's the scale that's making it look like that. But it does look like that.

Q Right. Maybe it would be easier to look at this on the graph below. So if we could scroll down just a little bit. There is one more graph.

So this, again, shows the 12-month moving average real price, and this is looking only at residential and commercial customers?

A That's correct.

Q To your knowledge, does that commercial include industrial? Is it meant to be business versus residential, or is that strictly commercial?

A I am not sure.

Q Okay. But you would agree that at every point on this graph, the blue line is higher than the red line?

A Yes. The rate, in general, is higher for residential, so yes.

Q And when we look at -- there is -- do you see the dotted lines that come off? In the key under the X

axis, it describes those as residential last year and commercial last year?
A Yes.
Q Do those represent a forecast of what prices would do that was made in the year before this document was produced?
A Those would have been the assumptions that we had used in the prior forecast --
Q Okay.
A -- if this was updated correctly. Sometimes we don't update every graph.
Q So assuming that TECO's document is correct here, this forecast shows that following 2022, prices would decrease for customers, at least the residential and commercial classes shown here?
A In real terms --
Q In real terms?
A -- that's what it looks like, yes.
Q In fact, they increased pretty significantly from that point?
A Yes. And again, it could be the CPI that we were using. We had eight percent, you know, inflation at some point.
Q Sure. I am just asking what the graph shows.
A Okay.

Q And so you would agree with that characterization?

A Repeat your characterization.

Q That, instead of declining after 2022, prices have increased -- or sorry, after -- yeah, from 2022 prices have increased on this chart?

A That's what the graph shows.

Q And I think that this gives us a better definition of what I was trying to ask about in the other chart.

You would agree, looking at the two lines here, that following the last rate case, the line for the blue class, the residential class, has a much steeper slope associated with it?

A It does look like it, but there is a footnote that's talking about the GBRAs and the fuel. I am not familiar with those -- all those components and what would, you know, what would drive the residential higher.

Q Fair to say that GBRA increases, general rate base adjustment increases are a -- is a modification to rates that is made in the context of a rate case? Are you familiar with the term GBRA?

A Yes.

Q You are -- okay. And so that --

A So these -- I am just saying these step increases that are being reflected in the graphs, I don't know if that's what's causing the steeper increase in the residential. There may be a difference in those step increases for the different classes. This is not my area of expertise when it comes to, you know, the actual rates.

Q Sure. Sure.

But just looking at this document, which was produced under your direction, you would agree that if we look at the data point for 2024, does it look to you like there has ever been a time on this chart when residential customers were further apart from the commercial class in terms of the higher price that they were paying?

A Not looking at this chart; but again, this chart may not reflect the same things that Witness Collins was looking at.

Q Yeah. I am not concerned with Mr. Collins' testimony. We will keep it to this since you weren't here.

But you would agree that on this chart -- it -- well, I will ask it to you this way: Is there any point in the history of this chart where residential customers have paid a higher -- have been further above

the commercial class than they are currently in terms of the real average -- the moving average real price?

A Not on this graph.

Q Okay. Thank you very much for your patience.

MR. LUEBKEMANN: That's all the questions I have.

CHAIRMAN LA ROSA: Let's move to FIPUG.

EXAMINATION

BY MR. MOYLE:

Q I have a question for you. I think I need a little clarification on an answer you gave previously.

You were asked a lot of questions about a lot of things, and temperatures, and peaks, and everything; but did I hear you to say that the coldest day that has ever occurred, I assume that translates into the highest peak, was a January day? Is that in ever, or is that since you have been with the company?

A So are you -- so the coldest temperature and the actual coldest demand may be different. Can you --

Q Well, I just -- you had made a reference. You just said January, you know, that January was the coldest day that I remember, and I just was --

A And I was speaking to January 2010. That's been our coldest winter peak.

Q And how long have you been with the company?

A Oh, 37 years. I don't know.
Q Okay. Thank you.
MR. MOYLE: That's all I have.
CHAIRMAN LA ROSA: FEA.
CAPTIAN GEORGE: No questions. Thank you.
CHAIRMAN LA ROSA: Sierra Club.
MR. SHRINATH: No questions. Thank you.
CHAIRMAN LA ROSA: Florida Retail.
MR. WRIGHT: No questions.
CHAIRMAN LA ROSA: Walmart.
MS. EATON: No questions.
CHAIRMAN LA ROSA: Staff.
MR. MARQUEZ: Yes, we do.
EXAMINATION
BY MR. MARQUEZ:
Q All right. Good afternoon, Ms. Cifuentes.
A Good afternoon.
Q Has TECO calculated its cooling degree days for July of 2024 using Tampa International Airport's recorded temperature data?
A For July?
Q Yes, for July. This past month.
A Yes, we have.
Q Okay. And what is that number?
A I don't have that in front of me.

Q Are you able to locate it?
A I am going to look to see if I -- I know I had June's. I will say that it was hot, so it was probably above -- it was above our normals, I am pretty sure. Was that good enough?
Q Okay. Earlier, I believe I heard you indicate that no Florida utility is using less than 20 years of historical temperatures to determine normal weather. Did I hear you correctly?
A That is my understanding as of May of this year.
Q Okay. So then would it surprise you to learn that on August 22nd of this year, Florida Public Utilities Company filed testimony with this commission basing its energy use per customer forecast on 10-year normals for cooling degree days in Docket No. 20240099-EI?
A That would surprise me. As of May, when all the utilities met, there wasn't any. I am not sure if they were represented at the Florida Reliability Coordinating Council.
Q So when you testified earlier today, you were unaware of that fact when you --
A Yes, I was.
Q Okay. I would like to go back to the Monte

Carlo simulation probabilities, if we could.

So did I understand correctly that TECO's projection of annual cooling days have a 50-percent probability of being higher than actual cooling degree days?

A That is correct.

Q Okay. And also the converse, a 50-percent probability of being lower than actual cooling days?

A Yes.

Q Okay.

A That's basically the same as using just a simple average.

Q Okay. And for the last nine years, for 2015 through 2023, every year TECO projected cooling degree days that were lower than actual cooling degree days, is that correct?

A That is correct.

Q Okay. Can you explain the method for calculating the probability of that occurrence?

A It's an automatic calculation by the Monte Carlo simulation software. We provide the 20 years worth of data monthly, and we have it go through -- I don't recall if it's 500 or 1,000 iterations of, you know, distribution, and it comes up with the probabilities from zero to 100 automatically.

Q But I am asking about the specific sequence that occurred of those nine years. Are you -- do you know how to calculate the probability of that occurring, the nine years of data from 2015 through 2023?

A Well, we did do a scenario where we just used -- they told us to use -- they, I am not sure if it was a staff or another intervener -- had us run the Monte Carlo simulation for a 10-year scenario, and we did that, and that's -- we looked at that earlier. It increased our sales by one percent and it increased revenues by approximately eight-tenths of a percent. So we have done that scenario.

Q So then let me ask you this: Would you agree that nine straight years of actual cooling degree days being above the 50-percent probability level is represented by the binomial of one over two to the 9th power, or one over 512, which would be 0.2 percent?

A I will trust your math. I can't do that in my head.

Q All right. Thank you very much, Ms. Cifuentes. I know it was a long day, so I appreciate you answering my questions.

A Thank you.

MR. MARQUEZ: We have nothing further for her.

CHAIRMAN LA ROSA: Great. Thank you.

Commissioners, any questions?

Seeing none, let's send it back to TECO for redirect.

MS. PONDER: No redirect.

CHAIRMAN LA ROSA: No redirect.

So then let's talk about exhibits and entering them into the record.

TECO.

MS. PONDER: Yes. Tampa Electric would like to move Exhibits 25 and 146, and the newly identified 138 into the record, please.

CHAIRMAN LA ROSA: Is there objection?

Seeing none, show them entered into the record.

(Whereupon, Exhibit Nos. 25, 146 & 838 were received into evidence.)

CHAIRMAN LA ROSA: OPC.

MS. WESSLING: And Florida Rising has graciously allowed us to steal one of their exhibits that we would move into evidence, FLL-120, which is hearing Exhibit 2 -- or 580.

CHAIRMAN LA ROSA: Is there objection?

Seeing -- no objection? Seeing none, show that entered into the record.

(Whereupon, Exhibit No. 580 was received into evidence.)

CHAIRMAN LA ROSA: LULAC/Florida Rising.

MR. LUEBKEMANN: Thank you, Mr. Chairman.

LULAC and Florida Rising would move in hearing Exhibit 511, 512, 766, 663 -- and I don't know how we want to approach staff Exhibit 3, which is 831. Do you want to move those in by attachment or move in the entire document --

CHAIRMAN LA ROSA: I'm not familiar with --

MR. LUEBKEMANN: -- or the entire exhibit, rather?

CHAIRMAN LA ROSA: I am not familiar with what else is attached to it, but I will look to staff on that.

MS. HELTON: I would recommend just making it a composite exhibit as -- and it's already been numbered as 831.

CHAIRMAN LA ROSA: Okay. So the whole exhibit -- over the whole exhibit?

MS. HELTON: Yes.

CHAIRMAN LA ROSA: All right. So the whole exhibit.

MR. LUEBKEMANN: Okay. I just didn't want to draw an objection bringing in too many things --

CHAIRMAN LA ROSA: Sure.

MR. LUEBKEMANN: -- but I would move in 831.
CHAIRMAN LA ROSA: Okay. We will see if there is an objection. Is that all, or is there anything else?
MR. LUEBKEMANN: That's all.
CHAIRMAN LA ROSA: Is there objection?
Okay. Seeing none, then show that entered.
(Whereupon, Exhibit Nos. 511, 512, 663, 766 & 831 were received into evidence.)
MS. HELTON: And, Mr. Chairman, could I ask, Ms. Ponder, when you said the last exhibit, did you mean 838? Because I think you said 138.
MS. PONDER: Oh, I meant to say 838.
MS. HELTON: Okay. I just want to -- and I may have heard wrong. Thank you.
CHAIRMAN LA ROSA: Well, then show 838, if there is no objection into the record.
MR. LUEBKEMANN: Thank you, Mr. Chair.
CHAIRMAN LA ROSA: And then the list that Florida Rising/LULAC has just offered into the record as well.
MS. HELTON: Yeah.
CHAIRMAN LA ROSA: Okay. Is there anything else? Any other exhibits?
Seeing none, Ms. Cifuentes, you are excused.

THE WITNESS: No.
CHAIRMAN LA ROSA: Oh, you're not?
THE WITNESS: I am sorry. What was your question?
CHAIRMAN LA ROSA: No. No. I just said that you are excused.
THE WITNESS: Oh, okay.
MR. WAHLEN: She wants to stay a little longer, if she could, I mean --
CHAIRMAN LA ROSA: Normally a witness doesn't deny that.
THE WITNESS: I thought you asked if I had any questions.
MR. LUEBKEMANN: Ms. Cifuentes, if you would you'd like to do more questions, we could do this all night.
THE WITNESS: I am good.
CHAIRMAN LA ROSA: As long as there is not a 30-year comparison, we are all right.
So thank you very much for your testimony.
(Witness excused.)
CHAIRMAN LA ROSA: So I will kick this back to TECO for introduction of their next witness.
MS. PONDER: Tampa Electric would call Ned Allis.

CHAIRMAN LA ROSA: Mr. Allis, I do not believe you have been administered your oath just yet. So if you don't mind just standing and raising your right hand.

Whereupon,

NED W. ALLIS

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: Yes.

CHAIRMAN LA ROSA: Excellent. Thank you.

So as he gets settled, still the plan is to break at six o'clock, so we are still on target. And we will just see how this line of questioning goes, and we will, you know, break halfway in the middle if we need to.

So I will send it over to TECO.

EXAMINATION

BY MS. PONDER:

Q Good afternoon, Mr. Allis.

A Good afternoon.

Q Sorry. Are you settled?

A Yes.

Q Okay. Would you please state your full name for the record?

A My name is Ned W. Allis. Allis is spelled A-L-L-I-S.

Q Who is your employer, your current employer and what is your business address?

A Gannett Fleming, at 207 Senate Avenue, Camp Hill, PA, 17011.

Q And did you prepare and cause to be filed in this docket, on April 2nd, 2024, prepared direct testimony consisting of 46 pages?

A Yes.

Q And did you prepare and cause to be filed in this docket, on July 2nd, 2024, prepared rebuttal testimony consisting of 43 pages?

A Yes.

Q Do you have any additions or corrections to your prepared direct or rebuttal testimony?

A I do not.

Q If I were to ask you the questions contained in your prepared direct and rebuttal testimony today, would your answers be the same as those contained therein?

A Yes.

MS. PONDER: Mr. Chairman, Tampa Electric requests the prepared direct and rebuttal testimony of Mr. Allis be inserted into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Ned W. Allis was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

NED ALLIS

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Ned Allis. My business address is 207 Senate Avenue, Camp Hill, PA 17011. I am Vice President of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"). Gannett Fleming provides depreciation consulting services to utility companies in the United States and Canada.

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

A. As Vice President, I am responsible for conducting depreciation, valuation and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before the Commission in Docket Nos. 160021-EI and 20210015-EI on behalf of Florida Power & Light Company, 20210016-EI on behalf of Duke Energy Florida, and Docket No. 20220069-GU on behalf of Florida City Gas.

Q. Please provide a brief outline of your educational background and business experience.

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in Easton, PA. I joined Gannett Fleming in October 2006 as an analyst. My responsibilities included assembling data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. I also developed and maintained Gannett Fleming's proprietary depreciation software. In March of 2013, I was promoted to the position of Supervisor, Depreciation Studies. In March of 2017, I was promoted to Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President.

C11-619

I am currently a past president of the Society of Depreciation Professionals (the "Society"). The Society has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 2011 and was recertified in March 2017. I am also an instructor for depreciation training sponsored by the Society.

I have submitted testimony on depreciation related topics to the Commission, the Federal Energy Regulatory Commission ("FERC"), and before the regulatory commissions of the states of California, Connecticut, District of Columbia, Florida, Illinois, Kansas, Maryland, Massachusetts, Maine, Missouri, Nevada, New Hampshire, New Jersey, New York, Rhode Island, Tennessee, Virginia, and Washington. I have also assisted other witnesses in the preparation of direct and rebuttal testimony in two Canadian provinces. Exhibit NA-1, Document No. 3 provides a list of depreciation cases in which I have submitted testimony.

Q. What are the purposes of your direct testimony?

A. I am sponsoring the results of Tampa Electric Company's

("Tampa Electric" or the "company") depreciation study (the "2023 Depreciation Study" or "Study"), filed on behalf of the company with the Florida Public Service Commission (the "Commission"), which is provided as Exhibit NA-1, Document No. 2 to my testimony. The service life and net salvage estimates in the Study are based in part on the analysis of historical data through December 31, 2022. The depreciation rates provided in Exhibit NA-1, Document Nos. 2 and 4 are based on the projected balances of depreciable electric properties in service as of December 31, 2024, the effective date of the depreciation study.

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

A. Yes. I am sponsoring the following exhibit, NA-1, containing four documents:

Document No. 1: List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Ned Allis

Document No. 2: 2023 Depreciation Study

Document No. 3: List of Cases in which Ned Allis Submitted Testimony

Document No. 4: Summaries of Depreciation Accruals Using Existing and Proposed

Depreciation Rates

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I sponsor or co-sponsor the MFR Schedules shown in Document No. 1 of my exhibit.

Q. Please summarize your testimony.

A. My testimony will explain the methods and procedures of the 2023 Depreciation Study and will set forth the annual depreciation rates that result from the Study. I also provide additional detail on each section of the Study in my testimony.

The overall result of the 2023 Depreciation Study is an increase in Tampa Electric's depreciation rates over the currently approved rates, which will increase the company's total depreciation expense as of December 31, 2024 by approximately $40.7 million. As I detail later in my testimony, this increase is primarily due to changes in the plant and reserve balances since the last study. The changes in estimates result in a moderate increase overall, which increases for transmission, distribution and general plant resulting from more negative net salvage estimates and shorter service lives for some accounts offset in part by overall longer lives for production plant accounts.

I. 2023 DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. The Uniform System of Accounts defines depreciation as:

> *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1]

Q. In preparing the 2023 Depreciation Study, did you follow generally accepted practices in the field of depreciation?

A. Yes. The methods, procedures and techniques used in the

C11-623

[1] 18 C.F.R. 101 (FERC Uniform System of Accounts), Definition 12.

Study are accepted practices in the field of depreciation and are detailed in my testimony.

