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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 10 - PAGES 2130 - 2397

PROCEEDINGS: HEARING

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

DATE: Thursday, August 29, 2024

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

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
734	As identified in the CEL		2148
736	As identified in the CEL		2148
739	As identified in the CEL		2148
741	As identified in the CEL		2148
138	As identified in the CEL		2148
139-141	As identified in the CEL		2158
35-41	As identified in the CEL		2267
42-57	As identified in the CEL		2363
58-59	As identified in the CEL		2396

P R O C E E D I N G S

(Transcript follows in sequence from Volume 9.)

CHAIRMAN LA ROSA: All right. Good morning, everybody. If you don't mind just maybe finding your seats as we get settled and get started here for today.

Just a kind of a quick recap of where we are. We reshuffled the deck last night. Thank you all for staying late yesterday. I know it's a quick turnaround, 10 hours or so, whatever the math is, right? Maybe 11 hours, and we are back here in the hearing room.

So we reshuffled the deck yesterday. I think we all agreed that we would start with staff's witnesses, so we are going to go a little bit out of order. So we will go to staff's witnesses, and then I will come back to OPC's witnesses. And I know there. Was some timing stuff there, so we will chat about that if that has to get readjusted as well.

So let's go ahead and get going, and I will turn it over to staff to call your witness.

MR. SPARKS: Thank you, Mr. Chairman.

Staff would like to call Tomer Kopelovich to the stand.

CHAIRMAN LA ROSA: I am sorry. Thank you.

MR. KOPELOVICH: I am here.

CHAIRMAN LA ROSA: Yeah. You are ready to go.

Do you mind standing really quickly, and just so I can administer the oath?

MR. KOPELOVICH: Sure.

CHAIRMAN LA ROSA: Please raise your right hand.

Whereupon,

TOMER KOPELOVICH

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.

Staff, you are ready.

EXAMINATION

BY MR. SPARKS:

Q Can you please state your name of the record?

A Tomer Kopelovich.

Q And you just took an oath to tell the truth in this proceeding?

A Yes.

Q And where are you currently employed?

A Public Service Commission.

Q And did you prepare and submit direct testimony in this case consisting of two pages?

A Yes.

Q Do you have any updates or corrections to that testimony?

A Yes.

In my testimony, it states that I am a Public Utility Analyst III, but I am now a IV.

Q And with that correction, if I were to ask you the questions in your testimony now, would your answers be the same?

A Yes.

MR. SPARKS: Mr. Chair, I would like to enter the testimony into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Tomer Kopelovich was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF TOMER KOPELOVICH

DOCKET NO. 20240026-EI

JUNE 10, 2024

Q. Please state your name and business address.

A. My name is Tomer Kopelovich. My business address is 24715 Portofino Drive; Lutz, FL; 33559.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a **Public Utility Analyst IV** ~~Public Utility Analyst III~~. I have been employed by the Commission since October 2002.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from University of South Florida in 1991 with a Bachelor of Science degree in Finance. I have worked for the Florida Public Service Commission for 21 years, and I have varied experience in the electric, gas, and water and wastewater industries. My work experience includes various types of rate cases, cost recovery clauses, and utility audits. I am also a Certified Public Accountant.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I presented testimony in several dockets before this Commission. Those dockets include Dockets 2009001-EI, 20110001-EI, and 20230020-EI.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor staff's Auditor Report of Tampa Electric Company which addresses the Utility's filing in Docket No. 20240026-EI. An Auditor's Report was filed in the docket on June 7, 2024. This report is filed with my testimony and is identified as Exhibit TK-1.

Q. Was this audit prepared by you or under your direction?

A. Yes. It was prepared under my direction.

Q. Please describe the objectives of the audit and the procedures performed during the audit?

A. The objectives and procedures are listed in the Objectives and Procedures section of the attached Exhibit TK-1, pages 2 through 6.

Q. Were there any audit findings in the Auditor's Report (Exhibit TK-1) which address the schedules prepared by the Utility in support of its filing in Docket No. 20240026-EI?

A. Yes. There are two audit findings.

Q. Please describe the audit findings.

A. The audit findings are detailed on pages 7 and 8 of the attached Exhibit TK-1.

Q. Does that conclude your testimony?

A. Yes.

BY MR. SPARKS:

Q Did your testimony include an exhibit that has been premarked TK-1?

A Yes.

MR. SPARKS: Mr. Chair, I would like to note for the record that Exhibit TK-1 has been included in the CEL as Exhibit 138.

CHAIRMAN LA ROSA: Okay.

MR. SPARKS: And before I tender the witness for cross-examination, I would just remind you to please speak into the mic so that everybody can hear you.

CHAIRMAN LA ROSA: Great. Thank you.

Let's go ahead and get started with OPC.

MR. WATROUS: Thank you, Mr. Chairman.

EXAMINATION

BY MR. WATROUS:

Q And good morning, Mr. Kopelovich.

A Good morning.

Q Yes. Let's start with, so you filed testimony on June 10th with a June 7th audit report attached, correct?

A Correct. Yes.

Q And the only resource you used in conducting the audit was the 2016 audit manual?

A No. Audit manual, plus the audit service request.

Q And in conducting the audit, you verified the postings for accuracy?

A Yes.

Q But you didn't do anything else to verify beyond what is outlined in the audit report?

A Correct.

Q And you have never analyzed affiliate transactions before this audit?

A Correct.

Q And your audit did not review the validity of any allocation methods used by the affiliates of TECO?

A Yes, we did.

MR. WATROUS: Mr. Chairman, yeah, give me a second so we can pass out some depositions, please.

CHAIRMAN LA ROSA: Sure. Thank you.

BY MR. WATROUS:

Q And, Mr. Kopelovich, do you have your deposition with you? And that would be from July.

A Yes.

CHAIRMAN LA ROSA: Thank you.

BY MR. WATROUS:

Q Thank you.

So the question I asked was, your audit did

not review -- oh, your audit did not review the validity of any allocation methods used by the affiliates of TECO. Can you please turn to page 36?

A Page 36, where?

CHAIRMAN LA ROSA: You have to indicate the numbers in the right corner of the box.

BY MR. WATROUS:

Q And you were asked in the deposition: Did your audit review the validity of any allocation methods used by the affiliates of TECO to allocate the costs to TECO?

A And where do we see that?

CHAIRMAN LA ROSA: I think he is looking for direction on the page, where the page number is. The page number is in the corner of each box.

MR. WATROUS: The page number is up in the corner of each box. That would be on --

CHAIRMAN LA ROSA: There is not a page number on the -- well, there is a page number, but a little confusing.

MR. WATROUS: My apologies, Mr. Chair.

CHAIRMAN LA ROSA: Oh, no problem.

BY MR. WATROUS:

Q And you are at page 36?

A 36. Yes.

Q And do you remember being deposed in July on this day?
A Can you repeat your question, please?
Q Yes.
Your audit did not review the validity of any allocation methods used by the affiliates of TECO, correct?
A No.
Q And that is an updated answer from your previous one?
A We reviewed the validity of the allocation.
Q We will move along, then.
Are you familiar with Rule 25-6.1351?
A I am aware of it.
Q And the purpose of the affiliate transaction audit was to see that it was in compliance with this rule?
A Correct.
Q And that does not include looking at whether the methodology used was the right methodology, correct?
A No.
Q Because that's outside of the scope of your audit?
A Yes.
Q And you reviewed internal audits?

A Yes.
Q And you reviewed external audits?
A Yes.
Q Can I have you please turn to page 43 in the deposition?
A 43. Okay.
Q And on lines 11 through 12, you were asked: Okay, can you read me the conclusion on this work paper? And can you please read your answer, lines 13 through 16?
A Okay. So what is it your question?
Q Can you please read me your answer on lines 13 through 16 on page 43 of your deposition?
A Yes.
Due to time constraint, external and internal audits will be reviewed in the Environmental Cost Recovery Clause Docket No. 20224 -- 20240007-EI, Audit Control No. 2024-031-1-1.
Q All right. Thank you.
And time constraints were the only reason those audits were not reviewed?
A Yes.
Q And if an exception was found in those audits, isn't it true that it could not be used in the current case?

A I can't answer that.
Q Thank you.
MR. WATROUS: No more questions from OPC.
CHAIRMAN LA ROSA: Great. Thank you.
Florida Rising/LULAC.
MS. LOCHAN: Thank you, Chairman. Good morning, Commissioners.

EXAMINATION

BY MS. LOCHAN:
Q Good morning, Mr. Kopelovich.
A Morning.
Q It's definitely morning, not afternoon this time.
As part of your audit, you reviewed invoices received by the company?
A Yes.
Q Thank you.
I am actually going to pull up a document. I don't know if you have used the system before, but it should -- this is going to be for FLL-274, which is master number F3.5-24640.
And you see -- this is the revised auditor's report?
A Okay. Yeah, I see that.
Q I am going to take you to page nine, which is

master number F3.5-24648. 648.

And here it states -- oh. And here it states that in the audit analysis, that staff -- audit staff reviewed all industry association dues and economic development expenses to determine whether the utility included the appropriate amount and expenses, and if any expense were for political purposes. Staff discovered transactions which should be removed, is that correct?

A Yes.

Q Okay. Thank you.

I would like to pull up now -- this is FLL-276, which is master number F3.5-24657.

So these are the invoices that staff reviewed during the audit, correct?

A Yes.

Q Okay. Thank you.

I am going to move to page 28 of this document, which is F3.5-24684. Thank you.

And this is a invoice from the Republican State Leadership Committee -- oh, right master number --

A What is the question?

Q Is this an invoice from the Republican State Leadership Committee?

A It looks like that.

Q How did -- would you agree that this is an

expense for a political purpose?

A Not at that moment. I was not the one that reviewed it. I was basically overseeing it.

Q In your role, how do you determine that these expenses are properly removed once determined?

A I did not work on that particular section. I -- somebody working under me, so I had some trust in them that they did the work. I just reviewed to make sure that they follow the correct steps.

Q So you do not know if it was removed?

A No.

Q Thank you.

I would like to now go to -- this is FLL-279, which is master number F3.5-24808.

And these were -- oh, are these the invoices for advertisements that were reviewed during the audit?

A Yes.

Q Thank you.

And now, I think our last document, it's FLL-281, which is master number F3.5-24828.

So for this document, you can see under column G the percentages of disallowances. And if we want, we can zoom in a little bit so we can see it a little better, if that's helpful. Thank you so much.

Do you see column G of allowance per utility?

A Yes.

Q How are those percentages of disallowances, like, how are those numbers -- how did the audit report come to these numbers and these disallowances?

A Like I said, I did not particularly work on that section. I just, in general, reviewed it and made sure that the steps are followed. You see at the bottom, you see testing criteria.

Q So you do not know how these disallowances were determined?

A I could not get into all the details.

Q So is that a no?

A Yes.

Q Okay. Thank you so much.

MS. LOCHAN: Those are my questions.

CHAIRMAN LA ROSA: Great. Thank you.

FIPUG.

MR. MOYLE: FIPUG does not have questions on this witness.

CHAIRMAN LA ROSA: Thank you.

FEA.

CAPTAIN GEORGE: No questions, Mr. Chairman. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Sierra Club has been excused.

Florida Retail.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Great. Thank you.

Walmart.

MS. EATON: No questions. Thank you.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions. Thank you.

CHAIRMAN LA ROSA: Commissioners, questions?

Seeing none, let's go back to staff for redirect.

MR. SPARKS: Can I have just a brief moment, Mr. Chairman?

CHAIRMAN LA ROSA: Sure.

MR. SPARKS: Thank you.

Staff has no questions for redirect. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

Let's now talk about moving exhibits into the record, are there any? OPC, none.

Okay. LULAC.

MS. LOCHAN: Florida Rising/LULAC would like to move Exhibits 234, 236 -- sorry, 734, 736, 739 and 741 into the record.

CHAIRMAN LA ROSA: Is there objections?

None, show them entered into record.

(Whereupon, Exhibit Nos. 734, 736, 739 & 741 were received into evidence.)

CHAIRMAN LA ROSA: I should have went to staff first on -- is there anything to enter into the record?

MR. SPARKS: Yeah. Staff would like to move Exhibit 138 into the record, please.

CHAIRMAN LA ROSA: 138. Is there objections?

Seeing none, show that entered into the record.

(Whereupon, Exhibit No. 138 was received into evidence.)

CHAIRMAN LA ROSA: Any further exhibits? Not seeing any, I believe we can move on.

Mr. Kopelovich, you are excused. Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: Staff, I will throw it back to you for your next witness.

MR. MARQUEZ: Okay. That will be Ms. Calhoun, Mr. Chairman, and she is approaching.

CHAIRMAN LA ROSA: Great.

Ms. Calhoun, before you have a seat, do you mind just administering the oath very quickly? Please raise your right hand.

Whereupon,

ANGELA L. CALHOUN

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.

Staff, I will throw it to you whenever you are ready.

MR. MARQUEZ: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MARQUEZ:

Q Hello, Ms. Calhoun.

A Good morning.

Q Good morning.

Would you please state your full name for the record for me?

A My name is Angela Calhoun.

Q Okay. And where are you employed?

A I am employed by the Florida Public Service Commission.

Q All right. And did you prepare testimony to be filed in these dockets, on or about June 10th of 2024?

A Yes.

Q And did you also prepare Exhibits ALC-1, ALC-2

and ALC-3 in connection with that direct testimony?
A Yes.
Q And also in this docket was filed amendments to Exhibit ALC-2 in July with the Prehearing Officer's approval, correct?
A Correct.
MR. MARQUEZ: Mr. Chairman, just to note, Exhibits ALC-1, -2 and -3 are identified on the Comprehensive Exhibit List as Exhibits 139, 140 and 141, respectively.
BY MR. MARQUEZ:
Q Ms. Calhoun, other than the change to Exhibit ALC-2, to the extent that it's discussed in your testimony, if I were to ask you the same questions in your direct today, would your answer still be the same?
A Yes.
MR. MARQUEZ: All right. Mr. Chairman, staff would move for Ms. Calhoun's testimony to be entered into the record as though read.
CHAIRMAN LA ROSA: Okay.
(Whereupon, prefiled direct testimony of Angela L. Calhoun was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF ANGELA L. CALHOUN

DOCKET NO. 20240026-EI

JUNE 10, 2024

Q. Please state your name and address.

A. My name is Angela L. Calhoun. My address is 2540 Shumard Oak Boulevard; Tallahassee, Florida 32399-0850.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as Chief of the Bureau of Consumer Assistance in the Office of Consumer Assistance & Outreach.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from Florida State University in 1993 with a Bachelor of Arts degree. I have worked for the Commission for more than 24 years, and I have experience in consumer complaints and consumer outreach. I work in the Bureau of Consumer Assistance within the Office of Consumer Assistance & Outreach where I manage consumer complaints and inquiries.

Q. What is the function of the Bureau of Consumer Assistance?

A. The Bureau's function is to resolve disputes between regulated companies and their customers as quickly, effectively, and inexpensively as possible.

Q. Do all consumers that have a dispute with their regulated company contact the Bureau of Consumer Assistance?

A. No. Consumers may initially file their complaint with the regulated company and reach a resolution without the Bureau's intervention. In fact, consumers are encouraged to allow the regulated company the opportunity to resolve the dispute prior to any Commission involvement.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss/outline the number of consumer complaints logged with the Commission against Tampa Electric Company under Rule 25-22. 032, Florida Administrative Code, Consumer Complaints, from April 1, 2020 through March 31, 2024. My testimony will also provide information on the type of complaints logged and those complaints that appear to be rule violations.

Q. What do your records indicate concerning the number of complaints filed for Tampa Electric Company?

A. From April 1, 2020 through March 31, 2024 the Commission logged 1,026 complaints against Tampa Electric Company. Of those, 615 were transferred to the company for resolution via Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to Tampa Electric Company customer service personnel. Once the call is transferred to Tampa Electric Company, the Company can provide the customer with a proposed resolution.

Q. What have been the most common types of complaints logged against Tampa Electric Company during the period of April 1, 2020 through March 31, 2024?

A. During the specified time period, approximately fifty-two (52%) percent of the complaints logged with the Commission concerned billing issues, while approximately forty-eight (48%) percent of the complaints involved quality of service issues.

Q. Do you have any exhibits attached to your testimony?

A. Yes. I am sponsoring ALC-1 and ALC-2, which are listings of consumer complaints logged with the Commission against Tampa Electric Company under Rule 25-22.032, Florida Administrative Code. The complaints listed were received between April 1, 2020 through March 31, 2024, and were captured in the Commission's Consumer Activity Tracking System (CATS). Exhibit ALC-1 lists quality of service complaints and Exhibit ALC-2 lists billing complaints. Both exhibits group the complaints by Close Type.

Q. What is a Close Type?

A. A Close Type is an internal categorization code. It is assigned to each complaint once staff completes its investigation, and a proposed resolution is provided to the consumer.

Q. Do you have any additional exhibits?

A. Yes. Exhibit ALC-3 is a listing of complaints resolved as Close Type GI-02, Courtesy Call/Warm Transfer.

Q. Can you explain Close Type GI-02?

A. Yes. Tampa Electric Company participates in the Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to the company's customer service personnel. Once the call is transferred to Tampa Electric Company it provides the customer with a proposed resolution. Customers who are not satisfied with the company's proposed resolution have the option of re-contacting the Commission. While the Commission is able to categorize each of the complaints in the GI-02 category, a specific Close Type is not assigned because the proposed resolution is provided by the company. Consequently, the GI-02 Close Type only allows staff to monitor the number of complaints resolved via the Commission's Transfer-Connect System.

Q. How many of the complaints summarized on your exhibit has staff determined may be a violation of Commission rules for Tampa Electric Company?

C35-3797

A. Staff determined that, of the 1,026 complaints logged against Tampa Electric Company during the period of April 1, 2020 through March 31, 2024, there were two (2) service quality complaints and two (2) billing complaints that appear to demonstrate a violation of Commission Rules.

Q. Does that conclude your testimony?

A. Yes.

MR. MARQUEZ: And we will tender the witness for any cross-examination.

CHAIRMAN LA ROSA: Great.

OPC.

MS. WESSLING: Thank you, Mr. Chair.

And with the understanding that the customer complaints have already previously been admitted in the Exhibit 833 on the CEL, OPC has no cross.

CHAIRMAN LA ROSA: Okay. Florida Rising/LULAC?

MS. LOCHAN: Thank you, Chairman.

EXAMINATION

BY MS. LOCHAN:

Q Good afternoon, Ms. Calhoun. Oh, my goodness. Good morning.

A Coffee. Yeah.

Q What is time?

You reviewed the customer complaints received by the Commission regarding the company, correct?

A Correct.

Q And not all customer complaints go through the Commission, would agree with that?

A What is -- what are you defining as complaint?

Q As in some customers go directly to the company.

A Correct.
Q And regarding the complaints you received, and as a matter of practice, the PSC does not handle any follow-up to see whether issues have been resolved?
A What do you mean by follow-up? I guess my question is follow-up when? After we receive complaint?
Q Yeah.
A Can you repeat your question? I am sorry.
Q Sure. Actually, I don't think we need to ask that.
To your knowledge, some of these complaints comes from disconnections from bill discrepancies?
A Potentially.
Q Potentially. Without more knowledge, this means customers have paid their bills but are getting disconnected?
A Not necessarily.
Q But that could be a case?
A Potentially.
Q Okay. Thank you.
I am going to pull up master number C35-3779, which I believe is an exhibit to your testimony. It is C35-3799. Perfect.
Could you explain what close type is on this document?

A A closed-out type is a designation that allows us to determine whether a case is closed without an apparent infraction or with an apparent infraction.

Q Under -- you will see some of the close types state high bill. What does that mean?

A That generally means -- high bill is the designation for this close type GI-05. That just means that was the type of complaint the customer had, and we determined at -- with a GI-05, that there wasn't any apparent infraction in that particular case.

Q Okay. Thank you so much. Those are all my questions for you. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

FIPUG.

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FEA.

CAPTAIN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: FRF.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions.

CHAIRMAN LA ROSA: Commissioners, do we have any questions?

Seeing none, I will throw it back to staff for redirect.
MR. MARQUEZ: We have no questions, Mr. Chairman.
CHAIRMAN LA ROSA: No redirect?
MR. MARQUEZ: Correct.
CHAIRMAN LA ROSA: Okay. Excellent.
All right. Then let's move to exhibits. Do we need to move any exhibits into the record?
MR. MARQUEZ: Yes. Staff would seek to move ALC-1 -- well, Exhibits 139, 140 and 141.
CHAIRMAN LA ROSA: Is there objection?
Seeing none --
MR. WAHLEN: No objection.
CHAIRMAN LA ROSA: Great. Thank you.
Seeing none, show entered them into the record.
(Whereupon, Exhibit Nos. 139, 140 & 141 were received into evidence.)
CHAIRMAN LA ROSA: Not seeing any -- no other exhibits? Okay. Then I think we are good.
Ms. Calhoun, thank you very much. You are excused.
(Witness excuse.)
CHAIRMAN LA ROSA: All right. So that's all

of staff's witnesses. So correct me if I am wrong, but we are going to go to OPC's witnesses. Ms. Wessling, which witness had a time constraint?

MS. WESSLING: I believe that was Witness Woolridge.

CHAIRMAN LA ROSA: All right. So are you guys ready to call your witnesses?

MS. WESSLING: We can start, and --

CHAIRMAN LA ROSA: Okay.

MS. WESSLING: -- perhaps, as long as there is a little bit of leeway with Mr. Woolridge.

CHAIRMAN LA ROSA: Sure. So let's go in the order, if we could, and then when we will get to him, then we will obviously skip and go to the next.

MS. WESSLING: Thank you, Mr. Chair.

CHAIRMAN LA ROSA: Great.

MS. WESSLING: All right. OPC calls Dr. David Dismukes.

CHAIRMAN LA ROSA: Dr. Dismukes, let's just take a quick oath if you don't mind. Please raise your right hand.

Whereupon,

DAVID E. DISMUKES

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Thank you.

EXAMINATION

BY MS. WESSLING:

Q Good morning.

A Good morning.

Q Once you get settled, if you could, please state your name and your business address for the record.

A My name is David E. Dismukes, D-I-S-M-U-K-E-S.

Q Thank you.

And did you cause to be filed prefiled responsive direct testimony consisting of 23 pages in this docket?

A Yes, I did.

Q And do you have any corrections to your testimony?

A No, I do not.

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

A Yes, they would be.

MS. WESSLING: I would ask that the testimony of Dr. Dismukes be entered into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of David E. Dismukes was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for rate increase by Tampa Electric Company. ______________________________ /	Docket No. 20240026 FILED: June 6, 2024

DIRECT TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

Patricia A. Christensen
Associate Public Counsel

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Attorneys for the Citizens
of the State of Florida

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EXHIBITS

DIRECT TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

On behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 20240026-EI

I. <u>INTRODUCTION</u>

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

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

A. I am testifying in this proceeding on behalf of the Florida Office of Public Counsel ("OPC").

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy

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industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located at 5800 One Perkins Place Dr., Suite 5-F, Baton Rouge, Louisiana 70808.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a professor emeritus at Louisiana State University ("LSU"). Prior to my retirement in January 2023, I served as a full professor, executive director, and director of policy analysis at the LSU Center for Energy Studies and as a full tenured professor in the Department of Environmental Sciences and the director of the Coastal Marine Institute in the LSU College of the Coast and Environment. I also serve as a senior fellow at the Institute of Public Utilities at Michigan State University, where I have taught energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries. I am also a Distinguished Fellow and Senior Economist with the Institute for Energy Research in Washington, D.C. Appendix A provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by OPC to provide an expert opinion to the Florida Public Service Commission ("Commission") on load forecasting and energy affordability issues and how those relate to the current base rate case increase proposed by Tampa Electric Company ("TECO" or "Company"). My testimony and accompanying exhibits have been prepared by me or those under my direction and control.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. The following exhibits have been prepared in support of my testimony:

- Exhibit DED-1: Base Revenue Impact,
- Exhibit DED-2: Out-of-Model Adjustments,
- Exhibit DED-3: Company Energy Sales and Customer Forecasts,
- Exhibit DED-4: Revised Sales Forecast based on Ten-Year Trend,
- Exhibit DED-5: Usage per Customer Utility Survey,
- Exhibit DED-6: Forecast Variance Analysis, and
- Exhibit DED-7: Energy Affordability Index.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations,
- Section III: Load Forecast,
- Section IV: Energy Affordability, and
- Section V: Conclusions and Recommendations.

II. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR LOAD FORECAST RECOMMENDATION.

A. I recommend the Commission reject the Company's energy sales forecast because it bears no resemblance to historic trends and is biased due to the introduction of a number of subjective out-of-model adjustments. Over the past several years, the Company has consistently prepared sales forecasts that were lower than actuals. I recommend the Commission accept a conservative, modified version of the Company's forecast that removes subjective out-of-model adjustments. The removal of out-of-model

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adjustments will increase the Company's test year sales forecast resulting in a 2025 sales projection of 20,635,457 megawatt-hours. This recommendation, if extended an additional two years, would support forecasted megawatt-hour sales of 20,886,730 in 2026 and 21,128,190 in 2027.

Q. PLEASE SUMMARIZE THE REVENUE IMPACTS RESULTING FROM YOUR LOAD FORECAST RECOMMENDATION.

A. My recommendation will result in an increase of 2025 test year retail revenues by $12 million. This recommendation, if extended an additional two years, would support retail revenue increases of $20 million in 2026 and $26 million in 2027. I consider this to be a conservative recommendation given that the Company's test year forecast has shown consistent biases (measured by prior forecast variances) from its two prior base rate case proceedings in 2013 and 2021. The average test year forecast variance in these two cases was 2.1 percent, which if applied to this case, would result in a retail revenue increase of $31 million in 2025, $37 million in 2026, and $39 million in 2027. Furthermore, a forecast aligned with the Company's ten-year historical trend would result in a retail revenue increase of $60 million in 2025, $78 million in 2026, and $89 million in 2027. Thus, a moderate sales/revenue adjustment which simply excludes several proposed yet poorly documented out-of-model adjustments, is reasonable. A summary of these forecasted revenues is provided in Exhibit DED-1.

Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING ENERGY AFFORDABILITY IN THE COMPANY'S SERVICE TERRITORY.

A. Energy affordability remains a challenging issue in the Company's service territory. TECO-specific electricity costs as a share of income remain unaffordable for the Company's low-income customers. The consistent march to more and more, and higher and higher rate requests are keeping affordable rates out of reach for low-income ratepayers. I recommend the Commission consider energy affordability in this proceeding, and all future utility base rate proceedings, in evaluating rate increase requests consistent with the trends in other U.S. regulatory jurisdictions.

III. <u>LOAD FORECAST</u>

A. TECO's Forecasting Process

Q. PLEASE EXPLAIN THE COMPANY'S FORECASTING PROCESS.

A. The Company's forecasting process involves econometric and end-use models to determine changes in usage per customer ("UPC"), peak demand, and customer growth.[1] The product of the UPC and customer forecasts are used to develop a total energy sales forecast and ultimately a forecast for test year revenues. Each of these forecasts rely on several economic and demographic variables originating from both internal and external sources. The results are used in not only in this rate case, but also in the Company's planning and budget processes.[2]

[1] Direct Testimony of Lori Cifuentes at p. 7, lines 15-18.
[2] Direct Testimony of Lori Cifuentes at p. 3, lines 1-6.

Q. PLEASE DISCUSS THE INPUTS USED IN THE COMPANY'S CUSTOMER GROWTH FORECAST.

A. The Company used a variety of variables in developing its customer forecast that include county population estimates, county employment, and building permits.[3] The Company's forecast also relied upon external forecasts conducted by the University of Florida's Bureau of Economic and Business Research ("BEBR") as well as Moody's Analytics.[4]

Q. PLEASE EXPLAIN THE COMPANY'S STATISTICALLY ADJUSTED END USE ("SAE") MODEL.

A. The Company's SAE model is econometric based and estimates UPC.[5] The parameters for the Company's SAE model rely primarily on three major types of variables:

- Those measuring saturation and efficiency trends in end-use equipment;[6]
- Those measuring how economic conditions and prices impact electricity consumption;[7] and
- Those measuring the impact of weather including the use of heating degree day and cooling degree day data based on 20-year "normal" weather trends.[8]

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[3] Direct Testimony of Lori Cifuentes at p. 8, lines 9-12.
[4] Direct Testimony of Lori Cifuentes at p. 8, lines 14-19.
[5] Direct Testimony of Lori Cifuentes at p. 9, lines 11-13.
[6] Direct Testimony of Lori Cifuentes at p. 9, lines 14-16.
[7] Direct Testimony of Lori Cifuentes at p. 9, lines 16-22.
[8] Direct Testimony of Lori Cifuentes at p. 9, lines 23-25 and p. 10, lines 1-2.

Q. DID THE COMPANY RELY UPON ANY "OUT-OF-MODEL" ADJUSTMENTS?

A. Yes. The Company relies on three major "out-of-model" adjustments to its sales forecast that includes: (1) revisions for changes in energy efficiency; (2) revisions for increases in electric vehicle adoption; and (3) revisions for increases in behind-the-meter solar installations.[9]

Q. WHAT DO YOU MEAN BY "OUT-OF-MODEL" ADJUSTMENTS?

A. An out-of-model adjustment is an additional, often subjective modification to statistical model results. These modifications are considered "out-of-model" since they either modify, change, or disregard the results that are derived from a statistical model, which in this case, is the Company's SAE model. Practitioners often make these adjustments if they feel forecast results are either deficient or not properly informed by their explanatory (or independent) variables or statistical/mathematical specifications. An example of an out-of-model adjustment includes those used in the recent past to account for an unknown and not otherwise experienced change in economic conditions brought on by the COVID pandemic. These adjustments, while often informed by empirical data, also included a large degree of subjectivity.

[9] Minimum Filing Requirement Schedule F-5, p. 6 of 16.

Q. PLEASE EXPLAIN THE COMPANY'S ENERGY EFFICIENCY ADJUSTMENTS.

A. The Company applied separate energy sales adjustments amounting to 93,294 megawatt-hours in 2025 as a reduction to their regression model results.[10] The adjustments are meant to represent the Demand Side Management ("DSM") savings resulting from forecasted growth in program participation and estimated energy savings per participant. The adjustments were applied to the residential, commercial, and industrial customer classes.

Q. WHAT SUPPORT DID THE COMPANY PROVIDE FOR THESE ENERGY EFFICIENCY ADJUSTMENTS?

A. As part of their initial filing, the Company did not provide any supporting details on the various components of its out-of-model adjustments nor did they provide the assumptions utilized to arrive at their results. The Company simply referenced the adjustment in testimony[11] and provided a brief description in their supporting filing schedules.[12] Upon request for more details on the models and their assumptions, the Company provided the forecasted adjustment results by customer type and month.[13]

10 Company Response to OPC's 7th Request for PODs (88-103), Attachment "BS 20063Energy Sales Calculations_2024-2025", tab "Conservation".
11 Direct Testimony of Lori Cifuentes at p. 19, lines 3-6.
12 Minimum Filing Requirement Schedule F-5, p. 6 of 16.
13 Company Response to OPC's 7th Request for PODs (88-103), Attachment "BS 20063Energy Sales Calculations_2024-2025", tab "Conservation".