Q. Please describe the contents of the 2023 Depreciation Study.

A. The Study is presented in eleven parts:

- Part I, Introduction, presents the scope and basis for the 2023 Depreciation Study;
- Part II, Estimation of Survivor Curves, explains the process of estimating survivor curves and the retirement rate method of life analysis;
- Part III, Service Life Considerations, discusses factors and the informed judgment involved with the estimation of service life;
- Part IV, Net Salvage Considerations, discusses factors and the informed judgment involved with the estimation of net salvage;
- Part V, Calculation of Annual and Accrued Depreciation, explains the method, procedure and technique used in the calculation of annual depreciation expense and the theoretical reserve;
- Part VI, Results of Study, sets forth the service life estimates, net salvage estimates, annual depreciation rates and accruals and theoretical reserves for each

depreciable group. This section also includes a description of the detailed tabulations supporting the 2023 Depreciation Study;

- Part VII, Service Life Statistics, sets forth the survivor curve estimates and original life tables for each plant account and subaccount;
- Part VIII, Net Salvage Statistics, sets forth the net salvage analysis for each plant account and subaccount;
- Part IX, Detailed Depreciation Calculations, sets forth the calculation of average remaining life for each property group;
- Part X, Detail of Production Plant, provides a description of the company's generating units and provides a discussion of the considerations that inform the service life and net salvage estimates for each plant account and the probable retirement dates for each generating unit; and
- Part XI, Detail of Transmission, Distribution and General Plant, provides a description of transmission, distribution and general plant by account and provides a discussion of the considerations that inform the service life and net salvage estimates for each plant account.

Q. Please identify the depreciation method that you used.

C11-625

A. I used the straight line- method of depreciation, remaining life technique, and the average service life (or average service life – broad group) procedure. The annual depreciation accruals presented in my study are based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

Q. What are your recommended annual depreciation accrual rates for the company?

A. My recommended annual depreciation accrual rates are the remaining life depreciation rates set forth in Exhibit NA-1, Document No. 2.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group - that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase. The next two sections of my testimony will explain each of these phases of the study.

II. SERVICE LIVES AND NET SALVAGE

Q. Please describe the first phase of the 2023 Depreciation Study, in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life and net salvage study consisted of compiling historical data from records related to Tampa Electric's plant; analyzing these data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from management and operating personnel concerning accounting and operating practices and plans; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. Did you physically observe Tampa Electric's plant and equipment as part of the 2023 Depreciation Study?

A. Yes. For the 2023 Depreciation Study, Gannett Fleming held meetings with operating personnel and made field visits to the company's properties to observe representative portions of plant. The meetings and field reviews were conducted to become familiar with the company's operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. What facilities did you observe?

A. In connection with the preparation of the 2023 Depreciation Study, Gannett Fleming visited the following facilities and observed operations and maintenance practices at each location:

- Big Bend Power Station
- Tampa Electric's Main Office
- Bayside Power Station
- Big Bend Solar Sites

A. Service Lives

Q. What is the process for the estimation of service lives in the 2023 Depreciation Study?

C11-628

A. The process for the estimation of service lives was based on informed judgment that incorporated a number of factors, including the statistical analyses of historical data, general knowledge of the property studied, and information obtained from field trips and management meetings. The method of estimation for each depreciable group depended on the type of property studied for each account. "Mass property" refers to assets such as poles, wires and transformers that are continually added and replaced. Depreciable transmission, distribution and general plant assets were studied as mass property. "Life Span property" refers to assets such as power plants for which all assets at a facility are expected to retire concurrently. The processes of estimating service life for mass property and life span property are described in the following sections.

1. Mass Property

Q. What historical data did you analyze for the purpose of estimating service life characteristics for mass property?

A. I analyzed the company's accounting entries that record plant transactions during the period available through 2022 for each account. The transactions included additions, retirements, transfers and the related balances. The company records also included surviving dollar value by year installed for each plant account as of December 31, 2022.

Q. What methods are generally used to analyze service life data?

A. There are two methods widely used in a typical depreciation study to analyze survivor curves and historical life experience for a group of plant assets; these are the simulated plant balances method and the retirement rate method.

The simulated plant record ("SPR") method is used for property groups for which the retirements of property by age are not known. However, it does require continuous records of annual plant activity and year-end plant balances. The method suggests probable survivor curves for a property group by successively applying a number of alternative survivor curves to the group's historical additions in order to simulate the group's surviving balance over a selected period of time. One of the several survivor curves which results in simulated balances that conform most closely to the book balance may be considered to be the survivor curve which the group under study is experiencing.

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The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. It is the preferred method when sufficient data are available. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts. Tampa Electric currently maintains aged data for all of its accounts. However, for some accounts the available actuarial data were supplemented with additional analysis. Historical retirements were statistically aged for certain transmission and distribution accounts (mass property accounts 355, 356, and 364 through 373) and studied with the retirement rate method. Additionally, these accounts were also analyzed with the SPR method, which was also used in the previous depreciation study for these accounts.

The application of the retirement rate method is illustrated through the use of an example in Part II of the 2023 Depreciation Study. The retirement rate method was used for mass property accounts (i.e., depreciable transmission, distribution and general plant accounts). As I will discuss in the next section on life span property, the retirement rate method was also used for the estimation of interim survivor curves for production plant accounts.

Q. Did you use statistical survivor characteristics to estimate average service lives of the property?

A. Yes. I used Iowa-type survivor curves.

Q. What is an "Iowa-type survivor curve," and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and expectations regarding future retirements. Iowa-type curves have been accepted by every state commission and the Commission.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, an Iowa 40-R2 designation indicates an average service life of forty years; a right-moded, or R-type curve (the mode occurs after average life for right-moded curves); and a moderate height, two, for the mode (possible modes for R-type curves range from 1 to 5).[2] The Iowa curves are discussed in more detail in Part II of Exhibit NA-1.

Q. How are Iowa type survivor curves compared to the historical data for the purpose of forecasting service lives?

A. For each depreciable property group, original life tables are developed from the company's historical records of aged additions, transfers and retirements. Original life tables can be developed using the full experience of historical data. Original life tables can also be developed using

[2] There are also half-mode curves (e.g., R1.5) that are the average of the full mode curves.

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different ranges of years of activity, such as the most recent 30 or 40 years of experience. The range of transaction years used to develop a life table is referred to as an "experience band," and the range of vintages used for the life table is referred to as a "placement band."

Once life tables have been developed using the retirement rate method, specific Iowa curves can be compared both visually and mathematically to the life tables. For visual curve matching, Iowa survivor curves are plotted on the same graph as an original life table, and the points of the curves are visually compared to the life table to assess how closely the Iowa curve matches the historical data. For mathematical curve matching, Iowa curves are compared to an original life table mathematically using an algorithm that compares the differences between an Iowa curve and the original life table.

For both visual and mathematical curve matching, not all of the historical data points should be given the same consideration, as different data points on a life table will have different significance based on both the level of exposures (i.e., the amount of assets that has survived to a given age) and the level of retirements. For example, data points for later ages in an original life table may be based on the experience of a small number of units of property. Due to a smaller sample size, these data points would not provide as meaningful information as earlier ages. Additionally, the middle portion of the curve is where the largest portion of retirements occur. This portion of the curve therefore often provides the best indications of the survivor characteristics of the property studied.

Q. Can you provide an example of the process of fitting Iowa curves to an original life table?

A. Yes. Account 362, Station Equipment provides a good example of this process. For this account, the life table for the overall experience and placement bands is shown on Exhibit NA-1, Document No. 2, pages VII-76 to VII-78. The original life table develops the percent of plant that has survived to each age for the experience and placement bands. The representative data points from this life table are depicted graphically on Exhibit NA-1, page VII-75.

Also shown on page VII-75 is the 45-R1 survivor curve. As can be seen in the chart, this curve is a visually good match of the historical data, as the smooth line depicting the 45-R1 survivor curve is close to the historical data points for most ages. The degree of mathematical fit can be measured by the residual measure,[3] which is a normalized sum of squares difference between the original life table and a given Iowa curve. The residual measure for the 45-R1 survivor curve and the data points through age 82.5 from the original life table is 2.60, which is considered to be a reasonably good fit.[4] The statistical analysis for this account, using both visual and mathematical techniques, therefore indicates that the 45-R1 survivor curve provides a good representation of the historical mortality characteristics for the account.

Q. Is the statistical analysis of historical data based on the retirement rate method the only consideration in estimating service life?

A. No. The estimation of service life is a forecast of the future experience of property currently in service, and therefore informed judgment that incorporates a number of factors must be used in the process of estimating service life. The statistical analysis can provide a good indication of what has occurred for the company's assets in the past, but other factors can affect the service lives

[3] The residual measure is the square root of the total sum of the squares of differences between points on the original and smooth curves divided by the number of points.
[4] The smaller the residual measure, the more closely the Iowa curve mathematically matches the original life table.

of the assets going forward. Further, the historical data often does not provide a definitive indication of service life. For these reasons other factors must be considered when estimating future service life characteristics.

Q. Was the process for estimating service lives for other accounts similar to Account 362?

A. Yes. A similar process for estimating service life was used for other mass property accounts. The estimated survivor curves for each account can be found in Part VII of the 2023 Depreciation Study. A narrative description of considerations for each estimate can be found in Part XI of the study.

2. Life Span Property

Q. What method was used to estimate the lives of production facilities?

A. For production facilities the life span method was used to estimate the lives of electric generation facilities, for which concurrent retirement of the entire facility is anticipated. In this method, the survivor characteristics of such facilities are described by the use of interim retirement survivor curves (typically Iowa curves) and capital recovery dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the facility. For a power plant, examples of interim retirements include the retirement of piping, boiler tubes, condensers, turbine blades, and rotors that occur during the life of the facility. Interim survivor curves were developed using the retirement rate method in a manner similar to that used for mass property. The capital recovery date, an estimate of the probable retirement date of a facility based on its anticipated operating life, affects each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age as of that date. The life span of the facility is the time from when the plant is originally placed in service to the expected date of its eventual retirement (i.e., the capital recovery date).

The use of interim survivor curves, truncated at the estimated capital recovery dates, provides a consistent method of estimating the lives of several years' installation for a particular facility inasmuch as a single concurrent retirement for all the years of installation will occur at that specified date.

Q. Is the life span method widely used in the electric industry to determine the depreciation rates for production plants?

A. Yes. The life span method has been used previously for the company and for other Florida utilities. My firm has also used the life span method in performing depreciation studies presented to many public utility commissions across the United States and Canada, and the life span method is the predominant method used for property such as production plants.

Q. Are interim survivor curves the most common method of estimating interim retirements for life span property?

A. Yes. The use of interim survivor curves to estimate interim retirements is also the predominant method of estimating interim retirements for assets such as power plants. The Commission has previously approved the use of interim survivor curves and they are currently used to estimate interim retirements for FPL and Duke Energy Florida.

Q. What are the capital recovery dates and what was your basis for each selection?

A. The capital recovery dates estimated in the study are set forth in Exhibit NA-1, Document No. 2 on page III-6. The capital recovery dates are based on a number of factors, including the operating characteristics of the facilities, the type of technology used at each plant, environmental and other regulations, and the company's outlook for each facility. Capital recovery dates are specific to each generating unit, and, therefore, the characteristics for each generating unit are considered when estimating a capital recovery date. Typically, the owner and operator of each facility best understands the operation and the outlook of each power plant and is therefore in the best position to determine the most probable retirement of each facility. The company performed an analysis of the life span for its steam, combined cycle, and simple cycle power plants. I have discussed the estimated life span of each facility with Tampa Electric. The company has retired a number of generating units in recent years and the experienced life spans of these retired facilities were also reviewed. Additionally, I incorporated my firm's experience performing depreciation studies for other utilities and our knowledge of other generating facilities and confirmed that Tampa Electric's estimates are reasonable and within the range of typical estimates in the industry.

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This process results in capital recovery dates for the 2023 Depreciation Study that are, in my judgment, the most reasonable based on the current information available. Further discussion of these estimates can be found in Part X of Exhibit NA-1, Document No. 2, as well as later in this testimony.

Q. What are the life span estimates for steam generating plants?

A. The company has retired many of its steam generating units. The one that remains is Big Bend Unit 4. Big Bend Unit 4 is a dual-fired generating unit placed in service in 1985. This unit is expected to be retired in 2040, which will result in a life span of 55 years. In prior studies, there have been separate depreciable groups for common plant and various environmental equipment such as Flue-Gas Desulpherization ("FGD") and Selective Catalytic Reduction ("SCR"). Because only one unit remains and all assets at the plant will be subject to the same retirement date, we have combined each of these depreciable groups with Big Bend Unit 4 for the study.

Q. Has the company retired any steam generating plants in recent years?

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A. Yes. The company has retired several steam generating plants. The facilities retired, as well as the retirement date and life span of each facility, are summarized in Table 1 below. The actual experienced life spans for these units ranged from 34 to 55 years, with an average life span of approximately 45 years. The recommended life span for Big Bend Unit 4 is, therefore, at the upper end of the range of experienced life spans for the company's steam production plants.

Table 1: Retirements of Tampa Electric Steam Generating Units

Generating Unit	Retirement Date	Life Span
F J Gannon Unit 1	2004	47
F J Gannon Unit 2	2004	46
F J Gannon Unit 3	2003	43
F J Gannon Unit 4	2003	40
Hookers Point Unit 1	2003	55
Hookers Point Unit 2	2003	53
Hookers Point Unit 3	2003	53
Hookers Point Unit 4	2003	50
Hookers Point Unit 5	2003	48
Dinner Lake Unit 1	2003	37
Big Bend Unit 1	2008	39
Big Bend Unit 2	2008	34
Big Bend Unit 3	2008	34

Q. What is the life span estimate for the company's combined cycle generating facilities?

A. The life span estimate for the combined cycle facilities is 35 years. This estimate is the same as currently used for Tampa Electric's combined cycle facilities.

Q. How does a 35-year life span compare to the range of estimates by others in the industry for combined cycle power plants?

A. A 35-year life span is within the range of typical estimates for combined cycle plants in the industry. Estimates for other utilities have most commonly been in the 35 to 40 year range.

Q. Has the company retired any combined cycle power plants?

A. No. The company's oldest combined cycle assets are around 20 years of age and, therefore, have not been in service long enough to experience 35-year life spans. However, there have been two combined cycle facilities in the state of Florida that have been retired in recent years. These are FPL's Putnam and Lauderdale plants. The experienced life spans for these facilities range from 25 years to 37 years. The estimated 35-year life span for Tampa Electric is within the range of these experienced life spans.

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Table 2: Retirements of Combined Cycle Generating Units in Florida

Generating Unit	Retirement Date	Life Span
Putnam Unit 1	2014	36
Putnam Unit 2	2014	37
Lauderdale Unit 4	2018	25
Lauderdale Unit 5	2018	25

Q. What are the life span estimates for other facilities?

A. The life spans for the company's simple cycle generating facilities vary from 40 to 50 years and are dependent on the specifics of each facility.

Q. What are the life expectations for solar facilities?

A. As the company (and other utilities) makes significant investments in solar facilities, the balance and number of solar sites has grown. Rather than study each site individually, a 30-year average service life is recommended for solar accounts. While this is shorter than the 35-year life span currently used, it is an overall average service life that incorporates retirements that will occur before the retirement of an entire facility (such as for inverters). A 30-year life is also consistent with the typical industry range for solar facilities and has been used previously in Florida. The resulting depreciation rates are reasonable to apply to both existing solar and new solar facilities that will be added before the next depreciation study.

Q. In addition to the life span, you have also recommended estimates for interim retirements. Is the estimation of interim retirements using the retirement rate method similar to the process of estimating survivor curves for mass property?

A. Yes. Similar to mass property, the interim survivor curve estimates are based on informed judgment that incorporates actuarial analyses of historical data using the retirement rate method of analysis. Iowa survivor curves have been estimated for each plant account which, combined with the life span estimate for each generating unit, provide the overall survivor curve, average service life and average remaining life for each plant account at each generating unit. A narrative discussion of the considerations for the estimation of interim survivor curves for each account can be found in Part X of the 2023 Depreciation Study. Graphical depictions of the interim survivor curves estimated for each generation plant account are presented in Part VII of the study.

A. Net Salvage

Q. Please explain the concept of "net salvage."

A. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Thus, net salvage is considered to be a component of the cost of an asset that is recovered through depreciation.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period (e.g., one year), it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

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For example, the full recovery of the service value of a $1,000 transformer may include not only the $1,000 of original cost, but also, on average, $300 to remove the transformer at the end of its life less $150 in salvage value. In this example, the net salvage component is negative $150 ($150 - $300), and the net salvage percentage is negative 15 percent (($150 - $300)/$1,000).

Q. Please describe the process you used to estimate net salvage percentages.

A. The net salvage estimate for each plant account is based on informed judgment that incorporates the analysis of historical net salvage data. I reviewed net salvage data from 1982 through 2022. Cost of removal and salvage were expressed as a percent of the original cost of the plant retired, both on an annual basis and a three-year moving average basis. The most recent five-year average was also calculated.

Q. Were there other considerations used in developing your final estimates for net salvage?

A. Yes. In addition to the statistical analyses of historical data, I considered the information provided to me by the company's operating personnel, general knowledge and experience of industry practices, and trends in the industry in general.

Q. Is the same process used for the estimation of net salvage for production plant?

A. The same process is used for interim net salvage for generating plant accounts as is used for the estimation of net salvage for mass property accounts. However, interim net salvage is applied only to the portion of plant expected to be retired as interim retirements. Assets expected to remain in service until the final retirement of a generating facility will experience terminal net salvage – that is, the cost to dismantle the facility.

Q. Do the depreciation rates used for electric generating facilities have a component for dismantlement?

A. No. The dismantlement component of net salvage is not included in the depreciation rates recommended in the 2023 Depreciation Study. Consistent with longstanding Commission practice, the company has made estimates of final dismantlement for their fossil and solar generation facilities, but these costs are handled separately and are

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not part of the 2023 Depreciation Study. Fossil and solar generation dismantlement costs are included separately in this docket, in testimony sponsored by Tampa Electric witness Jeff Kopp. Therefore, net salvage estimates for fossil and solar production facilities provided in this Study only reflect interim retirement activity.

Q. Has the company experienced a trend to increasing removal costs?

A. Yes, and as a result net salvage estimates for some accounts are more negative than the current estimates. Costs have increased for a number of reasons, including permitting costs, work requirements, environmental regulations, safety requirements, traffic control and labor and contractor costs.

Q. Please provide an example of how costs have increased.

A. Distribution poles provide a good example of factors that have resulted in increasing costs to retire assets. Tampa Electric’s poles are primarily wood poles. The retirement of a wood pole requires a multiple person crew as well as equipment including a pole truck. In addition to the replacement of the actual pole, the company must also

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transfer the primary and secondary cable, as well as other devices, from the old pole to the new pole.

Costs for retiring poles have increased for a number of reasons. Labor and contractor costs have increased over time. Permitting costs have increased, as have requirements for traffic control. Each of the factors described here contribute to higher cost of removal going forward than was the case fifteen or twenty years ago. This trend is consistent with the historical net salvage data, which indicates increasing cost of removal for distribution poles.

Q. Is the trend to higher cost of removal consistent with the experience of other utilities in the industry?

A. Yes. My firm conducts depreciation studies for utilities across the country. The trend towards increasing cost of removal is consistent with the experience of many others in the industry. The reasons that Tampa Electric's costs have increased are also experienced by other utilities.

III. REMAINING LIVES AND DEPRECIATION RATES

Q. Please describe the second phase of the 2023 Depreciation Study, in which you calculated composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life and determined net salvage characteristics to use for each depreciable property group, I calculated the annual depreciation accrual rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The recommended depreciation rates are based on forecast balances as of December 31, 2024, which is the effective date of the study.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method (also referred to as the straight line method and remaining life technique) of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

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A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life, and this rate is applied to the surviving balance of the group's cost. The average remaining life for the group is determined by first calculating the average remaining life for each vintage of plant within the group. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the average remaining life for the group is determined by calculating the dollar-weighted average of the calculated remaining lives for each vintage. The annual depreciation accruals for the group are calculated by dividing the remaining depreciation accruals (original cost less accumulated depreciation less net salvage) by the average remaining life for the group.

Q. Please use an example to illustrate the development of the annual depreciation accrual rate for a particular group of property in the 2023 Depreciation Study.

A. For purposes of illustrating this process I will use Account 368, Line Transformers. The survivor curve estimate

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for this account is the 30-S2, and the net salvage estimate is for negative 20 percent net salvage. A discussion of these estimates, as well as the statistical analyses that support the estimates for this account can be found on Exhibit NA-1, Document No. 2, page XI-22. The calculation of the annual depreciation related to the original cost of Account 368, Line Transformers as of December 31, 2024, is presented on Exhibit NA-1, Document No. 2, page VI-9. The calculation is based on the 30-S2 survivor curve, negative 20 percent net salvage, the attained age, and the book reserve. The calculated annual depreciation accrual and rate are based on the estimated survivor curve and net salvage, the original cost, book reserve, future accruals and composite remaining life for the account. The calculation of the composite remaining life as of December 31, 2024 is provided in the tabulations presented in Exhibit NA-1, Document No. 2, page IX-92. The tabulation sets forth the installation year, the original cost, the average service life, the whole life annual depreciation rate and accruals, the remaining life and theoretical future accruals factor and amounts. The average service life weighted composite remaining life of 28.21 years is equal to the total theoretical future accruals divided by the total whole life depreciation accruals.

Q. Did you use this same methodology for the general plant accounts?

A. Yes. This methodology was used for the general plant accounts that are depreciated. However, many of the general plant accounts are amortized in accordance with the company's current amortization periods.

Q. What were your overall results of the 2023 Depreciation Study?

A. The average service lives recommended in the study are similar to those approved in the settlement agreement in the previous rate case. Of the 32 transmission, distribution and general plant accounts, I recommend an increase in ASL for 4 accounts, a decrease in ASL for 8 accounts, and the same ASL for 20 accounts. The 2023 Depreciation Study results in increases in negative net salvage (i.e., net salvage estimates that are more negative) for certain transmission and distribution accounts, which is attributable to the increasing cost of removal discussed previously. A trend to more negative net salvage is also consistent with the experience of many other utilities.

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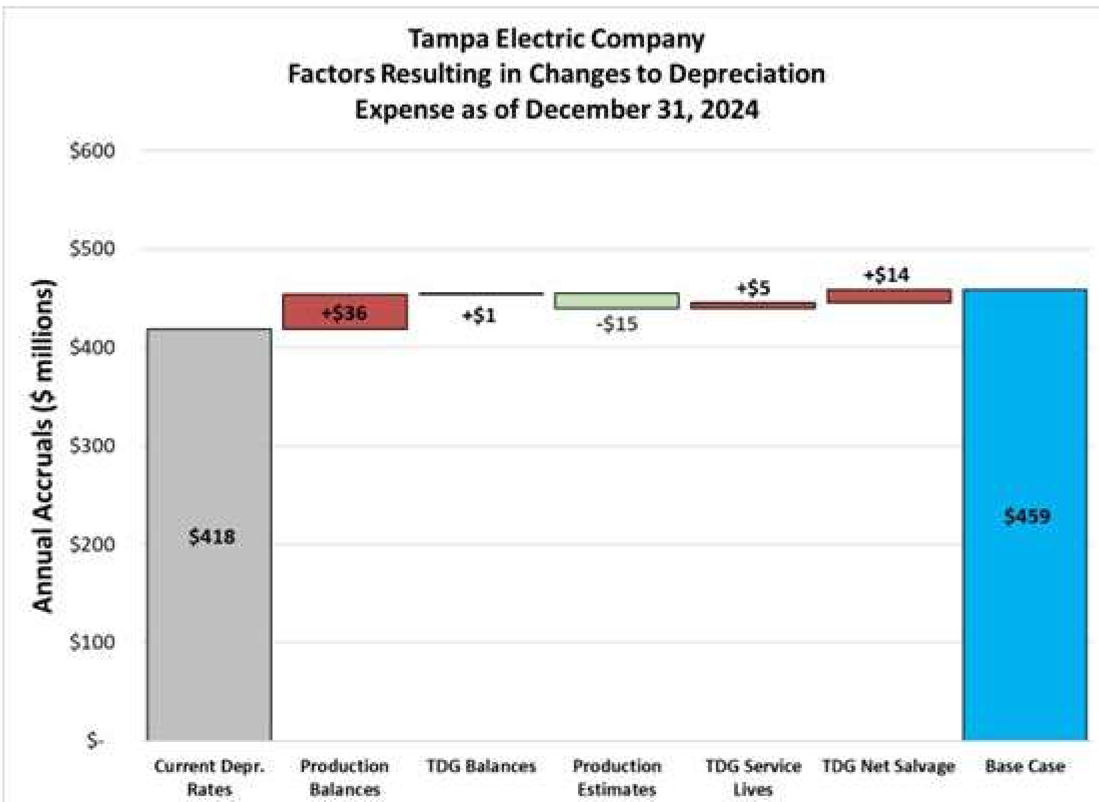
The Study results in an increase of total company depreciation expense of approximately $40.7 million as of December 31, 2024. This increase is primarily due to changes in the plant and reserve balances since the last study, with increases due to transmission and distribution plant service life and net salvage estimates offset in part by longer service life estimates for production plant accounts.

IV. FACTORS AFFECTING DEPRECIATION EXPENSE

Q. What are the major factors that affect the depreciation expense resulting from application of the 2023 Depreciation Study?

A. The changes in annual depreciation rates and expense are shown in Table 2 of the 2023 Depreciation Study and result in an overall increase in depreciation expense of approximately $40.7 million. Much of the increase is not due to the recommended service lives and net salvage in the study but is instead due to plant and reserve activity since the last case and that the current depreciation rates were insufficient to account for this activity. The change in plant and accumulated depreciation balances results in an increase of approximately $36.6 million in depreciation expense. The recommended service life and net salvage estimates result in a net increase in depreciation of approximately $5 million. Figure 1 below provides an illustration of the factors that result in the change in depreciation expense resulting from Gannett Fleming's recommendations.



<u>Other Production:</u> This class of plant has an overall increase in depreciation expense of approximately $21 million. The primary reason for the increase is related to a change in balances since the previous study, which represents a net increase of $36 million. The change in the recommended estimates for production plant resulted

in a decrease of $15 million in expense. The changes in estimates that result in this decrease are longer life spans for certain plants as well as changes to the interim survivor curve estimates. This is partially offset by the shorter service lives for solar assets.

<u>Transmission, Distribution and General ("TDG"):</u> The recommended service lives and net salvage for TDG result in a net increase in depreciation expense of approximately $19 million when compared to the depreciation rates that result from using the current service lives and net salvage. Most of this increase of $14 million is due to more negative net salvage estimates for several accounts.

Q. Why do capital additions for production plant result in an increase in depreciation rates?

A. Additions to life span property typically will result in an increase not only to depreciation expense due to a resulting higher plant balance, but also because additions typically increase the depreciation rate for this type of property. For life span property, interim additions (that is, additions added subsequent to the original in service date of the facility) will have a shorter service life than the original installation of the facility. This occurs because the facility has a final retirement date at which time all assets will be retired. Thus, for interim additions, the length of time between installation and the end of the life span of the facility is shorter than for the original installation of the plant.

To help illustrate this concept, consider as an example a power plant that is installed in 1970 for $1 million. For simplicity, assume that there will be no interim retirements and no net salvage. If the plant is retired in 2030, the life span of the facility is 60 years. The average service life for the 1970 vintage is also 60 years. The depreciation rate at the time of the original installation is 1.67 percent.[5] Assume that in 2000 an additional $500,000 is added to the facility. These assets will not have an average service life of 60 years, but instead will have an average service life of 30 years since they will be retired in 2030 with the balance of the plant. That is, the interim additions have a shorter service life than the original addition of the facility.

For this reason, the overall average service life of life span property will decrease as new interim additions are made. Similarly, the annual depreciation rate will tend to

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[5] Equal to 1/60

increase over time as interim additions occur. After the installation of the 2000 vintage assets the depreciation rate increases to 2.22 percent[6] from 1.67 percent. Thus, although the service life estimate for the plant did not change, the depreciation rate increased due to the interim additions to the facility.

This same concept explains many of the increases in depreciation rates for Tampa Electric’s production plant facilities, as significant additions have occurred at steam and combined cycle plants. All else equal, these additions cause increases in depreciation rates and are a primary factor contributing to the overall increase in depreciation expense resulting from the 2023 Depreciation Study.

V. THEORETICAL RESERVE IMBALANCE

Q. What is a theoretical reserve imbalance?

A. A theoretical reserve imbalance ("TRI" or "imbalance") is calculated as the difference between a company's book accumulated depreciation, or book reserve, and the calculated accrued depreciation, or theoretical reserve. I should note that in prior proceedings in both Florida and other jurisdictions, different terms have been used for

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[6] Equal to ($1,000,000/60+$500,000/30)/($1,000,000+$500,000)

the theoretical reserve imbalance, including "theoretical reserve variance," "reserve excess," "reserve surplus" or "reserve deficit" and "theoretical excess depreciation reserve." For this testimony, I will use the term "theoretical reserve imbalance," which is consistent with the terminology used in the National Association of Regulatory Utility Commissioners' ("NARUC") publication *Public Utility Depreciation Practices*.

Q. What is the book reserve?

A. The book reserve, also referred to as the "book accumulated depreciation" or the "accumulated provision for depreciation," is a running total of historical depreciation activity. It is equal to the historical depreciation accruals, less retirements and cost of removal, plus historical gross salvage. The book reserve also represents a reduction to the original cost of plant when calculating rate base.

Q. What is the theoretical reserve?

A. The theoretical reserve is an estimate of the accumulated depreciation based on the current plant balances and depreciation parameters (service life and net salvage estimates) at a specific point in time. It is equal to the portion of the depreciable cost of plant that will not be allocated to expense through future whole life depreciation accruals based on the current forecasts of service life and net salvage. The theoretical reserve is also referred to as the "Calculated Accrued Depreciation" or "CAD."

Q. Is the theoretical reserve the "correct" reserve?

A. No, the theoretical reserve is an estimate at a given point in time based on the current plant balances and current life and net salvage estimates. It can provide a benchmark of a company's reserve position, but it should not be thought of generally as the "correct" reserve amount. In Wolf and Fitch's *Depreciation Systems*, this point is explained as follows on page 86:

> The CAD is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.

Q. How is a TRI typically addressed in a depreciation study?

A. In most jurisdictions an explicit adjustment to the book reserve is not made. Instead, the remaining life technique is used. When using remaining life technique, there is an automatic adjustment, or self-correcting mechanism, that will increase or decrease depreciation expense to account for any imbalances between the book and theoretical reserves. The 2023 Depreciation Study uses the remaining life technique. The depreciation rates presented in the study therefore already include an adjustment for the theoretical reserve imbalance. No further adjustment is needed.

Q. What is the theoretical reserve imbalance, based on estimates from the 2023 Depreciation Study and plant and reserve balances as of December 31, 2024?

A. The theoretical reserve imbalance estimated in the 2023 Depreciation Study is approximately negative $167 million. That is, the book reserve is approximately $167 million lower than the theoretical reserve from the study.

Q. What do you recommend for the TRI?

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A. Consistent with prior depreciation studies I have performed, my recommendation is to address the theoretical reserve imbalance through remaining life depreciation rates. I do not recommend any additional amortization of the TRI.

Q. Do you recommend any reserve transfers based on the results of the depreciation study?

A. No. Our study did not identify the need for any reserve transfers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled rebuttal testimony of Ned W. Allis was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

IN RE: PETITION FOR RATREASE

BY TAMPA ELECTRIC COMPANY

PREPARED REBUTTAL TESTIMONY AND EXHIBIT

OF

NED ALLIS

ON BEHALF OF

TAMPA ELECTRIC COMPANY

DOCKET NO. 20240026-EI
FILED: 07/02/2024

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PREPARED REBUTTAL TESTIMONY AND EXHIBIT

OF

NED ALLIS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

NED ALLIS

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Ned Allis. My business address is 207 Senate Avenue, Camp Hill, PA 17011. I am Vice President of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. On whose behalf are you submitting this testimony?

A. I am submitting this rebuttal testimony before the Florida Public Service Commission ("Commission") on behalf of Tampa Electric Company ("Tampa Electric" or the "company").

Q. Did you previously submit testimony in the proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the testimonies of the Office of Public Counsel ("OPC") witness Lane Kollen and Federal Executive Agencies ("FEA") witness Brian Andrews. Specifically, I will respond to the portions of their testimony related to depreciation. Other topics raised by either witness are addressed by other Tampa Electric witnesses in this case.

Q. What do OPC's witness Kollen and FEA's witness Andrews propose?

A. OPC's witness Kollen proposes longer service lives for solar generation and energy storage assets. FEA's witness Andrews proposes longer life spans for combined cycle plants, as well as changes to service life or net salvage estimates for several transmission and distribution plant accounts.

Q. Do you agree with these proposals?

A. No. For the reasons I discuss in this testimony, I disagree with the proposals of OPC's witness Kollen and FEA's witness Andrews. Generally, I find the proposals to overstate service lives, understate net salvage, and fail to incorporate several important considerations that will impact the service lives of these assets. Additionally, based on my review of their recommendations, the depreciation rates recommended by each witness are not calculated correctly. Document No. 1 of my Rebuttal Exhibit NA-2 provides the depreciation rates for OPC's witness Kollen's proposals, which correct for the calculations provided by Mr. Kollen. Document Nos. 2 and 3 of my rebuttal exhibit provide those for FEA, which incorporates changes to composite net salvage percentages that result from the longer life spans recommended by Mr. Andrews.

I. LIFE SPAN PROPERTY AND PRODUCTION PLANT

Q. What is life span property?

A. Life span property describes assets such as generating units for which the entire facility is expected to retire concurrently. Upon the final retirement of a power plant, typically all assets will be retired and no longer will provide service, regardless of their age. Additionally, assets are replaced or retired during the life span of the facility. These retirements are referred to as "interim retirements," whereas the retirements that occur upon the final retirement of the facility are referred to as "final retirements" or "terminal retirements."