Q. DO YOU AGREE WITH THE INCLUSION OF THE COMPANY'S ENERGY EFFICIENCY ADJUSTMENTS INTO THE ENERGY SALES FORECAST?

A. No. The DSM goals that serve as the basis for this adjustment (2025-2034 proposal) are nearly three times the size as the prior period DSM goals (2020-2029).[14] Additionally, neither the 2024 nor the 2019 DSM goals proposed by the Company have been approved by the Commission. In the most recent Commission order regarding the review of numeric conservation goals, the Commission rejected the Company's proposed 2019 goals in favor of the 2014 goals stating, "we find that it is in the public interest to continue with the goals set in the last FEECA proceeding pursuant to the 2014 Goalsetting Order."[15] Further, the DSM goals approved by the Commission in this Order are for 2020 to 2024, and do not include the 2025 test year for the current case.

Q. PLEASE EXPLAIN THE COMPANY'S ELECTRIC VEHICLE ADJUSTMENTS.

A. The Company applied separate electric vehicle adjustments amounting to 173,285 megawatt-hours in 2025 as an addition to their regression model results.[16] The adjustments are meant to represent the impact electric vehicle growth will have on Company load. The forecast relies upon many assumptions including future

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[14] Direct Testimony of Ashley Sizemore at p. 15, lines 16-25.

[15] In re: Commission review of numeric conservation goals (Tampa Electric Company), Order No. PSC-2019-0509-FOF-EG. Issued November 26, 2019.

[16] Company Response to OPC's 7th Request for PODs (88-103), Attachment "BS 20063Energy Sales Calculations_2024-2025", tab "EV".

penetration levels, the average number of miles driven per year, the weighted average battery size, and the number of charges per year.[17] The adjustments were applied to the residential and commercial customer classes.

Q. WHAT SUPPORT DID THE COMPANY PROVIDE FOR THESE ELECTRIC VEHICLE ADJUSTMENTS?

A. As part of their initial filing, the Company did not provide the supporting details on this out-of-model adjustment, nor did they provide the numerical assumptions made to calculate their results. The Company simply referenced the adjustment in testimony[18] and provided a brief description in their supporting filing schedules.[19] Upon request for more modeling details and assumptions, the Company merely provided the forecasted adjustment results by customer type and month.[20]

Q. DO YOU AGREE WITH THE INCLUSION OF THE COMPANY'S ELECTRIC VEHICLE ADJUSTMENTS INTO THE ENERGY SALES FORECAST?

A. No. While many energy analysts anticipate that all utilities will face increasing electric vehicles sales over the next several years, the Company has failed to provide the supporting evidence necessary to prove their out-of-model adjustment for electric vehicle growth is reasonable. An understatement of these sales, for instance, could

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[17] Minimum Filing Requirement Schedule F-5, p. 6 of 16.
[18] Direct Testimony of Lori Cifuentes at p. 19, lines 17-18.
[19] Minimum Filing Requirement Schedule F-5, p. 6 of 16.
[20] Company Response to OPC's 7th Request for PODs (88-103), Attachment "BS 20063Energy Sales Calculations_2024-2025", tab "EV".

have important implications for test year revenue results. To date, the Company has simply failed to meet its burden of proof regarding the sales adjustments.

Q. PLEASE EXPLAIN THE COMPANY'S SOLAR ENERGY ADJUSTMENTS.

A. The Company applied separate solar energy adjustments amounting to 249,449 megawatt-hours in 2025 as a reduction to their regression model results.[21] These particular out-of-model adjustments are meant to estimate how behind the meter solar generation impacts future load. The model relies upon assumptions regarding future penetration levels and the impact of each installation.[22] The adjustments were applied to the residential and commercial customer classes.

Q. WHAT SUPPORT DID THE COMPANY PROVIDE FOR THESE SOLAR ENERGY ADJUSTMENTS.

A. As part of their initial filing, the Company did not provide the supporting details on this out-of-model adjustment, nor did they provide the numerical assumptions made to calculate their results. The Company simply referenced the adjustment in testimony[23] and provided a brief description in their supporting filing schedules.[24] Upon request for more details on the underlying assumptions and how these solar adjustments were modeled, the Company merely provided the forecasted adjustment results by customer

[21] Company Response to OPC's 7th Request for PODs (88-103), Attachment "BS 20063Energy Sales Calculations_2024-2025", tab "PV".
[22] Minimum Filing Requirement Schedule F-5, p. 6 of 16.
[23] Direct Testimony of Lori Cifuentes at p. 19, lines 11-12.
[24] Minimum Filing Requirement Schedule F-5, p. 6 of 16.

type and month.[25] Again, the Company has failed to provide the supporting evidence and proper documentation necessary to prove their out-of-model adjustment for solar growth is reasonable. An overstatement in the loss of sales, for instance, could have a significant impact on test year revenue results. To introduce a number of additional assumptions on top of the assumptions already made in the statistical model adds another level of uncertainty to the Company's load forecasting results. Given the immense size of this particular adjustment, the impact of introducing more uncertainty into the model raises the potential for adverse results. To date, the Company has simply failed to meet its burden of proof regarding the solar-energy based sales adjustments.

Q. HOW LARGE ARE THE COMPANY'S COLLECTIVE OUT-OF-MODEL ADJUSTMENTS?

A. Collectively, the Company's three out-of-model adjustments reduce their test year energy sales by 169,457 megawatt-hours. The individual and collective impacts of these adjustments are shown on Exhibit DED-2. These adjustments are part of a broader conclusion proposed by the Company that despite serving customers residing in one of the fastest growing regions of one of the fastest growing states, a decline in energy sales should be expected. This conclusion is completely inconsistent with past and currently expected trends. Not only is the state experiencing tremendous growth, but Tampa has also been among the top ten metro regions in the country at attracting

[25] Company Response to OPC's 7th Request for PODs (88-103), Attachment "BS 20063Energy Sales Calculations_2024-2025", tab "PV".

new residents.[26] The Company has maintained consistent growth over the past decade and shows few signs of reversing course in the manner suggested by the Company's forecast. I will discuss how the Company's forecast differs from these trends in the following subsection of my testimony.

B. Company Forecast Inconsistencies with Historic Trends

Q. HOW DOES THE COMPANY'S SALES FORECAST COMPARE TO ITS PRIOR HISTORIC TRENDS?

A. The Company forecasts a two percent sales decrease from 2023 to its 2025 test year[27] while customers are forecasted to increase by three percent.[28] The divergence between these two forecasts is contradictory. Consider that the Company's forecasts suggest that end-use reductions in UPC will be far larger than all the new incremental load added to the Company's system due to new customer growth. Exhibit DED-3 shows the Company's historic sales, customer, and UPC trends compared to its proposed forecast. The analysis decomposes changes in usage attributable to existing customers (efficiency changes) and new customers (growth changes). The forecast for 2024 shows the large decreases in UPC from existing customers are forecasted to be over two times larger in absolute value than usage changes attributable to new customer growth. Such an outcome has not happened since 2011 when the state was still reeling from the aftermath of the 2008 to 2009 recession.

[26] Kristie Wilder and Paul Mackun, "Sunshine State Home to Metro Areas Among Top 10 U.S. Population Gainers From 2022 to 2023," Census Bureau, 2024.
[27] Direct Testimony of Lori Cifuentes, Exhibit LC-1, Document No. 7.
[28] Direct Testimony of Lori Cifuentes, Exhibit LC-1, Document No. 5.

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Q. ARE THE COMPANY'S SALES PROJECTIONS CONSISTENT WITH HISTORICAL TRENDS?

A. No. The Company is projecting a sales decrease for the test year (and subsequent years) despite the fact that sales have steadily increased at an annualized rate of 1.2 percent from 2013 to 2023. In fact, over this historical period, sales grew for nine out of ten years and never experienced a decline over two years which is what the Company proposes the Commission accept in this proceeding to develop test year revenues. Moreover, the projected decrease from 2023 to 2024 would be larger than anything experienced during the most recent ten-year historical period. The Company's forecast sales decrease (476 GWh) is almost ten times larger than the only single decrease that has been reported over the past decade (i.e., 2017) and three times larger than the average annual decrease experienced from 2008 to 2012 during and immediately after the 2008 to 2009 recession. Exhibit DED-4 provides a chart comparing the Company's current forecast to a historic trend-based projection of ten-year sales. The difference between the two series is substantial and shows just how inconsistent the Company's sales forecast is with historic trends on a forward-going basis.

Q. ARE THE COMPANY'S UPC PROJECTIONS CONSISTENT WITH HISTORICAL TRENDS?

A. No. UPC declined by 0.6 percent on an annual average basis between 2013 and 2023 in direct contradiction to the Company's forecast which estimates a very large and steep 3.9 percent decline in 2024. In other words, much of the Company's test year projection hinges on their prediction that UPC will decrease at over six times the ten-year historic rate.

Q. IS THIS A LARGE DECREASE IN FORECAST UPC?

A. Yes. I have examined the changes in total company UPC for all southeastern investor-owned utilities going back to before the last recession from 2009 to 2022. This includes 166 utilities over 14 years for a total of 2,324 observations. The results are shown on Exhibit DED-5. In the most recent year only 7 utilities (4 percent) have seen an annual UPC decrease that equals or exceeds the UPC forecasted by the Company in this proceeding. Of those utilities, none were located in Florida or what could be considered a "growth" state comparable to Florida. The UPC projection made by the Company is more comparable to 2009 during the recession when 56 percent of utilities experienced an annual UPC decrease of an equal or greater magnitude. However, even during the 2009 recession, the average UPC decrease was 3.5 percent, lower than the Company's current projection.

Q. DOES THE COMPANY HAVE A HISTORY OF UNDERSTATING ITS LOAD FORECASTS?

A. Yes. The variance analysis contained in Exhibit DED-6 compares the Company's actual energy sales and customers from 2013 to 2023 to the forecasted energy sales and customers presented in the 2021 and 2013 rate cases. The results point to an unequivocal bias in the Company's forecasts understating sales, customer, and UPC projections in every single year. For example, the Company's 2021 energy sales

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forecast of 19,972 GWh for 2023 was four percent (or 819 GWh) lower than the 20,791 GWh of actual sales. The Commission should observe that these variances are not randomly distributed over and beyond actual values but are consistently understating forecast usage and UPC. The fact that forecasted sales have been lower than actual sales in every year over the past decade raises serious questions about the reliability and integrity of the forecasts.

C. Recommendations Regarding the Company's Load Forecasts

Q. PLEASE SUMMARIZE YOUR LOAD FORECAST RECOMMENDATION.

A. I recommend the Commission reject the Company's energy sales forecast because it bears no resemblance to historic trends and is biased due to the introduction of a number of subjective out-of-model adjustments. Over the past several years, the Company has consistently prepared sales forecasts that were lower than actuals. I recommend the Commission accept a conservative, modified version of the Company's forecast that removes subjective out-of-model adjustments. The removal of out-of-model adjustments will increase the Company's test year sales forecast resulting in a 2025 sales projection of 20,635,457 megawatt-hours. This recommendation, if extended an additional two years, would support forecasted megawatt-hour sales of 20,886,730 in 2026 and 21,128,190 in 2027.

Q. PLEASE SUMMARIZE THE REVENUE IMPACTS RESULTING FROM YOUR LOAD FORECAST RECOMMENDATION.

A. My recommendation will result in an increase of 2025 test year retail revenues by $12 million. This recommendation, if extended an additional two years, would support retail revenue increases of $20 million in 2026 and $26 million in 2027. I consider this to be a conservative recommendation given that the Company's test year forecast has shown consistent biases (measured by prior forecast variances) from its two prior base rate case proceedings in 2013 and 2021. The average test year forecast variance in these two cases was 2.1 percent, which if applied to this case, would result in a retail revenue increase of $31 million in 2025, $37 million in 2026, and $39 million in 2027. Furthermore, a forecast aligned with the Company's ten-year historical trend would result in a retail revenue increase of $60 million in 2025, $78 million in 2026, and $89 million in 2027. Thus, a moderate sales/revenue adjustment which simply excludes several proposed yet poorly documented out-of-model adjustments, is reasonable.

IV. ENERGY AFFORDABILITY

Q. HOW DO YOU DEFINE ENERGY AFFORDABILITY?

A. While there is no universally accepted definition of energy affordability, it is typically examined within the context of how expensive energy is relative to household income.[29] Affordability, more generally, can be utilized as an index number to

[29] *See,* "Understanding Energy Affordability" ACEEE, 2015, p. 1.

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measure, among other things, the ability of a specific type of household to pay for essential utility services such as water, electric, and/or natural gas.

Q. ARE THERE ANY THRESHOLDS AT WHICH ENERGY SIMPLY BECOMES "UNAFFORDABLE" OR "BURDENSOME?"

A. Yes. The most accepted and utilized threshold at which utilities, and thus energy, becomes unaffordable or burdensome is when the percentage of income spent on energy exceeds six percent.[30] This threshold comes from the Fisher, Sheehan, and Colton's Home Energy Affordability Gap Study from 2011. The threshold is based on the premise that total shelter costs (including rent/mortgage and all utilities) should not exceed 30 percent of income and that 20 percent of shelter costs should be allocated to energy bills. Thus, 20 percent of 30 percent yields a six percent affordable utility burden.[31] Utility burdens below six percent are classified as "affordable," and energy burdens above six percent are classified as "unaffordable."

Q. HOW DOES ACADEMIC LITERATURE EXAMINE UTILITY AFFORDABILITY?

A. The academic literature examines energy affordability through various metrics but predominantly through utility and energy burden rates. Utility burden rates measure the impact of a utility bill on household income. The American Council for an Energy Efficient Economy (ACEEE)'s *Understanding Energy Affordability* Report best

[30] *See,* "Understanding Energy Affordability" ACEEE, 2015, p. 2.
[31] Fisher, Sheehan, and Colton. "Home Energy Affordability in New York: The Affordability Gap 2008-2010", June 2011, p. 2.

encapsulates what academicians have studied. ACEEE's report determines four drivers of high energy burdens: (1) physical (i.e. housing age and type, poor insulation, weather extremes); (2) economic (i.e. chronic or sudden economic hardship); (3) behavioral (lack of access to information for bill payment assistance); and (4) policy (insufficient programs for bill assistance, high fixed customer charges).[32] It also examines utility burden rates throughout the United States, classifying any total utility burden above six percent as a household that experiences a high energy burden.[33]

Q. HOW IS THE CONCEPT OF ENERGY AFFORDABILITY RECOGNIZED IN REGULATION AND PUBLIC POLICY?

A. Energy affordability is increasingly becoming an important regulatory policy consideration with various states and local governments now setting energy affordability targets. Recently, New York set a state-wide goal of achieving a six percent energy burden.[34] The City of Portland, Oregon, released a Ten-Year Plan to Reduce Energy Burden in Oregon Affordable Housing.[35] The California Public Utilities Commission ("CPUC") developed the state's first energy affordability metric that tracks affordability for essential services (electric, gas, water, and communications).[36] The Pennsylvania Public Utility Commission ("PPUC") examined

[32] "Understanding Energy Affordability" ACEEE, 2015, p. 2.
[33] *Id.*, at p. 3.
[34] "Understanding and Alleviating Energy Cost Burden in New York City," (August 2019) NYC Mayor's Office of Sustainability and the Mayor's Office for Economic Opportunity, at p. 2.
[35] "Reducing the Energy Burden in Oregon Affordable Housing – Ten-year Plan," (2018), Built Environment Energy Working Group.
[36] California Public Utilities Commission Order 18-07-006, 2018.

home energy burdens for low-income Pennsylvanians in its Home Energy Affordability 2019 report[37] and subsequently issued a policy statement on March 21, 2020, establishing maximum energy burdens for customers.[38] These examples demonstrate that examining energy affordability has become paramount in utility regulation across the country.

Q. DO LOW INCOME HOUSEHOLDS SPEND PROPORTIONATELY MORE IN ELECTRICITY THAN HIGHER INCOME HOUSEHOLDS?

A. Yes. Lower income households spend a larger share of their income on electricity than higher income households. In other words, while households consume more electricity as income increases, the share of their income they spend on electricity decreases as their income increases.

Q. HAVE YOU ESTIMATED ENERGY AFFORDABILITY USING THE COMPANY'S PROPOSED RESIDENTIAL RATES?

A. Yes. Exhibit DED-7 presents residential Energy Affordability Index estimates at both the 15th and 20th income percentiles. This analysis finds that the 15th percentile index is already greater than six percent, indicating a significant level of energy burden for the lowest income bracket. Moreover, energy is expected to remain unaffordable for this income bracket as rates are increased again in 2025.

[37] Exhibit OPC (A)-24, Home Energy Affordability for Low-Income Customers in Pennsylvania, (January 2019) Pennsylvania Public Utility Commission.
[38] 52 PA. Code Ch. 69.

Q. ARE YOU AWARE THE COMPANY HAS PROPOSED A PROGRAM FOR LOW INCOME SENIOR CITIZENS?

A. Yes, it is my understanding that the Company is proposing a senior citizen low-income program that offers a fixed $10 monthly bill credit for its senior customers who are sixty-five years old or older.[39] This would seem to tacitly acknowledge there is an affordability issue with the Company's rates for its low-income customers.

Q. WHAT DO THESE FINDINGS MEAN FOR THE COMPANY'S PROPOSAL?

A. Energy affordability remains a challenging issue in the Company's service territory. TECO-specific electricity costs as a share of income remain unaffordable for the Company's low-income customers. The consistent march to more and more, and higher and higher rate requests are keeping affordable rates out of reach for low-income ratepayers. I recommend the Commission consider energy affordability in this proceeding, and all future utility base rate proceedings, in evaluating rate increase requests consistent with the trends in other U.S. regulatory jurisdictions.

V. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q. PLEASE SUMMARIZE YOUR LOAD FORECAST RECOMMENDATION.

A. I recommend the Commission reject the Company's energy sales forecast because it bears no resemblance to historic trends and is biased due to the introduction of a number of subjective out-of-model adjustments. Over the past several years, the Company has

[39] Direct Testimony of Jordan Williams at p. 46, lines 11-25 and p. 47, lines 1-20.

consistently prepared sales forecasts that were lower than actuals. I recommend the Commission accept a conservative, modified version of the Company's forecast that removes subjective out-of-model adjustments. The removal of out-of-model adjustments will increase the Company's test year sales forecast resulting in a 2025 sales projection of 20,635,457 megawatt-hours. This recommendation, if extended an additional two years, would support forecasted megawatt-hour sales of 20,886,730 in 2026 and 21,128,190 in 2027.

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Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING ENERGY AFFORDABILITY IN THE COMPANY'S SERVICE TERRITORY.

A. Energy affordability remains a challenging issue in the Company's service territory. TECO-specific electricity costs as a share of income remain unaffordable for the Company's low-income customers. The consistent march to more and more, and higher and higher rate requests are keeping affordable rates out of reach for low-income ratepayers. I recommend the Commission consider energy affordability in this proceeding, and all future utility base rate proceedings, in evaluating rate increase requests consistent with the trends in other U.S. regulatory jurisdictions.

Q. DO YOU RESERVE YOUR RIGHT TO SUPPLEMENT YOUR TESTIMONY IF NEW INFORMATION BECOMES AVAILABLE?

A. Yes. I reserve the right to supplement my testimony if material new information becomes available.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's petition. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

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A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2023-Current	Professor Emeritus
2014-2023	Executive Director (Retired in 2023)
2007-2023	Director, Division of Policy Analysis
2006-2023	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-2023	Professor (Joint Appointment with CES)
2010-2023	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-2023	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

Institute of Public Utilities

2018-Current	Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-1999	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT & ADVISORY APPOINTMENTS

2023 – Current	Distinguished Fellow & Senior Economist Institute For Energy Research Washington, D.C.
2017 -- Current	Member, National Petroleum Council. U.S. Department of Energy.
2020-2023	Co-Chairperson, Energy Advisory Committee, World Trade Center New Orleans, Louisiana.
2007-2023	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.

2007-2023	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Energy and Environment: The Grand Challenges of 21st Century.* (2022). With Chris F. D'Elia and Bryan F. Snyder. New York: Kendell Hunt Publishers. Pp. 153.
2. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press. Pp. 133.
3. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy. Pp. 60.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

1. "Anticipating and Adapting to the Future Impacts of Climate Change on the Health, Security, and Welfare of Low Elevation Coastal Zone (LECZ) Communities in Southeastern USA" (2021). With Thomas Allen, Joshua Behr, Anamaria Bukvic, Ryan S.D. Calder, Kiki Caruson, Charles Connor, Christopher D'Elia, Robin Ersing, Rima Franklin, Jesse Goldstein, Jonathon Goodall, Scott Hemmerling, Jennifer Irish, Steven Lazarus, Derek Loftis Mark Luther, Leigh McCallister, Karen McGlathery, Molly Mitchell, William Moore, Carhles Reid Nichols, Karinna Nunez, Matthew Reidenbach, Julie Shortridge, Robert Weisberg, Robert Weiss, Lynn Donelson Wright, Meng Xia, Kehui Xu, Donald Young, Gary Zarillo, and Julie C. Zinnert. *Journal of Marine Science and Engineering.* 9 (11) 1196.
2. "The Potential Impact of the U.S. Carbon Capture and Storage Tax Credit Expansion on the Economic Feasibility of Industrial Carbon Capture and Storage" (2021). With Brittany Tarufelli and Brian Snyder. *Energy Policy*. Vol. 149.
3. "Current Trends and Issues in Reforming State-level Solar Net Energy Metering Policies." (2020). *Journal of Energy Law and Resources*. Vol. VIII: 419-451.
4. "A cash flow model of an integrated industrial CCS-EOR project in a petrochemical corridor: a case study in Louisiana." (2019). With Brian Snyder and Michael Layne. *International Journal of Greenhouse Gas Control*. 93(08).
5. "Understanding the challenges of industrial carbon capture and storage: An example in a U.S. petrochemical corridor." (2019). With Michael Layne and Brian Snyder. *International Journal of Sustainable Energy* 38(1):13-23.
6. "Understanding the Mississippi River Delta as a coupled natural-human system: research methods, challenges, and prospects. (2018). With Nina S.N. Lam, Y. Jun Xu, Kam-Biu Liu, Margaret Reams, R. Kelly Pace, Yi Qiang, Siddhartha Narra, Kenan Li, Thomas Blanchette, Heng Cei, Lei Zou, and Volodymyr Mihunov. *Water*. 10(8).

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7. “Understanding the challenges of industrial carbon capture and storage: an example in a U.S. petrochemical corridor.” (2018). With Brian Snyder and Michael Layne. *International Journal of Sustainable Energy*. 38(1):1-11

8. “Sea level rise and coastal inundation: a case study of the Gulf Coast energy infrastructure.” (2018). With Siddhartha Narra. *Natural Resources*. 9: 150-174.

9. “The energy pillars of society: perverse interactions among human resource use, the economy and environmental degradation.” (2018). With Adrian R.H. Wiegman, John W. Day, Christopher F. D’Elia, Jeffrey S. Rutherford, Charles Hall. *BioPhysical Economics and Resource Quality*. 3(2) 1-16.

10. “Modeling the impacts of sea-level rise, oil price, and management strategy on the costs of sustaining Mississippi delta marshes with hydraulic dredging.” (2018). with Adrian R.H. Wiegman, John W. Day, Christopher F. D’Elia, Jeffrey S. Rutherford, James T. Morris, Eric D. Roy, Robert R. Lane, and Brian F. Snyder. *Science of the Total Environment* 618 (2018): 1547-1559.

11. “Identifying Vulnerabilities of Working Coasts Supporting Critical Energy Infrastructure.” (2016). With Siddhartha Narra. *Water*. 8(1).

12. “Economies of Scale, Learning Effects and Offshore Wind Development Costs” (2015). With Gregory B. Upton, Jr. *Renewable Energy*. 61-66.

13. “Economic impact of Gulf of Mexico ecosystem goods and services and integration into restoration decision-making.” (2014) With Shepard, A.N., J.F. Valentine, C.F. D’Elia, D.W. Yoskowitz. *Gulf Science*.

14. “An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity.” (2012). With Mark J. Kaiser and Christopher J. Peters. *Exploration & Production: Oil and Gas Review*. 30(1): 18-22.

15. “The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico.” (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis*. 4(2).

16. “Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US.” (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

17. “Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds.” (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation*. 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*).

18. “Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes.” (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.

19. “Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures.” (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.

20. “A is for Access: A Definitional Tour Through Today’s Energy Vocabulary.” (2001) *Public Resources Law Digest*. 38: 2.

21. “A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical

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Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

22. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

23. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

24. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics*. 21:153-166.

25. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

26. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

27. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal*. 63:1108-1112.

28. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

PUBLICATIONS: PEER REVIEWED PROCEEDINGS

1. "Hydraulic Fracturing: A Look at Efficiency and the Environmental Effects of Fracking" (2014). With Emily C. Jackson. *Environmental Science and Technology: Proceedings from the 7th International Conference on Environmental Science and Technology*. Volume1 of 2: edited by George A. Sorial and Jihua Hong. (Houston, TX: American Science Press, ISBN: 978-0976885368): 42-46.

2. "Economic and Policy Issues in Sustaining an Adequate Oil Spill Contingency Fund in the Aftermath of a Catastrophic Incident." (2014). With Stephen R. Barnes and Gregory B. Upton. *Proceedings of the Thirty-seventh AMOP Technical Seminar on Environmental contamination and Response.* June: 506-524.

3. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues*. September: 17-21.

4. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management*. March.

5. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" (2000). With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.

6. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.

7. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.

8. “Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf” (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

9. “Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico.” (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. “A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements” (2005). *Proceedings of the 23rd Annual Information Technology Meetings*. U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

2. “Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana.” (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.

3. “Competitive Bidding in the Electric Power Industry.” (2003). *Proceedings of the Association of Energy Engineers*. December 2003.

4. “The Role of ANS Gas on Southcentral Alaskan Development.” (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All*. October.

5. “A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities.” (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.

6. “Analysis of the Economic Impact Associated with Oil and Gas Activities on State Leases.” (2002). With Dmitry Mesyanzhinov, Robert H. Baumann, and Allan G. Pulsipher. *Proceedings of the 2002 National IMPLAN Users Conference*: 149-155.

7. “Do Deepwater Activities Create Different Impacts to Communities Surrounding the Gulf OCS?” (2001). *Proceedings of the International Association for Energy Economics: 2001: An Energy Odyssey?* April.

8. “Modeling the Economic Impact of Offshore Activities on Onshore Communities.” (2000). With Williams O. Olatubi. *Proceedings of the 20th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

9. “Empirical Challenges in Estimating the Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico” (2000). With Williams O. Olatubi. *Proceedings of the International Association for Energy Economics: Transforming Energy Markets*. August.

10. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

11. “Modeling Electric Power Markets in a Restructured Environment” (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology’s Critical Role in Energy and Environmental Markets*. October: 48-56.

12. “Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS.” (1996). With Allan Pulsipher, Omowumi Iledare, Bob Baumann, and Dmitry Mesyanzhinov. *Proceedings of the 16th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana: 162-166.

13. “Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators.” (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the 15th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

PUBLICATIONS: BOOK CHAPTERS

1. “The Role of Distributed Energy Resources in a Restructured Power Industry.” (2006). In *Electric Choices: Deregulation and the Future of Electric Power*. Edited by Andrew N. Kleit. Oakland, CA: The Independent Institute (Rowman & Littlefield Publishers, Inc.), 181-208.

2. “The Road Ahead: The Outlook for Louisiana Energy.” (2006). In *Commemorating Louisiana Energy: 100 Years of Louisiana Natural Gas Development*. Houston, TX: Harts Energy Publications, 68-72.

3. “Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World.” (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues.* With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.

4. “Alaskan North Slope Natural Gas Development.” (2003). In *Natural Gas and Electric Industries Analysis 2003*. With William E. Nebesky, Dmitry Mesyanzhinov, and Jeffrey M. Burke. Edited by Robert Willett. Houston, TX: Financial Communications Company, 185-205.

5. “Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry.” (2002). In *Natural Gas and Electric Industries Analysis 2001-2002*. Edited by Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.

6. “The Hydropower Industry of the United States.” (2000). With Dmitry Mesyanzhinov. In *Renewable Energy: Trends and Prospects*. Edited by E.W. Miller and A.I. Panah. Lafayette, PN: The Pennsylvania Academy of Science, 133-146.

7. “Electric Power Generation.” (2000). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference.

PUBLICATIONS: BOOK REVIEWS

1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges***. Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum*. (*2000*).

2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

3. Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

PUBLICATIONS: TRADE AND PROFESSIONAL JOURNALS

1. "The Impact of Globalization, Decarbonization, and Politicization: Forecasting the outlook for the energy and energy transition along the Gulf Coast." *Landman* (2023, Forthcoming, Fall Edition).

2. "Opportunities for Carbon Capture, Utilization and Storage in Louisiana." (2020). *LOGA Industry Report*. Summer: 18-21.

3. "The Challenges of the Regulatory Review of Diversification Mergers." (2016). With Michael W. Deupree. *Electricity Journal*. 29 (2016): 9-14.

4. "Unconventional Natural Gas and the U.S. Manufacturing Renaissance" (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).

5. "Louisiana's Tuscaloosa Marine Shale Development: Emerging Resource and Economic Potentials" (2012). *Spectrum*. January-April: 18-20.

6. "The Impact of Legacy Lawsuits on Louisiana's Conventional Drilling Activity" (2012). *LOGA Industry Report*. Spring 2012: 27-34.

7. "Value of Production Losses Tallied for 2004-2005 Storms." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.27: 32-26 (July 21) (part 3 of 3).

8. "Model Framework Can Aid Decision on Redevelopment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.26: 49-53 (July 14) (part 2 of 3).

9. "Field Redevelopment Economics and Storm Impact Assessment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.25: 42-50 (July 7) (part 1 of 3).

10. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236

11. "Executive Compensation in the Electric Power Industry: Is It Excessive?" (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(4): 913-940.

12. "Renewable Portfolio Standards in the Electric Power Industry." With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(3): 693-706.

13. "Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54 (2): 401-424.

14. "Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(1): 211-223.

15. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997.

16. “Can LNG Preserve the Gas-Power Convergence?” (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (3):783-796.

17. “Competitive Bidding as a Means of Securing Opportunities for Efficiency.” (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.

18. “The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide.” (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53(2): 479-494.

19. “The Challenges Associated with a Nuclear Power Revival: Its Past.” (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (1): 193-211.

20. “Deregulation of Generating Assets and The Disposition of Excess Deferred Federal Income Taxes: A ‘Catch-22’ for Ratepayers.” (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 873-891.

21. “Will Competitive Bidding Make a Comeback?” (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 659-674.

22. “An Electric Utility’s Exposure to Future Environmental Costs: Does It Matter? You Bet!” (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 457-469.

23. “White Paper or White Flag: Do FERC’s Concessions Represent A Withdrawal from Wholesale Power Market Reform?” (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 197-207.

24. “Clear Skies” or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change” (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 823-848.

25. “Economic Displacement Opportunities in Southeastern Power Markets.” (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue*. 11: 20-24.

26. "What’s Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 635-652.

27. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.

28. “The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance.” (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.

29. “Standardizing Wholesale Markets For Energy.” (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 207-225.

30. “Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?” (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.

31. “Will Electric Restructuring Ever Get Back on Track? Texas is not California.” (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50: 943-960.

32. “An Assessment of the Role and Importance of Power Marketers.” (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

33. “The EPA v. The TVA, et. al. Over New Source Review.” (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly*. 50:531-543.

34. “Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry.” (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.

35. “A is for Access: A Definitional Tour Through Today’s Energy Vocabulary.” (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49:947-973.