Both types of retirements, and their related net salvage, should be considered and estimated for life span property. I have described methods by which these estimates are made for life span property in more detail in my direct testimony. None of the parties challenge the approach and method used in the depreciation study for generating or energy storage facilities, although OPC proposes longer service lives for solar and energy storage and FEA proposes longer life spans for combined cycle plants and longer interim survivor curves. Mr. Kollen also proposes adjustments to the dismantlement accruals, which is also addressed by witness Jeff Kopp.

A. **<u>Life Span Estimates</u>**

Q. What have OPC and FEA proposed for the life spans of the company's power plants?

A. FEA proposes adjustments to the life spans for the company's combined cycle facilities, generally extending the life spans from 35 years to 40 years. OPC proposes adjustments to the average service life for solar facilities, proposing a 35-year average service life rather than the 30-year average service life in the depreciation study.[1] Additionally, OPC proposes a longer life for energy storage equipment, which I also address in this section because its useful life will be impacted by similar factors that will eventually lead to retirement.

Q. What is a life span estimate?

A. A life span estimate is an estimate of the useful life of a large facility such as a power plant, for which all assets will be retired concurrently upon the final retirement of the facility. For life span property, described in more detail in my direct testimony, the life span of a facility is typically estimated with a probable retirement date, or economic recovery date, which represents the best estimate of the time by which the capital investments in the facility should be recovered.

Q. For the assets at issue in this case – combined cycle plants, solar plants and energy storage – what factors cause the final retirement of a facility?

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[1] The life span method was not used for solar or energy storage in the depreciation study, nor was it used by Mr. Andrews or Mr. Kollen for these assets. Instead, a survivor curve is used for the group of assets in each function, which should incorporate both final and interim retirements since there is no estimated retirement date. However, many of the considerations for estimating a life span of a generating facility also apply to solar and energy storage.

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A. Generally, the retirement of an electric generating (or storage) facility is an economic decision. When replacement generation is available at a lower cost than continued operation of existing generation, it becomes more economical to replace the existing generating asset. There are often other benefits to replacement, such as lower emissions, fewer environmental risks, and better design for current or future operations. Importantly, experience shows that generating units can be and are replaced even when they could physically operate for a longer time because other considerations outweigh continued operation.

The economics of operation change over time, though not always evenly. When large capital components of a plant reach the end of their lives, the needed investments change the economics of continued operation and, as a result, life spans are often aligned with the useful lives of larger components (although this may be after, e.g., one large replacement project). Economics also change due to age as a larger percentage of components reach the end of their useful lives.

The economic competitiveness of new generation also changes over time. As new technologies emerge and become

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cost competitive, it becomes more attractive to replace existing generation. This becomes more economical as existing generating facilities age and become more costly to operate.

Legislative and regulatory actions can also impact the life spans of generation. For example, environmental regulations can increase the cost of existing generation. Tax or other incentives can lower the cost of new technologies, thereby increasing their attractiveness as replacement technologies.

Other external factors can also impact life spans, such as changes in commodity prices for, e.g., coal and natural gas, changes in demand, and increases in needs for flexible generating units to follow renewable generation.

Q. Are these factors also interrelated?

A. Yes. Consider, for example, the retirements of coal-fired generation that have occurred over the past two decades. Environmental regulations impacted the cost of existing coal-fired generation, particularly for plants that needed to make large investments in scrubbers or other assets to meet emissions regulations. At the same time, gas-fired generation became much less expensive, due both to improvements in efficiency and supply-driven declines in natural gas prices. Renewable generation also became more economical, which impacted not only new generation but also the operating profile of existing generating assets. As a result of these factors, many coal-fired generators were retired in the past ten years.

Q. Have you considered these factors when estimating life spans for the company's generating facilities?

A. Yes. I have also incorporated the company's input, as I have generally found that those who operate facilities have the best understanding of the outlook of their generating assets. For this study, I reviewed the company's initial estimates of retirement dates and discussed these factors, as well as specifics of each facility, with company personnel. The recommended retirement dates in the study are aligned with both the company's and my expectations for the future based on the best information available today.

Q. Are there other reasons you collaborate with a company when developing life span estimates?

A. Yes. Life spans vary from company to company and plant to plant. This is based on a variety of factors, but in general the economic decision from company to company or plant to plant is based on specific factors that impact each facility. These may include geography, fuel cost and availability, suitable locations for replacement generation, and the assessment of risks of factors such as greenhouse gas ("GHG") emissions and future commodity prices. For these reasons, discussions with and input from a company's personnel are often critical to developing the most reasonable life span estimates.

Q. Has Tampa Electric retired any of its power plants in recent years?

A. Yes. As I discuss in my direct testimony and the depreciation study, Tampa Electric has retired several steam and other production facilities in recent years. In general, these retirements have not occurred at ages older than has been typical in the industry for these types of generating facilities.

Q. What are some of the lessons learned from Tampa Electric's experience with these plants?

A. In addition to providing evidence of the life spans Tampa Electric's plants have experienced, the retirements of these plants illustrate causes of final retirement discussed above. Specifically, a power plant is often retired as the result of an economic decision. As a plant ages and becomes more expensive to operate, and as new technologies become more efficient and economical relative to existing generation, it eventually becomes economical to replace the existing plant. The retired plant may be able to physically operate for a longer period of time, but it would be a more costly option to keep the plant in service.

Thus, the process of estimating the life spans of the company's power plants is not to determine how long a plant could physically last, but instead estimating when the economic decision will be to replace the plant with newer generation.

Q. What has Tampa Electric's actual experience been with regard to the economics of its power plants?

A. Tampa Electric's actual experience indicates that it has been more economical to replace older, less efficient power plants with newer facilities. Further, with the benefit of hindsight, this has provided benefits in that the company has moved to lower cost and lower emission sources of energy, which has benefits in both economic and environmental terms but also reduces GHG emissions risk when compared to many other utilities across the country.

It would have been possible from a physical standpoint to operate these plants for a longer time. However, it would not have been economical to do so because these plants had become more expensive than the alternative of replacing them with newer, more efficient facilities.

Q. Based on your experience in the industry, what lessons can you learn from historical retirements of generating facilities?

A. The electric industry has seen a large-scale change in its generating fleet over the past two decades, which roughly corresponds with my career in the industry. In the early and mid-2000s, there was a widespread expectation (if not a consensus) that steam-fired generation, particularly coal-fired generation, would be able to be operated for long life spans – perhaps 70 years or more. Indeed, this was technically true from a physical standpoint. With enough capital investment, plants could be operated for very long life spans. As an example, early in my career I toured several coal plants from the 1940s, which were already close to 70 years of age. It was, perhaps, not irrational to expect that newer generation might attain similar life spans.

However, projecting this past experience (as well as the expectation that the physical life would dictate the overall life span) onto the future proved to be incorrect. By the early 2010s natural gas prices had fallen considerably, efficiency of combined cycles had increased significantly, and the cost of coal-fired generation increased – and would increase further, since various emissions rules would require investments in assets such as scrubbers to meet requirements by the mid-2010s.

Companies were faced with investment decisions, which at the time were often between investing in older coal-fired plants or constructing new combined cycle plants. With the benefit of hindsight, companies like Tampa Electric that retired existing generation (rather than invest further in coal, oil or gas-fired steam generation) ended

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up better off.[2] The Commission's approach of capital recovery schedules, as well as the inclusion of dismantlement recovery, also facilitated replacement of aging, uneconomical power plants with newer more efficient, lower emission and less costly generation. Other states that did not have such mechanisms, and states where utilities instead invested in scrubbers or other assets to extend the life spans of coal generation are now going through a similar transition to combined cycles (and now renewables), but with additional costs for coal generation that need to be recovered either over a short remaining life or after retirement. This can create challenges from an intergenerational equity standpoint and can impact the economic decision for replacement, thereby uneconomically extending the useful life of generating assets that no longer most efficiently meet the needs of the system.

Q. Do you have any examples of expectations from that time period about coal-fired generation?

A. Yes. For example, as recently as 2016, Mr. Kollen proposed

[2] I do not make this statement to be critical of past investment decisions for any utility, or commission. At the time there were valid arguments for investing in either coal-fired generation or new generation. Further, the considerations varied on a plant-by-plant and utility-by-utility basis. Additionally, many of the events that followed (such as election results and the shale gas boom) were impossible to predict at the time.

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extending the life span of coal fired generation for FPL's St. John's River Power Park ("SJRPP") to 65 years and Scherer Unit 4 to 63 years, even though large-scale retirements of coal-fired generation were already underway.

Q. Did these plants attain the life spans Mr. Kollen expected?

A. No. Both plants were retired within a few years of the conclusion of that case (SJRPP in January 2018 and Scherer Unit 4 in January 2022) at life spans of 31 and 33 years, respectively. These were about half the life spans that Mr. Kollen estimated.

Q. Do you see any indications that Mr. Kollen has considered all of these factors?

A. No. I do not see any indication that he has learned lessons from his previous over-estimation of life spans. His testimony does not address the factors discussed above and is merely limited to discussions of current estimates for Tampa Electric or other utilities.

Q. What are considerations related to generation today, particularly when you consider the future operating environment?

A. There are several factors in current operation that we should consider, which includes outlook for the generation mix and future load growth. The electric industry as a whole is beginning to rapidly transition to a much larger share of renewables, both reducing emissions and long term GHG risk. At the same time, load growth is increasing due to electrification of transportation and other energy uses, data centers and other technology uses, and a general increased prevalence of electrical devices throughout our lives. These factors will also mean that customer growth will occur at a faster pace, as each new customer will use more electricity.

These factors mean that there will be a need for additional capacity in the future. With the growth in renewables, this means both incremental renewable capacity and generation or storage that can follow changes in intermittent renewable generation.

Technology is changing rapidly. There are possibilities that existing generation may not meet future needs of the system and the pace of technology change means that it is more likely that newer generation or storage can better, and more economically, meet future needs. There is a similar dynamic to the replacement of coal-fired generation with newer and more efficient gas plant technology with fuel sourced using new gas extraction technologies. However, technology is changing at a faster pace than in the 2000s.

Importantly, these factors should be considered for both combined cycle generation and solar generation, as the dynamics and economics of each differ. I will discuss each in the following sections.

1. Combined Cycle

Q. What are the life span estimates proposed for combined cycle plants?

A. I have recommended life spans for combined cycle plants that are generally consistent with a 35-year life span,[3] which is the same estimate as currently used for the company's combined cycle facilities. However, my recommendation also considers the specifics of each unit, as discussed in more detail below. FEA witness Andrews proposes to extend the life span to 40-years. As I discuss

[3] Due to specifics of each facility, including the configuration of the plants, some estimates are longer than 35-years. However, in general, the combined cycle estimates are consistent with a life span of 35-years.

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later, he also proposes unusually long interim survivor curve estimates.

Q. To your knowledge, has Mr. Andrews toured the combined cycle facilities or met with Tampa Electric subject matter experts on these plants?

A. No. He has not indicated in testimony that he has toured any combined cycle plant.

Q. Did your study include site visits to these facilities?

A. Yes. Further, I have conducted site visits of combined cycle facilities across the country. For example, I have been to most of the investor-owned utilities' combined cycle plants in Florida (and colleagues have attended additional sites).

Q. Has Mr. Andrews provided any discussion of factors that would influence the life span of combined cycle facilities?

A. No. His discussion is limited to the estimates for other utilities, and I do not see any evidence that he considered important factors related to the operation of the combined cycle plants.

Q. What are factors that should be considered for the life spans of combined cycle generation?

A. As the Commission is aware, each of the investor-owned electric utilities in Florida, including Tampa Electric, have made significant investments in solar facilities in recent years, significantly increasing their renewable output. However, solar energy is not created consistently throughout the day and, as a result, other generation needs to come online – often quickly – to make up for the loss of solar generation when, for example, the sun goes down. Today, natural gas facilities most commonly follow these generation needs, with some also addressed with other technologies such as battery energy storage systems. As a result, it has become common for even newer base load facilities to follow load (or more precisely follow renewable generation) and cycle more frequently.

This dynamic will become even more pronounced in the future. Indeed, in some parts of the country, such as California or Nevada, there are times of the day where solar generation exceeds total load on the system. This means that, when the sun goes down, enough generation needs to come online quickly to offset the entire load on the system. Because solar generation is significant enough, this means that all plants – even base load plants – need to cycle multiple times during the day.

While the company (and Florida in general) has not yet reached the same scale of renewable penetration as California or Nevada, it is quickly trending in this direction. Even base load facilities have begun cycling frequently throughout the year.

Q. How does all of this impact the life spans of combined cycle plants?

A. Generally, increased cycling – particularly if there are more starts throughout the year – can limit or reduce the life span of the facility. At a minimum, it likely means more capital replacements and investments to continue operating the facility, impacting the overall economics of the facility. This, in turn means more replacement of assets and additional maintenance. These factors increase the overall economics of operating the facility, which is also affected by the fact that more cycling means a lower overall power output and less utilization. Additionally, most plants were not designed for this type of operation.

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For example, plants designed for true base load operations can develop more challenges when cycling frequently or following load.

Overall, these factors mean that the operations of the Tampa Electric's combined cycles will likely favor a shorter life, all else equal. Given that changes since the prior depreciation study would indicate shorter, not longer, lives, it would not be reasonable to increase the life span of these facilities at this time.

Q. Are there any other reasons that favor not increasing the life span?

A. Yes. As noted above, the electric industry is changing rapidly. Not only does increased renewable generation mean significant changes to the operations of these facilities, but new technologies mean the potential for obsolescence of existing technologies. Further, the general move to reducing GHG emissions and new technologies means that the likelihood of longer life spans for fossil generation has gotten smaller.

Q. Are there ways that combined cycle facilities could be modified to use lower emissions fuels?

A. Possibly, although not based on technology that is currently commercially available at scale. It is possible that, for example, current natural gas-fired generation could be fueled with a combination of hydrogen and renewable gas, thereby allowing longer operation with minimal emissions (and, in the case of hydrogen, effectively become large batteries for solar generation). However, these will require significant investments in new technologies that are not yet commercially available. For these reasons, a shorter life span is appropriate today. If such investments do occur in the future (which is far from certain) then there will be additional costs that will need to recover over the remaining life span (which in turn will increase future depreciation).

Q. Are there any specific characteristics of the company's plants that Mr. Andrews has failed to consider?

A. Yes. Bayside Units 1 and 2 are a different construction from many other combined cycle units. While the combustion turbines, heat-recovery steam generators and other assets are relatively new (constructed in 2003 and 2004), the plant uses existing steam turbines that were originally placed in service in the 1960s. Because a portion of the plant is relatively old, this will impact the overall life span of the plant and mean that a 40-year life span, as measured from the installation of the combustion turbines, is likely not attainable from an operational standpoint.

As an example, Florida Power and Light Company's Lauderdale Unit 4 and Unit 5 were combined cycle plants that had similar construction in that the Lauderdale units also reused the existing steam turbines that had been placed in service decades earlier. Lauderdale 4 and 5 were retired in 2018 with life spans of 25 years. Similarly, we should not expect a 40-year life span for Bayside Units 1 and 2.

Q. Given these considerations, do you agree with Mr. Andrews's proposal?

A. No. I do not believe a longer life span is appropriate at this time. At the current pace of technology change, 35 years is a long time. There will be significant changes in the electric industry over the next three decades and it is unclear whether combined cycles could attain longer life spans – at least without major investments. Additionally, the configuration of plants such as Bayside Units 1 and 2 do not support longer life spans. The company's past experience shows that it has replaced aging generation when no longer economical, which also favors the 35-year life span.

Q. Are there any other issues with Mr. Andrews's proposal?.

A. Yes. Mr. Andrews did not update the composite net salvage calculations for his revised life span and, as a result, uses the incorrect net salvage percentages in his calculations. While I disagree with Mr. Andrews's proposal, I provide for reference in Document Nos. 2 and 3 of my rebuttal exhibit, respectively, corrected calculations with the 40-year life span, as well as with a 40-year life span and Mr. Andrews' recommended interim survivor curves.

2. Solar

Q. What are the estimates proposed for solar?

A. For solar generation, the life span method was not used, which means that the estimates are based on a survivor curve that should incorporate both interim and final retirements of individual facilities (within a group comprised of the full population of solar facilities). My recommendation is a 30-S3 survivor curve. Because there will be interim retirements for assets such as inverters, this implies that the life spans of solar facilities would be slightly longer than the 30-year average service life. Mr. Kollen proposes a 35-year average service life with the same curve type.

Q. How does Mr. Kollen support his proposal?

A. Mr. Kollen argues that his proposal is consistent with the 35-year life span used for the current depreciation rates, which is based on a settlement agreement in the previous case (the company had proposed a 30-year life span). The only other support he provides is that the company uses the currently approved 35-year life span for resource planning purposes.