36. “California Dreaming: Are Competitive Markets Achievable?” (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 743-759.

37. “Distributed Energy Must Be Watched As Opportunity for Gas Companies.” (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal*. January: 9-16.

38. “Clean Air, Kyoto, and the Boy Who Cried Wolf.” (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

39. “Energy Conservation Programs and Electric Restructuring: Is There a Conflict?” (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

40. “The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry.” (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.

41. “Issues and Opportunities for Small Scale Electricity Production in the Oil Patch.” (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.

42. “Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry.” (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.

43. “Coming to a neighborhood near you: the merchant electric power plant.” (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48:433-441.

44. “Slow as molasses: the political economy of electric restructuring in the south.” (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48: 163-183.

45. “Stranded investment and non-utility generation.” (1999). With Michael T. Maloney. *Electricity Journal*. 12: 50-61.

46. “Reliability or profit? Why Entergy quit the Southwest Power Pool.” (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.

47. “Electric utility mergers and acquisitions: a regulator’s guide.” (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly.* January 1.

PUBLICATIONS: OPINION AND EDITORIAL ARTICLES

1. “Disappointing offshore wind lease sale is first step, but development process will be long.” *Baton Rouge Advocate*. Friday, September 8, 2023.

2. “Irreparable changes are coming to American oil and gas industry”. (2020). *10/12 Industry Report. Baton Rouge Business Report, Q1.*

3. “An exceptionally uncertain time for energy markets.” (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q4.

4. “LNG’s changing fortunes.” (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q3.

5. “A tenuous recovery.” (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q2.

6. “The 2019 Gulf Coast Energy Outlook.” (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q1.

7. “Why an offshore recovery may never happen.” (2018). *10/12 Industry Report. Baton Rouge*

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Business Report, Q4.

8. "The dangers of trade protectionism for Louisiana energy development." (2018). *10/12 Industry Report. Baton Rouge Business Report*, Q3.
9. "The irrelevance of energy dominance." (2018). *10/12 Industry Report. Baton Rouge Business Report*, Q2.
10. "The whys and hows of maintaining the oil price rise." (2018). *10/12 Industry Report. Baton Rouge Business Report*, Q1.
11. "Taxing energy infrastructure." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:4.
12. "A summer of discontent." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:3.
13. "Low cost hydrocarbons continue to benefit the Gulf Coast." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:2.
14. "Reading the tea leaves for 2017's crude oil markets." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.
15. "The unappreciated role of energy infrastructure." (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:4.
16. "Other ways in which the energy world is changing." (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:3.
17. "Are oil prices bouncing back?" (2016). *Baton Rouge Business Report*, May 10 edition. (reprint of Industry Report article).
18. "Are we there yet? Have energy prices started to rebound?" (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:2.
19. "Challenging Times for the South Louisiana Energy Economy." (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.
20. "Reading the Signs for the Energy Complex" (2015). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.
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PUBLICATIONS: REPORTS AND OTHER MANUSCRIPTS

1. *The economic implications of carbon capture and sequestration for the Gulf Coast economy: a case study of Gulf Coast Sequestration*. (2022). With Gregory B. Upton and Ron Minsk.

Baton Rouge, LA: LSU Center for Energy Studies, July, 2022. Pp. 54. Report prepared on behalf of Gulf Coast Sequestration.

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24. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. (2015). Louisiana Public Service Commission, In re: Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana, Docket No. X-33192. Notice of Issuance of Final Report dated September 11, 2015,* 187 pp.

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47. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

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58. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

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GRANT RESEARCH

1. *Co-Principal Investigator* (2022). With Gregory B. Upton, Jr. Estimating the benefits of electricity restoration to critical energy infrastructure. Funded by Entergy Corporation. Total Funding: $56,088. Status: Completed.

2. *Co-Principal Investigator*. (2021). With Gregory B. Upton Jr. Estimating the benefits of underground carbon dioxide storage investments. Funded by Gulf Coast Sequestration. Total Funding: $124,835. Status: In Progress.

3. *Principal Investigator*. (2021). Louisiana Greenhouse Gas Inventory Update and Report. Governor's Office of Coastal Affairs. Total Funding $65,830. Status: Completed.

4. *Principal Investigator*. (2021). Estimating Louisiana's power generation greenhouse gas emissions. The Nature Conservancy. Total Funding: $9,994. Status: Completed.

5. *Co-Principal Investigator*. (2021). With Gregory B. Upton. Estimating the economic impacts of methanol investments in St. James Parish. Koch Industries. Total Funding: $37,457. Status: Completed.

6. *Co-Principal Investigator*. (2019). With Gregory B. Upton Estimating the economic impact of TransCanada pipeline investments. TransCanada Pipelines. Total Funding: $40,798. Status: Completed.

7. *Co-Principal Investigator*. (2018). With Gregory B. Upton. Estimating the economic impact of Enable Pipeline Investments. Total Funding: $49,798. Status: Completed.

8. *Co-investigator*. Estimating offshore Gulf of Mexico carbon capture, sequestration, and utilization opportunities. (2018). With Southern States Energy Board, Advanced Resources International, Argonne Laboratories, University of Alabama, University of South Carolina, and Oklahoma State University. U.S. Department of Energy, National Energy Technology Laboratory. Total funding: $731,031 (LSU share of $4.0 million project, three years, in progress).

9. *Co-Principal Investigator*. Planning Grant: Engineering Research Center for Resiliency Enhancement and Disaster-Impact Interception ("READII") in the Manufacturing Sector. (2018). With Mahmoud El-Halwagi, Mark Stadtherr, Heshmat Aglan, Efstratos Postikopoulus. National Science Foundation (#1840512). Total Funding: $100,000 (one year). Status: Completed.

10. *Principal Investigator*. Understanding MISO long term infrastructure needs and stakeholder positions. (2017). Midcontinent Independent System Operator. Total Project: $9,500, six months. Status: Completed.

11. *Principal Investigator*. Offshore oil and gas activity impacts on ecosystem services in the Gulf of Mexico. (2017). With Brian F, Snyder. U.S. Department of the Interior, Bureau of Ocean Energy Management. Total Project: $240,982, two years. Status: Completed.

12. *Principal Investigator*. Economic Impacts of the Bayou Bridge pipeline. (2017). With Gregory B, Upton, Jr., Energy Transfer Corporation. $9,900. Status: Completed.

13. *Principal Investigator*. Integrated carbon capture, storage and utilization in the Louisiana chemical corridor. (2017). U.S, Department of Energy/National Energy Technology Laboratory. Total funding: $1,300,000 (18 months). Status: Completed.

14. *Co-Principal Investigator*. Gulf coast energy outlook and analysis. (2016). With Gregory B. Upton and Mallory Vachon. Regions Bank. Total funding: $20,000, one year. Status: Completed.

15. *Principal Investigator*. GOM energy infrastructure trends and factbook update. (2016). With Gregory B. Upton and Mallory Vachon. U.S. Department of the Interior, Bureau of Ocean Energy Management ("BOEM"). Total funding: $224,995, two years. Status: In progress.

16. *Principal Investigator*. Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 2: Follow-up and estimation. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: $69,990, three months. Status: Completed.

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18. *Principal Investigator*. Energy efficiency building codes for Louisiana. (2016). With Brian F. Snyder. Louisiana Department of Natural Resources. Total Project: $50,000, one year. Status: Completed.

19. *Principal Investigator*. An update of Louisiana's combined heat and power potentials, current utilizations, and barriers to improved operating efficiencies. (2016). Louisiana Department of Natural Resources. Total Project: $90,000, one year. Status: Completed.

20. *Principal Investigator*. Combined Heat and Power Stakeholder Meeting. (2016). Southeastern Energy Efficiency Council. Total Project $9,160, two months. Status: Completed.

21. *Co-Investigator*. "Expanding Ecosystem Service Provisioning from Coastal Restoration to Minimize Environmental and Energy Constraints" (2015). With John Day and Chris D'Elia. Gulf Research Program. Total Project: $147,937. Status: Completed.

22. *Principal Investigator*. "Coastal Marine Institute Administrative Grant" (2104). U.S. Department of the Interior. Total Project $45,000. Status: Completed.

23. *Principal Investigator*. "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana." (2013). Louisiana Department of Natural Resources. Total Project: $90,000. Status: Completed.

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25. *Principal Investigator*. "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status:

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26. *Principal Investigator*. "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: $76,708. Status: Completed.

27. *Principal Investigator*. "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

28. *Principal Investigator*. "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: approximately $50,000. Status: Completed.

29. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

30. *Principal Investigator*. "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

31. *Principal Investigator*. "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

32. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

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34. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Completed.

35. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, Completed.

36. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

37. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, Completed.

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39. *Principal Investigator*. "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R.

Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

40. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

41. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

42. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

43. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

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45. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

46. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

47. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

48. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

49. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

50. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

51. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded

Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.
2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.
3. "Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach." (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.
4. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.
5. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks" (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.
6. "Modifying Renewables Policies to Sustain Positive Economic and Environmental Change" (2015). IEEE Annual Green Technologies ("Greentech") Conference. April 17.
7. "The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities." (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.
8. "Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion" (2014). With Siddhartha Narra. American's Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.
9. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.
10. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.
11. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.
12. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. “Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure.” (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. “An Examination of LNG Development on the Gulf of Mexico.” (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. “OCS-Related Infrastructure on the GOM: Update and Summary of Impacts.” (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. “The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure.” (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America’s Estuaries. New Orleans, Louisiana, December 11.

19. “The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey.” (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. “The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast.” (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. “Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned.” (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. “An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana.” (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. “Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases.” (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. “GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand.” (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. “Are There Any In-State Uses for Alaska Natural Gas?” (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: “Energy Markets in Turmoil: Making Sense of It All.” Vancouver, British Columbia, Canada. October 7.

26. “The Economic Impact of State Oil and Gas Leases on Louisiana.” (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

27. “Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana.” (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

28. “New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico.” (2002). With Vicki Zatarain. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

29. “Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring.” (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

30. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

32. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

33. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

34. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

35. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

36. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

37. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

38. “Benchmarking Electric Utility Distribution Performance.” (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

39. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry.” (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

40. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

41. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

48. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

49. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

50. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

51. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

52. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. "Fuel Security, Resource Adequacy & Value of Transmission." (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.
2. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.
3. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.
4. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.
5. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.
6. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
7. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.
8. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.
9. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
10. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.
11. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "The role and outlook for CCS in Louisiana energy manufacturing development." (2024). GINP-CCS International Network. February 20, 2024.
2. "Louisiana energy manufacturing development outlook and the energy transition." (2024). Greater Baton Rouge Industry Alliance. February 1, 2024.
3. "Gulf Coast Energy Outlook 2024." (2023). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2023.
4. "Louisiana clean, green industry: reconciling industrial decarbonization, capital formation, and growth." (2023). Louisiana State Bar Association, Public Utility Section. December 1, 2023.

5. “Expert witness training: considerations for preparation and effective execution during public utility regulatory hearings and proceedings.” (2023). On the Behalf of the National Association of State Utility Consumer Advocates, Accounting and Finance Subcommittee. September 21, 2023.

6. “Gulf cost energy outlook: traditional resources and the energy transition.” (2023). AAPL/Gulf Coast Land Institute Meetings. April 26, 2023.

7. “Ratepayer considerations in the promotion of clean energy.” (2023). Public Utility Law Section Roundtable Discussion. April 21, 2023.

8. “Gulf coast energy outlook: traditional resources and the energy transition.” (2023). Louisiana Engineering Society. April 19, 2023.

9. “Carbon capture & storage: three thoughts and considerations.” (2023). Gulf Coast Power Association. 9th Annual MISO/SPP Conference. March 9, 2023.

10. “Natural gas markets: prices; trends; and ratepayer impacts.” (2023). Maryland Energy Advocates Virtual Monthly Meeting. February 17, 2023.

11. “Hydrogen overview and its role in Louisiana decarbonization.” (2022). Louisiana Public Service Commission Monthly Business & Executive Meeting. November 17, 2022.

12. “High winter natural gas prices and ratepayer impacts.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Annual Conference. November 14, 2022.

13. “Facing the future together: the Louisiana energy transition, industrial decarbonization, and capital formation trends.” (2022). Louisiana Chemical Association: Annual Meeting 2022. October 27, 2022.

14. “Louisiana and the energy transition: reconciling industrial decarbonization, capital formation, and growth.” (2022). Louisiana Air and Waste Management 2022 Annual Meeting. October 26, 2022.

15. “The Louisiana energy transition, industrial decarbonization, and industrial capital formation trends.” (2022). Postlethwaite & Netterville: 2022 Governmental Update. August 4, 2022.

16. “Identifying and mapping regulatory requirements for CCUS projects.” (2022). SECARB Offshore GOM Gulf Regulator Workshop. New Orleans LA. May 16, 2022.

17. “Louisiana industrial decarbonization opportunities.” (2022). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Meeting. May 11, 2022. Baton Rouge, LA.

18. “Natural Gas outlook, 2022: supply, demand, and geopolitical considerations.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. March 30, 2022.

19. “Louisiana industrial decarbonization opportunities.” (2022). LSU Law School, Journal of Energy Law and Resources Symposium on Energy Transitions. February 4, 2022. Baton Rouge, LA.

20. Panelist. Grid Resiliency in the Era of Extreme Weather. Gulf Coast Power Association 8th Annual MISO/SPP Regional Meeting. February 9, 2022. New Orleans, LA.

21. Panelist. Natural Gas Industry Update. (2022). National Association of State Utility Consumer Advocates Annual Meeting. (virtual). November 8, 2021.

22. "Overview of Louisiana's greenhouse gas emissions and trends." (2021). Louisiana Energy Users Group ("LEUG") Meeting. November 11, 2021.

23. "State of energy in Louisiana: a preview of the 2021 Gulf Coast Energy Outlook." (2021). Financial Planning Association of Baton Rouge. November 10, 2021.

24. "Replacing natural gas and industrial decarbonization: utility and ratemaking issues." (2021). Virtual Joint Annual Meeting: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, and Virginia Industrial Gas Users Group Workshop. September 8, 2021.

25. "Louisiana 2021 GHG Inventory: Update and summary of preliminary findings." (2021). Presentation before the Climate Initiative Task Force. July 29, 2021.

26. "Opportunities for the development of a hydrogen economy in Louisiana." (2021). Louisiana Energy Climate Solutions Workshop. June 15, 2021.

27. "Natural gas: Building gas system resilience. Overview of the 2021 polar vortex and its implications for gas resiliency." (2021). National Association of State Utility Consumer Advocates ("NASUCA"). Virtual mid-year meeting. June 14, 2021.

28. "Status and briefing on the Louisiana greenhouse gas inventory and emissions analysis." (2021). Scientific Advisory Group ("SAG") Meeting, Governor's Climate Initiative Task Force. March 29, 2021.

29. "Louisiana carbon capture: sinks; sources; and the role of transportation in industrial applications." (2021). LSU Journal of Energy Law & Resources Symposium on Carbon Capture and Solutions. February 5, 2021.

30. "Natural gas outlook, 2021: production, demand, pandemic and policy." (2021). National Association of State Utility Consumer Advocates ("NASUCA") Monthly Natural Gas Committee Webinar. January 20, 2021.

31. "Consumer Perspectives on the Rate Design of the Future." (2020). National Association of State Utility Consumer Advocates ("NASUCA"). Annual Conference, November 10.

32. "Evaluation of Louisiana's Depleted Gas Reservoirs for Geological Carbon Sequestration." (2020). Louisiana Mid-Continent Oil and Gas Association ("LMOGA") Carbon Capture and Underground Storage ("CCUS") Committee Meeting. August 25.

33. "The 2020 Gulf Coast Energy Outlook: COVID-19 update." (2020). Baton Rouge Area Chamber of Commerce Business Webinar. COVID-19 and Global Supply Impacts on the Capital Region and Louisiana Economies. Baton Rouge, LA. June 3.

34. "Ratepayer benefits of reforming PURPA". (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.

35. "Pipeline industry: economic trends and outlook". (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association ("LMOGA") and the Louisiana Oil and Gas Association ("LOGA"). Lake Charles, LA March 5.

36. "The outlook for natural gas: storm clouds ahead?" (2020). National Association of State Utility Consumer Advocates ("NASUCA"). Natural Gas Committee Webinar, February 26.

37. "The 2020 Gulf Coast Energy Outlook". (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.

38. “Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor”. (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.

39. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.

40. “2020 Louisiana business climate outlook: the view from the energy sector.” (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA

41. “The urgency of PURPA reform in protecting ratepayers.” (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.

42. “Louisiana’s coast and the energy industry.” (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

43. “Reforming PURPA: implications for ratepayers.” (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.

44. “Natural gas outlook: supply, demand and prices.” (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.

45. “The economic impacts and outlook for LNG development on the Gulf Coast.” (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)

46. “Natural gas outlook: supply, demand, and prices.” (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.

47. “Overview of Louisiana LNG issues and trends.” (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.

48. “Overview of Louisiana energy issues and outlook.” (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.

49. “Gulf Coast Energy Outlook 2019: Regional trends and outlook.” (2019). Women’s Energy Network. Baton Rouge, LA, April 23.

50. “MISO Grid Vision 2033.” (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.

51. “Ratepayer benefits of reforming PURPA.” (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.

52. “Incentives, risk, and the changing nature of regulation.” (2019). NASUCA Water Committee monthly meeting/webinar. March 13.

53. “Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends.” (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.

54. “A golden age: energy outlook 2019.” (2019). Engineering News Record Webinar. February 13.

55. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.

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56. "MISO Grid Vision 2033." (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.

57. "Gulf Coast Energy Outlook 2019." (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.

58. "How LNG is transforming Louisiana's energy economy." (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.

59. "Overview of Louisiana LNG issues and trends." (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.

60. "Infrastructure and capacity: challenges for development." (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.

61. "Louisiana industrial cogeneration trends." (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.

62. "Gulf Coast industrial development: overview of trends and issues." (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.

63. "Energy outlook – reflection on market trends and Louisiana implications." (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.

64. "Integrated carbon capture and storage in the Louisiana chemical corridor." (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.

65. "The outlook for natural gas and energy development on the Gulf Coast." (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.

66. "Critical energy infrastructure: the big picture on resiliency research." (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.

67. "The changing nature of Gulf of Mexico energy infrastructure." (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.

68. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.

69. "Crude oil and natural gas outlook: Where are we and where are we going?" (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.

70. "Navigating through the energy landscape." (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.

71. "The 2017-2018 Louisiana energy outlook." (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.

72. "The Gulf Coast energy economy: trends and outlook." (2017). Society for Municipal Analysts. New Orleans, LA, April 21.

73. "Gulf coast energy outlook." (2017). E.J. Ourso College of Business, Dean's Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.

74. "Recent trends in energy: overview and impact for the banking community." (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

75. "How supply, demand and prices have influenced unconventional development." (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

76. "The Basics of Natural Gas Production, Transportation, and Markets." (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

77. "Gulf Coast industrial development: trends and outlook." (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

78. "The future of policy and regulation: Unlocking the Treasures of Utility Regulation." (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

79. "Utility mergers: where's the beef?". (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.

80. "Overview of the Clean Power Plan and its application to Louisiana." (2016). Shell Oil Company Internal Meeting. April 12.

81. "Energy and economic development on the Gulf Coast: trends and emerging challenges." (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.

82. "Unconventional Oil and Gas Drilling Trends and Issues." (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.

83. "Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?" (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.

84. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.

85. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.

86. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.

87. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural Electric Cooperative Meeting. November 5.

88. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.

89. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets." (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.

90. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

91. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.

92. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

93. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.

94. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

95. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

96. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

97. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

98. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

99. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

100. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

101. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

102. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.

103. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

104. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

105. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

106. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

107. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

108. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.

109. "Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues." (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

110. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.

111. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

112. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

113. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

114. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

115. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

116. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

117. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

118. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

119. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

120. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

121. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

122. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.

123. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

124. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

125. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

126. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

127. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

128. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

129. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

130. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

131. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

132. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

133. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

134. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

135. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

136. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

137. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

138. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

139. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

140. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

141. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

142. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

143. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

144. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

145. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

146. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27,

2012.

147. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges." Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

148. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

149. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

150. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

151. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

152. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

153. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

154. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

155. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

156. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

157. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

158. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

159. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

160. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

161. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

162. "Energy Outlook and Trends: Implications for Louisiana." (2011). Executive Briefing,

Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

163. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

164. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

165. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

166. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

167. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

168. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

169. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

170. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

171. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

172. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

173. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

174. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

175. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

176. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

177. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting.

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November 10, 2009.

178. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

179. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

180. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

181. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

182. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

183. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

184. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

185. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

186. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

187. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

188. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

189. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

190. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

191. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

192. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

193. “Regulatory Issues in Rate Design, Incentives, and Energy Efficiency.” (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

194. “Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency.” (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

195. “Regulatory and Policy Issues in Nuclear Power Plant Development.” (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

196. “Oil and Gas in the Gulf of Mexico: A North American Perspective.” (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

197. “Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency.” (2007). National Association of State Utility Consumer Advocates (“NASUCA”) Gas Committee Monthly Meeting. February 13, 2006.

198. “Recent Trends in Natural Gas Markets.” (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

199. “Energy Markets: Recent Trends, Issues & Outlook.” (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

200. “Energy Outlook” (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

201. “Global and U.S. Energy Outlook.” (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

202. “Interdependence of Critical Energy Infrastructure Systems.” (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

203. “Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure.” (2006) The Economic and Market Impacts of Coastal Restoration: America’s Wetland Economic Forum II. Washington, DC September 28, 2006.

204. “Relationships between Power and Other Critical Energy Infrastructure.” (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

205. “Outlook, Issues, and Trends in Energy Supplies and Prices.” (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

206. “Energy Sector Outlook.” (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

207. “Oil and Gas Industry Post 2005 Storm Events.” (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

208. “Concentration of Energy Infrastructure in Hurricane Regions.” (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

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209. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

210. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

211. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

212. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

213. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

214. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

215. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

216. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

217. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

218. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

219. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

220. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

221. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

222. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

223. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

224. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's

Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

225. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

226. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

227. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

228. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

229. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

230. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

231. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

232. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

233. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

234. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

235. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

236. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

237. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

238. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

239. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

240. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

241. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

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242. “Natural Gas and LNG Issues for Louisiana.” Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

243. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

244. The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

245. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

246. “Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy.” Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

247. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

248. “Natural Gas Outlook: Trends and Issues for Louisiana.” Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

249. “Natural Gas Outlook” Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

250. “Competitive Bidding in the Electric Power Industry.” Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

251. “Regional Transmission Organization in the South: The Demise of SeTrans” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

252. “Affordable Energy: The Key Component to a Strong Economy.” Presentation before the National Association of Regulatory Utility Commissioners (“NARUC”), November 18, 2003, Atlanta, Georgia.

253. “Natural Gas Outlook.” Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

254. “Issues and Opportunities with Distributed Energy Resources.” Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

255. “What’s Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

256. “An Introduction to Distributed Energy Resources.” Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

257. “Merchant Energy Development Issues in Louisiana.” Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

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258. "Merchant Power Plants and Deregulation: Issues and Impacts." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

259. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

260. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

261. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

262. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

263. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

264. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

265. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

266. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

267. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

268. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

269. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

270. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

271. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

272. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

273. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

274. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

275. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

276. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

277. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

278. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

279. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

280. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

281. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

282. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

283. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

284. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

285. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

286. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

287. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

288. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

289. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

290. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

291. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

292. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

293. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

294. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

295. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

296. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

297. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

298. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

299. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Cause No. 46011. (2024). Before the State of Indiana, Indiana Utility Regulatory Commission. *Petition of Ohio Valley Gas, Inc. for (1) authority to increase its rates and charges for gas utility service, (2) approval of new schedules of rates and charges, (3) approval of decoupling through a new sales reconciliation component rider, and (4) approval of necessary and appropriate accounting relief and other requests.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: decoupling, sales reconciliation component rider.

2. Expert Testimony. Docket No. 2024-UA-42. (2024). Before the Mississippi Public Service Commission. *Joint Application of Centerpoint Energy Resources Corp. and Delta Utilities MS, LLC for all necessary authorizations and approvals for Delta Utilities MS, LLC to acquire the assets of Centerpoint Energy Resources Corp. and for approval of a certificate of public convenience and necessity for Delta Utilities MS, LLC, and for related relief.* On Behalf of Delta Utilities MS, LLC. Issues: economic benefits, ratemaking, other benefits.

3. Expert Testimony. Docket No. S-37187. (2024). Before the Louisiana Public Service Commission. *Delta Utilities No. LA, LLC, Delta Utilities S. LA., and Centerpoint Energy Resources Corp. Ex. Parte. In RE : Application for authority to operate as a local distribution company and incur indebtedness and joint application for approval for transfer and acquisition of local distribution company assets and related relief.* On Behalf of Delta Utilities No. LA, LLC. Issues: economic benefits, ratemaking, other benefits.

4. Expert Testimony. D.P.U. 23-150. (2024). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid Pursuant to G.L. c. 164 § 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Ratesand Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Issues: capital tracker, Y-factor, IDRF, PBR, alternative regulation, benchmarking analysis.

5. Expert Testimony. Cause No. 45990. (2024). Before the Indiana Utility Regulatory Commission. *Verified Petition of Southern Indiana Gas and Electric Company D/B/A Centerpoint Energy Indiana South ("CEI South) for (1) Authority to modify its rates and charges for electric utility service through a phase in of rates (2) approval of new schedules of rates and charges and new and revised riders, including but not limited to a new tax adjustment rider and a new green power rider (3) approval of a critical peak pricing ("CPP") pilot program, (4) approval of revised depreciation rates applicable to electric and common plant in service, (5) approval of necessary and appropriate accounting relief, including authority to capitalize as rate base all cloud computing costs and defer to a regulatory asset amounts not already included in base rates that are incurred for third-party cloud computing arrangements, and (6) approval of an alternative regulatory plant granting CEI South a waiver from 170 IAC 4-1-16(f) to allow for remote disconnection for non-payment.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: proposed rate increases, cost of service study, minimum system study, revenue distribution, rate design, TOU-CPP pilot.

6. Expert Testimony. Cause No. 45967. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42, 8-1-2-42.7 and 8-1-2-61 for (1) authority to modify its retail rates and charges for gas utility service through a phase in of rates; (2) approval of new schedules of rates and charges, general rule sand regulations, and riders (both existing and new): (3) approval of a new sales reconciliation adjustment mechanism; (4) approval of revised gas deprecation rates applicable to its gas plant in service; (5) approval of necessary and appropriate accounting relief, including but not limited to approval of certain deferral mechanisms for pensions, other post-retirement benefits and line locate expenses; and (6) to the extent necessary, approval of any of the relief requested herein pursuant to Ind. Code Ch. 8-1-2-5.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: sales reconciliation adjustment.

7. Expert Testimony. F.C. No. 1176. (2024). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia.* On Behalf of the Office of the People's Counsel for the District of Columbia. Issues: affordability, revenue distribution, rate design, multi-year rate planning, bill stabilization adjustment.

8. Expert Testimony. Case No. 23-0460-E-42T (2023). Before the Public Service Commission of West Virginia Charleston. *In the Matter of Monongahela Power Company and the Potomac Edison Company rule 42T tariff filing to increase rates and charges.* On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: cost of service, zero intercept study, revenue allocation, rate design, net energy metering rider.

9. Expert Testimony. Docket No. DPU 23-81. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for*

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Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan. On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

10. Expert Testimony. Docket No. DPU 23-80. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

11. Expert Testimony. Case No. 23-03803-W-42T and 23-0384-S-42T (2023). Before the Public Service Commission of West Virginia Charleston. In the Matter of West Virginia-America Water Company rule 42T application to increase rates and charges. On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: revenue distribution, rate design, affordability, service quality.

12. Expert Testimony. Cause No. 45933 (2023). Before the Indiana Utility Regulatory Commission. *Petition of Indiana Michigan Power Company an Indiana Corporation, for authority to increase rates and charges for electric utility service through a phase in rate adjustment; and for approval of related relief including: (1) revised depreciation rates, including cost of removal less salvage, and updated depreciation expense; (2) accounting relief, including deferrals and amortization; (3) inclusion of capital investment; (4) rate adjustment mechanism proposals, including new grant projects rider and modified tax rider; (5) a voluntary residential customer powerpay program; (6) waiver or declination of jurisdiction with respect to certain rules to facilitate implementation of the powerpay program; (7) cost recovery for cook plant subsequent license renewal evaluation project; and (8) new schedules of rates, rules and regulations.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: cost of service, rate design, revenue distribution, service fees.

13. Expert Report. (2023). *Alternative regulation deficiencies and potential ratepayer harms*. On Behalf of the Office of the Consumer Advocate of Iowa. October 3, 2023.

14. Expert Testimony. Docket No. 2023.06.057. (2023). Before the Public Service Commission of the State of Montana. *In the Matter of Energy West Montana's Application for Approval of Gas Cost Hedging Plan for West Yellowstone.* On Behalf of the Montana Consumer Counsel. Issues: gas hedging program.

15. Legislative Testimony. (2023). Ratepayer harms from alternative regulation in Oklahoma. Appearing on the Behalf of the Petroleum Alliance of Oklahoma. October 23, 2023.

16. Expert Testimony. Cause No. 45911. (2023). Before the State of Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for authority to increase rates and charges for electric utility service, and for approval of related relief, including (1) revised depreciation rates, (2) accounting relief, including deferrals and amortizations, (3) inclusion of capital investments, (4) rate adjustment mechanism proposals, including new economic development rider, (5) remote disconnect/reconnect process and (6) new schedules of rates, rules and regulations for service.* On Behalf of Indiana Office of Utility Consumer Counselor. Direct and Cross-Answering. Issues: allocated cost of service, revenue distribution, rate design, trackers.

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17. Expert Testimony. Docket No. 23-06007. (2023). Before the Public Utilities Commission of Nevada. *In the Matter of the Application by Nevada Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.* On Behalf of the Nevada Bureau of Consumer Protection. Issues: marginal cost of service study, embedded cost of service study, revenue distribution, rate design.

18. Expert Testimony. Docket No. UE-230172. (2023). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission, Complainant v. Pacificorp dba Pacific Power & Light Company, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: rate design, revenue distribution, cost of service.

19. Expert Testimony. Case No. U-21389. (2023). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for other Relief*. On Behalf of the Michigan Department of the Attorney General. Issues: capital expenditure adjustments, overview of proposal.

20. Expert Report. Case No. 22-1094-WW-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

21. Expert Report. Case No. 22-1096-ST-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc*. *For the period July 1, 2022 through June 30, 2023*. Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

22. Expert Report. *Analysis of the effectiveness and ratepayer impacts regarding the Natural Gas Rate Stabilization Act of 2005. (S.C. Code Ann. Section 58-5-410).* On Behalf of the South Carolina Department of Consumer Affairs. July 27, 2023.

23. Expert Testimony. Docket No. 2023-70-G. (2023). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc's application for adjustments in its natural gas rate schedules and tariffs.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: revenue credit, revenue distribution, rate design. Direct and Surrebuttal.

24. Expert Testimony. Docket No. E-01345A-22-0144. (2023). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of the Utilities Division Arizona Corporation Commission.* Issues: cost of service, revenue distribution, rate design. Direct and Surrebuttal.

25. Expert Testimony. Docket No. 23-0068 (consol.) 23-0069. (2023). Before the Illinois Commerce Commission. *North Shore Gas Company, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

26. Expert Testimony. Docket No. 23-067. (2023). Before the Illinois Commerce Commission.

Ameren Illinois Company Proposed general increase in gas delivery service rates. On Behalf of the Illinois Attorney General. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

27. Expert Testimony. Docket No. 23-066. (2023). Before the Illinois Commerce Commission. *Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed general increase in gas rates.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

28. Expert Testimony. Docket No. U-22-081. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study Designated as TA334-4 Filed by Enstar Natural Gas Company, A Division of SEMCO Energy, Inc.* On Behalf of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, revenue distribution.

29. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, seasonal rates, revenue allocation, customer charge.

30. Expert Testimony. Docket No. 2022.11.099. (2023). Before the Department of Public Service Regulation. *In the Matter of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Answering. Issues: rate increase, cost of service study, marginal cost of service, revenue allocation, rate design.

31. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: rate design, cost of service, revenue allocation, seasonal rates.

32. Expert Testimony. Docket No. U-21193. (2023). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: Resource planning, coal retirements, asset amortization, financial compensation mechanism.

33. Expert Testimony. Docket No. RP22-1033. (2023). Before the Federal Energy Regulatory Commission. *Northern Natural Gas Company.* On Behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. Issues: tariff provisions, rate analysis, discount adjustment.

34. Expert Testimony. Docket No. 22-061-U. (2023). Before the Arkansas Public Service Commission. *In the Matter of an Investigation into Potential Cost Shifting Associated with Net Metering.* On Behalf of the Office of Tim Griffin, Attorney General of Arkansas. Issues: policy, net metering background.

35. Expert Testimony. Docket No. 22F-0263EG. (2023). Before the Public Utility Commission of the State of Colorado. *Olson's Greenhouses of Colorado, LLC. Complainant, v. Public Service Company of Colorado Respondent.* On Behalf of Olson's Greenhouses of Colorado, LLC. Issues: reliability, system upgrades, weather normalization.

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36. Expert Testimony. Docket No. 2022.07.078. (2022). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Intervenor. Issues: riders, fixed cost recovery mechanism, power cost adjustment, cost of service, revenue distribution.

37. Expert Testimony. Docket No 2022-254-E. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of South Carolina Department of Consumer Affairs. Direct and Surrebuttal. Issues: Cost of service, revenue allocation, rate design.

38. Expert Testimony Docket No. 22-06014. (2022). *Before the Public Utilities Commission of Nevada. In the Matter of the Application by Sierra Pacific Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers*. On Behalf of the Nevada Bureau of Consumer Protection. Issues: rate design, cost of services, marginal cost of service, revenue distribution.

39. Expert Testimony Docket No. 2022.06.067. (2022). *Before the Public Service Commission of the State of Montana. In RE NorthWestern Energy's Application for an Advanced Metering Opt-Out Tariff.* On Behalf of the Montana Consumer Counsel. Direct and Rebuttal. Issues: meter issues, opt-out fees, tariffs options.

40. Expert Testimony Docket No. 16-036-FR. (2022). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, INC., Pursuant to APSC Docket NO. 15-015-U. On Behalf of the Arkansas Attorney General Leslie Rutledge.* Issues: Rate design, netting adjustment, performance standards, projected year adjustments.

41. Expert Testimony Formal Case No. 1169. (2022). *Before the Public Service Commission of the District of Columbia. In the Matter of the application of Washington Gas Light Company for authority to increase existing rates and charges for gas service.* On Behalf of the People's Counsel for the District of Columbia. Direct and Rebuttal. Issues: Revenue allocation, weather normalization, rate design.

42. Expert Testimony Case No. U-21224. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, policy overview.

43. Expert Report. Case No. 695287. (2022). Before the Nineteenth Judicial District Court, The Parish of East Baton Rouge, State of Louisiana. *Washington-St. Tammany Electric Cooperative, Inc. and Claiborne Electric Cooperative, Inc., Plaintiff v. Louisiana Generating, L.L.C., Defendant.* On Behalf of Louisiana Generating, L.L.C. Issues: environmental regulations, re-fueling, regulatory rules, collateral benefits.

44. Expert Report. Case No. 0:20-cv-60981-AMC. (2022). *Café, Gelato & Panini LLC, d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, Plaintiff v. Simon Property Group, Inc., Simon Property Group, L.P., M. S. Management Associates, Inc. And The Town Center at Boca Raton Trust, Defendant.* On Behalf of Simon Property Group, Inc.

45. Expert Testimony Case No. U-20836. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, peer comparison.

46. Expert Testimony. D.P.U. 22-22. (2022*). Before the Department of Public Utilities of the Commonwealth of Massachusetts. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, §94 and 220 C.M.R. §5.00.* On Behalf of Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate design, TFP analysis, rate increases, benchmark analysis, revenue distribution. Direct and Surrebuttal.

47. Expert Testimony. Docket No. 21-097-U. (2022). In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs. On Behalf of the Office of Arkansas Attorney General. Issues: cost of service, rate design, reliability, billing determinant adjustment.

48. Expert Testimony. Docket No. 2021-361-G. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc.'s Request for Approval of New Natural Gas Energy Efficiency Programs*. On Behalf of South Carolina Department of Consumer Affairs. Issues: DSM Rider, energy efficiency, shared savings. Direct and Surrebuttal.

49. Expert Report. Case No. 21-596-ST-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the Period January 1, 2021 through December 31, 2021*. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

50. Expert Report. Case No. 21-595-WW-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period January 1, 2021 through December 31, 2021.* Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

51. Expert Testimony. Docket No. 2021.09.112. (2022). *Before the Public Service Commission of the State of Montana. In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes.* On Behalf of the Montana Consumer Counsel. Issues: wholesale energy hedging, market exposure, overview of PCCAM filing, demand side management costs.

52. Expert Affidavit. Docket No. 2:21-cv-1074. (2021). In the United States District Court for the Western District of Louisiana. *The State of Louisiana by and through its Attorney General, Jeff Landry et al. Plantiffs, v. Joseph R. Biden, Jr., in his official capacity as President of the United States; et al., Defendants.* On Behalf of the Attorney General of Louisiana. Issues: social cost of carbon, carbon tax, environmental policy.

53. Expert Testimony. Case No. U21090. (2021). *Before the Michigan Public Service Commission. In the matter of the application of Consumers Energy Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, certain accounting approvals, and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: IRP, coal plant retirements, acquisition premiums, financial compensation mechanism.

54. Expert Testimony. Docket No 16-036-FR. (2021). Before the Arkansas Public Service

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Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: netting adjustments, rate increases, projected year adjustments, reliability.

55. Expert Report. Docket JCCP No. 4861. (2021). Before the Superior Court of the State of California County of Los Angeles, Central Civil West. *Coordination Proceeding Special Title [Rule 3.550] Southern California Gas Leak Cases.* On Behalf of Toll Brothers. Issues: gas leak, public service obligation, integrity management.

56. Expert Testimony. Docket No. U-35927. (2021). Before the Louisiana Public Service Commission. *In Re: Application of 1803 Electric Cooperative, Inc. for Approval of Power Purchase Agreements and for Cost Recovery.* Direct and Cross-Answering. On Behalf of Cleco Cajun LLC. Issues: tolling agreements, generation acquisition, risk factors.

57. Expert Testimony. Docket No. 21-060-U. (2021). Before the Arkansas Public Service Commission. *In the Matter of Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. For all Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. To Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and necessity for Summit Utilities Arkansas, Inc.* Direct and Surrebuttal. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: asset acquisition, ratepayer benefits, acquisition synergies, Rider FRP.

58. Expert Affidavit. Civil Action No. 2:21-cv-00778 (2021). Before the United States District Court for the Western District of Louisiana. *The State of Louisiana v. Joseph R. Biden, Jr.* Issues: leasing and drilling moratorium, state revenue, coastal restoration, economic activity.

59. Expert Testimony. Docket No. 21-044-U (2021). Before the Arkansas Public Service Commission. *In the Matter of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas' Request to Extend Rider FRP.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: ratepayer benefits, service quality, cost of service, FRP extension.

60. Expert Testimony. Docket No. 17-010-FR (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: rate increase, investment and expense trends, revenue deficiency, leak performance.

61. Expert Testimony. Case No. U-20963 (2021). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, peak allocation, revenue distribution.

62. Expert Testimony. U-20-072, U-20-073, U-20-074. (2021). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement study and Tariff Filing designated as TA886-2 filed by Alaska Power Company, In the Matter of the Revenue Requirement study and Tariff filing designated as TA6-521 filed by Goat Lake Hydro, Inc., In the Matter of the Revenue Requirement study and Tariff filing designated as TA4-573 filed by BBL Hydro, Inc.* On Behalf of the Alaska Office of Attorney General. Issues: rate groups, cost of service.

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63. Expert Testimony. Docket No. P20-001. (2021). Before the Louisiana Pilotage Fee Commission. *In Re: Request for Increase in Approved Pilot Complement; Increased Funding for necessary Additional Manpower; Upward Adjustment of Estimated Average Annual Pilot Compensation; and Related Relief Pursuant to LA R.S. 34:112.* On Behalf of the Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA). Issues: unreasonable requests, fee structure, economic impact, over earnings.

64. Expert Testimony. D.P.U. 20-120. (2021). Before the Commonwealth of Massachusetts Before the Department of Public Utilities. *Petition of Boston Gas Company d/b/a National Grid Pursuant to G.L. c. 164, 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate increase, accelerated depreciation, benchmarking analysis, performance incentive mechanism.

65. Expert Testimony. RPU-2020-0001. (2020). Before the Iowa Utilities Board. *In Re: Iowa-American Water Company.* On Behalf of the Office of Consumer Advocate. Issues: rate increase, test trackers, RSM accounting ratemaking construct.

66. Expert Testimony. BPU Docket Nos. QO19010040 and GO20090622. (2020). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanisms Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 et seq. and 48:3-98.1 et seq.* On behalf of the Division of Rate Counsel. Issues: CBA requirements, capacity benefits, volatility benefits.

67. Expert Testimony. Docket No. 2020-125-E. (2020). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313).* On Behalf of the South Carolina department of Consumer Affairs. Issues: cost of service, revenue allocation, rate design.

68. Answering Testimony. Before the United States of America Federal Energy Regulatory Commission. Docket No. RP20-614-000 and RP20-618-000. (2020). *Transcontinental Gas Pile Line Company, LLC.* On Behalf of the North Carolina Utilities Commission. Issues: Tariff revisions, assessment of Transco claims.

69. Expert Testimony. Docket No. 16-036-FR. (2020). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U. Direct and Surrebuttal*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increases, investment and expenses trends, load forecast, historic year netting adjustment, reliability issues.

70. Expert Testimony. Docket No. 2019.12.101. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Approval of Capacity Resource Acquisition.* On the Behalf of the Montana Consumer Counsel. Issues: sale of capital asset, evaluation benefits, ratepayer cost exposure, reserve fund.

71. Expert Testimony. Formal Case No. 1162. (2020). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*. On Behalf of the Office of the People's Counsel. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.

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72. Expert Testimony. Docket No. E-01345A-19-0236. (2020). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for Ratemaking Purposes to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return*. Direct and Surrebuttal. On Behalf of the Utilities Division of the Arizona Corporation Commission. Issues: Cost of Service, Revenue Distribution, Rate Design.

73. Expert Testimony. Docket No. 17-010-FR. (2020). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.

74. Expert Testimony. Case No. U-20697. (2020). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. On Behalf of the Michigan Department of Attorney General. Issues: cost of service, revenue distribution, rate design.

75. Expert Testimony. Docket No. 2019.09.058. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. On the Behalf of the Montana Consumer Counsel. Issues: purchase power expenses, cost sharing, PCAAM power cost.

76. Expert Testimony. Formal Case No. 1156. (2020). Before the Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Direct, Rebuttal, Surrebuttal, Supplemental, and Second Supplemental. On Behalf of the Office of the People's Counsel. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

77. Expert Testimony. Case No. U-20561. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. On Behalf of the Michigan Department of Attorney General. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.

78. Expert Testimony. Cause No. 45253. (2019). Before the Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. On Behalf of the Indiana Office of Utility Consumer Counsel. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

79. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer*

Arrangement for a Renewable Resource and for all other Related Approvals. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues*:* Solar investment, risk assessment, proposed rider.

80. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

81. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar project approval, ratepayer risk, cost allocation.

82. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: retail rates, leak analysis, revenue deficiency, investments.

83. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of Attorney General. Issues: load forecasting, least-cost system planning.

84. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* On Behalf of the City of Leesburg. Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

85. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, decoupling mechanisms.

86. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

87. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* On Behalf of the Mississippi Public Utilities Staff. Issues: Net-metering, distributed generation.

88. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer

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Counsel. Issues: Net-metering, cost of service, revenue distribution, rate design.

89. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger impacts, rates, tariffs.

90. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

91. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

92. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues: cost of service and rate design.

93. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or Less, Located in St. Martin Parish; Barry Scott Carline, et al.* Issues: economic impacts.

94. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* On behalf of the Division of Rate Counsel. Issues: regulatory policy and cost-benefit analyses.

95. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief.* On behalf of the Division of Rate Counsel. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

96. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2.* On Behalf of Energy XXI GOM, LLC. Issues: cost of service, rate design, and alternative regulation.

97. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, billing determinates.

98. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources*

Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

99. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. On Behalf of the North Dakota Service Commission Advocacy Staff. Issues: cost of service, marginal cost of service, and rate design.

100. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

101. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

102. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

103. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

104. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

105. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

106. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* On Behalf of the Office of the Kentucky Attorney General. Issues: rate design, revenue allocation, economic development.

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107. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

108. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

109. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.

110. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

111. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

112. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

113. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

114. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC.* Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.

115. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Office of Consumer Advocate. Issue: revenue stabilization mechanism, revenue decoupling.

116. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

117. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

118. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

119. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

120. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

121. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc*. On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

122. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

123. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

124. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

125. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of*

approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont. On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

126. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

127. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

128. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

129. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

130. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

131. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

132. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

133. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities*

of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

134. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

135. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

136. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

137. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

138. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

139. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan.* On the behalf of AARP-Vermont. Issues: Alternative Regulation.

140. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

141. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

142. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

143. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

144. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

145. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

146. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

147. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

148. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

149. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

150. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

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151. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

152. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

153. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

154. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

155. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

156. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

157. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

158. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

159. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012.

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Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

160. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

161. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

162. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

163. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

164. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

165. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

166. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

167. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce

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Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

168. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

169. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

170. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

171. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

172. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

173. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

174. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

175. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

176. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

177. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

178. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

179. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

180. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

181. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

182. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

183. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380-A, ex parte, (2009). Before the Louisiana Public Service Commission. In re: Environmental Adjustment Clause and Environmental Certification for Electric Power Generation Resources. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets cost recovery treatment; other generation planning issues.

184. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues:

revenue decoupling, energy efficiency program review, weather normalization.

185. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

186. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

187. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

188. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

189. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

190. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

191. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

192. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

193. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public

C20-1964

Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

194. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

195. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

196. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

197. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

198. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

199. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

200. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

201. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

202. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

203. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

204. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service

C20-1965

Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

205. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

206. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

207. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

208. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

209. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

210. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

211. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

212. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff

C20-1966

Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

213. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

214. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

215. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

216. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

217. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

218. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

219. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

220. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

221. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

222. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

223. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745;

491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

224. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

225. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

226. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

227. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

228. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

229. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

230. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

231. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

232. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

233. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

234. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central

Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

235. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

236. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

237. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

238. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

239. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

240. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

241. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

242. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

243. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

244. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

245. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service

C20-1969

Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

246. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current, *Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

Baton Rouge Business Report, Selected as one of the "Capital Region 500" (2023).

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current).

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Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)
Completed:
8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. "Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners. Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

C20-1973

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

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BY MS. WESSLING:

Q And did you also prefile -- or did your prefiled testimony have seven exhibits labeled DED-1 through DED-7?

A Yes, they did.

Q Do you have any corrections to make to your exhibits?

A No, ma'am. I do not.

Q Would you please summarize your testimony?

A Yes, I would.

Good morning, Commissioners. Thank you for the opportunity to present a summary this morning.

The purpose of my testimony is to address two primary areas. The first is the company's proposed load forecast, and the second has to do with energy affordability issues.

Relative to the load forecasting issues, I am recommending that the Commission utilize a forecast that excludes many of the company's proposed out-of-model adjustments. Many of those will result a negative decrease in sales for the test year. I raise a number of issues in my direct testimony about those out-of-model adjustments. From a statistical and econometrics perspective, those are usually not commonly done. And usually, when you make an out-of-model adjustment, you are trying to correct for essentially what we would refer to as an out-of-sample inference, or an out-of-sample event.

So if you -- you know, quick kind of statistics 101, if you are building a forecast, you usually build that off of historic information. That gives you a wide range of observations on low prices, high prices, a good economy, bad economy, et cetera.

And that variation is good in developing that forecast, but every now and again, a forecaster is faced with a situation where there is an event that it hasn't seen in the past, and it has to deal with that in doing the forecast. So you can think of events like COVID as being something like, that or 9/11, which this Commission has had to deal with in the past before, on how to adjust sales forecasts as a consequence of those.

Those can often be legitimate reasons for doing that, but we don't see that right now in the company's out-of-model forecast. That's -- out-of-model adjustments for this particular forecast. These are, you know, common events that have been in the history for Florida for some time. Energy efficiency goals have been around for as long as I can remember, as long as I have worked here, which is well over 30 years. So these are adjustments that I don't think are very appropriate here.

The other problem, I think, from a general perspective, as I noted in my testimony, is that most of your out-of-model adjustments can often be subjective. Many times they suffer from challenges with transparency and replicatability. So they are usually not advised on, on a broad-scale perspective.

The last two issues that I raise in my testimony with regards to that load forecast has to do with the fact that, you know, they don't sync up with what we have seen in the historic sales for the company over the last couple of years. And so you kind of look at the proof of the pudding and the eating, it certainly is a substantial decrease, and one that is inconsistent with what we have seen over the last decade, where we have seen increases nine out of last 10 years.

And lastly, you are looking at decreases for most of these forecasts that are inconsistent with what we see with utilities overall. You -- really large proposed significant decreases in use per customer over the test year period.

So if you kind of look at those various factors, the fact that you have this out-of-model adjustment, you have a deviation from trend, you are seeing deviations relative to what we see from other utilities, that is essentially the basis for my recommendation on the load forecasting issue.

On the other issue with regards to energy affordability, I am sure, you know, this is a topic of national debate right now. There was actually an article this morning on Fox News about energy affordability and electric utility business. It's a problem throughout the United States. I think as we spend more and more money on capital investments throughout the industry, it challenges the affordability for many, particularly lower income households.

We -- I provided some numbers in my testimony that shows that for the 15th lowest percentile for this company's service territory, there are some challenges right now in affordability, close challenges for the lower 20 percent as well.

These are things that other regulators are starting to take into account when they are assessing rate impacts and rate proposals throughout the country. Some examples would include California, Indiana, Pennsylvania, District of Columbia, other places that are looking at these kinds of issues. So I would advise you to think about that and consider that as you are evaluating the company's proposed increase in this proceeding.

Again, thank you for having me this morning and letting me give this survey -- this summary.

Q Thank you.

MS. WESSLING: And at this time, I will tender the witness for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

Florida Rising.

MR. LUEBKEMANN: No questions from Florida Rising.

CHAIRMAN LA ROSA: Thank you.

FIPUG.

MR. MOYLE: No questions from FIPUG.

CHAIRMAN LA ROSA: FEA.

CAPTAIN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: FRF.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MS. PONDER: No questions.

CHAIRMAN LA ROSA: Great. Staff.

MR. SPARKS: Staff has no questions. Thank you.

CHAIRMAN LA ROSA: Commissioners, do we have any questions?

Seeing none, I will send it back to OPC for redirect.

MS. WESSLING: Thank you. And no redirect.

At this time, I would like to move Exhibits DED-1 through DED-7, which I believe are marked CEL Exhibits 35 through 41, into the record.

CHAIRMAN LA ROSA: Is there objection?

Seeing none, show that entered into the record.

(Whereupon, Exhibit Nos. 35-41 were received into evidence.)

CHAIRMAN LA ROSA: Any other exhibits? Any other parties have any other exhibits?

Seeing none, Dr. Dismukes, you are excused. Thank you.

THE WITNESS: Thank you. I appreciate it.

(Witness excuse.)

CHAIRMAN LA ROSA: I turn it back over to you, OPC, when you are ready for -- to call your next witness.

MS. CHRISTENSEN: Good morning, Commissioners. OPC would like to call Lane Kollen to the stand, and we would ask that all our witnesses be sworn in, because I do not believe they were here previously.

CHAIRMAN LA ROSA: Okay. Mr. Kollen, if you don't mind stay standing, if -- to take a quick oath.

Whereupon,

LANE KOLLEN

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

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Thank you.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning. Can you please state your full name and business address for the record, please?

A Yes. My name is Lane Kollen. My business address is J. Kennedy and Associates, Incorporated, 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q And did you cause to be prefiled direct testimony consisting of 64 pages with cover pages?

A Yes.

Q And do you have any corrections to your testimony today?

A One correction was made previously by filing with the Commission to remove a word, or strike a particular word in the testimony on page 36. Other than that, no.

Q And did you also have exhibits attached to your testimony?

A Yes.

Q And do those consist of 16 exhibits?

A Correct.

Q Do you have any changes to those exhibits?

A No.

Q Would you please summarize your testimony?

A Good morning, Mr. Chairman and Commissioners.

In my testimony, I address and make recommendations on specific issues that affect the requested base rate increase for the 2025 test year, the requested a competitive energy transition mechanism, or CETM, rate increase for the 2025 test year, and the additional increases in 2026 and 2027, the two subsequent year adjustments.

Last week, the company filed various corrections and revisions to its requested increase -- increases, several of which reflect adjustments that I included in my recommendations. I summarize the effects of all OPC recommendations that affect all four of the requested rate increases.

I also addressed the company's request to include business as normal distribution costs in the

2026 and 2027 SYA increases. I also address the company's request to continue the tax changes provision of the 2021 stipulation and settlement agreement from the company's last base rate case.

I recommend a base rate increase effective January 1, 2025, of no more than $75.3 million. This is a reduction of 221.3 million from the company's requested $296.6 million rate increase. Keep in mind that the amounts that I am citing do not reflect the company's revisions that were filed last week.

I recommend a CETM rate reduction effective January 1, 2025, of at least $1.8 million. This is a reduction of $3.6 million from the company's requested $1.8 million rate increase.

I recommend an SYA rate increase on January 1, 2026, of no more than 60.3 million. This is a reduction of at least 39.8 million from the company's requested $100.1 million rate increase.

And then, in terms of the sequence of rate increases that the company has requested, I recommend an SYA rate increase on or about January 1, 2027, of no more than 24.3 million. This is a reduction of at least 47.6 million from the company's requested $71.8 million rate increase.

I provide two tables in my testimony that summarize all of the issues, listing them out, and then providing the effect on the company's rate increases. And those are shown in two tables, and based upon the recommendations not only that I make, but also all of the other OPC witnesses. For example, Dr. Dismukes and Dr. Woolridge.

The tables show the effects of each of the four rate increases for each issue and adjustment, and I identify the OPC witness supporting the underlying issue. Although, on certain issues, I quantify the effect on the rate increases.

The reduction of the company's requested base rate increase in 2025 is a result of numerous issues and related adjustments identified and addressed by OPC witnesses shown on the first of my two tables.

I address and recommend adjustments to, No. 1, normalized planned generation maintenance expense for major outages. The company had bunched together a number of outages in the test year, and my recommendation is to normalize the expense of that so that it isn't reflected in the revenue requirement at an abnormally high level.

No. 2, to remove capitalized and other portions of pension expense and OPEB expense. The company included the full cost, and should have included only the expensed portion.

No.3, remove long-term incentive plan expense tied to financial performance metrics. The Commission has previously disallowed these expenses, or allocated them to the company's shareholder, in this case, Emera. Remove 50 percent of directors and officers insurance expense in terms of a sharing with share -- the shareholder, Emera. And again, this is consistent with Commission precedent. Similarly, 50 percent of the board of directors expense shared with the shareholders.

I recommend a reduction in depreciation expense by using a 20-year service life for battery storage assets. That includes those that are in the test year, the 2025 test year, and also the two subsequent year adjustments. In the company's revisions last week, they agreed to use the 20-year service period.

I also recommend reducing the depreciation expense to reflect the 30-year service -- 35-year service life for solar assets that are presently reflected in the solar depreciation rates. The company's proposal in this case is to shorten it to 30 years.

I also recommend that the Commission reduce the dismantlement expense to reflect these longer lives, both for the battery storage assets and the solar assets.

I also recommend that the Commission add deferred carrying costs to deferred production tax credits for the years 2022 through 2024. Those were not passed through pursuant to decisions that the company made and, as I understand, had some discussions with OPC on in terms of deferring the PTCs, but there was no -- there were savings as a result of the deferral of the PTC that were retained by Tampa in the form of carrying cost savings, financing cost savings. My recommendation is to include those in the deferral and pass those through to customers over three years. The company has proposed 10 years.

And I also recommend that all of the IRA, the Inflation Reduction Act investment tax credits be deferred and amortized over three years. The company's proposal is to amortize those over the life of the assets, and also not to elect out of the normalization requirements, which harms customers because the company then keeps the return on the investment tax credits.

I see that my red light is on, so I will complete my summary then. Thank you very much, Commissioners.

CHAIRMAN LA ROSA: Thank you.

MS. CHRISTENSEN: We would ask that Mr. Kollen's testimony be entered into the record as though read, and then we tender our witness for cross.

CHAIRMAN LA ROSA: Okay. Great.

(Whereupon, prefiled direct testimony of Lane Kollen was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company
______________________________________/

Docket No. 20240026-EI

Filed: June 6, 2024

DIRECT TESTIMONY

OF

LANE KOLLEN

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

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Attorneys for the Citizens
Of the State of Florida

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DIRECT TESTIMONY

OF

LANE KOLLEN

On Behalf of the Citizens of the State of Florida

Before the

Florida Public Service Commission

Docket No. 20240026-EI

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

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

A. My name is Lane Kollen. I am the President and a Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 70 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Business Administration ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo. I also earned a Master of Arts ("MA") degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant ("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, Institute of Management Accounting, Georgia Society of CPAs, and Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than forty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on hundreds of occasions in proceedings before regulatory commissions and courts at the federal and state levels. In those proceedings, I have addressed ratemaking, accounting, finance, tax, and planning issues, among others.

I have testified before the Florida Public Service Commission on numerous occasions, including base rate, fuel adjustment clause, acquisition, and territorial proceedings involving Tampa Electric Company ("Company"), Peoples Gas System, Inc., Florida Power & Light Company, Duke Energy Florida, Talquin Electric Cooperative, City of Tallahassee, and City of Vero Beach.[1]

B. <u>Purpose of Testimony</u>

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing this testimony on behalf of the Florida Office of Public Counsel ("OPC").

Q. DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to address and make recommendations on specific issues that affect the base revenue requirement and requested increases in this proceeding effective for the 2025 test year and the requested 2026 and 2027 subsequent year adjustments ("SYAs"). I also summarize the effects of all OPC recommendations

[1] I have attached a more detailed description of my qualifications and regulatory appearances as my Exhibit LK-1.

that affect the base revenue requirement and the SYAs, including my recommendations and the recommendations of OPC witnesses David Dismukes (sales and base electric revenues in the test year and in 2026 and 2027), Bion Ostrander (affiliate transactions expense in the test year), Randall Woolridge (return on equity), and Kevin Mara (distribution plant in the test year and distribution plant and operation and maintenance ("O&M") expenses included in the requested 2026 and 2027 SYAs). In addition, I address the Company's request to continue the tax changes provision of the 2021 Stipulation and Settlement Agreement ("2021 Settlement") approved by the Commission in Docket 20210034-EI.

C. <u>Summary of Testimony</u>

Q. PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I recommend the Florida Public Service Commission ("Commission") authorize a base revenue increase effective on or about January 1, 2025 of no more than $75.269 million, a reduction of $221.342 million from the Company's requested increase of $296.611 million.

I recommend the Commission authorize a Competitive Energy Transition Mechanism ("CETM") revenue reduction effective on or about January 1, 2025 of at least $1.828 million, a reduction of at least $3.597 million from the Company's requested $1.769 million increase.

I recommend the Commission authorize an SYA revenue increase on or about January 1, 2026 ("2026 SYA") of no more than $60.257 million, a reduction of at least

$39.818 million from the Company's requested $100.075 million increase.[2] I recommend the Commission authorize an SYA revenue increase on or about January 1, 2027 ("2027 SYA") of no more than $24.286 million, a reduction of at least $47.562 million from the Company's requested $71.848 million.

On the following two tables, I provide a summary of the issues and adjustments to the requested increases in base revenues and CETM revenues, and the requested incremental increases in base revenues through the 2026 and 2027 SYAs that are addressed by OPC witnesses, including the issues and adjustments that I address and the issues and adjustments that are addressed by other OPC witnesses.[3] I note that all amounts shown on the following tables are the revenue effects of OPC recommendations. The rate base effects of OPC recommendations are detailed in my electronic workpapers, as are the revenue effects of the rate base adjustments and cost of capital adjustments recommended by OPC.

[2] OPC Witness Mara also addresses the distribution "electric delivery infrastructure" costs included in the Company's requested 2026 and 2027 SYA revenue increases and recommends that certain costs be excluded from the two SYA increases. The effects of his recommendations to exclude these costs are subsumed in my adjustments to remove all distribution "electric delivery infrastructure" investment costs from the two SYA increases.

[3] The calculations of the amounts shown on the two summary tables and cited throughout my testimony are detailed in my electronic workpapers. In addition, I calculate the effects of Witness Woolridge's recommendation for return on equity on the base revenue requirement and increase, the CETM, and the 2026 and 2027 SYAs, and the effects of Witness Mara's recommendations to remove certain plant costs from thebase revenue requirement.