Q. Do you agree with Mr. Kollen's arguments?

A. No. First, the company's practice for resource planning (which is consistent with other companies in Florida) is to use the currently approved life span estimates. As a result, the fact that a 35-year life span has been used for resource planning provides no additional support for that life span, since it is based on the life agreed to in a settlement in the last case. Second, solar generation is still relatively new, and technology will likely continue to improve, both of which suggest that a shorter life for depreciation purposes would be better than a longer life.

Q. Has Mr. Kollen considered any of the other factors that will influence the life of solar facilities?

A. No. Based on his testimony, he has not considered any factors other than the current life span (which he incorrectly applies as an average service life).

Q. Are there any other considerations related to solar?

A. Yes. FERC Order 898 modifies the Uniform System of Accounts for renewable and storage generation. This will include providing additional subaccounts for assets such as inverters and collector systems, at least some of which may have different life characteristics than the overall facilities. Mr. Kollen's proposal to use an average service life of 35 years rather than a life span of 35 years is to effectively increase the service life of solar assets. I do not believe it is reasonable to do so until, at a minimum, these accounting changes are implemented and the new subaccounts can be studied in a new depreciation study in the next rate case.

Q. Given these considerations, do you agree with Mr. Kollen's proposal?

A. No. I do not believe a longer life span is appropriate at this time. At the current pace of technology change, 30 years is a long time. Increasing the life span to 35 years is at a minimum premature, given all of the factors discussed above. Importantly, while Mr. Kollen's proposal could reduce depreciation in the short term, in the long-term it will be more costly to customers as more will need to be recovered in the future and rate base will be lower than had a 30-year average service life been used. If the life spans of these facilities end up shorter than Mr. Kollen's proposal, the use of his depreciation rates would also mean future customers would pay a disproportionate share of the cost of these assets, perhaps even after already retired.

Q. Are there any other issues with Mr. Kollen's proposal?

A. Yes. Mr. Kollen to my knowledge does not have depreciation software to perform remaining life depreciation calculations, as he does not typically perform depreciation studies. I have provided calculations using his proposed estimates, which are the correct rates to use if a 35-year average service life were to be used, in Document No. 1 of my rebuttal exhibit.

3. Battery Energy Storage

Q. What are the proposals for Battery Energy Storage Systems ("BESS")?

A. BESS assets are new assets of an emerging technology and can vary in size and function. As a result, there is limited historical data on the service lives and operations of these types of assets, and the life expectations may differ from location to location.

My recommendation in the depreciation study is to continue to use the currently approved 10-year average service life for storage facilities, which is appropriate and reasonable for many BESS assets. In some instances, there may be larger facilities or facilities with specific agreements that may favor a longer life. However, for the assets in the study, I believe the current 10-year average service life is most appropriate.

Q. What has Mr. Kollen proposed?

A. Mr. Kollen proposes a 20-year average service life – doubling the currently approved average service life estimate.

Q. What support does Mr. Kollen provide?

A. While Mr. Kollen claims he has proposed an "industry standard" estimate of 20-years, he provides no support other than to cite to a handful of utility-specific filings and reports from government agencies.

Q. To your knowledge, does Mr. Kollen have extensive experience estimating useful lives for BESS systems?

A. No. Further, in discovery I provided estimates for other utilities with BESS assets.[4] Most estimates are lower than the 20-year life span Mr. Kollen proposes and the longer estimates are not necessarily comparable to Tampa Electric's. There are also estimates of 10-year average service lives, which shows that the currently approved estimate is within the industry range and, as a result, there is not a need to increase the service life.

Q. In addition to not considering this information, does Mr.

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[4] Please refer to the response provided to OPC Set 4 Request No. 94.

Kollen's testimony provide any indication that he considered other factors that can impact the lives of BESS assets?

A. No. Based on his testimony, I believe he has failed to incorporate important considerations.

Q. What are considerations for estimating service lives for BESS assets?

A. Many considerations related to technology are similar to those discussed about solar. Because BESS is a new technology, there is the potential for obsolescence as BESS systems improve in capacity, operations and cost. There is also uncertainty over how the assets will perform over time, both from a physical and function standpoint.

Q. How do you believe these considerations should inform the service life estimate?

A. In my judgment, these favor a shorter service life. Particularly for new technologies, all else equal it is most reasonable to favor a shorter service life. At a minimum, I do not believe there is justification to change from the 10-year service life previously approved by the

Commission. This can be adjusted in future studies as more data is available and as new accounting rules are fully implemented.

B. **<u>Interim Retirements</u>**

Q. What does Mr. Andrews propose for interim retirement estimates?

A. Similar to the depreciation study, Mr. Andrews estimates interim retirements using interim survivor curves. However, his proposals and approach are missing several key elements and, as a result, he has recommended unreasonable interim survivor curves for several accounts.

Q. What is the basis for Mr. Andrews's recommendations?

A. Mr. Andrews provides no support other than mathematical curve fitting results. However, his curve fitting results fail to properly consider the company's historical data and, as a result, incorrectly project the experience of older, different technologies onto the company's current generation fleet. Further, Mr. Andrews's testimony gives no indication that he incorporated any information in addition to the statistical analysis. As I discuss, other factors such as information from site visits, meetings and general knowledge of the property should be considered when estimating service lives.

Q. Did the apparent lack of including any of this information negatively affect Mr. Andrews's proposals?

A. Yes. For example, for Account 312.00, Boiler Plant Equipment, Mr. Andrews has selected the 60-O3 survivor curve. O3 curves are rarely used for utility property, due in part to the unusual curve shape that anticipates a significant percentage of assets to retire early but then for most remaining assets to have very long lives. I do not recall ever seeing an O3 curve used for this account, nor should it be.

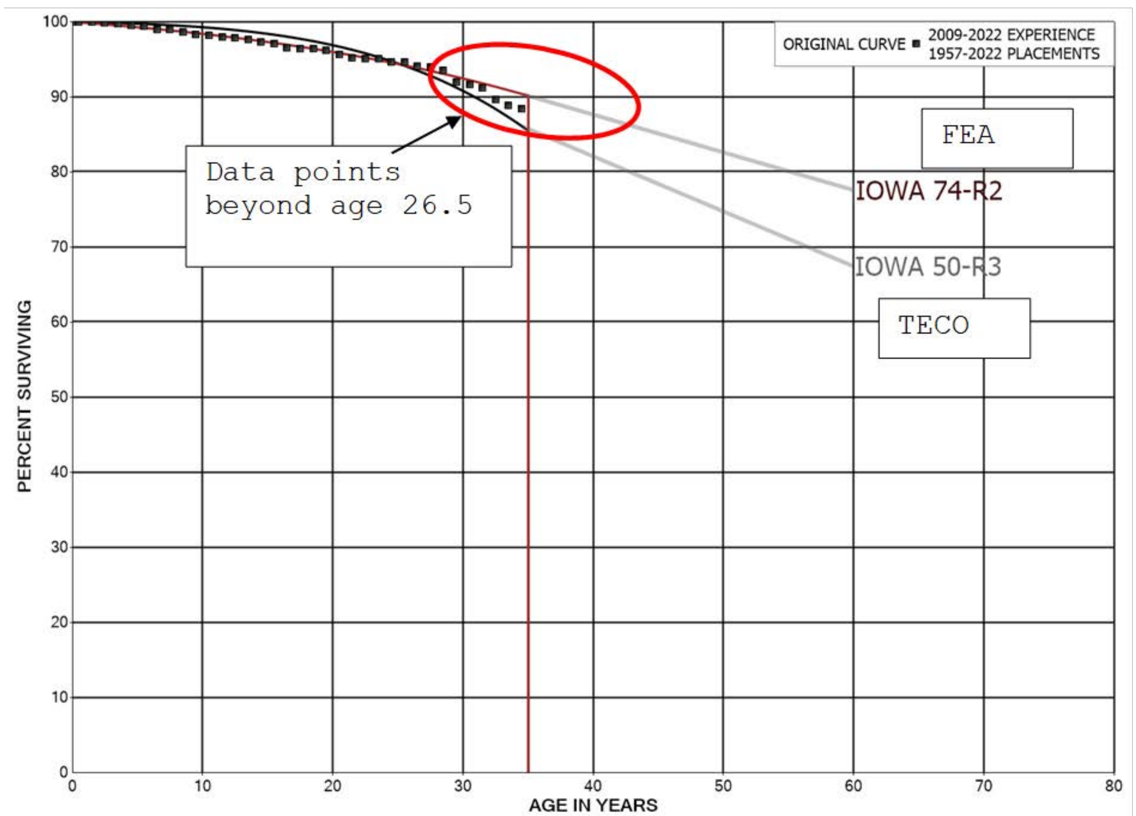
Additionally, Mr. Andrews's curve fitting does not consider the relevance and importance of different data points from the historical analysis. For example, his analysis for Account 341.00, Structures and Improvements, is based on data through approximately age 50. However, the company's current power plants in other production accounts have all been constructed within the last 30 years. As a result, the data points beyond age 30 do not provide meaningful indications of the retirement experience for the plants currently in service (this is particularly true because the type of power plants in this function of plant are much different today than 40 or 50 years ago). Data points beyond age 25 or 30 should be given little consideration in the analysis for other production plant. Further, he considers data points beyond his recommended life spans, which should further demonstrate that he is projecting the experience of dissimilar facilities onto the company's current fleet.

Q. Does Mr. Andrews properly consider these aspects of the data?

A. No. Mr. Andrews's curve fitting appears to fit most, if not all, of the data points, including many that are not relevant to the analysis for assets currently in service. For example, Figure 1 shows historical data and both my and Mr. Andrews' estimate for Account 341.00, Structures and Improvements. This chart shows the same data points as those shown by Mr. Andrews. However, the points circled below, which are those beyond age 26.5, are based on much smaller levels of investment for older technology plants that are no longer in service. As a result, these data points should be given more limited consideration in the analysis. However, as can be seen in the graph, Mr.

Andrews's estimate is largely based on these older, less meaningful data points.

Figure 1: Comparison of Interim Survivor Curve Estimates for Account 341, Structures and Improvements



Q. Given these considerations, do you agree with Mr. Andrews proposal?

A. No. As I have discussed, there are analytical issues with Mr. Andrews's recommendations, which also lead to atypical results. Additionally, Mr. Andrews does not appear to have considered anything beyond the data. My recommendations are not only reasonably consistent with the available data, but also incorporate my knowledge and understanding of the assets from other studies and, as a result, are consistent with the operation of these types of plants. For these reasons, my recommended interim survivor curves are better estimates than those of Mr. Andrews.

C. <u>Dismantlement Accruals</u>

Q. What issue does Mr. Kollen raise regarding the dismantlement accruals?

A. Mr. Kollen makes several adjustments or criticisms of the company’s dismantlement study and dismantlement accruals.

Q. Will you address the dismantlement study or calculation of dismantlement accruals?

A. No. While I disagree with Mr. Kollen’s proposals, in part because I am not aware of his having expertise in dismantlement studies or the dismantlement accrual approach used in Florida, witness Kopp and Chronister address the dismantlement study and dismantlement accruals. However, I would like to comment and clarify a few points regarding how dismantlement studies interrelate with depreciation studies.

Q. Please explain.

A. In other jurisdictions, the dismantlement cost estimates are included in depreciation rates, typically by converting the cost estimate to a net salvage percentage that is incorporated into the remaining life depreciation calculations. Florida instead prescribes a separate dismantlement accrual calculation.

Mr. Kopp's testimony is conceptually correct, in that his estimates are incorporated into an accrual to be included as depreciation or amortization expense. However, for Tampa Electric, these were not included in my recommended depreciation rates. Instead, consistent with prior studies, the company performed the dismantlement accrual calculations consistent with Commission practices and with previous depreciation studies.

II. Mass Property

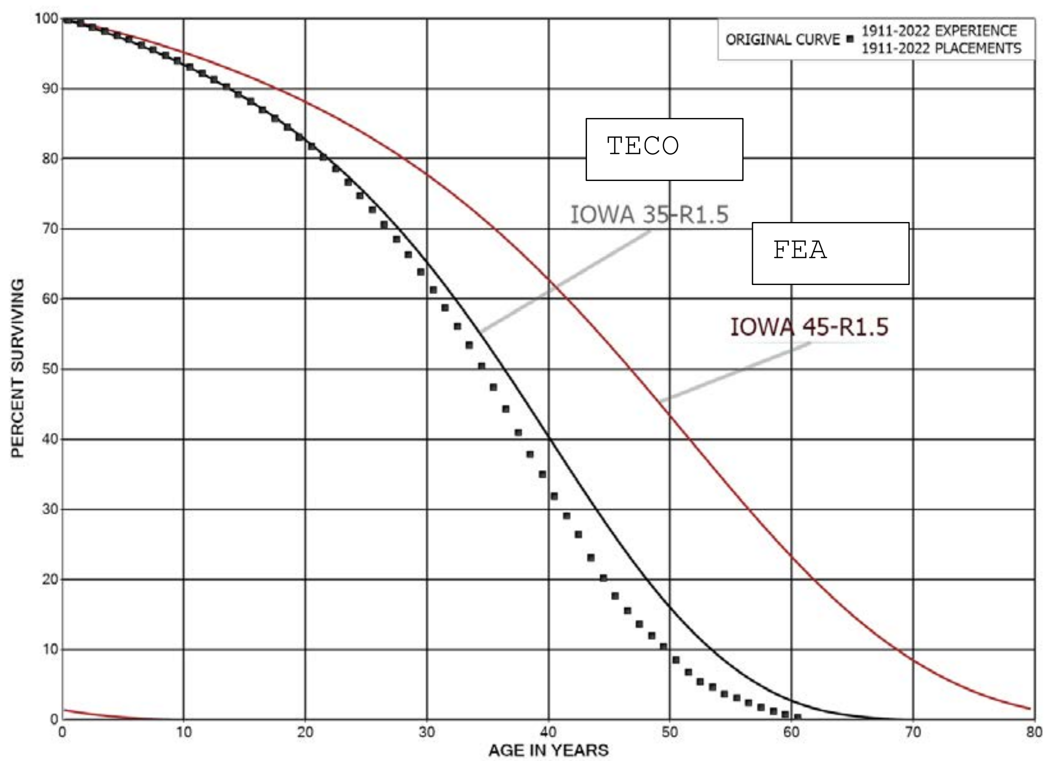
D. <u>Service Life for Account 367.00, Underground Conductors and Devices</u>

Q. Please discuss Account 367.00, Underground Conductors and

Devices.

A. For this account, I recommend the 35-R1.5 survivor curve. The current estimate for this account is the 45-R1.5. Mr. Andrews proposes to retain this estimate. Historical retirements for this account, based on actual retirement data from 1911 through 2022 that was statistically aged, support an average service life of 35-years or shorter. The 35-R1.5 is a good fit of the historical data, as can be seen in Figure 2 below.

Figure 2. Comparison of Tampa Electric vs FEA Proposed Survivor Curves for Account 367



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In addition to the actuarial analysis, Simulated Plant Record ("SPR") analysis was performed and supported a similar service life. For example, the 33-R1.5 survivor curve had the highest conformance index of curves with a good retirement experience index for the analysis of the 1993-2022 period. While estimates for other utilities may have longer average service lives than 35 years, Tampa Electric's available data supports a shorter service life. Additionally, assets in Florida typically have shorter lives than other parts of the country due to higher temperatures, humidity, a higher water table, proximity to the coast and other factors unique to the southeastern United States.

Q. Can the actuarial analysis based on statistically aged data, combined with SPR analysis, provide a reasonable basis for determining a service life estimate?

A. Yes. My analyses used industry-accepted practices and were most reasonable based on the available data. These analyses were based on retirements that were recorded by Tampa Electric over the period 1911 through 2022.

Q. Please address the accuracy of Mr. Andrews's comments that "when companies rely on simulated data and the SPR procedure, the resulting ASLs are almost always understated. The simulations are very dependent on the survivor curves that are used to estimate the data, therefore, the results tend to be skewed to the downsides, resulting in higher depreciation rates."[5]

A. Mr. Andrews provides no support for this statement, and it is not generally consistent with my experience. However, SPR analyses does produce results that are more difficult to interpret and require an experienced analyst to recognize the limitations of the analysis. For example, if mortality characteristics are dynamic over time, then the analysis may favor higher or lower mode curves. The selection of higher mode curves in these instances could produces shorter lives, although lower mode curves would have the opposite effect. I have seen instances in which the SPR analysis, particularly the Retirement Experience Index ("REI"), favors higher mode curves due to low REIs for lower mode curves. This could at times favor shorter average service lives.

However, these limitations do not apply for this account to effectively ignore the available analysis, as Mr. Andrews proposes. My recommended survivor curve,

[5] Page 23, Line 7-10 of Mr. Andrews Direct Testimony

supported by the statistical results, uses a mid-mode R1.5 survivor curve.