TAMPA ELECTRIC COMPANY
REVENUE REQUIREMENT RECOMMENDED BY OPC - BASE RATES
DOCKET NO. 20240026-EI
TEST YEAR ENDING DECEMBER 31, 2025
($ MILLIONS)

	Jurisdictional Adjustment After Gross Up	Witness
Requested Base Rate Increase per TEC Filing	**296.611**	
Operating Income Adjustments:		
Increase Revenues Related to Load Growth	(12.298)	Dismukes
Normalize Planned Generation Maintenance Expense for Major Outages	(12.430)	Kollen
Remove Capitalized and Other Portion of Pension Expense	(0.489)	Kollen
Remove Capitalized and Other Portion of Active Employee OPEB Expense	(0.806)	Kollen
Remove Long Term Incentive Plan (LTIP) Expense Tied to Financial Performance	(7.170)	Kollen
Remove SERP Expense	(0.107)	Kollen
Reduce Affiliate Transaction Expense	(6.313)	Ostrander
Remove 50% of D&O Insurance Expense to Share with Shareholders	(0.151)	Kollen
Remove 50% of Board of Directors Expenses to Share with Shareholders	(0.376)	Kollen
Remove Depreciation Expense Related to Distribution Feeder Hardening Plant Reduction	(0.147)	Mara
Reduce Depreciation Expense by Using 20 Year Service Life for Battery Storage Assets	(5.942)	Kollen
Reduce Depreciation Expense by Using Approved 35 Year Service Life for Solar Generating Assets	(9.519)	Kollen
Reduce Dismantlement Expense to Exclude Cost and Expense Escalations After the End of the Test Year	(7.110)	Kollen
Reduce Dismantlement Expense By Removing Solar Site Restoration Environmental Costs	(2.614)	Kollen
Reduce Dismantlement Expense By Using Approved 35 Year Service Life for Solar Generating Assets	(0.955)	Kollen
Include Deferred Carrying Costs on Deferred Production Tax Credits through Dec 31, 2024	(0.460)	Kollen
Amortize Deferred Production Tax Credits Incl Deferred Carrying Costs Over Three Years	(13.845)	Kollen
Amortize Deferred Investment Tax Credits Pursuant to IRA Over Three Years (Grossed Up)	(12.607)	Kollen
Increase Income Tax Expense to Amortize Pre 2022 Solar ITCs Over 35 Versus 30 Years (Grossed Up)	1.636	Kollen
Rate Base Adjustments:		
Remove Spare Power Transfomers	(0.362)	Mara
Remove Distribution Feeder Hardening Plant	(0.356)	Mara
Reduce Accumulated Depreciation to Reflect Solar Battery Storage Service Life of 20 Years	0.275	Kollen
Reduce Accumulated Depreciation to Reflect Solar Service Life of 35 Years	0.440	Kollen
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Carrying Charges	(0.427)	Kollen
Reflect Changes in Production Tax Credit Regulatory Liability Balance - Amortization	0.663	Kollen
Capital Structure and Rate of Return Adjustments:		
Adjust Cost of Capital to Reflect Zero Cost ITCs for Battery Storage Assets	(3.493)	Kollen
Set Return on Equity at 9.5%	(126.379)	Woolridge
Total OPC Adjustments	**(221.342)**	
OPC Recommended Maximum Base Rate Increase	**75.269**	
Requested Levelized Revenue Increase for CETM per TEC Filing	**1.769**	
Adjust Cost of Capital to Reflect Zero Cost ITCs on Battery Storage Assets	(0.100)	Kollen
Set Return on Equity at 9.5%	(3.497)	Woolridge
OPC Recommended Change in Levelized CETM Rates	**(1.828)**	

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TAMPA ELECTRIC COMPANY
REVENUE REQUIREMENT RECOMMENDED BY OPC
BASE RATES CHANGE FOR 2026 AND 2027 SYAs
DOCKET NO. 20240026-EI
TEST YEAR ENDING DECEMBER 31, 2026
($ MILLIONS)

	2026 SYA	2027 SYA
Base Rate Change for 2026 and 2027 SYAs per TEC Filing	**100.075**	**71.848**
Revenue Requirement Adjustments:		
Remove Grid Grid Reliability & Resilience Projects	(4.599)	(28.788)
Remove Income Tax Gross-Up on Non Equity Return (NOI Multiplier)	(4.529)	(2.453)
Reflect Additional Revenue Due to Customer Growth During SYA Periods	(7.994)	(6.123)
Remove Incremental O&M Expense	(6.696)	(3.420)
Reflect Longer Service Lives for the Solar and Battery Projects	(3.670)	(1.612)
Reflect 3 Year Amortization for Solar Battery Storage ITCs	(2.792)	-
Adjust COC to Reflect Zero Cost Solar Battery Storage ITCs	(0.265)	(0.144)
Set Return on Equity at 9.5%	(9.273)	(5.022)
Total OPC Adjustments	**(39.818)**	**(47.562)**
OPC Recommended Maximum 2026 and 2027 SYA Rate Changes	**60.257**	**24.286**

As reflected in the preceding table for the 2026 and 2027 SYAs, I recommend the Commission reject the Company's request to fundamentally change the present ratemaking framework for limited post-test year base revenue increases to recover increases in certain "business as normal" distribution "electric delivery infrastructure" investment costs.[4] The Company's request is especially troubling given Company Witness Jeff Chronister's deposition testimony that the Company seeks increases to recover these certain "business as normal" costs solely to enhance its earned returns on

[4] Witness Kevin Mara also addresses these "business as normal" distribution "electric delivery infrastructure" investment costs and recommends the costs be removed from the requested 2026 and 2027 SYAs.

equity in the two years after the test year.[5] There has been no change in the statutory ratemaking framework or in the Commission's administrative rules that either precipitated or justify this request. The Company has not even offered a forecast of its earned returns or the underlying costs and revenues to demonstrate need. If the Commission adopts this request, then it will fundamentally change the course and form of ratemaking in the state, unleashing a real and imminent risk of future requests not only by the Company, but also by all other utilities, for SYA rate increases unrestrained by the limited increases for new generating plant assets previously allowed by the Commission. If the Commission is inclined to consider SYAs for "business as normal" distribution costs by the Company and other utilities, then it should establish a rulemaking proceeding to allow all interested parties statewide to participate in the process. If the Commission decides to proceed on an *ad hoc* basis in this proceeding, then I provide a proposed framework to assess the Company's request in this proceeding.

II. OPERATING EXPENSE ISSUES

A. <u>Normalize Planned Generation Maintenance Expense</u>

Q. DESCRIBE THE COMPANY'S GENERATION MAINTENANCE EXPENSE IN THE TEST YEAR.

A. The Company included $68.539 million in generation maintenance expense in the test year. Of this amount, the Company included $25.205 million for planned generation

[5] Transcript of Deposition of Jeff Chronister taken on April 24, 2024 at 137. I address Witness Chronister's deposition testimony on this in greater detail in the SYA section of my testimony.

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maintenance expense. The Company plans three major generating unit outages in 2025, which are described generally by Company Witness Carlos Aldazabal as follows:[6]

> There are three major needed outages happening in 2025. These include a 70-day major outage for Bayside Unit 1, a 70-day outage for Polk Unit 2, and a one-month outage for Big Bend Unit 4.

Witness Aldazabal provides a more detailed description for each of these three major generating unit outages.[7] He asserts the Bayside Unit 1 "outage is necessary because the run hours on the steam turbine are expected to be 380,000 and beyond the recommended OEM design of 250,000 hours."[8] He asserts the Polk Unit 2 outage is necessary because the run hours on the turbine are expected to be 66,000 and beyond the OEM recommendation for "a major overhaul at 50,000 hours of operation."[9] He notes further that "[t]his will be the first time opening the turbine since installation in 2017."[10] He asserts the Big Bend 4 outage is necessary for "compressed air system improvements, seawall cathodic protection, boiler circulating pump work, and intake screen replacement."[11]

Q. HOW DOES THE GENERATION MAINTENANCE EXPENSE IN THE TEST YEAR COMPARE TO PRIOR YEARS?

A. The generation maintenance is significantly greater due to the number and scope of outages in the test year compared to actual expenses in prior years. The Company

[6] Direct Testimony of Carlos Aldazabal at 32.
[7] *Id.*, pp. 32-33.
[8] *Id.*, p. 33.
[9] *Id.*
[10] *Id.*
[11] *Id.*

incurred $52.202 million in 2021, $44.830 million in 2022, and $46.738 in 2023. It budgeted $59.132 million in 2024 and forecasts $68.539 million in the test year.[12] The test year expense is $21.801 million, or 46.6%, greater in the test year than the actual expense incurred in 2023.

The planned generation maintenance component of the generation maintenance expenses follows this same pattern whereby the test year expense is significantly greater compared to actual expenses in prior years. The Company incurred $8.044 million in planned generation maintenance expense in 2019, $11.072 million in 2020, $10.252 million in 2021, $12.017 million in 2022, and $9.484 million in 2023.[13] It budgeted $13.315 million in 2024 and forecasts $25.205 million in the test year.[14] The test year expense is $16.021 million, or 68.9%, greater than the actual expense in 2023.

Q. IS THE GENERATION MAINTENANCE EXPENSE IN THE TEST YEAR RECURRING AT THIS LEVEL?

A. No. The generation maintenance expense is abnormally high in the test year compared to actual expenses in prior years. This is due, in significant part, to the number and scope of outages in the test year compared to the prior years. The Company delayed the planned maintenance beyond the original equipment manufacturer ("OEM") recommended run hours and then bunched the outages and a significantly greater level of expense into the test year compared to prior years. This has the effect of significantly

[12] Schedule C-06, sum of total steam power maintenance expense and other power maintenance expense.
[13] Response to Interrogatory No. 37 in OPC's First Set of Interrogatories, excluding now retired Big Bend 1, Big Bend 2, and Big Bend 3 coal-fired generating units. I have attached a copy of this response as my Exhibit LK-2.
[14] Schedule C-06, sum of total steam power maintenance expense and other power maintenance expense.

increasing the requested base revenue increase. The Company provided no evidence that the abnormally high level of expense will recur in the years subsequent to the test year for the generating assets that were in-service in the test year. In addition, by recording these costs as expense, rather than as "betterments" capital expenditures, the Company has chosen the highest and most harmful revenue requirement pathway. The FERC Uniform System of Accounts ("USOA") allows costs that normally would be expensed to be capitalized if they qualify as "betterments," meaning that they have future utility over multiple years.

Q. IS THE FACT THE GENERATION MAINTENANCE EXPENSE IS ABNORMALLY HIGH AND NONRECURRING AT THE LEVEL IN THE TEST YEAR A CONCERN FOR RATEMAKING PURPOSES?

A. Yes. The level of the test year expense included in the revenue requirement should represent the recurring level of expense to ensure that abnormally high expense in the test year is not embedded into the base revenues as if it were recurring. Assuming the planned generation maintenance expense reverts to the lower normalized level of expense in subsequent years, the Company nevertheless will recover the abnormally high level of expense in the test year and will continue to recover this abnormally high level of expense again and again in subsequent years until base rates are reset in a future rate case proceeding. Such a windfall is unreasonable and will harm customers for the sole purpose of enriching the Company's shareholder.

I also note that the Company included incremental maintenance expenses for new generation assets placed in service in 2026 and 2027 in its requested 2026 and

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2027 SYA increases, but did not reflect a reduction in generation maintenance expenses in those years for the existing generation assets.

Q. WHAT IS THE RATEMAKING SOLUTION TO ABNORMALLY HIGH EXPENSES IN THE TEST YEAR?

A. The ratemaking solution is to "normalize" the expense in the test year without any deferrals (i.e. the expenses are adjusted to reflect the more historic levels of planned generation maintenance absent any specific rationale for such increases in subsequent years). An alternative solution is to direct or otherwise allow the Company to capitalize the costs of "betterments" to CWIP instead of expensing the costs. Another alternative solution is to defer the abnormally high expense in excess of the normalized expense and amortize the deferral over an extended period in an attempt to allocate the benefits of the abnormally high expense to the periods benefitting from the planned maintenance scope of work and expenses.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission "normalize" the planned generation maintenance expense in the test year by averaging the actual expense incurred in the years 2019 through 2023 and the budget and forecast expenses in the years 2024 and 2025.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a $12.392 million reduction in the planned generation maintenance expense in the test year, and a reduction of $12.430 in the base revenue requirement and the requested base revenue increase.[15]

B. <u>Correct Capitalization Credit to Pension and OPEB Costs</u>

Q. DESCRIBE THE COMPANY'S REQUESTS FOR PENSION AND OPEB EXPENSE.

A. The Company requests recovery of its total pension cost and total OPEB cost without reductions for the amounts that will be capitalized.[16] The amounts the Company included for pension expense and OPEB expense in the test year match the total pension cost and total OPEB cost reflected in the actuarial reports for 2025, meaning the total costs were not reduced for the amounts that will be capitalized.[17]

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH ITS ACTUAL ACCOUNTING DESCRIBED IN RESPONSE TO OPC DISCOVERY AND THE AMOUNTS RECORDED TO EXPENSE AND CAPITAL IN PRIOR HISTORIC YEARS?

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[15] I note that I removed the since retired Big Bend 1, Big Bend 2, and Big Bend 3 planned maintenance expense before calculating the average for the existing generating assets over the seven-year period.

[16] Refer to the response to Interrogatory No. 22 in OPC's First Set of Interrogatories, which shows no credit for the capitalized amounts in the test year or the 2024 budget. Refer also to the response to POD No. 125 in OPC's Tenth Request for Production of Documents, which shows no credit for the capitalized amounts in the test year or the 2024 budget, but shows the credits for the capitalized amounts in all historic years 2016-2023. I have attached a copy of these responses as my Exhibit LK-3.

[17] Refer to the Confidential response to POD No. 5 in OPC's First Request for Production of Documents Bates 2572-2588, "TECO Energy 2024-2025 Retirement Forecasts." I have not attached a copy of this Confidential response.

A. No. The Company uses a "fringe rate" methodology to load its pension and OPEB costs onto payroll costs expensed and payroll costs capitalized for actual accounting purposes.[18] The Company records the total pension cost and total OPEB cost in account 926, then records a credit to account 926 for the capitalized portion of the total actuarial pension and OPEB costs.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reduce the pension and OPEB cost to reflect the credit for the portions of the costs that will be capitalized. OPC has asked several times for the breakdown of the test year total pension cost and the total OPEB cost between expense and capital. In every response, the Company simply provided the total pension cost and the total OPEB cost with no breakdown. The Company's pension "expense" and OPEB "expense" match the total pension cost and total OPEB cost shown in the Mercer actuarial report for 2025 before any reductions for the capitalized portions of the costs. The actuarial reports provide only pension and OPEB costs; they do not breakdown the costs between expense and capital because that is a function of the Company's accounting for payroll and related costs.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effect is a reduction of $0.489 million in the revenue requirement for the reduction in pension expense and a reduction of $0.806 million in the revenue requirement for

[18] Response to Interrogatory No. 167 in OPC's Ninth Set of Interrogatories, a copy of which I have attached a copy of this response as my Exhibit LK-4.

the reduction in OPEB expense to reduce the requested amounts for the capitalized portions.

C. <u>Allocate Incentive Compensation Tied to Financial Performance Metrics to Shareholder</u>

Q. DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF LONG TERM INCENTIVE COMPENSATION EXPENSE IN THE REVENUE REQUIREMENT.

A. The Company included $7.173 million (total Company) in Long Term Incentive Plan ("LTIP") compensation expense in the revenue requirement. This amount represents compensation paid directly to certain Tampa Electric Company employees, net of allocations from the Company to affiliates and from affiliates to the Company.[19]

Q. DESCRIBE THE COMPANY'S LTIP COMPENSATION EXPENSE.

A. The LTIP compensation expense is tied to the financial performance of its parent Company, Emera, Inc. ("Emera"). The LTIP compensation expense is generally available to all department directors and officers.[20] According to the Company's testimony, "the purpose of the LTIP is to align the long-term incentive pay for senior leaders with corporate and shareholder goals."[21] The Company's testimony also states that "LTIP is administered through the Emera Performance Share Unit ("PSU") Plan

[19] Responses to Interrogatory Nos. 15 and 16 in OPC's First Set of Interrogatories, copies of which I have attached as my Exhibit LK-5.

[20] Direct Testimony of Marian Cacciatore at 13.

[21] *Id.* at p. 20.

and the EMERA Restricted Share Unit ("RSU") Plan."[22] These compensation payments are made in the form of stock grants of Emera stock. Thus, 100% of the LTIP compensation expense is tied to reaching the financial performance goals of Emera that include its stock price. The stock price, by definition, is a measure of Emera's financial performance.

Q. WHAT IS THE COMMISSION'S HISTORIC PRACTICE CONCERNING INCENTIVE COMPENSATION EXPENSE TIED TO FINANCIAL PERFORMANCE METRICS?

A. The Commission has a long-standing practice of disallowing such expenses. In its order in a Progress Energy Florida, Inc. rate case, the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals such as earnings per share ("EPS"). In its discussion related to the disallowance, the Commission stated:[23]

> Accordingly, we believe that incentive compensation tied to EPS should not be passed on to ratepayers.

Likewise, in its order in a Florida Power and Light Company rate case, the Commission specifically disallowed incentive compensation expense tied to EPS or other earnings measures. In its discussion related to the disallowance, the Commission stated:[24]

> We find that the entire executive incentive compensation program is designed to benefit the shareholders by creating long-term shareholder

[22] *Id.*
[23] *In Re*: Docket 090079-EI, Petition for Increase in Rates by Progress Energy Florida, Inc., Order No. PSC-10-0131-FOF-EI, p. 114.
[24] *In Re*: Docket 080677-EI, Petition for Increase in Rates by Florida Power & Light Company, Order No. PSC-10-0153-FOF-EI, p. 149.

> value. We find that the executive incentive compensation program is designed to place the interests of executives in the same light as that of shareholders, thus creating incentive to increase the value of FPL Group's shares. Because these programs are designed for the benefit of shareholders, those costs shall be borne exclusively by shareholders.

Finally, in its order in a Tampa Electric Company rate case, the Commission specifically disallowed incentive compensation expense tied to the financial goals of its parent company at that time, TECO Energy. In its discussion related to the disallowance, the Commission stated:[25]

> We also find, however, that the incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent Company TECO Energy. Therefore, jurisdictional operating expenses shall be reduced by $540,000 ($560,000 system) for that portion of incentive compensation pay tied directly to TECO Energy's results as recalculated by witness Chronister.

Q. DID THE COMPANY MAKE THE ARGUMENT IN TESTIMONY THAT THE LTIP PAYOUTS ARE PART OF THE TOTAL DIRECT COMPENSATION AND SHOULD BE RECOVERABLE BASED ON THE RESULTS OF ITS MARKET DATA ANALYSES?

A. Yes. The Company's testimony discussed its assertion that the total direct compensation had an overall score of 99.5% in relation to the market median for 2023 it had derived.[26] However, that testimony also details the fact that the Company's internal analysis was based on its own updates to a 2019 comprehensive review, not a current comprehensive review.[27]

[25] *In Re*: Docket 080317-EI, Petition for Rate Increase by Tampa Electric Company, Order No. PSC-09-0283-FOF-EI, p. 58.
[26] Direct Testimony of Marian Cacciatore at pp. 21-23.
[27] *Id.*

Q. SHOULD THE COMMISSION INCLUDE THE LTIP INCENTIVE COMPENSATION EXPENSE TIED TO EMERA'S FINANCIAL PERFORMANCE IN THE COMPANY'S REVENUE REQUIREMENT?

A. No. The question for ratemaking purposes is not whether the incentive compensation expense tied to financial performance metrics is reasonable in comparison to a market study, but whether customers or shareholders should pay for the expense. The Commission historically has allocated incentive compensation expenses incurred to incentivize the achievement of financial performance metrics, such as earnings per share and total shareholder return, to shareholders and not to customers. The Commission had made these allocations to shareholders because incentive compensation tied to financial performance metrics benefits shareholders to the detriment of customers in rate proceedings such as this. All of the LTIP expense projected in the test year is to incentivize the achievement of financial metrics that benefit shareholders; it was not incurred to incentivize the achievement of metrics that benefit customers and/or otherwise achieve other strategic and societal goals, such as safety.

Further, incentive compensation incurred to incentivize Emera financial performance also provides the Company's department directors and officers a direct incentive to seek greater and more frequent rate increases from customers in order to improve Emera's stock price. The greater the rate increases and revenues, the greater Emera's stock price, all else equal, and the greater the incentive compensation expense. There is an inherent conflict between achieving lower rates for customers on the one hand and achieving greater financial performance for shareholders and greater

C21-2004

incentive compensation for department directors and officers on the other hand. Thus, all LTIP expense should be allocated to shareholders, not to customers.

Finally, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling. The additional revenues ensure that the expense is recovered regardless of the Company's actual performance and regardless of its operational and safety performance. Thus, the expenses should be directly assigned to Emera shareholders, not to the Company's customers.

In summary, the Company's requests for recovery of LTIP expense tied to Emera's stock price and shareholder return fall clearly within the disallowance precedent and should be allocated to Emera shareholders and not recovered from the Company's customers.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission disallow the LTIP incentive compensation expense tied to Emera's financial performance.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect is a reduction of $7.170 million in the claimed revenue requirement and requested base rate increase, including the gross up for bad debt expense and PSC fees.

C21-2005

D. Supplemental Executive Retirement Plan Expense

Q. DESCRIBE THE COMPANY'S REQUEST TO INCLUDE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP") EXPENSE IN THE BASE REVENUE REQUIREMENT.

A. The Company requests recovery of $0.107 million in SERP expense in the base revenue requirement.[28] These expenses are incurred to provide certain highly compensated executives retirement benefits in addition to the benefits otherwise available through the Company's pension and OPEB plans. These are considered to be non-qualified plans because the additional compensation exceeds deductible compensation limits set forth in the Internal Revenue Code.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission deny the Company's request to recover this expense. The SERP expense is discretionary. It is incurred to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the Company's shareholders rather than its customers. The expense is not necessary to provide regulated utility service and it is not reasonable to impose the expense on utility customers.

[28] Response to Interrogatory No. 17 in OPC's First Set of Interrogatories, a copy of which I have attached as my Exhibit LK-6.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effect is a reduction of $0.107 million in the claimed revenue requirement and requested base rate increase.

E. <u>Reduce Directors and Officers Insurance Expense and Board of Directors' Expense to Reflect Sharing Between Company's Shareholders and Customers</u>

Q. DESCRIBE THE TWO CORPORATE RELATED EXPENSES THE COMPANY INCLUDED IN THE REVENUE REQUIREMENT IN THIS PROCEEDING.

A. The Company included expenses related to its parent company, Emera, and its own corporate governance in the revenue requirement. The Company excluded expenses related other investor services from the revenue requirement. Emera's stock and other securities are publicly traded. Emera incurs certain governance expenses and liability insurance expenses related to its directors and officers and charges those expenses to Tampa Electric Company and other Emera affiliates. Tampa Electric Company also incurs certain governance expenses related to its own directors and officers.

The Company incurred Directors & Officers ("D&O") liability insurance expense of $0.303 million (total Company) during the test year.[29] D&O insurance is designed to protect the individual directors and officers of an organization from personal liability and potential losses arising from their service and decisions made while serving in those roles. D&O insurance also may defray the legal and other costs

[29] Response to Interrogatory No. 34 in OPC's First Set of Interrogatories, a copy of which I have attached as my Exhibit LK-7.

incurred to defend against corporate liability and potential losses related arising from decisions made by directors and officers on behalf of an organization.

In addition, the Company included Board of Directors expenses of $0.753 million during the test year, consisting of expenses the Company incurred directly and expenses incurred by Emera and charged to the Company.[30] Emera maintains an investor relations organization to interact with present and potential investors. The Emera website details the communications supplied to investors.[31] The communications include such things as news releases, investor presentations, regulatory filings, analyst reports, and other statistical and reporting information.

Q. SHOULD THERE BE A SHARING OF THESE KINDS OF CORPORATE EXPENSES BETWEEN CUSTOMERS AND SHAREHOLDERS?

A. Yes. the benefits from such activities inure primarily to shareholders, not to customers.

Q. HAS THE COMMISSION PREVIOUSLY RULED ON THE SHARING OF THESE KINDS OF EXPENSES?

A. Yes. The Commission determined there should be an equal sharing of D&O insurance expense costs between customers and shareholders in at least two prior rate cases, one for Gulf Power Company and the other for Progress Energy Florida.[32]

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[30] Response to Interrogatory No. 56 in OPC's Second Set of Interrogatories, a copy of which I have attached as my Exhibit LK-8.

[31] Home| Emera. Corporate Profile | Emera

[32] Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, Docket No. 11-0138-EI, In re: Petition for increase by Gulf Power Company, at p. 101; Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc. at p. 99.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an equal sharing of the Company's D&O insurance and Board of Directors expenses between customers and shareholders to allocate these expenses equally based on an assumption the expenses benefit both ratepayers and shareholders, as recognized in previous Commission orders.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction of $0.151 million in D&O insurance expense and the revenue requirement and a reduction of $0.375 million in Board of Directors expenses and a reduction of $0.376 million in the revenue requirement after the gross-up for bad debt and Commission fees.

F. Modify Depreciation Rates and Expense to Reflect Industry Standard Service Lives for Battery Storage Assets

Q. DESCRIBE THE COMPANY'S REQUESTED SERVICE LIFE FOR BATTERY STORAGE ASSETS DEPRECIATION PURPOSES.

A. The Company proposes a 10-year service life for battery storage assets for depreciation purposes.

Q. IS A 10-YEAR SERVICE LIFE FOR BATTERY ENERGY STORAGE SYSTEM ("BESS") ASSETS REASONABLE FOR DEPRECIATION PURPOSES?

C21-2009

A. No. It is unduly short. It is not consistent with the Company's plans to actually operate the battery storage assets beyond a 10-year period. Nor is it consistent with the industry standard service life of 15 to 20 years used for planning and ratemaking purposes. For example, the Wisconsin Public Service Commission recently approved the Grant County BESS in WPSC Docket 9804-CE-100, in which Wisconsin Power and Light Company asserted that the BESS had a 20-year service life.[33] Santee Cooper relies on a 20-year service life for Integrated Resource Plan ("IRP") purposes.[34] Lazard relies on a 20-year service life for economic valuations of utility-scale BESS under different configurations.[35] NREL relies on a 15-year service life for utility-scale BESS in its Annual Technology Baseline ("ATB") for resource planning purposes.[36]

Q. DID COMPANY WITNESS NED ALLIS MAKE ANY ATTEMPT TO JUSTIFY THE PROPOSED 10-YEAR SERVICE LIFE FOR THE BATTERY STORAGE ASSETS BASED ON THEIR PHYSICAL LIFE IN THE DEPRECIATION STUDY?

A. No. Witness Allis relied exclusively on the presently approved 10-year life, noting only that "estimates for other utilities typically range from 10 to 15 years (while 20-years may have been used for some larger, newer facilities)."[37] As I noted previously, the trend has been toward longer service lives, with the most recent industry and utility

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[33] https://psc.wi.gov/Pages/CommissionActions/CasePages/GrantCountySolar.aspx.

[34] Santee Cooper Integrated Resource Plan Public Stakeholder Meeting June 28, 2022 at 98. I have attached a copy of the cover page and the referenced page as my Exhibit LK-9.

[35] Lazard's Levelized Cost of Storage Analysis Version 7.0 at 4. I have attached a copy of the cover page and the referenced page as my Exhibit LK-10.

[36] https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage.

[37] Exhibit No. NA-1 Document No 2 page 388 attached to the Direct Testimony of Ned Allis.

planning studies reflecting a 20-year service life. Other Company witnesses, including Witness Latta and Witness Chronister, did not independently evaluate the service life, but simply relied on the 10-year life proposed by Witness Allis to calculate the resulting depreciation expense and decommissioning expense. This circular justification among the Company and its outside experts provides no justification whatsoever and fails the Company's required burden of proof.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's proposed 10-year service life service life for the existing and new battery storage assets and instead adopt a 20-year service life for these assets. Battery technology continues to improve and authoritative technology data sources and utilities now widely assume a 20-year service life for planning and economic analyses, as well as for cost recovery purposes. There is no compelling reason to continue to use an outdated, unsupported, and irrelevant 10-year service life in lieu of the 20-year service life widely used for planning and cost recovery purposes.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effect is a net reduction of $5.667 million in the revenue requirement and requested increase. This net reduction reflects a reduction $5.942 million in depreciation expense and the related revenue gross-up expenses, offset in part by $0.275 million for the reduction in the grossed-up return on the increase in rate base due to the resulting lower accumulated depreciation in the test year.

C21-2011

G. <u>Correct Depreciation Rates and Expense to Reflect Presently Approved Service Lives for Solar Assets</u>

Q. DESCRIBE THE COMPANY'S REQUESTED SERVICE LIFE FOR SOLAR ASSETS.

A. The Company proposes a 30-year service life for solar assets.

Q. HOW DOES THE REQUESTED SERVICE LIFE COMPARE TO THE PRESENTLY APPROVED SERVICE LIFE FOR SOLAR ASSETS?

A. The presently approved service life for solar assets is 35 years.[38]

Q. HOW DOES THE REQUESTED SERVICE LIFE FOR SOLAR ASSETS COMPARE TO THE SERVICE LIFE ASSUMED FOR EACH OF THE NEW SOLAR ASSETS INCLUDED IN THE COMPANY'S 2024 10-YEAR SITE PLAN FILED ON APRIL 1, 2024?

A. The Company assumed a service life of 35 years for each of the new solar assets included in the 2024 10-Year Site Plan. The Company filed the 2024 10-Year Site Plan on April 1, 2024, one day before it filed its Petition in this rate case proceeding. The proposed 30-year service life in this proceeding would accelerate the ratemaking recovery by 5 years compared to the planned 35-year physical service life for these assets reflected in the 2024 10-Year Site Plan.

[38] *In Re*: Docket 20210034-EI, Petition for Rate Increase by Tampa Electric Company, 2021 Stipulation and Settlement Agreement, p. 11.

Q. HAS THE COMPANY PROVIDED ANY EVIDENCE THAT IT WILL NOT OPERATE THE EXISTING AND NEW SOLAR ASSETS FOR 35 YEARS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the Company's proposed reduction in the service life for the existing and new solar assets. The Company's recently filed site plan assumes the solar assets will operate for 35 years. If the Company is unable physically to operate these solar assets for the 35 years assumed in its site plan, then it can seek to shorten the service lives of its solar assets if and when the physical evidence supports that conclusion. The Company is not harmed by continuing to use the presently approved service life for depreciation expense, dismantlement expense, and income tax expense; however, customers are harmed by prematurely shortening the service life.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effect is a net reduction of $8.398 million in the revenue requirement and requested increase. This net reduction reflects a reduction of $9.519 million for a reduction in depreciation expense and a reduction of $0.955 million for a reduction in dismantlement expense, offset in part by $1.636 million for the reduction in ITC amortization expense on a revenue equivalent basis for solar assets that were eligible for ITC prior to the effective date of the IRA and offset in part by $0.440 million for the reduction in the grossed-up return on the increase in rate base due to the resulting lower accumulated depreciation in the test year.

H. <u>Reduce Dismantlement Expense to Remove Post Test Year Escalations of Estimated Costs, Reduce Estimated Solar Site Restoration Costs, And Reflect Longer Service Lives for Solar and Battery Assets</u>

Q. DESCRIBE THE COMPANY'S REQUEST TO RECOVER DISMANTLEMENT EXPENSE FOR EXISTING AND NEW GENERATING ASSETS, INCLUDING EXISTING AND FUTURE SOLAR ASSETS.

A. The Company seeks to recover estimated future dismantlement and site restoration costs for the all existing and new generating assets, including existing and future solar assets. No Company witness in either this proceeding or the depreciation proceeding addressed the calculation of the dismantlement expense. The only Company witness to address the estimated dismantlement costs used for the calculation of the dismantlement expense was Witness Kopp, who developed an estimate of these costs in 2023 dollars and excluded any potential contingency costs in the dismantlement study. Witness Kopp did not address the dismantlement expense calculation in this proceeding or the depreciation proceeding, apparently under the mistaken impression that dismantlement would be included in the depreciation rates developed by Witness Allis.[39] Witness Allis does not address the dismantlement costs or dismantlement expense accruals or include them in his proposed depreciation rates.

In response to discovery from OPC in this proceeding, the Company acknowledged that Witness Kopp did not address the dismantlement expense

[39] In the Direct Testimony of Jeff Kopp at p. 5 in this proceeding, he states "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."

calculation.[40] In that same response, the Company identified Witness Chronister as the witness supporting the Company's calculations and request for dismantlement expense.[41] Yet, that response is incorrect as well; Witness Chronister has not testified in this proceeding or in the depreciation proceeding regarding the calculation of the proposed dismantlement expense accrual. To the contrary, Witness Chronister apparently was under the impression that Witness Allis and Witness Kopp were the witnesses addressing the calculation of this expense.[42]

In my review of the Company's calculations in this proceeding, I determined that some undisclosed person(s) acting on behalf of the Company made the decision to increase Witness Kopp's estimated dismantling costs by adding 15% for potential contingency costs in 2025 dollars before it calculated the dismantlement expense for 2025.[43] The Company provided no documentary support for this 15% addition, no testimony, and even failed to identify the Company witness or, indeed, any person, responsible for the decision to add these potential contingency costs given that Witness Chronister does not address this issue or any other dismantlement cost issue in his testimony.

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[40] Response to Interrogatory No. 90 in OPC's Fourth Set of Interrogatories, a copy of which I have attached as my Exhibit LK-11.

[41] *Id.*

[42] Direct Testimony of Jeff Chronister at 11 wherein he states: "The increases in new depreciation rates results in a 2025 expense increase of $46.9 million and the increase in the new dismantlement accrual results in a 2025 expense increase of $9.4 million. These changes are discussed further by Tampa Electric witnesses Ned Allis and Jeff Kopp in their direct testimony." That testimony is incorrect, but still has not been revised.

[43] As noted previously, no Company witness provided testimony or otherwise offered any support for the calculation of the dismantlement expense accruals or the addition of the 15% adder for potential contingency costs. Compounding the failure to provide any testimony on the dismantling expense accruals, the Company also failed to provide the calculations of the requested expense accruals in electronic format, despite repeated requests through written and deposition discovery, until a mere two weeks prior to the intervenor testimony due date, thus precluding any additional written discovery prior to the intervenor testimony filing date.

In the final step of the Company's calculations in this proceeding, I determined that it further escalated the 2025 expense, including the potential contingency costs, to future dollars in 2026, 2027, and 2028, and then calculated the proposed dismantlement expense as the average of the expenses in escalated 2025, 2026, 2027, and 2028 future dollars. The Company performed these calculations for each existing and new generating asset, including the existing and new solar generating assets.

Q. SHOULD THE COMPANY BE ALLOWED TO CALCULATE DISMANTLEMENT EXPENSE BASED ON PROJECTIONS OF THE EXPENSE IN FUTURE DOLLARS ESCALATED BEYOND THE TEST YEAR TO 2026, 2027, AND 2028?

A. No. The Company is limited to the test year costs, including dismantlement expense, which already reflects a forecast of the dismantlement cost extending two years beyond the most recent historic year. The test year concept is important because it is intended to be a comprehensive measure of the cost of service and present revenues for a defined time period. The Company's proposed dismantlement expense goes another three years beyond the test year, a selective adjustment that fails to recognize any other changes in those years to reflect potential increases in revenues due to customer growth and other changes in costs, including rate base and expenses, including reductions in expenses. Such reductions in expenses include reductions in payroll expenses due to productivity gains achieved through investments in rate base and reductions in regulatory assets as they continue to amortize after the test year, among the other hundreds of rate base, revenues, expense, and cost of capital components included in the cost of service, revenue requirements, and revenue deficiencies or surpluses.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission limit the dismantlement expense to costs escalated only through the test year and exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A The effects are a reduction of at least $7.088 million in the proposed dismantlement expense and a reduction of at least $7.110 million in the claimed revenue requirement and requested base revenue increase. This recommendation is extremely conservative given that the unsupported and unjustified potential contingency costs still are included in the dismantlement cost estimate and the proposed dismantlement expense through the test year.

Q. DESCRIBE THE COST CATEGORIES OR COMPONENTS WITNESS KOPP INCLUDED IN HIS ESTIMATED DISMANTLEMENT COSTS FOR THE SOLAR ASSETS.

A. Witness Kopp included labor, material and equipment, disposal, and environmental costs in his estimated costs, which he reduced for scrap proceeds (salvage income). The removal of the solar panels includes labor, material and equipment, and disposal. The panel racks/support costs include labor, material and equipment. The electrical

C21-2017

wiring costs include labor, material and equipment. The on-site restoration costs include labor, material and equipment, and environmental. The on-site concrete crushing and removal and the debris costs include only disposal. The environmental costs include removal of access roads, removal of the perimeter fencing, grading and seeding disturbed site areas, and restoration of the rooftop underneath rooftop solar panels.[44]

Q. ARE ALL OF THESE COSTS REASONABLY KNOWN AND MEASURABLE?

A. No. First, for most of the solar facilities, Witness Kopp did not review the terms of the ground leases to assess whether the Company or the owner of the site is responsible for site restoration and environmental remediation or the scope of any activities required by the Company, if any.[45] Witness Kopp explained that the lease agreements include such requirements and that the requirements affect the party(ies) responsible for site restoration and environmental remediation and the scope of the required activities. In response to OPC discovery, Witness Kopp stated "[a] lease agreement states requirements for the leased land on which a storage or solar facility are constructed. These requirements may impact decommissioning assumptions."[46] Witness Kopp also stated that he did not review most of the lease agreements because the "lease agreement was not provided by Tampa Electric for my team to review."[47]

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[44] Response to Interrogatory No. 89(d) in OPC's Fourth Set of Interrogatories, a copy of which I have attached as Exhibit LK-12.
[45] Response to Interrogatory No. 89(e) in OPC's Fourth Set of Interrogatories. See Exhibit LK-12.
[46] *Id.*
[47] *Id.*

Second, neither Witness Kopp nor the Commission know at this time whether the solar sites will be abandoned or remain in use with new equipment installed after the original equipment is retired and removed some 35 years in the future. Witness Kopp simply assumed that the sites will be abandoned. He assumed they will not be refitted with new equipment that will extend the service life of the sites beyond the service life assumption for the original panels, inverters, and other equipment. Yet, there is at least an equal probability that the sites will remain in use refitted with new equipment and that site restoration and environmental costs will not be incurred or will be incurred at a much lower cost when the original equipment is retired and removed.

Third, neither Witness Kopp nor the Commission know at this time the scope of the site restoration, even assuming that it is the responsibility of the Company, including the extent of environmental remediation. The dismantlement, removal of the equipment and structures, and on-site concrete crushing and removal are included as separate components of the estimated costs and can be reasonably estimated based on the need to remove the old equipment; however, it is not known whether, or if so, what additional site restoration and environmental activities will be necessary.

Fourth, 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.

Q. IS THERE A PERMANENT PENALTY COST IMPOSED ON CUSTOMERS FOR PREMATURE RECOVERY OF DISMANTLEMENT COSTS BEFORE THE COSTS ACTUALLY ARE INCURRED?

A. Yes. There is a tax penalty in the form of an asset accumulated deferred income tax ("ADIT"), which reduces the cost-free liability ADIT reflected in the cost of capital and increases the base revenue requirement, SYA revenue requirements, and all other rider revenue requirements that include a return on rate base.

This tax penalty is unnecessary, but at least can be minimized by removing or otherwise reducing speculative, uncertain, unknown, and unmeasurable dismantlement costs from the revenue requirement. If, at some later date, these costs are known and measurable, then they can be recovered at that time.

Q. WHAT IS YOUR RECOMMENDATION ON DISMANTLEMENT COSTS FOR THE SOLAR GENERATING ASSETS?

A. I recommend the Commission minimize the dismantlement expense due to the tax penalty and the speculative assumptions as to the scope of the dismantling activities when the original equipment is retired and removed. I recommend the Commission exclude at least the environmental component of the dismantlement costs on the solar generating assets. The costs that may be incurred are extremely speculative and are not known and measurable, and are based on Witness Kopp's unsupported assumptions regarding the abandonment of the sites and that the Company will be responsible for the site restoration, further compounded by the Company's unsourced and undescribed potential contingencies assumption, all of which are extremely speculative and not known and measurable.

C21-2020

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A The effects are a reduction of at least $2.606 million in the proposed dismantlement expense and a reduction of at least $2.614 million in the claimed revenue requirement and requested base revenue increase. These effects are in addition to the effects on the dismantlement expense from limiting the escalation of the dismantling cost estimate and the dismantlement expense only through the test year.

I. <u>Include Deferred Carrying Costs on Deferred Production Tax Credits through December 31, 2024</u>

Q. DESCRIBE THE TERM IN THE 2021 SETTLEMENT THAT ADDRESSED THE EFFECTS ON THE 2023 AND 2024 GBRAS FROM CHANGES IN THE TAX LAW.

A. Section 11(c)(vi) of the 2021 Settlement agreement approved by the Commission in the prior base rate proceeding states:

> The company will adjust any GBRA that has not gone in effect up or down to reflect the new corporate income tax rate and the normalization of any new tax credits applicable to Future Solar projects on the revenue requirement for the GBRA.

Q. IN FACT, WERE THERE CHANGES IN THE TAX LAW THAT MODIFIED EXISTING AND ESTABLISHED NEW TAX CREDITS?

A. Yes. The Inflation Reduction Act of 2022 ("IRA") was signed into law on August 16, 2022. The IRA implemented significant changes in the tax law that increased the investment tax credits ("ITC") percentage rate to 30% for new solar generating assets, extended the availability of the ITC credit to battery storage assets on a standalone basis, established a new production tax credit ("PTC") for solar generating resources based on energy production, gave taxpayers the choice between PTCs and ITCs for solar generating assets, and allowed utility taxpayers to elect out of the so-called normalization requirements that previously applied to the ITCs, meaning that the utility could elect to provide both the ITC amortization benefit and the ITC cost-free capital benefit to customers rather than electing one or the other. It also allowed the utility's regulator to enforce that election to provide both benefits to customers for ratemaking purposes. In addition, it allowed the utility's regulator to separately specify the amortization period for the ITC untethered to the service life of the asset used for depreciation purposes.

Q. DID THESE CHANGES IN THE TAX CREDITS AVAILABLE TO THE COMPANY AND THE NORMALIZATION REQUIREMENTS AFFECT THE 2023 AND 2024 GBRAS?

A. Yes. The Company elected the PTCs in lieu of the ITCs that it had previously included in the calculation of the 2023 and 2024 GBRA rate increases for solar generating assets.[48] The economic value of the PTCs was greater than the ITCs. In addition, the PTCs earned in 2022 through 2024 were greater than the amortization of the ITCs

[48] Letter from counsel to Tampa Electric Company dated February 19, 2024 addressed to the Commission in which the Company described its election for PTCs in lieu of ITCs and its "proposal" to defer and amortize the PTCs in excess of the ITC amortization included in the calculations of the GBRA rate increases approved by the Commission. For ease of reference, I have attached a copy of this letter and the attached proposal as my Exhibit-13.

earned that the Company assumed in the calculation of the 2023 and 2024 GBRA rate increases approved by the Commission in the last base rate proceeding. Instead of flowing through the PTCs to customers in the form of reductions to the approved 2023 and 2024 GBRA rate increases, as required pursuant to the 2021 Settlement in that proceeding, the Company decided unilaterally to defer the PTCs earned in those years in excess of the ITC amortization reflected in the calculation of the 2023 and 2024 GBRA rate increases approved by the Commission. The Company then informed the Commission of its decision to defer the PTCs instead of flowing through the savings to customers. The Company recorded the revenue equivalent of the deferred PTCs as a regulatory liability on a revenue equivalent basis.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE PTCS IN THIS PROCEEDING?

A. The Company proposes to amortize the regulatory liability over ten years as a reduction to the base revenue requirement. It also proposes to flow through the revenue equivalent of the PTCs earned in the test year in the base revenue requirement and the revenue equivalent of the PTCs earned by the new solar generating assets included in the 2026 and 2027 SYA revenue requirements.

Q. DOES THE COMPANY'S PROPOSAL INCLUDE A RETURN ON THE DEFERRED PTCS FROM 2022 THROUGH THE END OF 2024?

A. No. Unlike the ITCs prior to the IRA, the PTCs were not subject to the so-called normalization requirement, meaning that the Company could immediately flow

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through the PTCs to its customers, or if it deferred the PTCs for future amortization, then it could also subtract the deferred PTCs from rate base or include those amounts as cost-free tax credits in its cost of capital. The Company simply deferred the PTCs for future amortization, but failed to address the savings due to the cost-free capital during the deferral period.

Q. IN THE ABSENCE OF FLOWING THROUGH THE PTCS TO CUSTOMERS AS THEY WERE EARNED BY REDUCING THE 2023 AND 2024 GBRA INCREASES, HOW SHOULD THE COMPANY HAVE ADDRESSED THE PTCS TO ENSURE THAT CUSTOMERS WERE MADE WHOLE?

A. The Company should have added a deferred return to the deferred PTCs on a revenue equivalent basis to ensure that customers received the same economic value as if the PTCs had been flowed as reductions to the 2023 and 2024 GBRA rate increases as the PTCs were earned each year. The failure to flow through the reductions in the GBRA rate increases allowed the Company to retain the cash from the PTCs and the related savings in financing costs in those years due to the avoided investor equity and debt financing. Instead of deferring the savings in financing costs as an increase to the regulatory liability, the Company simply retained those savings. This situation can and should be corrected.

I note the Company acknowledges there has been a savings in financing costs by subtracting the regulatory liability from rate base in the test year. While it is appropriate to subtract the regulatory liability from rate base in the test year, that does not address the savings for the deferral years 2022 through 2024, which need to be

C21-2024

addressed separately through an addition of a deferred return to the deferred PTC regulatory liability for those three years.

Q. SHOULD THE COMPANY'S CUSTOMERS BE PROVIDED THE COMPANY'S SAVINGS IN FINANCING COSTS?

A. Yes. The savings in financing costs belong to customers who were deprived of the timely flow through of the PTCs earned in the years through 2024.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission compensate customers for carrying costs on the deferred PTCs by adding the deferred carrying costs calculated at the allowed return from the prior rate case to the regulatory liability.

Q. WHAT IS THE EFFECT OF YOUR RECOMMENDATION?

A. The effects are a reduction of at least $0.887 million in the claimed revenue requirement and requested base revenue increase, consisting of an increase of $0.460 million in the *negative* amortization expense and a decrease of $0.427 million due to the additional regulatory liability in the test year times the grossed-up rate of return (equity only).

J. <u>Amortize Deferred Production Tax Credits Over Three Years</u>

Q. IS THE COMPANY'S PROPOSAL TO AMORTIZE THE REVENUE EQUIVALENT OF THE DEFERRED PTCS OVER TEN YEARS REASONABLE?

A. No. The ten years is unduly long. Customers were entitled to the PTCs as they were earned through reductions to the base revenue requirement and reductions to the 2023 and 2024 GBRAs pursuant to the 2021 Settlement in the prior rate case. The refunds to these customers should be made sooner rather than later, especially since the Company failed to record deferred carrying costs on the deferred PTCs and failed to include the PTCs as cost-free capital in the capital structure.

The Company offered no rationale for the ten years other than the PTCs are available for new solar resources annually for ten years. However, there is no nexus between the number of years the PTCs are available for new solar generating assets going forward (test year and subsequent years) and the refunds related to the deferral period preceding the test year. This should be clear based on the Company's request to flow through the annual PTCs earned starting in the test year and each year thereafter.

Q. WHAT IS A REASONABLE AMORTIZATION PERIOD?

A. A three-year amortization period is reasonable. That is the likely number of years until the Company's next base rate case proceeding when base rates will again be reset based on the Company's recent filing history.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission refund the regulatory liability, including the deferred return on the regulatory liability for the years 2022 through 2024, over a three-year amortization period.

C21-2026

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction of at least $13.182 million in the claimed revenue requirement and requested base revenue increase, consisting of a $13.845 million increase in the negative amortization expense, offset in part by $0.663 for the increase in the test year rate base due to shorter amortization period multiplied by the grossed-up cost of capital.

K. <u>Amortize Deferred Investment Tax Credits Pursuant to The IRA Over Three Years</u>

Q. DESCRIBE THE COMPANY'S DECISIONS TO DEFER AND AMORTIZE THE ITC OVER THE SERVICE LIFE OF THE BATTERY STORAGE ASSETS AND TO *NOT* ELECT OUT OF THE NORMALIZATION REQUIREMENTS.

A. There are two discretionary decisions the Company made, both of which harm customers in order to benefit its shareholder.[49] The first was to defer the ITCs on the battery storage assets and amortize the deferred ITCs over the service life of those assets. The longer the amortization period, the less value of the ITCs to customers and the greater the economic value to the Company's shareholders.

The second was to *not* elect out of the normalization requirements. The failure to elect out of the normalization requirements for these ITCs means that the ITCs must be deferred and amortized over the service life in order to avoid a so-called normalization violation and the loss of the ITCs as a consequence. The failure to elect

[49] Response to Interrogatory 91 in OPC's Fourth Set of Interrogatories. I have attached a copy of this response as my Exhibit LK-14.

out of the normalization requirements also means that the Company cannot reflect the cost-free capital in the cost of capital.

The Company's failure to elect out of the normalization requirements was a decision that it made to retain a significant portion of the economic value of the ITCs rather than providing the entirety of the tax savings to the customers who are required to pay the entirety of the cost of the new battery storage assets.

Q. THE COMPANY CLAIMS THAT IT MADE THE DECISION TO *NOT* ELECT OUT OF THE NORMALIZATION REQUIREMENTS TO "ALLOW REGULATED COMPANIES AND CUSTOMERS TO SHARE BENEFITS" AND TO AVOID VOLATILITY IN THE COMPANY'S TAX EXPENSE PROFILE. PLEASE RESPOND TO THESE REASONS.[50]

A. The short response to both stated reasons is that the Company inequitably and opportunistically chose to benefit its shareholder at the expense of its customers. Fundamentally, the Company has no entitlement to "share" in the ITC benefits when it does not share in the costs of the new battery storage assets. Despite its apparent wish to the contrary, the Company still remains subject to cost-based regulation. The Company's argument to retain some of the benefits and recover all costs is asymmetric, inconsistent with historic cost-based regulation and is conceptually and practically flawed. The only reason for the historic sharing of the pre-IRA ITCs between the utility shareholders and customers was that it was required by the normalization requirements in the Internal Revenue Code. Those requirements do not apply to the new ITCs if the

[50] *Id.*

Company elects out of the normalization requirements. The Commission now has the opportunity and discretion to reflect the entirety of ITC benefit in the cost of service to reduce the cost to customers of new battery storage assets through a negative amortization expense and to include the deferred ITC as cost-free capital in the cost of capital rather than being forced to concede this latter benefit to the Company or "share" it with the Company.

As to the Company's assertion that its decision to *not* elect out of the normalization requirements somehow is necessary to avoid volatility in the Company's tax expense profile is simply wrong. The Commission has the discretion to direct the Company to defer the ITC rather than flowing it through as earned, similar to the Company's unilateral decision to defer the PTCs during the years 2022 through 2024 rather than flowing through those tax credits as they were earned, and then amortize the deferred ITC over a specific and defined amortization period. The deferral and amortization inherently acts to smooth the effect on the Company's tax expense profile. It is not necessary to use the service life for this purpose unless the Commission allows the Company to *not* elect out of the normalization requirements and to harm customers, which I do not recommend.

In summary, there is no benefit to customers from the Company's decision to *not* elect out of the normalization requirements. There is only harm because the Company has acted against the interests of its customers in favor of its own. It is that simple.

C21-2029

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reflect the ITCs as if the Company elected and will continue to elect out of the normalization requirements. It is an annual election and the Company has not yet filed its 2023 federal income tax return or its 2024, 2025, 2026, or 2027 federal income tax returns. If the Company is unwilling to elect out of the normalization requirements each year, then I recommend a reduction in the Company's authorized return on equity or some other form of penalty commensurate with the offense for taking this path of self-interest and self-dealing at the expense of, and harm to, its customers.

I also recommend the Commission direct the Company to defer the ITCs pursuant to the IRA earned each year, but to amortize the deferred ITCs over a three-year amortization period, the same period that I recommend for the deferred PTCs earned in the years 2022 through 2024 and for the same reasons.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATIONS?

A. The effects of the first recommendation are a reduction of $3.493 million in the base revenue requirement and a reduction of $0.100 million in the CETM revenue requirement due to the reduction in the cost of capital by including the new ITCs since 2022 as cost-free capital in the capital structure instead of including the new ITCs at the weighted average cost of capital. There are additional effects on the 2026 and 2027 SYA revenue requirements that I subsequently address in the SYA section of my testimony.

The effects of the second recommendation are a reduction of $12.607 million in the base revenue requirement due to the shorter amortization period. There is no effect on the CETM revenue requirement. There are additional effects on the 2026 and 2027 SYA revenue requirements that I subsequently address in the SYA section of my testimony.

III. COST OF CAPITAL ISSUES

A. Reduce Return Component of Revenue Requirement to Reflect Witness Woolridge's Recommended Return On Equity

Q. HAVE YOU QUANTIFIED THE EFFECT ON THE COMPANY'S REVENUE REQUIREMENT OF THE 9.50% RETURN ON EQUITY RECOMMENDATION SPONSORED BY WITNESS WOOLRIDGE?

A. Yes. The effect is a reduction of $126.379 million in the Company's claimed base revenue requirement and requested rate increase. I calculated this effect in a sequential manner and it is incremental to all prior cost of capital adjustments that I have addressed and quantified for the base revenue requirement. The effects also include a reduction of $3.497 million in the Company's CETM revenue requirement. In addition, there are effects on the requested 2026 and 2027 SYA revenue requirements that I address in the SYA section of my testimony.

Q. HAVE YOU QUANTIFIED THE EFFECT OF EACH 0.10% RETURN ON COMMON EQUITY?

A. Yes. The effect of each 0.10% return on common equity is $6.319 million on the base revenue requirement. The effects of each 0.10% return on common equity is $0.175

million on the CETM revenue requirement. There also are effects on the requested 2026 SYA and 2027 SYA revenue requirements that I address in the SYA section of my testimony.

IV. SUBSEQUENT YEAR ADJUSTMENT ISSUES

A. Reject Company's *Ad Hoc* Proposal to Modify the Historic Ratemaking Framework to Include Post Test Year Rate Increases for "Business As Normal" Distribution Capital Investment Costs

Q. DESCRIBE THE COMPANY'S *AD HOC* PROPOSAL TO MODIFY THE HISTORIC RATEMAKING FRAMEWORK TO INCLUDE POST TEST YEAR RATE INCREASES TO RECOVER "DELIVERY INFRASTRUCTURE" CAPITAL INVESTMENT COSTS AND OPERATING EXPENSES.

A. The Company's requested 2026 SYA and 2027 SYA revenue requirements and rate increases include "delivery infrastructure" capital investment costs and operating expenses. The Company characterizes these delivery infrastructure projects as "incremental investments in Grid Reliability and Resilience."[51]

Q. TO YOUR KNOWLEDGE, HAS THE COMMISSION PREVIOUSLY ALLOWED ADJUSTMENTS FOR "BUSINESS AS NORMAL" "DELIVERY INFRASTRUCTURE" CAPITAL INVESTMENT COSTS AND OPERATING EXPENSES?

[51] Petition at paragraph 27.

A. No. In some cases, the Commission previously has allowed generation base rate adjustments ("GBRAs") for specific new and material generation capital investment costs and operating expenses for the Company and for other utilities,[52] but to the best of my knowledge, it never has allowed SYAs for "delivery infrastructure" capital investment costs and operating expenses.

Q. THE COMPANY CITES RULE 25-6.0425, FLORIDA ADMINISTRATIVE CODE (F.A.C.), RATE ADJUSTMENT APPLICATIONS AND PROCEDURES IN ITS PETITION IN SUPPORT OF ITS REQUESTED 2026 SYA AND 2027 SYA RATE INCREASES. WHAT DOES THIS RULE STATE?

A. Rule 25-6.0425, F.A.C., ("the Rule") states:

> **25-6.0425 Rate Adjustment Applications and Procedures.**
>
> The Commission may in a full revenue requirements proceeding approve incremental adjustments in rates for periods subsequent to the initial period in which new rates will be in effect.

Q. DOES THIS RULE PROVIDE A FRAMEWORK, ESTABLISH LIMITATIONS, SET FORTH ANY GUIDELINES, AND/OR PROVIDE ANY OTHER CUSTOMER PROTECTIONS FOR SUCH INCREMENTAL ADJUSTMENTS?

A. No.

[52] The Commission approved the Company's requests for one GBRA rate increase in 2022 and another GBRA rate increase in 2023, albeit for reduced amounts due to multiple errors in the Company's calculations of the as-filed requests that were corrected in the 2021 Settlement approved in Docket No. 202100034-EI, the Company's last base rate case proceeding. The two requests allowed the Company to "recover the cost of its investment in, and operation of, Phase Two of its Big Bend Modernization Project and Phases Two and Three of its Future Solar projects to the extent of the GBRAs as specified in this Paragraph 4," reciting paragraph 4(a) of the 2021 Settlement.

Q. WHY IS THIS A PROBLEM?

A. It is a problem because there is no framework, no limitations, no guidance, and no customers protections in the Rule or in any other rule for such rate adjustments. In this case, the Company, on an *ad hoc* basis, simply forecasted additional "electric delivery" infrastructure costs that it may or may not actually incur in 2026 and 2027 and included them in its requested 2026 SYA and 2027 SYA revenue requirements.

The Company offered no framework, offered no limitations on the costs that could be included in the 2026 SYA and 2027 SYA in this proceeding or in SYAs in any future proceeding, offered no guidelines for such incremental adjustments, and failed to offer any reasonable customer protections. Among other potential harms to customers, there is no requirement actually to incur the capital costs included in the SYA revenue requirements, to measure or reflect any savings in maintenance expense or storm costs in the SYA revenue requirements, or to prove up the benefits from the expenditures and expenses, if any.

An *ad hoc* approach, such as this, is ripe for abuse because, ultimately, the Company and/or other utilities may seek subsequent year adjustments based on forecasts of any or all capital investment costs and operating expenses on a selective or comprehensive basis. The Company and/or other utilities may include forecast generation, transmission, distribution, and general costs, both capital and expenses, for an unlimited number of future years, subject to no or only limited reporting oversight, with no reconciliation to actual revenues or costs in those future years, with no assurance that the forecasts are comprehensive, let alone reasonable, and with no offsets for growth in base revenues due to customer and sales growth from year to year.

The Company and/or other utilities may base their forecasts on increasingly unknown, unmeasurable, and speculative assumptions, and wish lists well beyond the test year, with the result they will seek to essentially transfer the ratemaking oversight from the Commission to themselves to do as they wish. In that manner and in those circumstances, the purpose, role, and relevance of agency regulation is titular at best, essentially devolving into regulation of, by, and for the utilities themselves for their own self-interest and to the harm of their customers.

Q. WHAT ARE SOME POTENTIAL SOLUTIONS TO THESE PROBLEMS IN THIS PROCEEDING?

A. There are at least three potential solutions. The first and most obvious, is to simply deny the Company's requests for the requested "delivery infrastructure" costs in the 2026 SYA and 2027 SYA revenue requirements and requested increases. If the requests are denied, then the Company can adjust its actual capital expenditures or not, or for that matter, seek to include them, if appropriate, in its Storm Protection Plan ("SPP") and in its SPP Cost Recovery Clause ("SPPCRC") for cost recovery to the extent not already included in the programs approved in the SPP and in the costs already recoverable through the SPPCRC.

The second solution is to deny the Company's requests for these costs in this proceeding, but then initiate a rulemaking to allow all interested parties to participate in establishing a framework, limitations, and guidance applicable to all utilities and on a consistent basis. As with the first solution, if denied, then the Company can adjust its actual capital expenditures or not, or for that matter, seek to include them, if appropriate, in its Storm Protection Plan ("SPP") and in its SPP Cost Recovery Clause ("SPPCRC") for cost recovery.

The third solution is to establish an *ad hoc* framework, limitations, and guidance applicable solely to the Company and solely to its request to include electric delivery costs in the requested 2026 SYA and 2027 SYA.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission deny the Company's requests for recovery of these electric delivery costs in the 2026 SYA and 2027 SYA. OPC Witness Kevin Mara makes this same recommendation in his Direct Testimony in this proceeding, albeit with reference to the Grid Resilience and Reliability projects, the term used by the Company to describe the "electric delivery infrastructure" projects included in its requested SYAs. Alternatively, I recommend the Commission establish an *ad hoc* framework, limitations, guidance, and customer protections applicable solely to the Company in response to the Company's *ad hoc* requests applicable solely to the Company in this proceeding, at least at this time.

If the Commission adopts the alternative approach, then I recommend it adopt the following framework, limitations, guidance, and customer protections, and then assess each of the Company's requested electric delivery infrastructure projects against this framework to establish the projects and costs, if any, for this purpose, that should be included in the 2026 SYA and 2027 SYA. These factors are as follows:

1. Incremental adjustments to rates in periods after the test year in a full revenue requirements proceeding are not a substitute in whole or part for a petition by the utility for a full revenue requirements proceeding and are

allowed only if the projects and/or costs meet certain dollar and other qualification thresholds.

2. Incremental adjustments to rates are limited to the recovery of material and known costs of new identifiable and discrete projects placed in service in a subsequent year, historically, the costs of new generating assets.

3. Incremental adjustments to rates are not permitted for new or expanded programs or categories of costs and are not allowed to annualize costs and increase recovery of the costs that may have been included for a partial year in the cost of service in a full revenue requirements proceeding.

4. Incremental adjustments to rates are not permitted for forecasted increases in "business as normal" costs included in the cost of service and the approved base revenue requirement in the test year used in a full revenue requirements proceeding, including the costs of new forms of assets or new technology used to replace retired assets.

5. Incremental adjustments to rates for the recovery of the costs of new identifiable and discrete projects placed in service in a subsequent year, such as new generating units, are to be offset by the forecasted incremental base revenues in the subsequent year on a weather normalized basis as the result of customer growth in the subsequent year compared to the forecasted base revenues in the test year used in a full revenue requirements proceeding.

6. Related to simultaneous significant reductions in costs included in base revenues and/or reductions or other changes costs included in clause recoveries, such as recoveries embedded into base rates for costs that no longer will be incurred or changes in costs recoverable through the fuel adjustment clause and other clauses.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION TO REMOVE THE COSTS OF THE DELIVERY INFRASTRUCTURE PROJECTS FROM THE 2026 SYA AND THE 2027 SYA?

A. The effects are a $4.599 million reduction in the 2026 SYA revenue requirement and a $28.788 million reduction in the 2027 SYA revenue requirement.

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B. <u>Correct Errors And Otherwise Modify Company's Calculations of 2026 and 2027 SYA Revenue Requirements</u>

Q. DESCRIBE THE COMPANY'S QUANTIFICATION METHODOLOGY FOR THE SUBSEQUENT YEAR ADJUSTMENTS.

A. The Company's quantification methodology is applied on a project by project basis and detailed in the Excel workbook provided in support of Witness Latta's Exhibit RL-1, Document 5, now sponsored by Witness Chronister.[53] The Company calculated the incremental capital related costs for each project by month in the test year and in the subsequent years 2026 and 2027, including rate base, the return on rate base, income taxes on the return on rate base, tax credits grossed up to revenue equivalents, depreciation expense, and property tax expense.[54] The Company also included estimated incremental operation and maintenance expense on a project by project basis by month in the test year and in the subsequent years 2026 and 2027.

The Company calculated gross plant additions based on the estimated in-service dates, accumulated depreciation based on the monthly depreciation expense starting the month after the in-service date using its proposed depreciation rates, although it failed to provide any of the calculations until mere days before the Intervenor testimony filing date, and property tax expense starting in January in the year following the in-service date using an estimated property tax rate for each year.

The Company utilized its requested return in this proceeding, including its requested ratemaking capital structure and return on equity.