E. Net Salvage Estimates

Q. Please summarize the different net salvage estimates proposed by Tampa Electric and FEA.

A. See Figure 3 below for a summary of the net salvage estimates proposed by Tampa Electric and FEA. FEA proposed a change in net salvage percentages for six asset classes:

Figure 3. Net Salvage Estimate Comparison

Account	**Tampa Electric Proposal**	**FEA Proposal**
356	(50)	(40)
362	(20)	(15)
364	(75)	(70)
365	(30)	(20)
367	(15)	(10)
392	20	25

Q. Please explain why Tampa Electric's estimates are more reasonable than those proposed by FEA.

A. Tampa Electric's estimates are more reasonable than FEA's because they align more closely with recent trends in net salvage experience, and they more appropriately consider the trend towards increasing cost of removal in the utility industry.

Figure 4 below provides a summary of the historic net salvage percentages; the overall experience band, as well as the most recent 10- and 5-year bands of data are shown alongside Tampa Electric's and FEA's proposals:

Figure 4. Experienced Net Salvage

Account	Overall Experienced Net Salvage	Recent 10-Year Experienced Net Salvage	Recent 5-Year Experienced Net Salvage	Tampa Electric Proposal	FEA Proposal
356	(39)	(46)	(93)	(50)	(40)
362	(14)	(22)	(33)	(20)	(15)
364	(73)	(92)	(113)	(75)	(70)
365	(21)	(38)	(34)	(30)	(20)
367	(13)	(20)	(16)	(15)	(10)
392	(29)	25	45	20	25

With the exception of Account 392, the more recent 10- and 5-year analyses of historic net salvage are trending more negative.[6] For example, for Account 364, Mr. Andrews cites the overall net salvage percentage of (73) as not being supportive of Tampa Electric's proposed (75) estimate. First, (73) rounded to the nearest five is (75) percent and, since net salvage estimates are customarily made in increments of five, the overall average does support my estimate. Additionally, the recent 10-year average is (92) and the 5-year average is (113). When the complete data set is considered, not only the overall average but more recent averages and trends as well, the data is more supportive of my recommendation.

Q. Is Mr. Andrews's reliance on overall net salvage[7] rates to estimate future net salvage an appropriate approach to estimating future costs?

A. No. While the overall average is a statistic I rely on, I also consider trends in the data as well as current estimates and estimates for other utilities. For most of the accounts at issue, my estimates are within 5 basis points of the overall average but are less negative than the most recent five and ten year averages. For each

[6] Gross salvage for Account 392 is impacted by the market for used automobiles and, in the future, could be impacted by a transition to electric vehicles.
[7] Page 25, Line 22-25 of Mr. Andrews Direct Testimony. Mr. Andrews states that his estimates never exceed "more than 1%" of the overall net salvage rate.

account except Account 392, my estimate is less negative than the most recent five-year average.

Q. Have removal costs increased in the industry?

A. Yes. There are multiple, and sometimes inter-related, reasons for increasing removal costs. Many of these reasons are outside of the company's control. Environmental rules have increased removal costs. As an example, disposal requirements for treated wood poles have increased over time, increasing the cost to dispose of wood poles (and therefore increasing removal costs). Permitting requirements have become more restrictive and burdensome, which increases costs.[8] As an example, municipalities or counties may require work to only be performed at certain hours of the day, increasing project costs. Another example is the requirements for restoring the site after assets are removed. Municipalities have required restoration of sidewalks or landscaping, which increases removal costs. Increasing requirements for traffic control has also added to costs.

Labor costs have increased because of wage increases and a shortage of skilled workers in the utility sector.

[8] Note that "permitting requirements" does not necessarily mean the cost of permits, but instead can mean the actual work requirements dictated by the permit.

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Similarly, material and equipment costs have increased due to overall inflation and increased demand across various industries. This has become more pronounced as utilities across the country have increased investments to modernize the electric grid.

Q. Do you agree with Mr. Andrews's proposals?

A. No. My estimates better reflect trends in the data and other factors discussed above.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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BY MS. PONDER:

Q Mr. Allis, did you prepare and cause to be filed with your direct testimony an exhibit marked NA-1, consisting of four documents?

A Yes.

Q And did you also prepare and cause to be filed with your rebuttal testimony an exhibit marked NA-2, consisting of three documents?

A Yes.

MS. PONDER: Mr. Chairman, Tampa Electric would note for the record that Exhibits NA-1 and NA-2 have been identified on the CEL as Exhibits 26 and 147.

CHAIRMAN LA ROSA: Okay.

BY MS. PONDER:

Q Mr. Allis, would you please summarize your prepared and direct -- excuse me, your prepared direct and rebuttal testimony?

A Yes.

Good afternoon, Chairman and Commissioners. My name is Ned Allis, and I performed the depreciation study on behalf of Tampa Electric Company, and my direct testimony presents and explains that study.

The depreciation study was conducted based on industry standard methods and procedures that are consistent with prior depreciation studies performed for utilities in Florida. The study recommends service life and net salvage estimates for each property account, as well as lifespan estimates for each of the company's generating facilities. Those are then used along with the company's current balances to calculate depreciation rates for each of these property groups.

The estimates that I have recommended incorporated statistical analyses of historical data, information obtained from site visits and meetings with company personnel, as well as the overall experience of myself and my staff, which includes conducting similar depreciation studies for utilities across the country, including other Florida utilities as well.

The study results in an overall increase of depreciation expense of approximately $40.7 million as of December 31st, 2024. This overall increase is the result of several factors, the largest of which is actually just the mechanical updating of depreciation rates to incorporate current balances. That accounts for about 36 of that $40 million increase.

The recommended service life and net salvage estimates I have made in the study for transmission distribution accounts result in an increase, which is offset by a decrease due to longer average service lives for generation accounts that net to about a $4 million increase.

My rebuttal testimony responds to the depreciation related testimonies of OPC witness Lane Kollen and FEA witness Brian Andrews. Mr. Kollen proposes adjustments to the lifespans of solar facilities, as well as to the average service life for energy storage, which I understand has now been stipulated.

FEA proposes longer lifespans for combined-cycle facilities, as well as different interim survivor curves for production plant accounts, a longer service life for underground distribution conductor, and less negative net salvage estimates for several accounts.

As I discuss my rebuttal testimony, I disagree with each of these recommendations. OPC and FEA's proposals for longer lifespans for solar and combined-cycle plants do not, in my opinion, adequately consider factors that will contribute to the retirement of these facilities, such as changing technology, changes to the operating environment, and other economic factors that I believe are likely to limit the overall lifespans of these facilities.

Additionally, FEA's proposed interim survivor curves are outside of kind of best practices and typical estimates in the industry. As an example, the estimate of an '03 survivor curve is very unusual and doesn't really suit the property study particularly well.

Additionally, I think Mr. Andrews' estimates don't properly interpret the historical data, and this is also true with the net salvage estimates I have made. In general, I think my recommendations are better aligned with the data once properly interpreted and analyzed.

In summary, I think the other parties' proposals are based on limited information, analyses and fail to consider the many ways that the company and, really, the entire industry will change in the coming decades. I think my recommendations for each of these accounts best reflect the future life and net salvage estimates -- or life and net salvage expectations based on the information and data we have today.

Thank you. That concludes my summary.

MS. PONDER: Mr. Chairman, we tender Mr. Allis for cross-examination.

CHAIRMAN LA ROSA: OPC, you are recognized when you are ready.

MR. WATROUS: Thank you, Mr. Chair.

EXAMINATION

BY MR. WATROUS:
Q And hello, Mr. Allis.
A Good afternoon.
Q How are you doing today?
A I am doing well.
Q All right. Well, if you don't mind, I would like to jump right into questioning.
You recommended a 30-year average service life for solar facilities, correct?
A Yes.
Q Isn't it true TECO's current Commission-approved service life for solar facilities is 35 years?
A Not exactly. Based on settlement in the prior case, there is a 35-year lifespan, and the company had proposed a 30-year life span in the prior depreciation study.
Q Thank you.
And in 2021, you testified on behalf of Florida Power & Light Company's depreciation study?
A Yes.
Q In 2021, at the request of FPL Witness Ferguson, you calculated a 35-year lifespan for solar facilities?
A I had done a calculation at the request of

Witness Ferguson. I had proposed a 30-year lifespan for solar facilities in that case.

Q And FPL's current life for solar facilities is 35 years?

A Based on the result of that case, yes.

Q And in this case, you provided calculations for a 35-year average service life?

A I did. In my rebuttal testimony, I wanted to make sure that the calculated depreciation rates from other proposals were performed consistent with how we had done it in the depreciation study, so I provided that in my rebuttal testimony.

Q And that's on Exhibit NA-2, page one of two, correct?

A Yes.

Q Okay. And your calculations are not unreasonable in support of a 35-year overall service life for solar generation facilities?

A I am not sure I fully understand the question. Could you perhaps rephrase that?

Q So are your calculations for a 35-year service life for Tampa Electric solar generation facilities reasonable?

A So I have proposed a 30-year lifespan, so I would expect that -- I believe that to be the most reasonable. 35 is an, I suppose, outside an overall range of possibilities, but I think a 30-year lifespan would be more reasonable.

Q   So a 35-year lifespan is reasonable?

A   No, that's not what I said. I said it's within a range of, you know, potential, I suppose, more reasonable possibilities for the future.

MR. WATROUS: Thank you. That's all from OPC.

CHAIRMAN LA ROSA: Florida Rising/LULAC.

MS. LOCHAN: Sure. I just have very short questions. Thank you, Chairman.

EXAMINATION

BY MS. LOCHAN:

Q   Good afternoon -- good evening, Mr. Allis.

Generally, would you agree that it makes sense, as a practice, to match depreciation with service life?

A   Yes.

Q   Okay. Thank you so much.

MS. LOCHAN: That's my questions.

CHAIRMAN LA ROSA: Thank you.

FIPUG.

MR. MOYLE: I have just a few.

EXAMINATION

BY MR. MOYLE:

Q In response to the question about the combined-cycle lives, you said there is a range that's reasonable. What's the range?

A He asked me about solar lifespans, I think, right?

Q Okay. What was your range when you said there was a range on solar?

A I -- for solar, we have typically seen lifespans in the 25- to 35-year range, with 30 being kind of in the midpoint of that.

Q Have you looked, or do you have knowledge that a lot of leases that are being done with solar are 35 years with five-year options, and those kind of things?

A I am not sure if you are referring to any specific ones. I know that some solar sites have leases, and they may have varying terms.

Q I am just asking, you know -- I mean, you do this pretty regularly with solar, right?

A I am not familiar with every lease term. I know that there are lease terms, and things like that, that I have --

Q Okay.

A -- probably been involved with studies that have had hundreds of different solar facilities.

Q In your opening, you said, well, the entire

industry is going to change materially in the future. What did you mean by that?

A Well, there is quite a bit to it, right? I mean, first of all, technology. Technology has changed a lot. You know, I look back to when I started about 18 years ago, when most of the generating fleet, there was a lot more, say, coal-fired generation, and things like that. And in the past 18 years, we have seen that turnover, a lot sooner than people expected, I think too. That's been driven by new gas-fired combined-cycle technology that's gotten much more efficient, and then solar and other things like that.

I think in the future, we are going to see a lot more of those types of changes, and that will potentially impact existing generation. It might be that there is new things we haven't even thought of yet sort of thing.

I think we are seeing changes in load growth, electrification and things like that will have an impact. Obviously, there is a need to make systems resilient and reliable, and there is a lot of investments going on.

I mean, really, from my experience, I think there is a lot that is going to change in the coming, say, two decades, that will impact probably just about everything.

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

CHAIRMAN LA ROSA: Thank you.

FEA.

CAPTIAN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: Thank you.

Sierra Club.

MR. SHRINATH: No questions.

CHAIRMAN LA ROSA: FRF.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: Staff.

MR. MARQUEZ: Yes, Mr. Chairman.

EXAMINATION

BY MR. MARQUEZ:

Q Mr. Allis, is it correct that TECO recently filed an updated revenue requirement, which includes an increase of battery storage life from your proposal of 10 years to 20 years?

A I don't know exactly what was filed, but my understanding is that, yes, that they had stipulated to a 20-year life for energy storage.

Q Okay. And will that increase in service life

have any impact on TECO's theoretical reserve imbalance as of December 31st of 2024?

A So, yes, it would. Although, because those are fairly new assets, I wouldn't expect it to have that big of an impact.

Q Okay. Well, when you say you don't expect it to have that much of an impact, do you have any sort of estimate or number that you could give me, you know, roughly?

A Actually, I may. That might be in the -- I think we did calculations with 20-year lives in my rebuttal testimony. Actually, I don't know that I have that in front of me. It's certainly something that we could calculate.

Q Okay. I also wanted to ask you, is it correct that OPC proposed to use 35-year service life for the solar facilities instead of your 30?

A Yes, a 35-year average service life instead of a 30-year average service life.

Q Okay. And if the Commission approved a 35-year service life, what would be the impact, again, on the reserve imbalance?

A Yeah. Similarly, it would change. I don't know that I have -- I forget. There might have been discovery that we responded to that, actually.

Q Up? Down?

A So with a longer life, the theoretical reserve would decrease, which would -- it would make the reserve imbalance, I suppose -- well, it depends on whether it's a, you know, a positive or negative number, but it would change the theoretical reserve, which might make it larger or smaller, depending on where the book reserve is.

Q All right. Thank you, Mr. Allis.

MR. MARQUEZ: I have nothing further for that witness.

CHAIRMAN LA ROSA: Thank you.

Commissioners, questions?

Seeing none, TECO I will send it back to you for redirect.

MS. PONDER: No redirect.

CHAIRMAN LA ROSA: Okay. Great. Thank you.

Let's talk about exhibits into the record. TECO.

MS. PONDER: Yes. Tampa Electric would like to move Exhibits 26 and 147 into the record, please.

CHAIRMAN LA ROSA: Is there objection?

Seeing none, show them entered into the record.

(Whereupon, Exhibit Nos. 26 & 147 were received into evidence.)

CHAIRMAN LA ROSA: OPC, any exhibits?

MR. WATROUS: No exhibits from OPC.

CHAIRMAN LA ROSA: Any other parties have any exhibits?

Okay. Seeing none, Mr. Allis, thank you for being here today.

THE WITNESS: Thank you.

CHAIRMAN LA ROSA: You are excused.

(Witness excused.)

CHAIRMAN LA ROSA: All right. So it's about seven minutes before six o'clock. So I said we will break at 6:00. Let's go ahead and break early now, and then if we can reconvene at 6:30.

Thank you. We will see you guys then.

(Brief recess.)

CHAIRMAN LA ROSA: I think we are ready to reconvene.

So where we have left off, it is now back in TECO's hands to introduce their next witness.

MS. PONDER: Thank you, Mr. Chairman.

Tampa Electric will call Jeff Kopp to the stand.

CHAIRMAN LA ROSA: Thank you, Mr. Kopp. Do you mind standing up real quick just to administer the oath?

Whereupon,

JEFFREY T. KOPP

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: Yes.

CHAIRMAN LA ROSA: Thank you.

EXAMINATION

BY MS. PONDER:

Q Good evening, Mr. Kopp. Would you please state your full name for the record?

CHAIRMAN LA ROSA: Mr. Kopp, I think your microphone might be off. It would be a green light that ignites when you press a button. Excellent.

THE WITNESS: All right. Jeffrey T. Kopp, K-O-P-P.

BY MS. PONDER:

Q Who is your current employer and what is your business address?

A My employer is 1898 & Co. Part of Burns & McDonnell Engineering Company. Address is 9400 Ward Parkway, Kansas City, Missouri.

Q And did you prepare and cause to be filed in

this docket, on April 2nd, 2024, prepared direct testimony consisting of 19 pages?

A Yes, I did.

Q Did you prepare and cause to be filed in this docket, on July 2nd, 2024, prepared rebuttal testimony --

A Yes.

Q -- consisting of 16 pages?

A Yes.

Q And do you have any additions or corrections to your prepared direct or rebuttal testimony?

A No.

Q If I were to ask you the questions contained in your prepared direct and rebuttal testimony today, would your answers be the same as those contained therein?

A Yes.

MS. PONDER: Mr. Chairman, Tampa Electric would like the prepared direct and rebuttal testimony of Mr. Kopp to be inserted into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Jeffrey T. Kopp was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEFF KOPP

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114. I am employed by 1898 & Co., which is the consulting group within Burns & McDonnell Engineering Company, Inc. ("1898 & Co."), as the Senior Managing Director of the Energy & Utilities Consulting Department.

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

A. I am a professional engineer with 22 years of experience consulting to electric utilities. I have been involved in numerous decommissioning studies and served as project manager or project director on the majority of them. I have helped prepare decommissioning studies on all types of power plants, utilizing various technologies and fuels.