[53] (BS 100d) RL Exhibit 5a Support and (BS 100e) RL Exhibit 5b Support.
[54] *Id.*

The Company estimated operation and maintenance expense, but failed to provide any assumptions, data, or calculations in support of its estimates.

The Company also estimated the ITCs (amortization expense only) and PTCs utilized/earned, but failed to provide any of the underlying calculation support, such as the amount of the ITC utilized/earned, the calculations of the amortization expense over the estimated service lives of the projects, and the income tax gross-up to a revenue equivalent, if any, until mere days before the due date for Intervenor testimony. It also failed to provide any of the underlying calculation support for the PTCs, which required estimates of energy generation, the PTC rate per kWh, and the income tax gross-up to a revenue equivalent, if any, until mere days before the due date for Intervenor testimony. OPC requested all Excel workbooks and calculations in its initial discovery in this proceeding and in subsequent discovery requests, including through the deposition of Witness Chronister, yet the Company failed to provide the Excel workbooks, including the assumptions, data, sources of data, and the calculations of the ITC deferred, ITC amortization, and the PTCs generated until mere days before the due date for Intervenor testimony.

Q. DESCRIBE THE MOST SIGNIFICANT ERROR IN THE COMPANY'S CALCULATIONS.

A. The most significant error is that the Company included an income tax expense gross-up on the weighted debt component of the cost of capital used for the rate of return. This error significantly overstates the revenue requirement for each project in each year of the requested SYAs. The Company made a similar error in its initial as-filed

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calculations of the proposed generation base revenue adjustments ("GBRAs") in the prior rate case, but it agreed to correct the error by reducing the as-filed requested GBRA revenue requirements in the 2021 Settlement agreement in that proceeding.[55]

The Company's calculation of the revenue requirement multiplied the requested weighted average cost of capital times the rate base. Instead of correctly grossing up only the weighted equity component of the return for income taxes, the Company incorrectly grossed up the entire cost of capital for income taxes, including the weighted debt component of the return.[56] There is no income tax gross up on the debt return. The revenue recovered for the debt return is exactly offset by the underlying interest expense deduction in the calculation of taxable income and income tax expense, resulting in no income tax expense applicable to the revenue recovery and thus, no need to gross up the debt return for income taxes. The revenue recovered for the equity return is different in that there is no equity return deduction in the calculation of taxable income and income tax expense, meaning that the revenue requirement must include an addition for the income tax expense. This addition for the income tax expense is calculated by multiplying the weighted equity return times an "NOI multiplier," also referred to as an income tax gross-up.

[55] I was personally involved in identifying this error in the prior case and ensuring on behalf of the OPC that it was corrected in the 2021 Settlement. It was my understanding the Company recognized that it was an error and not a negotiated concession. Thus, my reference to the 2021 Settlement is not to cite a settlement concession as precedent, but to note that the error was acknowledged and corrected in the last case.

[56] Response to Interrogatory No. 83(c) in OPC's Fourth Set of Interrogatories. I have attached a copy of the entirety of the response as my Exhibit LK-15.

Q. THE COMPANY REFUSES TO ACKNOWLEDGE THIS ERROR, DESCRIBING THE CALCULATION "AS A REASONABLE PROPOSAL IN THE CONTEXT OF A RATE CASE PROCEEDING."[57] PLEASE RESPOND.

A. The Company's gross-up of the weighted debt return for the 2026 and 2027 SYAs is an outright error. It is not "reasonable" in any conventional usage of that term to calculate the 2026 and 2027 SYA rate increases with an error in the calculation formula. The Company has made no attempt whatsoever to justify the error or explain why it is not an error. It is not a defense to simply claim that an error is a "reasonable proposal."

Q. TO REINFORCE THAT THE GROSS-UP OF THE WEIGHTED DEBT RETURN FOR THE 2026 AND 2027 SYAS IN THIS PROCEEDING IS AN ERROR, DOES THE COMPANY GROSS-UP THE WEIGHTED DEBT RETURN IN THE STORM PROTECTION PLAN REVENUE REQUIREMENT CALCULATIONS?

A. No. The Company's calculation of the return applied to rate base in the Storm Protection Plan revenue requirement calculations correctly grosses-up only the weighed equity return; it does not gross-up the weighted debt return. The Company's Excel workbook filed in that proceeding shows the calculations of the equity and debt components of the grossed-up rate of return and only the equity component is grossed-up for income taxes.[58]

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[57] Response to Interrogatory No. 83(d) and (e) in OPC's Fourth Set of Interrogatories. See Exhibit LK-15.

[58] Excel workbook (BS_54) SPP 2020 Plan Filing Revenue Requirements tab Capital p1 filed by the Company in Docket 20200067-EI. I have attached a copy of the 2020 portion of this tab as my Exhibit LK-16. I note that the line showing the weighted debt return on rate base states that it is grossed-up; however, it is not,

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission correct this error in the calculation of the 2026 and 2027 SYA increases. This is an error that overstates the revenue requirement. It is axiomatic there is no income tax gross-up on the debt component of the return on rate base. The Company's assertion the error is a "reasonable proposal" should be rejected. It is not a reasonable proposal. If the Commission condones this error in this proceeding, then it will encourage Tampa to repeat the error and other utilities to adopt the error in their future requests for GBRAs or other forms of SYAs.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATION?

A. The effects are a reduction of $4.529 million in the 2026 SYA revenue requirements and a reduction of $2.453 million in the 2027 SYA revenue requirements.

Q. ARE THERE ADDITIONAL PROBLEMS WITH THE COMPANY'S CALCULATIONS OF THE SYA REVENUE REQUIREMENTS THAT REQUIRE MODIFICATIONS TO THOSE CALCULATIONS?

A. Yes. First and foremost, the Company failed to reflect increases in revenues due to customer and other sales growth from the test year to each of the subsequent years. The failure to reflect the additional revenues overstates the Company's requested SYAs. OPC witness Dismukes further addresses and quantifies these additional revenues related to the 2026 and 2027 SYAs.

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as demonstrated by the related footnotes for the weighted equity return, which states that it is grossed up, and the weighted debt return, which does not state that it is grossed up, and, in fact, is not grossed up in the actual calculations.

Second, the Company included incremental operation and maintenance expense, but failed to subtract the variable O&M expense savings that it estimated in its cost effectiveness determinations.[59] The failure to reflect these savings overstates the Company's requested SYA revenue requirements.

Third, the Company used unduly short service lives to calculate the depreciation expense for the solar generating and battery storage assets. As I noted in the Operating Income section of my testimony, the Company used a 10-year service life for the battery projects and a 30-year service life for the solar projects included in the test year and the SYAs. The industry standard for battery assets is a 20-year service life. In the last rate case, the order approving the 2021 Settlement established a 35-year service life for the solar projects included in the test year and in the GBRAs. As I previously noted, the Company has failed to provide any compelling argument that the presently authorized 35-year service life for solar assets is unreasonable and should be shortened.

Fourth, the Company failed to elect out of the ITC normalization requirements on the battery storage assets. As I noted in the Operating Income section of my testimony, the Company's failure to elect out of the ITC normalization requirements is unreasonable and harms customers by limiting the ITC amortization period to the service life of the battery storage assets and limits the ability to reflect the cost-free ITCs in the cost of capital.

[59] Direct Testimony of Jose Aponte at pp. 14-33.

Q. WHAT ARE YOUR RECOMMENDATIONS TO ADDRESS THE ADDITIONAL PROBLEMS WITH THE COMPANY'S REQUESTED 2026 SYA AND 2027 SYA REVENUE REQUIREMENTS?

A. I recommend the Commission reduce the requested 2026 and 2027 SYA revenue requirements and requested increases by the revenue amounts quantified by OPC witness Dismukes to reflect the additional base revenues due to growth in customers and sales in 2026 compared to the test year and then in 2027 compared to 2026 for application as credits against the 2026 SYA and 2027 SYA revenue requirements.

I recommend the Commission exclude all incremental O&M expense for the projects reflected in the 2026 and 2027 SYAs to address the Company's failure to reflect the O&M expense savings the Company estimated in its cost effectiveness determinations for those projects.

I recommend the Commission reject the Company's unjustified and unduly short service lives for the solar and battery projects included in the 2026 and 2037 SYAs that I addressed in the Operating Income section of my testimony.

I recommend the Commission amortize the ITCs on the battery storage assets over a three-year amortization period for the reasons that I addressed in the Operating Income section of my testimony.

I recommend the Commission reflect the ITCs on the battery storage assets as cost-free capital in the cost of capital applied to rate base.

I recommend the Commission use the cost of capital reflecting my recommendations regarding capital structure and OPC witness Woolridge's recommended return on equity.

Q. WHAT ARE THE EFFECTS OF YOUR RECOMMENDATIONS?

A. The effects include reductions of $7.994 million for the 2026 SYA and $6.123 million for the 2027 SYA to reflect an increase in base revenues due to the Company's forecast growth in customers in 2026 and 2027 along with additional base revenues to remove the out of model adjustments in the same manner as those adjustments are addressed by Witness Dismukes.

The effects include reductions of $6.696 million and $3.420 million to exclude all incremental O&M expense for the 2026 SYA and 2027 SYA revenue requirements, respectively.

The effects include reductions of $3.670 million for the 2026 SYA and $1.612 million for the 2027 SYA to reflect my recommendation for longer service lives for the solar and battery projects.

The effects include a reduction of $2.792 million for the 2026 SYA to reflect my recommendation for amortizing deferred ITCs over a three-year amortization period. The Company's 2027 SYA did not include an amortization of ITCs.

The effects include reductions of $0.265 million for the 2026 SYA and $0.144 million for the 2027 SYA to reflect my recommendation to include deferred ITCs as cost-free capital in the cost of capital.

The effects include reductions of $9.273 million for the 2026 SYA and $5.022 million for the 2027 SYA to reflect Witness Woolridge's return on equity recommendation. I calculated these effects in a sequential manner and they are incremental to all prior cost of capital adjustments that I have addressed and quantified for the 2026 and 2027 SYA revenue requirements.

Finally, the effects of each 0.10% return on common equity is $0.464 million on the 2026 SYA revenue requirement and $0.251 million on the 2027 SYA revenue requirement.

V. OTHER ISSUES

A. <u>Reject Company's Request for Unknown Future Tax Change Rate Adjustments</u>

Q. DESCRIBE THE COMPANY'S REQUEST TO PREEMPTIVELY ADDRESS THE EFFECTS OF ANY FUTURE CHANGES IN CORPORATE INCOME TAXES THAT AFFECT THE BASE REVENUE REQUIREMENT, 2026 SYA, 2027 SYA, AND CETM.

A. The Company's Petition states:[60]

> The company requests approval to extend the Corporate Income Tax Change provisions in Section 11 of the 2021 Agreement ("Tax Reform Provision") to be effective January 1, 2025 and thereafter until the company's base rates are next set in a general base rate proceeding like this one.

Q. DESCRIBE THE CORPORATE INCOME TAX CHANGE PROVISIONS IN SECTION 11 OF THE 2021 AGREEMENT.

A. Section 11 broadly describes the effects of potential changes in tax law that could affect the Company's costs in the test year in that proceeding, future year GBRAs, and the CETM until base rates are reset in a general base rate proceeding. That provision of the 2021 Settlement agreement expires when new base rates go into effect resulting from this proceeding.

[60] Petition at paragraph 31.

Among other terms in Section 11, the 2021 Settlement agreement describes the effects on income tax expense, including the amortization of deficient (if the income tax rate goes up) or excess (if the income tax rate goes down) deferred income taxes (protected and unprotected), ADIT, and tax credits resulting from changes in income tax rates and the modification of existing tax credits and new tax credits. It also prescribes a general methodological approach for calculating the effects using the Company's "forecasted earnings surveillance report for the calendar year that includes the period in which Tax Changes are effective to calculate the impact of Tax Changes." I also am aware that OPC intends to make legal arguments opposing this request similar to its arguments in Docket 20230023-GU in the Peoples Gas System rate case.

Q. IS THERE ANY COMPELLING REASON TO EXTEND THE CORPORATE INCOME TAX CHANGE PROVISIONS IN SECTION 11 OF THE 2021 AGREEMENT?

A. No. The effects of any corporate income tax changes can be addressed by the Commission on its own initiative and on a statewide basis or through a Petition filed by the Company on its own initiative if and when such corporate income tax changes are enacted. There is no need in this proceeding to attempt to preemptively prescribe future Company Petitions or the calculation methodologies in such filings, which may be considered to have presumptive validity.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission deny the Company's request. It is unnecessary and may inappropriately affect the agency's future actions that otherwise would be applicable to all utilities statewide.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's requested base revenue increase, CETM increase, and the SYA increases. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

C21-2048

(Whereupon, revised prefiled direct testimony - page 36 - of Lane Kollen was inserted.)

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PAUL RENNER
Speaker of the House of Representatives

June 21, 2024

Adam J. Teitzman, Commission Clerk
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 20240026-EI

Dear Mr. Teitzman:

Enclosed for filing in this docket on behalf of the Office of Public Counsel ("OPC") is corrected "strike and type" page 36 of the direct testimony and exhibits of Lane Kollen filed, June 6, 2024. We can file a complete copy of the testimony at the Commission's request.

If you have any questions or concerns; please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

/s/Patricia A. Christensen
Patricia A. Christensen
Associate Public Counsel

cc: All Parties of Record

C21-2049

earned that the Company assumed in the calculation of the 2023 and 2024 GBRA rate increases approved by the Commission in the last base rate proceeding. Instead of flowing through the PTCs to customers in the form of reductions to the approved 2023 and 2024 GBRA rate increases, as required pursuant to the 2021 Settlement in that proceeding, the Company decided ~~unilaterally~~ to defer the PTCs earned in those years in excess of the ITC amortization reflected in the calculation of the 2023 and 2024 GBRA rate increases approved by the Commission. The Company then informed the Commission of its decision to defer the PTCs instead of flowing through the savings to customers. The Company recorded the revenue equivalent of the deferred PTCs as a regulatory liability on a revenue equivalent basis.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE PTCS IN THIS PROCEEDING?

A. The Company proposes to amortize the regulatory liability over ten years as a reduction to the base revenue requirement. It also proposes to flow through the revenue equivalent of the PTCs earned in the test year in the base revenue requirement and the revenue equivalent of the PTCs earned by the new solar generating assets included in the 2026 and 2027 SYA revenue requirements.

Q. DOES THE COMPANY'S PROPOSAL INCLUDE A RETURN ON THE DEFERRED PTCS FROM 2022 THROUGH THE END OF 2024?

A. No. Unlike the ITCs prior to the IRA, the PTCs were not subject to the so-called normalization requirement, meaning that the Company could immediately flow

CHAIRMAN LA ROSA: Let's go to Florida Rising/LULAC.

MR. LUEBKEMANN: Thank you, Mr. Chair. We have no questions.

CHAIRMAN LA ROSA: FIPUG.

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FEA.

CAPTAIN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: Florida Retail.

MR. LAVIA: No questions.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. WAHLEN: No questions.

CHAIRMAN LA ROSA: Staff.

MR. MARQUEZ: Yes, sir.

EXAMINATION

BY MR. MARQUEZ:

Q Good morning, Mr. Kollen.

A Good morning.

Q Mr. Kollen, to the extent that you are able, what is your understanding of any deferment or normalization discussions that took place between OPC and TECO regarding the PTCs for the 2023 and 2024 GBRAs?

A First of all, I was a party to some of the discussions early on, but not all of them. And the resolution, as I understand it, was reflected in a letter from Tampa to the Commission that it was going to treat the deferred production tax credits in a particular manner, the amounts in excess of what were reflected in the 2023 and 2024 subsequent year adjustments, or as they were referred to, in that case, Generation Base Rate Adjustments, in excess of the amortization of the investment tax credits.

The production tax credits came about as a result of the Inflation Reduction Act. The letter did not indicate that it had any agreement from any other party, but in any event, requested the Commission's approval for the treatment that it proposed. The letter did not address deferred carrying cost, and I don't think it addressed the amortization period, but it may have.

Q And that letter that you are mentioning, it didn't indicate agreement, but it also didn't indicate any objection; correct?

A That's correct. It was silent on that point, if I recall correctly.

Q So the phrase normalization of any new tax credits as it appears in the 2021 settlement agreement, what did that language mean to you?

A   Well, at the time, it may have had multiple meanings. With respect to the investment tax credit, at that time -- and this is before the Inflation Reduction Act and the investment tax credits that were enacted into law with that act -- normalization meant that you had to amortize the investment tax credit over the service life of the asset, and that the utility was allowed to keep the carrying costs, or the financing cost savings.

But with respect to the broader use of the term normalization, it was simply that it would be normalized in the sense of, like, normalizing planned generation maintenance expense. In other words, you would attempt to not have it be some unusual amount.

Now, after the Inflation Adjustment Act was enacted into law, there no longer was a normalization requirement on the investment tax credits if the utility elected out. Tampa decided not to elect out, and that is a significant issue in this case. It should have -- the customers have the right to both the amortization of the investment tax credits post --

Q   And, Mr. Kollen, we will discuss the electing out or not later.

So I would like to go to your testimony. So you testified that TECO failed to include PTCs, the

production tax credits, as cost of cost-free capital in the capital structure, right?

A Yes. Production tax credits is differentiated from investment tax credits. That's correct. Simply deferred those amounts, but there were additional benefits, additional value from those production tax credits, and the company ignored the financing cost savings.

Q Did you propose any adjustments to include the PTCs as cost-free capital in TECO's capital structure?

A Not in the test year, because I -- not in the test year, because the company subtracted the production tax credits from rate base, the ones from 2022 to 2024 that were deferred. And so that essentially gives you the cost-free capital in that manner, by subtracting from rate base, rather than reflecting it as cost-free capital in the capital structure.

Q Okay.

A So the company did the right thing there, but -- starting January 1, 2025. But my concern is the period of deferral, from 2022 to 2024. Something needs to be done to address the savings in financing costs for that three-year period.

Q So now I would like to shift the topic of conversation to the ITCs, the investment tax credits.

So you recommend that the Commission reflect ITCs as if TECO elected out of the IRS normalization requirements. Are you recommending that the Commission order TECO to elect out of those requirements?

A To the extent that it's possible or legally permissible to do so, yes.

Q Okay.

A And I recommend that if Tampa decides, the Commission can make such a determination and reflect the investment tax credits as cost-free capital under the presumption that Tampa had elected out of the normalization requirements, which it is entitled to do, and then Tampa will have a decision to make of whether or not it does so.

Now, Tampa will tell you that, well, that will blow us up with the IRS. It will violate the normalization provisions of the code, the Internal Revenue Code. So one way to circumvent that is to, A, direct them, and if they do not do so and, in fact, do enter into a normalization violation, have them come back in and give the Commission a chance to correct that, or find an alternative workaround.

Q So, Mr. Kollen --

A One of the things that I suggest --

Q -- I am trying to understand that if you are

saying -- so if TECO chooses to not elect out of the normalization requirements, but the Commission treats TECO as having elected out, that would be a normalization violation? Am I understanding correctly?

A   Well, it would, but it would be a self-imposed normalization violation.

So the Commission, I think, as the regulator, has the opportunity, and I think, really, the obligation to customers to find some way to address this. And I think it's outrageous, quite frankly, that Tampa Electric has just elected not to elect out of the normalization provisions.

I mean, this is a specific provision in the Internal Revenue Code that gave regulators like you the ability -- who are overseeing these utilities -- the ability to look at what they are doing, and Tampa has not done the right thing here. And you will see a more extensive discussion of that in my testimony.

Q   Mr. Kollen, I just wanted to clarify a second point. So then, if the Commission imposes a penalty on TECO for not electing out of the IRS normalization requirements, would that be a normalization violation?

A   I don't think so. That law has not been developed yet, that case law, but I just -- I think it's, you know, an issue of prudence and reasonableness on the part of Tampa that it has not elected out.

Other utilities throughout the country have readily elected out, and intentionally elected out, because they believe that this is a benefit, a tax benefit that belongs entirely to the customers who are paying the entire cost of the battery storage assets that are generating the investment tax credit. In other words, if the customer is going to pay 100 percent, they should get 100 percent of the tax benefits.

What Tampa is arguing is, Oh, no, we should share those with the customers, and we get to keep the cost-free capital, and we get to amortize it over 30 years, rather than over the three years, or a shorter period of time, like OPC is recommending. And, in fact, I am recommending three years.

So this is a choice that Tampa has made, and it's harmful to the customers, and it's beneficial to Tampa.

Q Mr. Kollen, I heard you already mention the Inflation Reduction Act. Are you also familiar with the Internal Revenue Code that deals with battery storage ITCs?

A Yes.

Q Okay. And does the option to elect out of normalization rules apply only to battery storage ITCs

specifically, or to TECO's overall accounting methodology used for the tax filing year?

A   It's the investment tax credits that were the result of the Inflation Reduction Act. In other words, it's not retroactive to the pre-Inflation Reduction Act investment tax credits. Those already are just the amortization going to the customers, and the company retains the financing savings, because that was the law prior to the Inflation Reduction Act.

Q   In your testimony, on page C21-2027, master page, line 21, continuing on to the next page. And I'll wait until it pops up on your laptop there.

CHAIRMAN LA ROSA: You should also see it in the screen in front of you on the --

THE WITNESS: Yeah, I do. Yes.

CHAIRMAN LA ROSA: Okay.

BY MR. MARQUEZ:

Q   You infer that if TECO elects out of the normalization requirements, the company cannot reflect the cost-free capital in the capital structure. Would you explain what you mean by that?

A   I don't see it. Hang on just a minute.

Yeah. The recommendation and the effects that are discussed on this page of my testimony are to shorten the amortization period to three years for the deferred ITCs pursuant to the Inflation Reduction Act from the company's proposal to amortize them over 30 years. So that's the source of the amount reflected.

Q Okay. I am going to object as nonresponsive and I am going to ask you the question again.

A Okay.

Q All right. So if you look on line --

MR. MARQUEZ: Oh, sustained?

CHAIRMAN LA ROSA: Yes, sustained. Yeah.

MR. MARQUEZ: Thank you, Mr. Chairman.

BY MR. MARQUEZ:

Q So we are going to look at line 21, and continuing on to the top of the next page.

So if I am understanding this correctly, you are inferring that if TECO elects out of the normalization requirements, the company cannot reflect the cost-free capital in the capital structure. So what do you mean by that specifically?

A And where is this again, if you could point me to it?

Q On line 21 --

A Okay.

Q -- and then continuing on to the next page.

A And this is page 40 of my -- as indicated on my written testimony, right?

Q Yes, sir.

A Okay. Well, it is what it says. In other words, it says that the failure to elect out of the normalization requirements for these ITCs, meaning the post Inflation Reduction Act ITCs, means that the ITCs must be deferred and amortized over the service life in order to avoid a so-called normalization violation and the loss of the ITCs as a consequence.

I think that's directly responsive to your question.

Q I will move on, Mr. Kollen.

So should the ITCs from investing in battery storage be recorded as cost-free capital in TECO's capital structure?

A Well, that's not really an issue in terms of recording for accounting purposes. They are recorded as --

Q So then, is that a yes or a no?

A Well, the question is not answerable in the way in which it was posed. I am trying to, you know, clarify it and then give you an answer. Would you like me to do that or not?

Q A yes or no and then explain.

A Well, there isn't a yes or no --

Q Would you like me to ask the question again?

A You may ask the question again, but I don't think there is a yes or no answer.

CHAIRMAN LA ROSA: Can we allow the witness to give --

MR. MARQUEZ: Sure --

CHAIRMAN LA ROSA: -- an explanation and then --

MR. MARQUEZ: -- of course.

CHAIRMAN LA ROSA: -- maybe readdress if yes or no, or maybe something in between, can be offered?

So I am going to suggest for the question to be reasked.

MR. MARQUEZ: The witness can answer the question as he feels is appropriate, then.

THE WITNESS: The issue of cost-free capital is one for ratemaking determination. The accounting is the predicate, really, in terms of it is recorded as a deferred amount, a deferred ITC, and then -- on the company's accounting books. Then the question is, well, how is that treated for ratemaking purposes?

And that -- your question suggested that you were asking for an answer to an accounting question with the use of the word record. When you said record as cost-free capital, that -- the recording is agnostic, you know, in terms of whether it's cost-free or costs something.

But for ratemaking purposes, whether or not it's included in the capital structure makes a difference in terms of the revenue requirement, but that's not an issue of recording. That's why I couldn't answer your question yes or no.

MR. MARQUEZ: Could I have a moment, Mr. Chair?

CHAIRMAN LA ROSA: Sure. Absolutely. Let's take a three-minute break.

(Brief recess.)

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

We left off, staff was in the middle of questioning the witness and was readjusting your thoughts, I believe. That's -- try that now. Sorry.

MR. MARQUEZ: Okay. Thank you, Mr. Chairman, for the time to allow me to confer. We have no additional questions for Mr. Kollen. Thank you.

CHAIRMAN LA ROSA: Okay. Great.

Commissioners, do we have any questions for the witness?

Commissioner Fay.

COMMISSIONER FAY: Thank you. Thank you, Mr. Kollen.

Just one quick question. I am trying to follow this discussion a little bit of what staff has asked, but just clarify for me, so if it's not to -- if the reason to not opt out is not for tax purposes, just help me understand what -- I know you are arguing the customers wouldn't benefit. What's the benefit to the utility?

Make sure your mic is on, Mr. Kollen.

CHAIRMAN LA ROSA: Yeah, Mr. Kollen, double check your mic.

THE WITNESS: Yeah. There are savings when you get production tax credits, as you can imagine, that reduces your income tax expense and your payments. It's like a grant from the government. And the Inflation Reduction Act allows the utility to elect out of what were previous -- the previous requirements.

The previous requirements is that you amortize the benefit of the investment tax credit -- in other words, the principal amount -- over the service life of the assets, but the utility gets to keep the financing savings. You know, you have

$100 million worth of cash, that saves you financing costs. It's not a matter of recording. It's how you treat that for ratemaking purposes.

COMMISSIONER FAY: And that's the previous treatment?

THE WITNESS: That's the previous --

COMMISSIONER FAY: Okay.

THE WITNESS: -- prior to the Inflation Reduction Act. The Inflation Reduction Act said that the utility can elect out of those requirements and, instead, provide the investment tax credit as it's earned, you know, when it first is placed into service, and just give the money all to customers at that time, or it can amortize it how it sees fit, and it can provide the financing cost savings to customers.

Tampa, unlike most of the other utilities, in fact, all of the other utilities that I have encountered, which is many of them, are -- have decided to elect out of the normalization requirements and provide the principal balance, the ITC amortization, to customers, as well as the financing cost savings.

And what this commission could do is direct Tampa to elect out and reflect that in the rate increases, not only for the 2025 test year, but also the two subsequent year adjustments. And then if Tampa decides it doesn't want to, it can appeal that decision and tell you why it doesn't want to provide the tax benefits to customers, the ones that are paying 100 percent of the cost.

COMMISSIONER FAY: And if they -- if, hypothetically, if -- let's say it's with -- not within the Commission's jurisdiction to direct that as it relates to the tax components from the IRS, the resolution -- I am trying to understand the resolution you are proposing, because essentially, if we direct them to do otherwise, it will be deemed a violation of what is required on the tax side, is that correct?

THE WITNESS: Well, if you either direct them to elect out of the normalization requirements, or reflect that in the revenue requirement, the rate increase, okay, through a lower rate increase, Tampa will have a decision to make. And the decision to make is, do they simply comply then and do the right thing, or do they appeal it, or do they blow up the -- their ability to take investment tax credit in the future?

And I don't think that -- I know it may sound like a game of chicken, but it really is not. I think you tell them straight up, we expect this from you. That is the prudent and reasonable thing to do, and we are going to reflect it in the revenue requirement, and you are free to appeal it.

But they will have to go then, not only on rehearing before you and explain why they didn't do it, why customers should not get the full benefit of the investment tax credit. And if you hold firm and they appeal it, they will have to explain it to a court. And quite frankly, I don't think they have a case.

COMMISSIONER FAY: Yeah. And two more questions --

CHAIRMAN LA ROSA: Sure.

COMMISSIONER FAY: -- just follow up. Thank you.

So then going forward, they still have the ability to opt out at first -- for certain years?

THE WITNESS: Yes. It's an annual -- it's whatever they do on their tax return essentially. They don't actually have to file, check a box that say, we elect out. They just simply say, you know, this is how we are treating it.

COMMISSIONER FAY: Okay. And then you

mentioned it -- I guess, your language was unusual. I know you are involved in a lot of different rate cases, and testify a lot.

It's your testimony that this is the only time you have seen where the opt-out hasn't taken place?

THE WITNESS: Yes, where the utility has not elected to elect out. I know that's a double negative, but hasn't done the election out of the normalization requirements.

COMMISSIONER FAY: Okay. Thank you.

Thank you, Mr. Chair.

CHAIRMAN LA ROSA: Thank you.

Let's go back to OPC for redirect.

FURTHER EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Kollen.

A Good morning.

Q And I just have a few, I think, questions to follow up on Commission staff witness' questions and follow up with Commissioner Fay's questions.

Does the company still get the tax benefit if -- even if they elect out from the ITCs?

A Yes.

Q Okay. And do you think that that --

A Let me clarify.

Q I am sorry.

A It isn't able to take the 30-percent investment tax credit for the battery storage and other qualifying assets if it has a normalization violation. But whether or not it has a normalization violation is up to Tampa. In other words, if the Commission says, listen, we are not going to reflect, you know, this 30-year life for amortization purposes of the principal, and we are going to reflect, and going to reflect a shorter life, and we are going to reflect the deferred ITC as cost-free capital in the capital structure. Tampa says, well, we are going -- we are not going to do that. We are not going to elect out. That's Tampa's decision, and it should bear to full repercussions of that.

I think the Commission is just going to have to be very firm with Tampa, because if Tampa gets away with it, as we all know, Florida Power & Light will get away with it. As we all know, Duke will get away with it. They all watch each other. And so you are taking a lot of money out of the pockets of the citizens of the state of Florida if you allow Tampa to get away with this.

Q Do you think that the battery ITCs should be treated as cost-free capital for ratemaking purposes?

A I do. Because as one of the benefits of electing out of the normalization requirements, the customers are allowed to get the entirety of the benefits of the investment tax credits, the customers that are paying 100 percent of the cost of those battery assets.

Q And if you -- if the Commission decides that it should essentially reflect a ratemaking decision as if Tampa Electric had opted out of the ITC normalization, do you believe this would be a penalty?

A I don't. It's the right answer, and then Tampa, I believe, will comply with that.

Q And I think you recall earlier a conversation with Mr. Marquez regarding carrying costs, and who should receive the benefit from the deferred PTCs for the period of 2020 to 2024. Do you recall that?

A Yes, it's '22 to 2024. The PTCS arose as a result of the Inflation Reduction Act in 2022.

Q And you talked about the carrying costs. Are you asking that those carrying costs be added to the deferral from 2022 to 2024 for the deferred PTCs?

A Yes. And that is one of the values of the production tax credits. If they are not flowed through immediately to customers and are deferred, then it should represent some form of cost-free capital. In other words, the company shouldn't get to keep the financing savings. They should be added to the deferral.

Now, in support of that, in the company's 2025 rate filing, they took the deferred production tax credits and subtracted them from rate base, essentially acknowledging that they are cost-free capital, and giving that benefit to customers. But they -- their proposal is that they keep those savings for the deferral period, 2022 through 2024. The way to redress that is to add those deferred carrying costs to the deferral, and then provide the full value to customers through amortization and a subtraction from rate base.