As a Senior Managing Director at 1898 & Co., I oversee a group of more than 250 engineers and consultants who provide consulting services to clients primarily in the electric power generation and electric power transmission industries, but also to other industrial and commercial clients. The services provided by this group of engineers and consultants include decommissioning cost studies, independent engineering assessments of existing power generation assets, economic evaluations of capital expenditures, new power generation development and evaluation, electric and water rate analysis, electric transmission planning, generation resource planning, renewable power development, and other related engineering and economic assessments.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I provided direct testimony on behalf of Tampa Electric Company ("Tampa Electric" or the "company") in Docket No. 20210034-EI. I provided rebuttal testimony on behalf of Progress Energy Florida, Inc. in Docket No. 20090079-EI in support of the dismantlement study I prepared for Progress Energy Florida to support their depreciation rates in that filing. I also provided rebuttal testimony on behalf of

Florida Power & Light Company in Docket Nos. 20160021-EI and 20160062-EI and I am currently providing testimony on behalf of Duke Energy Florida in Docket No. 20240025-EI, and I did perform the dismantlement study that was included as an exhibit and approved as part of the settlement in Duke Energy Florida's prior rate case.

Q. Have you previously testified before other state or federal regulatory commissions?

A. Yes. I have provided written or oral testimony in various proceedings listed in Document No. 3 of my Exhibit No. JK-1.

Q. Please provide a brief outline of your educational background and business experience.

A. I have a Bachelor's Degree in Civil Engineering from the University of Missouri – Rolla (now the Missouri University of Science and Technology) and a Masters of Business Administration from the University of Kansas. In my role as a group manager, project manager, and project engineer, I have worked on and have overseen consulting activities for coal, natural gas, wind, solar, hydroelectric, and biomass power generation facilities. I have included my

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resume and curriculum vitae as Document No. 2 of my exhibit.

Q. Do you hold any certifications?

A. Yes, I am a registered professional engineer in the states of Florida, Illinois, Indiana, and Missouri.

Q. What are the purposes of your direct testimony?

A. The purposes of my prepared direct testimony are to (1) discuss the Fleet Decommissioning Cost Study ("Dismantlement Study" or "the Study") conducted for Tampa Electric and (2) support the reasonableness of the Dismantlement Study costs included in the company's rate request. The Dismantlement Study is an update of a prior study that I prepared for Tampa Electric to support their filing in Docket No. 20210034-EI.

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

A. Yes. Exhibit No. JK-1 was prepared under my direction and supervision. My exhibit consists of three documents, entitled:

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Document No. 1 Decommissioning Cost Estimate Study

Document No. 2 Resume of Jeffrey Kopp

Document No. 3 List of Proceedings in Which Mr. Kopp Has Submitted Testimony

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. No.

Q. Which Tampa Electric generating units does the Study assume will be dismantled?

A. The Study assumes that all units in Tampa Electric's generation fleet will be dismantled.

Q. Are there other witnesses submitting direct testimony in this proceeding that addresses dismantlement costs for Tampa Electric, and if so, how does their testimony relate to your testimony?

A. Yes. Tampa Electric witness Ned Allis is testifying to and sponsoring the depreciation rate calculations. The dismantlement costs that I prepared were used as an input for end-of-life costs in the depreciation calculations.

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1898 & CO. Experience & Qualifications

Q. What qualifies 1898 & Co. to prepare accurate estimates of dismantlement costs and why should the Commission rely on these estimates?

A. Over the years, 1898 & Co. has worked closely with demolition contractors in developing decommissioning cost estimates in order to more accurately estimate the costs for activities that the demolition contractors will perform. 1898 & Co. has prepared numerous decommissioning studies for various clients considering different technologies in several different states and has provided services to clients on decommissioning project execution that has included review and evaluation of bids from demolition contractors. 1898 & Co. has utilized this experience preparing decommissioning estimates as well as reviewing demolition contractor bids to confirm the reasonableness of the cost estimates prepared by 1898 & Co.

At the time the company decides to decommission the plants, means and methods will not be dictated to the contractor by 1898 & Co. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning and dismantling the Plants at the lowest possible cost. However, based on 1898 & Co.'s experience

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with decommissioning projects and discussions with demolition contractors, the costs estimated by 1898 & Co. are reflective of what contractors would bid, through a competitive bidding process given the option to select safe and efficient means and methods.

As indicated above, 1898 & Co. has vast experience in preparation of decommissioning studies, overseeing demolition projects, and executing construction projects. In order to execute over $2 billion of construction projects on an annual basis, 1898 & Co. has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates. If we routinely estimated costs too high, we would not be successful in winning projects. If we routinely estimated costs too low, we would not be able to execute projects profitably and would no longer be active in this market.

Our long history, large market presence, and top industry rankings demonstrate our ability to effectively and accurately estimate costs. In addition, we have seen competitive bids from demolition contractors for power plant demolition projects, and we have worked with demolition contractors over the years to refine our estimating process for decommissioning studies to align our costs with theirs.

1898 & CO. DISMANTLEMENT STUDY

Q. Please describe the purpose of the Dismantlement Study.

A. The company retained 1898 & Co. to provide it with a recommendation regarding the total cost, in 2023 dollars, of dismantlement of each company-owned generation unit at the end of its useful life, as well as the total cost of dismantlement of the common facilities at these generating plants. The total dismantlement cost as determined by 1898 & Co. and reflected in the Dismantlement Study is net of salvage value for scrap materials at each plant. 1898 & Co. had previously prepared a similar study for the company in 2020 in support of the company's depreciation filing. The current Dismantlement Study serves to update the costs presented in the 2020 study for changes to market conditions, physical changes that have occurred at the plants, and incorporating new facilities that have been constructed or acquired since 2020.

Q. What plants did 1898 & Co. evaluate in the Dismantlement Study?

A. For purposes of the Dismantlement Study, we evaluated the following company-owned electric generating and storage plants.

- Agrivoltaics Solar
- Alafia Solar
- Balm Solar
- Bayside Power Station
- Big Bend Power Station
- Big Bend Floating Solar
- Big Bend Solar
- Big Bend Solar II
- Bonnie Mine Solar
- Brewster Solar
- Bull Frog Creek Solar
- Cotton Mouth Ranch Solar
- Durrance Solar
- Eastern PVS and ES Solar
- English Creek Solar
- Florida Aquarium Pavilion Solar
- Future Solar Site I
- Future Solar Site II
- Grange Hall Solar
- Jamison Solar
- Juniper Solar
- Lake Hancock Solar
- Lake Mabel Solar

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- Laurel Oaks Solar
- Legoland Solar
- Lithia Solar
- Little Manatee Solar
- MacDill Air Force Base RICE and Battery
- Magnolia Solar
- Mountain View Solar
- Payne Creek Solar
- Peace Creek Solar
- Polk Power Station
- Riverside Solar
- Tampa International Solar
- Wimauma Solar

Q. What was the extent of your personal involvement in the preparation of the Dismantlement Study?

A. I served as the 1898 & Co. BMcD project director on the Dismantlement Study. I worked directly with all individuals and parties involved in the preparation of the dismantlement cost estimates in the Dismantlement Study. I was responsible for the overall project and was involved in the development of the dismantlement assumptions, dismantlement estimating methodology, preparation and review of the estimates, and preparation and review of the report.

Q. What was the extent of your personal involvement in the preparation of the prior Dismantlement Study prepared for Tampa Electric Company?

A. I also served as the 1898 & Co. project director on the prior study and testified to the reasonableness of those costs to support their filings in Docket No. 20210034-EI.

Q. Did individuals from 1898 & Co. visit each of the sites included in the Dismantlement Study?

A. No. In 2017, I visited a representative portion of sites for which dismantlement cost estimates were prepared as part of a prior study, along with other individuals from 1898 & Co. and representatives from the company. As part of the current Dismantlement Study, individuals from my team re-visited a portion of these same sites and a representative portion of the solar sites.

Q. What level of dismantlement and demolition did 1898 & Co. assume was performed at each of the sites?

A. The basis of the 1898 & Co. cost estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility.

Q. What does restoring the sites for industrial use require?

A. The sites will have all above grade buildings and equipment removed, foundations removed to three feet below grade, be rough graded, and seeded. The sites also will have small diameter underground pipes capped and abandoned in place. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use.

Q. What process did you follow in preparing the Dismantlement Study?

A. The estimates of dismantlement costs were prepared with the intent of most accurately representing what 1898 & Co. would anticipate contractors bidding to dismantle the equipment, address environmental issues, and restore the site through a competitive bidding process.

As outlined in the Dismantlement Study, we prepared these cost estimates by estimating quantities and then applying current market pricing for labor rates, equipment costs, scrap, and disposal costs specific to the area in which the work is to be performed. This results in the total cost of dismantlement for each site.

Q. Are there industry-standard methods or inputs used when preparing such a study and what are they?

A. Yes. We reviewed Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies, as a guide for preparing our study. We also incorporated the methodologies used in prior studies we prepared that have been approved by the Commission and other utility commissions throughout the country. Furthermore, many of the inputs in our estimates come directly from industry standard data sources and publications, including:

- RSMeans Heavy Construction Cost
    - RSMeans is an industry standard publication of construction cost data that is used throughout North America by engineers to prepare construction and demolition cost estimates. The RSMeans database includes adjustments to the base costs based on location, to provide a more accurate estimate for the area in which the project will take place. RSMeans includes data for all types of construction and demolition activities, including materials, labor, hauling, and disposal. RSMeans has been

publishing construction and demolition costs annually since the 1940s.

- Fastmarkets AMM
    - Fastmarkets AMM has been in business since they began as American Metal Market in 1882. They are the leading publication of metal pricing, including scrap metal pricing. They provide an independent market perspective on metal prices in North America, using data from market transactions.

Q. Did Tampa Electric provide data to you for use in the Study?

A. Yes.

Q. What data did the company provide?

A. The company provided numerous drawings for each of the sites evaluated in the Study. Other documents that had applicable requirements for decommissioning activities were provided as well.

Q. Please describe the key assumptions of the Dismantlement Study.

A. As I stated earlier, the basis of the estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility. We also assumed that all units at each power station will be dismantled as part of a single demolition project, therefore, no selective demolition was included in the estimates. Additional assumptions are outlined in Sections 3.1 and 3.2 of the Study in Document No. 1 of my exhibit.

Q. Please generally explain the types of costs reflected in the Study?

A. The cost estimates reflected in the Dismantlement Study are inclusive of direct costs associated with dismantling the plant equipment and facilities and restoring the sites to an industrial-ready condition. The direct costs include environmental remediation costs for asbestos removal and other hazardous material handling and disposal, as well as costs for removing and disposing of contaminated soil around transformers. The Dismantlement Study does not include any estimates of indirect costs to be incurred by the company during dismantlement, nor any contingency costs. Indirect owner's costs and contingency costs were applied by Tampa Electric separate from the Study.

Q. How were the direct costs estimated for purposes of the Study?

A. As part of the Dismantlement Study, site-specific cost estimates were developed using a "bottom-up" cost estimating approach, where cost estimates are developed from scratch through the development of site-specific quantity estimates and the application of unit pricing rates to the quantity estimates.

As outlined in the Dismantlement Study, 1898 & Co. prepared these cost estimates by estimating quantities for existing equipment based on visual inspections, review of engineering drawings, review of 1898 & Co.'s in-house database of plant equipment quantities and using 1898 & Co.'s professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each dismantlement effort. Current market pricing for labor rates and equipment was used to develop unit pricing rates for each task. These unit pricing rates were applied to the quantities for the plants to determine the total direct cost of dismantlement for each site. Additionally, unit pricing for scrap values was applied to the scrap quantities to determine anticipated salvage values, which were subtracted from the gross direct costs to arrive at a net project cost in 2023 dollars.

Q. Is it your conclusion that the Study results are reasonable estimates?

A. Yes, the Dismantlement Study results and cost estimates are reasonable estimates and are useful for planning purposes. It is appropriate for the company to rely on these estimates for inclusion in their dismantlement reserve needs.

SUMMARY

Q. Please summarize your direct testimony.

A. The company retained 1898 & Co. to provide it with a recommendation regarding the total cost, in 2023 dollars, of dismantlement of each company-owned generation unit at the end of its useful life as well as the total cost of dismantlement of the common facilities at these generating plants. 1898 & Co. is qualified to prepare dismantlement cost estimates and has vast experience in preparing decommissioning studies, overseeing demolition projects, and executing construction projects. The estimates of dismantlement costs were prepared with the intent of most accurately representing what 1898 & Co. would anticipate contractors bidding through a competitive bidding process to dismantle the equipment, address environmental issues, and restore the site. The Dismantlement Study is consistent with Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies, incorporates the methodologies used in prior studies we prepared that have been approved by the Commission and other utility commissions throughout the country, and incorporates industry standard data. The Study results and cost estimates are reasonable estimates and appropriate for the company to rely on for their dismantlement reserve needs.

Q. Was the Dismantlement Study attached to your testimony as Document No. 1 of your exhibit prepared by you or under your supervision?

A. Yes.

Q. Are the estimated costs reflected in the Dismantlement Study reasonably reflective of the actual costs necessary to dismantle the company's plants?

A. Yes, they are.

Q. Are these estimated costs appropriate for use in the development of dismantlement accrual for the company's electric generating plants?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C12-1138

(Whereupon, prefiled rebuttal testimony of Jeffrey T. Kopp was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

REBUTTAL TESTIMONY

OF

JEFF KOPP

ON BEHALF OF TAMPA ELECTRIC COMPANY

D9-511

DOCKET NO. 20240026-EI
FILED: 07/02/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

JEFF KOPP

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114. I am employed by 1898 & Co., which is the consulting group within Burns & McDonnell Engineering Company, Inc. ("1898 & Co."), as the Senior Managing Director of the Energy & Utilities Consulting Department.

Q. On whose behalf are you testifying in this docket?

A. I am testifying on behalf of Tampa Electric Company ("Tampa Electric" or the "company").

Q. Are you the same Jeff Kopp who filed direct testimony on behalf of Tampa Electric in this docket?

A. Yes.

D9-512

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

A. The purposes of my prepared rebuttal testimony are to rebut the testimony of Intervenor The Citizens of the State of Florida's witness Lane Kollen who testifies regarding certain recommendations in the Fleet Decommissioning Cost Study ("Dismantlement Study" or "the Study") that I prepared.

Q. Please summarize your rebuttal testimony and recommendations.

A. I address the following three issues raised in the Direct Testimony of Florida Office of Public Counsel ("OPC") witness Lane Kollen.

1. Dismantlement expense should exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year.[1]
2. That the Commission exclude at least the environmental component of the dismantlement costs on the solar generating assets.[2]
3. That the Company's unsourced and undescribed

[1] Direct Testimony of Lane Kollen, pg 30, lines 6 - 7
[2] Direct Testimony of Lane Kollen, pg 33, lines 14 - 16

potential contingencies assumption are extremely speculative and not known and measurable.

Q. Do you agree with Witness Kollen's position that dismantlement expense should exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year?

A. No. The dismantlement costs should include "escalation rates" used in converting the current estimated dismantlement costs to future estimated dismantlement costs" as outlined in Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies. It is reasonable and appropriate that the 2023 costs I provided in my Dismantlement Study should be escalated to future years, to account for the impact of inflation, to put them in the year dollars in which they will be expended, and to most accurately reflect the actual costs to be incurred, consistent with Rule 25-6.04364.

Q. Did you perform the escalation of dismantlement expense in this proceeding?

A. No. The company performs the dismantlement accrual model calculation and, consistent with previous filings, applies a 15 percent contingency factor to the decommissioning cost estimates. The company's methodology was explained in Tampa Electric's answer to the Office of Public Counsel's Fourth Set of Interrogatories, Number 90 and is also described in witness Jeff Chronister's rebuttal testimony.

Q. Is it reasonable to escalate the dismantlement expenses?

A. Yes. Regardless of who applied the escalation to the 2023 costs, it is reasonable to do so. Escalation is typically applied by others as part of depreciation or accrual calculations. It is reasonable that the costs I provided in my Dismantlement Study should be escalated to future years, to account for the impact of inflation. The cost should be in the years they will be incurred. Furthermore, the application of escalation on dismantlement costs is included in Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies. Please see witness Ned Allis's rebuttal testimony for further explanation.

Q. Do you agree with witness Kollen's position that the Commission exclude at least the environmental component of the dismantlement costs on the solar generating assets?

A. No. These are reasonable and appropriate costs that should be included and accounted for at the solar generating asset facilities just as they are at the other generating facilities. In fact, it's even more important to include these costs, since the solar generating assets are all located on leased land.

Q. What is Mr. Kollen's reason for excluding the environmental component of the dismantlement costs on the solar generating assets?

A. Mr. Kollen incorrectly states that the costs that may be incurred are extremely speculative and are not known and measurable and are based on my unsupported assumptions regarding the abandonment of the sites and that the company will be responsible for the site restoration. Mr. Kollen suggests the leases may not require the company to be responsible for site restoration[3] or environmental remediation. Mr. Kollen provides no basis for this assumption.

Q. Can you please explain why Mr. Kollen's statement is

[3] Direct Testimony of Lane Kollen, pg 33, lines 17 - 19

incorrect?

A. Yes. First of all, Mr. Kollen incorrectly states that it is an assumption that the solar sites will be abandoned. Just like all the other generating asset types evaluated in the Study, we calculate the dismantlement costs at the end of the useful life of the facility. Contrary to Mr. Kollen's statement, we don't assume that a site will be abandoned, retained, or reused. We simply assume that that the assets on the site have reached end of life, need to be removed, and the site restored to a condition suitable for various options – retaining the site, repowering the site, or sale of the site. As stated in my direct testimony, the basis of our estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use, sold, or returned to the lessor.

Q. Is Mr. Kollen's position consistent with Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies?

A. No. Rule 25-6.04364, Florida Administrative Code, provides definitions and guidance on dismantlement studies for electric utilities. It defines "Dismantlement Costs" as "the costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service." Mr. Kollen's suggestion to exclude the environmental component of the dismantlement costs on the solar generating assets, which includes site restoration costs, is not only arbitrary, but in direct conflict with the Florida Administrative Code.

Q. What about Mr. Kollen's suggestion that the leases may not require the company to be responsible for site restoration or environmental remediation?

A. Mr. Kollen provides no basis for this assumption. I have not seen a lease that did not put the liability for removal of improvements and site restoration on the solar facility owner.

Q. Why do you review the leases for the solar facilities, as part of your preparation of dismantlement studies for those facilities?

A. We review the land leases to see if any additional requirements to site restoration are included in the leases than our standard assumptions to restore the site to a level of industrial use. This would potentially include additional foundation depth of removal or other activities to restore the land to a condition suitable for something other than industrial use, such as agricultural use.

Q. Does the absence of a land lease being available for review give you any concern that you have overestimated environmental or site restoration costs or included speculative costs?

A. No, not at all. A land lease will likely only increase the need for environmental and site restoration costs beyond what is stated in the Florida Administrative Code and included in our estimates. This typically comes in the form of language that specifically requires the lessee to remove equipment and restore the sites to a defined condition, which simply reinforces the definition of "Dismantlement Costs" in the Florida Administrative Code as including site restoration. It can also increase the site restoration costs, by requiring additional foundation depth of removal than our standard assumption.

Lacking a lease to review certainly does not give me any concerns or indications that environmental and site restoration costs are speculative or should not be included in the dismantlement costs.

Q. Will environmental and site restoration costs still be required in the event the service life of the sites is extended beyond the service life assumption for the original panels, inverters, and other equipment?

A. Yes. If the service life of the sites were to be extended, the decommissioning costs would still be required at the end of the extended service life. Extending the life of the site merely delays the costs; it does not eliminate them. And even assuming that those costs are delayed is pure speculation by Mr. Kollen. In order to even partially accept Mr. Kollen's suggestion, and assume that these site restoration costs would be delayed, we must assume that new generating assets will be constructed at these same sites "some 35 years in the future[4]," and that they are constructed immediately following removal of the current assets, so drainage and erosion is not a concern, and that all current site grading and surfacing is suitable for the new generation assets, which is particularly

[4] Direct Testimony of Lane Kollen, pg 32, lines 3

speculative.

Q. Do you agree with Mr. Kollen's statement that, "other utilities intentionally exclude dismantlement costs because of the uncertainties as to costs that may be incurred and whether the salvage income will exceed any such costs[5]?"

A. No. This is not an accurate representation of what is typical, based on my experience preparing dismantlement studies throughout the country and in particular in the state of Florida. First, every dismantlement study I have prepared, including the studies I have performed in Florida for Tampa Electric Company, Duke Energy Florida, and Florida Power and Light, have included site restoration costs. Second, utilities don't simply exclude these costs "because of the uncertainties as to costs that may be incurred whether the salvage income will exceed any such costs[6]." Instead, utilities typically hire an engineering firm to estimate the costs for "the ultimate physical removal and disposal of plant and <u>site restoration</u>, minus any attendant gross salvage amount, upon final retirement of the site or unit from service[7],"

[5] Direct Testimony of Lane Kollen, pg 32, lines 17 - 19
[6] Direct Testimony of Lane Kollen, pg 32, lines 17 - 19
[7] Definition of "Dismantlement Costs" from Florida Administrative Code 25-6.04364

consistent with Florida Administrative Code. This allows a site specific cost estimate to be used to make a determination of how much salvage income will offset the costs, rather than simply speculating that they might exceed restoration costs. Lastly, even if some utilities in other parts of the country have gone with the speculative approach of intentionally excluding these costs because salvage income *may* exclude the costs, that is not consistent with Florida Administrative Code Rule 25-6.04364, and therefore not relevant.

Q. Is the application of 15 percent contingency costs to the direct costs reasonable?

A. Yes. The application of contingency is not only appropriate, but also standard industry practice.

Q. Can you explain the relationship between the dismantlement cost estimates and contingencies?

A. Yes. It is important to understand how the dismantlement cost estimates are developed to understand the relationship of contingency to those costs. The estimate of direct decommissioning costs is prepared with the intent of accurately representing what contractors would bid to decommission and demolish the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known decommissioning tasks under ideal conditions. In addition to these known tasks under ideal conditions, contingency is added to account for unknown, but reasonably expected to be incurred costs. The application of contingency is a common and prudent reasonable practice in the construction industry, and it is included in order to recognize the probability of increases in cost due to the unknowns as described above. Importantly, contingency is a cost that is typically included by owners throughout all stages of planning through execution of the project.

Q. What is included in the contingency costs?

A. A contingency cost includes unspecified but reasonably expected additional costs to be incurred by the company during the execution of decommissioning and demolition activities. For decommissioning projects, there is some uncertainty associated with work conditions, the scope of work and how the work will be performed. There also is some uncertainty associated with estimating the quantities for dismantlement of facilities. These uncertainties result from the age and limits on drawings available, as well as the absence of testing results for environmental contamination prior to preparation of these types of studies. These uncertainties also include issues related to weather delays, unknown environmental contamination, discovery equipment or materials not shown on drawings, or additional dewatering requirements. Contingency costs account for these unspecified but expected costs and are in addition to the direct costs associated with the base decommissioning costs for known scope items.

Q. Please explain how an appropriate level of contingency costs is determined and why a 20 percent contingency factor is reasonable on these decommissioning estimates?

A. The percentage of contingency applied to any cost estimate is directly related to the level of unknowns associated with the project. When preparing construction cost estimates for a new fossil-fuel generation facility on a greenfield site, we would typically determine the level of contingency based on the stage of planning or execution that we are in, which impacts the level of unknowns. We would apply higher contingency typically between 10 percent and 15 percent at early stages of planning when there are more potential unknowns. These would include potential scope changes as well as weather delays and other factors. As engineering design progresses and some of these unknowns can be reduced through subsurface investigations, engineering design drawings, and engineering specifications, the amount of contingency may be reduced and a lower level of contingency would be applied. However, contingency would never be completely eliminated, even after full detailed design is completed, since some unknowns, as common as weather delays, cannot be completely eliminated.

The decommissioning cost estimates prepared as part of this filing are most similar to the cost estimates developed in the early stages of planning for a new fossil-fuel generation facility on a greenfield site. However, when preparing a decommissioning cost estimate, there is a greater level of unknowns than new construction, which cannot be eliminated at this stage of the planning process. For example, decommissioning activities occur on sites where power generation has been ongoing for many years and environmental contamination is more likely than a greenfield site. In addition, no on-site testing for hazardous materials and potential environmental contamination has been performed during these planning stages to fully identify all of these items. No subsurface investigations or groundwater sampling has been performed to identify and define remediation requirements. And some unknowns, such as below grade storage tanks or piping, which may contain hazardous materials, may not be uncovered until the decommissioning process is underway.

In general, it is reasonably expected that changes to the scope of decommissioning that could occur at the time of execution of the decommissioning project would result in cost increases, over the base cost estimates. For example, 1898 & Co.'s cost estimates include minimal levels of environmental remediation, so contingency is required to cover the risk that additional contamination exits.

In addition, other factors that impact risk include changes to market conditions, weather delays, scrap price changes, etc. The further out in the future that the decommissioning activities will occur, the greater the risk that pricing could exceed the current baseline estimates.

Q. What level of contingency do you typically recommend be included in dismantlement cost estimate studies?

A. For all the reasons outlined above, we typically recommend and include a 20 percent contingency be added to the direct costs as reasonable and warranted based on the level of risk associated with the dismantlement projects. Therefore the 15 percent contingency applied by the company is less than our typical recommendation.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BY MS. PONDER:
Q Mr. Kopp, did you also prepare and cause to be filed with your direct testimony an exhibit marked JK-1, consisting of three documents?
A Yes.
MS. PONDER: Mr. Chairman, Tampa Electric would note for the record that Exhibit JK-1 has been identified in the CEL as Exhibit 27.
CHAIRMAN LA ROSA: Okay.
BY MS. PONDER:
Q Mr. Kopp, would you please summarize your prepared direct and rebuttal testimony?
A Yes.
Commissioners, I provided direct testimony in this case regarding the dismantlement study prepared by me and my team at 1898 & Co. for Tampa Electric Company. As outlined in my direct testimony, the purpose of the study was to review Tampa Electric's fleet of generating assets, and make recommendations to the company regarding the total cost to dismantle the facilities at the end of their useful lives. My team and I had previously prepared a similar study for the company in 2020 in support of the company's depreciation filing.
The current dismantlement study serves to update the costs presented in the 2020 study for changes

to market conditions, physical changes that have occurred at the plants, and incorporating new facilities that have been constructed or acquired since 2020.

My team and I relied upon our vast experience and in-house data, as well as information from Tampa Electric Company to perform the study. The total dismantlement costs, as determined by 1898 & Co., and reflected in the dismantlement study are net of salvage value for scrap materials at each plant.

The dismantlement costs in the study were utilized as an input in calculating dismantlement accruals in this case. The estimates of dismantlement costs were prepared with the intent of most accurately representing what 1898 & Co. would anticipate contractors bidding to dismantle the equipment, address environmental issues and restore the sites through a competitive bidding process.

Site specific cost estimates were developed using a bottom-up cost estimating approach, where cost estimates are developed from scratch through the development of site specific quantity estimates and the application of unit pricing rates to the quantity estimates.

The dismantlement study is consistent with Rule 25-6.04364 of the Florida Administrative Code regarding electric utilities dismantlement studies; incorporates methodologies used in prior studies we have prepared that have been approved by this commission and other utility commissions throughout the country, and incorporates industry standard data. The study results and cost estimates are reasonable estimates and appropriate for the company to rely on for their dismantlement reserve needs.

My rebuttal testimony addresses three issues raised by the direct testimony of Florida Office of Public Counsel witness Lane Kollen. Witness Kollen recommends the dismantlement expense should exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year. However, Rule 25-6.04364 of the Florida Administrative Code, regarding electric utilities dismantlement studies, specifically includes escalation rates used in converting the current estimated dismantlement costs to future estimated dismantlement costs.

It is reasonable and appropriate that the 2023 costs I provided in my dismantlement study should be escalated to future years to account for the impact of inflation, to put them in the year dollars in which they will be expended, and to most accurately reflect the actual costs to be incurred consistent with this rule.

Witness Kollen also recommends that the Commission exclude the environmental component of the dismantlement costs on the solar generating assets. The costs that he suggests removing are for site restoration activities at each of these facilities.

Rule 25-6.04364 of the Florida Administrative Code, regarding electric utilities dismantlement studies, specifically includes site restoration in its definition of dismantlement costs. These are reasonable and appropriate costs that should be included and accounted for at the solar generating asset facilities, just as they are at the other generating facilities.

Lastly, Mr. Kollen states that the company's contingency assumptions are extremely speculative and not known and measurable. Again, Rule 25-6.04364 of the Florida Administrative Code, regarding electric utilities dismantlement studies, also specifically addresses contingency as a component of dismantlement studies.

Furthermore, the application of contingency is not only appropriate, but also standard industry practice, which has been approved by this commission on prior cases for Tampa Electric and other utilities.

This concludes my summary.

MS. PONDER: Mr. Chairman, we tender Mr. Kopp for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

OPC, you are recognized when you are ready.

MR. WATROUS: Thank you, Mr. Chairman.

EXAMINATION

BY MR. WATROUS:

Q And good evening, Mr. Kopp.

A Good evening.

Q I will go ahead and get right into questioning.

Would you agree that a lease agreement typically states the requirements for the leased land on which a solar facility is constructed?

A Yes.

Q And those requirements may impact decommissioning assumptions?

A Yes.

Q May impact decommissioning obligations?

A Yes.

Q Requirements such as environmental remediation?

A Yes, that could be one component.

Q And requirements such as site restoration?

A Yes.

Q And isn't it true you did not review the

leases of 25 of 32 solar sites?

A Yes. Some of these lease agreements were not available for review.

Q And so you do not know the environmental remediation requirements for the 25 sites?

A I don't know if there were any additional --

Q Mr. Kopp, could you please answer the question with a yes or no and then provide an explanation?

A Okay. Yes.

No, I don't know if there were any requirements specifically stated in those leases, but typically those requirements are above and beyond our standard assumptions for site restoration. We typically include a minimum level of site restoration that's appropriate. And we review those leases to see if there is additional requirements beyond those minimum requirements.

Q Thank you for your time today.

MR. WATROUS: OPC has no more questions.

CHAIRMAN LA ROSA: Thank you.

Florida Rising/LULAC.

MS. LOCHAN: Thank you, Chairman.

EXAMINATION

BY MS. LOCHAN:

Q Good evening, Mr. Kopp.

A Good evening.

Q I just have one question for you.

Generally speaking, do TECO's future projected peaks affect dismantlement costs?

A No.

Q Okay. Thank you.

MS. LOCHAN: That's my question.

CHAIRMAN LA ROSA: Great. Thank you.

FIPUG.

EXAMINATION

BY MR. MOYLE:

Q Good evening. Jon Moyle for the Florida Industrial Power Users Group.

You mentioned that you reviewed some leases. Do you recall if those were 35-year leases?

A I don't recall. I wasn't looking for the duration of the lease, just if site requirements -- or site restoration requirements were included.

Q And do you have any information with respect to property owners possibly not wanting the solar facilities removed from their property if they are continuing to produce energy? If that were the case, there wouldn't be any dismantlement costs associated with that, correct?

A I am not aware of any of the leases -- I guess

I am not quite sure I understand the question.

Q If you own property and you lease it for 30, 35 years to a utility, and the utility comes in and puts a bunch of solar assets on it. Let's say after 15 years, they said, you know what, there is new, more efficient solar, and they put solar assets on it, and they got another 15 years on a lease. At the end, if the landowner had the option to say, thank you, the lease is over, go about your business, but you don't need to get the solar off the property. Just leave it here. I will take it over. I will sell the energy from it and operate the solar field. Have you ever seen that or heard of that?

A I've heard of it being an option in the lease, but our studies are all looking at the liability at the end of useful life of the facilities, so this is what is the cost for restoring the sites. And that obligation is still typically on the utility, at the end of life, to take it out.

Q But if you had -- if you were looking at a lease and you saw that provision, would you make an adjustment for that; or would you just assume, no, they are going to come get all this stuff and they have to take it out?

A I mean, I have seen leases that include the option for the owner to make their decision about leaving in things like roads at a wind farm, or things like that, but the obligation is still always on the lessor -- or sorry, the lessee, the utility, to take out everything at the end of life.

Q Okay. That's all I have. Thank you.

CHAIRMAN LA ROSA: Thank you.

FEA.

CAPTIAN GEORGE: No questions, sir. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Sierra Club.

MR. SHRINATH: No questions, Mr. Chairman. Thank you.

CHAIRMAN LA ROSA: FRF.

MR. WRIGHT: No questions. Thank you, Mr. Chairman.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions. Thank you.

CHAIRMAN LA ROSA: Staff.

MR. MARQUEZ: No questions. Thank you.

CHAIRMAN LA ROSA: Commissioners?

Seeing none, TECO, it's back in your hands for redirect.

MS. PONDER: No redirect.

CHAIRMAN LA ROSA: Thank you.

Let's talk about exhibits. TECO, do you have any exhibits to enter into the record?

MS. PONDER: Yes. Sorry. Yes, Mr. Chairman.

We would move Exhibit 27 into the record, please.

CHAIRMAN LA ROSA: 27. Is there objection?

Seeing none, show that entered into the record.

(Whereupon, Exhibit No. 27 was received into evidence.)

CHAIRMAN LA ROSA: OPC. None.

Is there any other parties that have any exhibits?

Seeing none. Excellent.

All right. Mr. Kopp, thank you for being here today. You are excused.

(Witness excused.)

(Transcript continues in sequence in Volume 9.)

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 2nd day of October, 2024.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028