Q And could you explain why -- do you recall a conversation with Mr. Marquez regarding the TECO '21 settlement?

A I do.

Q And do you recall your discussion regarding the term normalization within that settlement?

A I do.

Q Could you explain why the term normalization, as used in the 2021 settlement, could not have contemplated the investment tax -- or the IRA changes?

A Yes.

Normalization, at the time of 2021 settlement, was before the Inflation Reduction Act. And there were certain rules in the tax code that said, for example, on the investment tax credit, that it had to be shared. Customers could get the amortization but not the financing cost savings. Couldn't get both. And the utility couldn't get both. It was a sharing. And there were no production tax credits before the Inflation Reduction Act.

But with the Inflation Reduction Act, things changed very significantly. The utility could elect out of the normalization requirements for investment tax credits, and there never were any normalization requirements for the production tax credits, ever. There -- because production tax credits were available only for nuclear power plants prior to the Inflation Reduction Act. So this was something new for renewable energy.

Q Thank you.

MS. CHRISTENSEN: I don't think I have any further redirect.

CHAIRMAN LA ROSA: Great. Thank you.

Any exhibits that need to be moved into the record?

MS. CHRISTENSEN: Yes, Commissioners. OPC would move in Mr. Kollen's Exhibits LK-1 through

LK-16, and I believe those are premarked as 42 through 57 on the Comprehensive Exhibit List.

CHAIRMAN LA ROSA: All right. Is there objection?

Seeing none, show them entered into the record.

(Whereupon, Exhibit Nos. 42-57 were received into evidence.)

CHAIRMAN LA ROSA: Is there further exhibits?

Seeing no further exhibits, Mr. Kollen, thank you. You are excused.

THE WITNESS: You are welcome. Thank you.

(Witness excuse.)

CHAIRMAN LA ROSA: I will give it back to OPC, when y'all are ready, to call up your next witness.

MR. WATROUS: Thank you, Mr. Chair. OPC would like to call Mr. Mara to the stand, and he has not been administered an oath.

CHAIRMAN LA ROSA: Great. Thank you.

Mr. Mara, if you don't mind, stay still standing and take the administer -- or administer the oath.

Please raise your right hand.

Whereupon,

KEVIN J. MARA

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

THE WITNESS: I do indeed.

CHAIRMAN LA ROSA: Thank you.

EXAMINATION

BY MR. WATROUS:

Q Good morning, Mr. Mara.

A Good morning.

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

A My name is Kevin Mara. My business address is 1850 Parkway Place, Marietta, Georgia.

Q And did you cause to be filed prefiled responsive direct testimony consisting of 25 pages in this docket?

A I did.

Q And do you have any corrections to your testimony?

A No, I do not.

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

A Yes, they would.

MR. WATROUS: I would ask that the testimony be entered into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Kevin J. Mara was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 20240026-EI

Filed: June 6, 2024

DIRECT TESTIMONY

OF

KEVIN J. MARA, P.E.

ON BEHALF OF THE CITIZENS

OF

THE STATE OF FLORIDA

Walt Trierweiler
Public Counsel

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Attorneys for the Citizens
of the State of Florida

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY

DOCKET NO: 20240026-EI

DIRECT TESTIMONY

OF

KEVIN J. MARA, P.E.

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

KEVIN J. MARA

On Behalf of the Citizens of the State of Florida

Before the

Florida Public Service Commission

DOCKET NO: 20240026-EI

I. INTRODUCTION

Q. WHAT ARE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS?

A. My name is Kevin J. Mara. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067. I am the Executive Vice President of the firm GDS Associates, Inc. ("GDS") and Principal Engineer for a GDS company doing business as Hi-Line Engineering. I am a licensed engineer in Florida and 22 additional states.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. I received a degree of Bachelor of Science in Electrical Engineering from Georgia Institute of Technology in 1982. Between 1983 and 1988, I worked at Savannah Electric and Power as a distribution engineer designing new services to residential, commercial, and industrial customers. From 1989-1998, I was employed by Southern Engineering Company as a planning engineer providing planning, design, and consulting services for electric cooperatives and publicly-owned electric utilities. In 1998, I, along with a partner, formed a new firm, Hi-Line Associates, which specialized in the design and planning of electric distribution systems. In 2000, Hi-Line Associates became a wholly owned subsidiary of GDS Associates, Inc. and the name of the firm was changed to Hi-Line Engineering, LLC. In 2001, we merged our operations with GDS Associates, Inc., and Hi-Line Engineering became a department within GDS. I serve as the Principal Engineer for Hi-Line Engineering and am Executive Vice President of GDS. I have field experience in the operation, maintenance, and design of transmission and distribution systems. I have performed numerous planning studies for electric cooperatives and municipal systems. I have prepared short circuit models and overcurrent protection schemes for numerous electric utilities. I have also provided general consulting, underground distribution design, and territorial assistance.

Q. PLEASE DESCRIBE GDS ASSOCIATES, INC.

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Bedford, New Hampshire; Augusta, Maine; Orlando, Florida; Folsom, California; Redmond, Washington; and Madison, Wisconsin. GDS has over 180 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, and statistical services. Our clients are primarily publicly owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have submitted testimony before the following regulatory bodies:

- Vermont Department of Public Service;
- Federal Energy Regulatory Commission;
- District of Columbia Public Service Commission;
- Public Utility Commission of Texas;
- Maryland Public Service Commission;
- Corporation Commission of Oklahoma;
- Public Service Commission of South Carolina; and
- Florida Public Service Commission ("PSC" or "Commission").

I have also submitted expert opinion reports before United States District Courts in California, South Carolina, and Alabama.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit KJM-1, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. GDS was retained by the Florida Office of Public Counsel ("OPC") to provide technical assistance regarding Tampa Electric Company's ("Tampa Electric" or

"Company") petition for a rate increase. Accordingly, I am appearing on behalf of the Citizens of the State of Florida.

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

A. I have reviewed the transmission and distribution costs for inclusion in base rates. I have focused on the subsequent year adjustments ("SYAs") related to the Grid Reliability and Resiliency Program and on the separation of Storm Preparation Plan costs and base rates costs.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARATION OF YOUR TESTIMONY?

A. I reviewed the Company's filing, including the direct testimony and exhibits. I also reviewed the Company's responses to OPC's discovery, the Company's responses to the Commission's Staff's discovery, deposition testimony, and other materials pertaining to the case and its impacts on the Company.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS BASED ON YOUR REVIEW OF THE COMPANY'S TRANSMISSION AND DISTRIBUTION INVESTMENT.

A. In summary, I recommend:

1. The total costs associated with the Grid Reliability and Resiliency Programs be excluded from the SYAs.

2. A disallowance of $7.94 million for an excessive number of spare power transformers.

3. That all Distribution Feeder Hardening costs be included in the SPP. This will disallow $7.97 million from the revenue request which includes costs for 2025. I will need to amend this value once I receive responses from Tampa Electric asking for data for 2024 costs.

Q. WHAT IS YOUR UNDERSTANDING OF THE TEST YEAR USED IN THIS CASE?

A. Tampa Electric is proposing a test year of 2025 with SYAs for 2026 and 2027. My focus is on the transmission and distribution costs and how those costs are captured in the test year and the SYAs.

Q. WHAT IS YOUR UNDERSTANDING OF CAPITAL COSTS INCLUDED IN THIS RATE CASE AND OF THOSE CAPITAL COSTS THAT ARE INCLUDED IN THE STORM PROTECTION PLAN ("SPP")?

A. Tampa Electric obtained approval for certain projects to be included in their SPP and the true-up of the actual costs of the SPP programs are accomplished through the Storm Protection Plan Costs Recover Clause ("SPPCRC"). These costs should be excluded from the capital costs within this rate case. My understanding is that Tampa Electric uses accounting attributes for funding projects, work orders, and plant maintenance orders to separate SPP costs from rate base projects that are incorporated into base rates.[1]

II. GRID RELIABILITY AND RESILIENCY PROJECT

Q. CAN YOU DESCRIBE THE GRID RESILIENCY AND RELIABILITY PROJECT?

A. Yes. This is Tampa Electric's long-term plans for significant investments for grid resilience and reliability.[2] The program consists of projects across six primary domains including: (1) telecommunications; (2) control center operational technology; (3) back-office information technology; (4) distributed energy resources ("DER") infrastructure; (5) field devices; and (6) substations. I have summarized the actual capital costs and future capital budgets for this long-term program in Table 1. More details are included in Exhibit KJM-2 of my testimony.

Table 1
Grid Reliability and Resiliency Projects
Source: Response to OPC Interrogatory 126

Primary Domains	2024	2025	2026	2027	2028	2029	2030	Total 2024-2030
Telecom:	$11,868,996	$54,579,471	$31,351,255	$4,183,006	$0	$0	$0	$101,982,728
Control System OT:	$9,170,282	$21,747,762	$37,721,010	$20,458,794	$9,918,014	$27,181,135	$789,056	$126,986,054
Back-Office IT	$8,605,127	$48,635,557	$59,551,961	$16,444,573	$6,645,398	$35,883,957	$120,000	$175,886,574
DER Infrastructure	$0	$7,188,850	$12,731,332	$13,198,867	$20,343,265	$9,385,248	$13,439,850	$76,287,411
Field Devices:	$1,314,738	$14,686,083	$35,008,116	$48,319,418	$53,199,069	$51,515,734	$73,102,795	$277,145,954
Substations:	$2,000,000	$11,136,809	$19,496,030	$22,113,043	$16,887,529	$16,196,616	$12,205,345	$100,035,372
Totals	**$32,959,142**	**$157,974,532**	**$195,859,705**	**$124,717,701**	**$106,993,276**	**$140,162,690**	**$99,657,046**	**$858,324,092**

[1] Response to OPC Interrogatory No. 44.
[2] Whitworth Direct Testimony, page 21, lines 13-15.

Q. HAS TAMPA ELECTRIC INCLUDED THE CAPITAL COSTS FOR THE GRID RELIABILITY AND RESILIENCY PROGRAM ("GRRP") IN THE SYAS?

A. Yes. Mr. Whitworth stated that some of the costs associated with the GRRP are included in the 2026 and 2027 SYA.[3] Mr. Lukcic stated that the specific items included in the SYAs include the following:[4]

- Private LTE implementation;
- Line Sensor Software;
- Work Management System ("WMS"); and
- Distribution Planning Software upgrades.

However, the budgeted values in these systems do not exactly match with the SYAs values contained in Mr. Lotta's Exhibit Document 5, page 1 of 2 (subsequently adopted by Mr. Chronister). I have summarized a comparison of these values in Table 2. I believe the budgeted amounts in 2025 will carry over to 2026 and 2027, so I have compared the budgeted amounts for 2025-2027 to the SYA values for 2026 and 2027. OPC has requested additional detail as to the exact programs and costs contained in the SYA and based on those responses I may amend my testimony.

[3] Whitworth Direct Testimony, page 36, lines 24-25 and page 37 line 1.
[4] Lukcic Direct Testimony, page 56, lines 17-21.

Table 2
Programs included in the SYAs

	2025	2026	2027	Total 2026 -2027	Source:
GRRP in SYA		$ 33,327,710	$ 128,546,521	**$ 161,874,231**	Latta Document 5 page 1 of 2

	2025	2026	2027	Total 2025 - 2027	
GRRP Telecomm	$ 54,579,471	$ 31,351,255	$ 4,183,006	$ 90,113,732	OPC IRR 7-126
GRRP Line Sensor Software	$ 2,459,785	$ 7,379,355	$ -	$ 9,839,140	OPC IRR 7-126
GRRP Work Mgmnt	$ 24,953,877	$ 19,664,333	$ -	$ 44,618,210	OPC IRR 7-126
GRRP Planning Upgrades					OPC IRR 7-126
Short Cycle Work Mgt Upgrade	$ -	$ 6,633,931	$ 5,939,009	$ 12,572,940	OPC IRR 7-126
Distribution Design Tool	$ 3,875,451	$ 7,635,533	$ 3,875,451	$ 15,386,435	OPC IRR 7-126
Sys Planning / Reliab Tool Upgrade	$ -	$ 1,049,304	$ -	$ 1,049,304	OPC IRR 7-126
			Total	**$ 173,579,761**	

Q. HOW ARE THE TYPE OF PROGRAMS IN THE GRRP USUALLY TREATED FOR RATEMAKING PURPOSES?

A. In traditional ratemaking, the capital projects are planned for and deployed between rate cases or during the test year of the current rate case, then the costs are reviewed for prudence in the next base rate case or current rate case. Further, the types of maintenance and replacement of obsolete equipment are normally included in the Company's annual budgets and would be accounted for in a representative test year which includes costs and revenue one year into the future. However, increases in the test year costs for these routine type of activities above normal levels unnecessarily increases costs for customers and should be scrutinized for imprudent spending.

Q. WHAT ARE THE CONCERNS WITH THESE PROGRAMS IN A SYA?

A. These GRRP in the SYAs, with their forecasted costs of forecasted programs, have compounded the problem of the speculative nature of the costs and deployment timing since they are further out into future (i.e. the further out into the future, the less reliable the forecast). This shifts the risk of deploying these complex systems from the utility, where it should be, to the customers. Even if the Commission were to grant the additional revenues for these projects, the company is under no obligation to spend the revenues on these projects. The Company could choose to use the revenue elsewhere or not at all. In a traditional rate case, deployment with any problems or failures can be viewed from the prospective of prudent management and costs.

Q. IN YOUR OPINION IS IT NECESSARY TO USE THE SYA FOR GRRP?

A. No. I believe there are several reasons why the SYA is not the proper funding mechanism for the GRRP. First, GRRP is collectively a long term project which will not be fully completed by the end of SYAs, as evidenced in Table 1 of my testimony which shows spending beyond 2027. Prudent management and deployment of these complex systems are necessary and should be judged without forecasted costs. Second, many of these projects are simply planned replacement of aged or obsolete infrastructure. Replacement of aging or obsolete infrastructure should be accounted for during the test year in a traditional rate case and does not require subsequent post-test year adjustments. Third, none of this project -- in either its sub-parts or its totality – had been approved by either the Tampa Electric or Emera Boards of Directors at the time the case was filed.[5] Finally, the projects to be included in GRRP will not be completed until 2030, a significant period of

[5] Whitmore Deposition, page 69, lines 20-25 and page 70 lines 1-8.

time after the projected 2025 test year, and therefore should not be included in the costs associated with this rate case.

Q. DO YOU AGREE THAT TELECOMM COSTS WHICH ARE PART OF THE GRRP SHOULD BE INCLUDED IN THE SYAS?

A. No. The cornerstone of the telecom activity is replacement of an older, obsolete communication system. Specifically, according to Mr. Whitworth the existing old radio system needs to be replaced.[6] The new system which is a private cellular network ("PLTE") has advantages in terms of communication security, greater bandwidth, and lower latency (faster communication speed). These are significant advantages. However, Tampa Electric has a legacy system that needed an upgrade, and the Company should prudently plan for its replacement. In fact, in 2022 Tampa Electric engaged a consultant to help analyze options for the communication system.[7] This type of replacement of an older obsolete system is consistent with standard rate design which accounts for cost recovery in the next test year and the new system would become part of the rate base when it is used and useful. There is no need for use of an extraordinary treatment with a SYA to account for these normal type of replacement activities which should be reasonably anticipated and budgeted for in system planning. The traditional test year should be sufficient to allow for the systematic deployment of these capital expenditures.

[6] Whitworth Deposition, page 26 line 23-25 and page 27 lines 1-18.
[7] Lukcic Direct Testimony page 31, lines 18-21.

Q. WHAT IS YOUR UNDERSTANDING WHEN THE PLTE WILL BE COMPLETED?

A. The rollout of the system will require three years and will have a 20-year deployment of technologies enabled by the network.[8] The completion date of the system is projected to be December 2026[9] which is after the end of the test year. Further, this system is used to enable other technologies (DER, field devices, etc.) that will not be fully capable during the affected rate period.

Q. WHAT ABOUT THE OTHER TELECOMM SUBPROGRAM, SHOULD THESE COSTS BE INCLUDED IN SYAS?

A. No. These communication upgrades are needed for greater bandwidth than the existing communication system can provide.[10] Essentially the existing system is obsolete in terms of capacity and upgrades for capacity should be accomplished by means of standard rate design and not by means of the SYAs.

Q. SHOULD THE LINE SENSOR SOFTWARE WHICH IS PART OF THE CONTROL SYSTEM BE INCLUDED IN SYAS?

A. No. This is new software to manage data from line sensors and other field devices and provide data analytics.[11] This system will not be completed until 2026.[12] The software requires input from field devices which will be installed between 2025

[8] Lukcic Direct Testimony page 32, lines 14-16.
[9] Lukcic Deposition, page 83, lines 11-17.
[10] Lukcic Deposition, page 98, lines 19-23.
[11] Lukcic Direct Testimony, page 36, lines 15-19.
[12] Lukcic Deposition, page 82, lines 8-9.

and 2030. Thus, the effective usefulness of the system will not be experienced without these field devices.

Q. REGARDING THE WORK ORDER MANAGEMENT SYSTEM, SHOULD THIS COST BE INCLUDED IN SYAS?

A. No. The system upgrades contained in the Back-Office IT are simply upgrades to existing IT systems and these capital costs are more appropriately included in a traditional rate case. The largest project cost in the Back-Office IT is the upgrade to the existing work order management system. This system will not be completed until the end of 2026[13] which is significantly after the end of the test year. Since this is an upgrade of an existing system, and can be planned and budgeted accordingly, I do not believe these programs need to be in SYAs.

Q. ARE ANY OF THE BACK-OFFICE IT SYSTEMS IN NEED OF REPLACEMENT?

A. Yes. Tampa Electric's core work management system (WorkPro), short-cycle work management system (PragmaCAD), and distribution system planning model (Synergi) are either at end of life, obsolete, or unable to support Tampa Electric future needs.[14] Further, according to Tamp Electric, these systems are no longer in line with industry best practice.[15]

[13] Lukcic Direct Testimony, page 56, lines 19-23.
[14] Response to OPC Interrogatory No. 140.
[15] *Id*.

Q. IS THE WORK ORDER MANAGEMENT SYSTEM DIFFERENT FROM THE ENERGY MANAGEMENT SYSTEM?

A. Yes, these systems are different. The Work Order Management System ("WMS") is at its core an accounting system to manage the flow of work. Projects are identified in the WMS, then these projects are tracked and scheduled, and costs are collected to this system. The Energy Management System, when coupled with the Advanced Distribution Management system is used to control field devices, grid edge devices (behind the meter solar), and monitor the electric grid.

Q. SHOULD THE DISTRIBUTION PLANNING SOFTWARE UPGRADES WHICH ARE PART OF THE BACK-OFFICE IT BE INCLUDED IN SYAS?

A. No. As stated earlier, the distribution system planning model (Synergi) is at its end of life, obsolete, or unable to support Tampa Electric future needs.[16] The collection of new planning modules includes the short cycle work management upgrades, distribution design tool, and the system planning/reliability tool upgrade. Two of the projects are upgrades to existing software solutions and the distribution design tool is a replacement of an existing program. These software applications are scheduled for completion 12 months[17] after the end of the fully projected 2025 test year. These costs that occur after 2025 should be covered by traditional base rates rate base and need not be included in SYAs.

[16] Response to OPC Interrogatory No. 140.
[17] Lukcic Direct Testimony, page 56, lines 19-23.

Q. ARE THERE OTHER GRRP PROJECTS INCLUDED IN THE SYAS?

A. Requests have been made to Tampa Electric for details of projects and costs included in the SYAs. Based on those responses, I may need to amend my testimony.

III. POWER TRANSFORMERS

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE REPLACEMENT OF POWER TRANSFORMERS?

A. Some power transformer replacements are being replaced as part of the GRRP due to obsolescence and to accommodate the Fault Location, Isolation, and Service Restoration ("FLISR") system,[18] while other transformers are being replaced and having capacity increased due to traditional distribution system planning.

Q. DO YOU HAVE CONCERNS REGARDING REPLACEMENT OF POWER TRANSFORMERS IN GRRP?

A. Yes. The power transformer replacements needed for FLISR should be accomplished as part of Tampa Electric traditional planning for grid capacity expansion. Some power transformer replacements are being replaced as part of the GRRP to accommodate FLISR. A FLISR system will automatically transfer load from a failed feeder or failed power transformer to an adjacent feeder or adjacent substation. This can result in a shift from normal loading on a feeder or substation to emergency loading. However, Tampa Electric planning criteria requires the

[18] Lukcic Deposition, page 59, lines 24-25 and page 60, lines 1-4.

distribution system be able to carry the system summer instantaneous peak load following an outage (and restoration switching) of any single system component failure.[19] As such, the need for additional capacity strictly for FLISR would indicate that Tampa Electric failed to design their system in accordance with their own planning criteria. The determination of capacity increases needs to be justified per Tampa Electric's traditional planning criteria.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING POWER TRANSFORMER REPLACEMENTS?

A. Yes. Tampa Electric provided a list of power transformers purchased for the years 2021 to 2023 and the budgets for future transformer purchases. My observation is that Tampa Electric has been, and is, budgeting to purchase an inordinate number of spare transformers. As shown in Table 3, the number of spare transformers for the period of 2021 through 2027 is 29 and the number of transformers assigned to substations is 33. These units range in cost from $975,000 to $1,250,000. The budgeted fleet of spare transformers for 2024 to 2027 is $16,785,000. Normally, utilities will standardize on transformer sizes to minimize their fleet of spare transformers. This number of spares budgeted in the future appears to be excessive. This is another reason why including power

transformers in SYA is not necessary and limits the opportunity for prudence review.

[19] Response to OPC Interrogatory No. 127.

Table 3
Power Transformer Purchases
Source: Response to OPC IRR 7-114

	Assigned to Substation	Spare Unit
2021	9	3
2022	3	3
2023	4	7
2024	6	4
2025	5	4
2026	2	4
2027	4	4
Total	33	29

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE SPARE TRANSFORMERS?

A. Yes. I recommend that four 37 MVA transformers be excluded from rate base. The number of spares is excessive. Even with excluding four 37 MVA transformers, Tampa Electric would still have four spares (one for each service area) and additional six spares purchased between 2021 and 2023. The Table 4 below details the transformers and costs I recommend be excluded from rate base.

Table 4
Power Transformers

Year		Size	Budget		Exclude from Rate Base
2024	Spare	28MVA	$	780,000	
2024	Spare	37MVA	$	975,000	
2024	Spare	37MVA	$	975,000	
2024	Spare	37MVA	$	975,000	Yes
2025	Spare	37MVA	$	975,000	Yes
2025	Spare	37MVA	$	975,000	Yes
2025	Spare	37MVA	$	975,000	Yes

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2025	Spare	37MVA	$	975,000
		Total	$	7,605,000
		Amount to be Excluded		$ 3,900,000

IV. SPP COSTS EXCLUDED FROM BASE RATES

Q. ARE THE CAPITAL COSTS ASSOCIATED WITH SPP PROJECTS INCLUDED IN BASE RATES?

A. No. My understanding is that investments in SPP are recovered through the SPPCRC and are separated from the base rates.

Q. HOW DOES TAMPA ELECTRIC MANAGE THE SEPARATION OF SPP CAPITAL COSTS AND BASE RATES CAPITAL COSTS?

A. I understand that SPP costs are identified using Tampa Electric's accounting system attributes to assign a specific number which is labeled with a code indicating to which SPP program the costs are attributable.[20]

Q. ARE FEEDER HARDENING ACTIVITIES A SPP CAPITAL EXPENDITURE?

A. Yes. Storm hardening of distribution feeders was included in Tampa Electric's SPP plan. Further, in Mr. Whitworth's testimony he noted that 27 feeders were hardened as part of the SPP.[21]

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[20] Response to OPC Interrogatory No. 44.
[21] Whitworth Direct Testimony, page 18, line 11.

Q. WERE ALL OF THE COSTS FOR THE STORM HARDENING FOR THESE 27 FEEDERS EXCLUDED FROM THE BASE RATES?

A. No. A portion of the costs for this storm hardening work was assigned to the SPP and a portion was assigned to rate base that Tampa Electric proposes to include in base rates.

Q. WHAT DO TAMPA ELECTRIC'S ANNUAL BUDGETS FOR 2022-2031 SPP REVEAL FOR FEEDER HARDENING?

A. Tampa Electric's 2022-2031 SPP defined set amounts for Feeder Hardening and Order No. PSC-2022-0386-FOF-EI approved the budgets for 2021, 2022, and 2023. I have created Table 5 illustrating these budgets along with the actual and projected spending through 2027 except for 2024. I am waiting for a response to a data request for the information for 2024. The data shows Tampa Electric is projected to spend up to the limit of the annual approved budgets for the SPP for feeder hardening and excess feeder hardening costs appear to be shifted to base rates.

Table 5
Feeder Hardening
Budgets

Year	Budget (1)	PSC Approved(2)	SPP Spending or Budget (3)	Base rates Spending or Budget (3)
2022	$32.84	$33.40	$9.29	$2.48
2023	$30.12	$30.70	$4.94	$1.59
2024	$30.00	$30.70	(3)	(3)
2025	$29.99		$30.00	$3.90
2026	$29.99		$30.50	$3.90
2027	$30.00		$30.00	$3.90
2028	$29.99			
2029	$29.99			

2030	$36.99
2031	$36.99

(1) Docket 2022048-EI Witness Pickles Page 70 of 78
(2) Order No. PSC-2022-0386-FOF-EI, Docket No. 20220048-EI Table 2.
(3) Response to OPC Interrogatory No.121.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE SPENDING FOR THE FEEDER HARDENING?

A. Yes. Currently, the spending even on the feeder level is split between SPP and base rates which suggests Tampa Electric's method for tracking SPP and rate base projects is not working as intended or Tampa Electric is purposefully moving dollars from the SPP to base rates. I recommend that all feeder hardening costs be shifted to the SPP. As such the total downward adjustment to the base rates rate base would be $7.97 million which includes costs for 2025. I will need to amend this value once I receive responses from Tampa Electric for data for 2024.

Q. ARE LATERAL UNDERGROUNDING PROJECTS A SPP CAPITAL EXPENDITURE?

A. Yes. Lateral undergrounding projects are included in Tampa Electric's SPP plan. Further, in Mr. Whitworth's testimony he noted that 239 lateral undergrounding projects were completed as part of the SPP.[22]

[22] Whitworth Direct Testimony, pages 18 line 11.

Q. WERE ALL OF THE COSTS FOR THE LATERAL UNDERGROUNDING PROJECTS FOR THESE 239 FEEDERS EXCLUDED FROM THE RATE CASE?

A. No. A portion of the costs for these lateral undergrounding projects was assigned to the SPP and a portion was assigned to base rates.

Q. WHAT ANNUAL BUDGETS DOES TAMPA ELECTRIC'S 2022-2031 SPP HAVE FOR LATERAL UNDERGROUNDING?

A. Tampa Electric's 2022-2031 SPP defined set amounts for Lateral Undergrounding and Order No. PSC-2022-0386-FOF-EI approved the budgets for 2021, 2022, and 2023. I have created Table 6 with these budgets along with the actual and projected spending through 2027 except for 2024. I am waiting for a response to a data request for the information for 2024.

Table 6
Lateral Undergrounding

Year	Budget (1)	PSC Approved(2)	SPP Spending or Budget (3)	Rate Base Spending or Budget (3)
2022	$105.66	$105.80	$86.60	$5.50
2023	$104.54	$104.70	$86.60	$4.30
2024	$105.00	$105.20	(3)	
2025	$105.00		$128.20	$7.20
2026	$105.00		$148.00	$10.10
2027	$105.00		$150.50	$10.30
2028	$105.00			
2029	$105.00			
2030	$115.00			
2031	$115.00			

(1) Docket 2022048-EI Witness Pickles Page 70 of 78.

(2) Order No. PSC-2022-0386-FOF-EI, Docket No. 20220048-EI
Table 2.
(3) Response to OPC Interrogatory No.122.

Q. CAN YOU EXPLAIN THE LATERAL UNDERGROUNDING COSTS ASSIGNED TO BASE RATES?

A. Yes. Tampa Electric receives requests from customers for undergrounding and these undergrounding costs are assigned to base rates.[23]

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE SPENDING FOR THE LATERAL UNDERGROUNDING COST ASSIGNED TO BASE RATES?

A. No. However, I am concerned about the accelerated costs for undergrounding especially since this was an issue in the SPP. Within Docket 20220048-EI, some parties argued for restraint in undergrounding costs which represented 60% of the Tampa Electric's SPP budget. The data in Table 6, indicates that Tampa Electric has budgeted for significantly larger levels of undergrounding spending and will necessitate review in subsequent SPPCRC review.

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

[23] Response to OPC Interrogatory No. 115.

A. Yes. I reserve the right to revise my recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS COMPLETE YOUR DIRECT PREFILED TESTIMONY?

A. Yes, at this time. However, the compressed procedural schedule in this proceeding for filing Intervenor testimony has limited the time to complete OPC's investigation into the issues and effects of those issues on the Company's petition. Consequently, it is my understanding that OPC reserves the right to file supplemental testimony to fully address these issues and effects of those issues, if necessary.

BY MR. WATROUS:

Q Did your prefiled testimony have two exhibits attached, labeled KJM-1 and KJM-2?

A Yes, it did.

Q Do you have any corrections to make to your exhibits?

A No, I do not.

Q And would you please summarize your testimony?

A Yes.

Good morning, Commissioners. As an introduction, I am an electrical engineer with more than 40 years of experience in the design and operation utility systems. I am a registered professional engineer here in Florida and 22 other states. I am on the National Electric Safety Code, specializing in structural strength and reliability.

In sum -- my summary is on the current issues in this hearing. The focus of my testimony is on distribution and transmission costs for inclusion in base rates. In addition, I address the inclusion of T&D costs in the subsequent year adjustments from the capital projects are included in base rates for costs, including the test year. And so this would include new capital projects, as well as replacement of existing and obsolete equipment and facilities.

Tampa Electric is proposing a subsequent test year adjustment for certain projects that were shown in Mr Latta's direct testimony in Exhibit 5, which I understand has been adopted by Mr. Chronister.

Of particular interest in my testimony were the costs in subsequent test year adjustments, '26 and '27, for the grid reliability and resiliency projects. These were 33 million in 2006, and 128 million in 2027, as shown in my testimony on Table 2.

I understand these costs have since been reduced. Tampa has removed the cost of software for field devices and distribution planning software upgrades.

In my opinion, the costs associated with the grid reliability and resiliency projects should not be granted special treatment in this subsequent year adjustments. First, these projects collectively would not be complete by 2027. Prudent management and deployment of these complex systems are necessary and shouldn't be judged on forecasted costs.

Secondly, many of the projects are, in fact, just planned replacements of existing and obsolete facilities, which can be planned and forecasted by the utility, and handled that way, rather than through a subsequent year adjustment.

Third, these particular projects were not all approved by Tampa's board at the time the case was filed.

And finally, the collective projects will not truly be completed until 2030, which is significant time past the test year.

My testimony also included the information about spare transformers, specifically in the fault isolation -- Fault Locating Isolation and Service Restoration, referred to as FLISR system. To be fully functional at peak, Tampa feels like they need to upgrade power transformers. And I believe these upgrades should be done through traditional planning methods, as opposed through the grid resiliency and the FLISR program; although, I didn't make any specific adjustment in my testimony for these upgrades.

In addition, I recommended eliminating 437 MBAs power transformers from base rates. I reviewed TECO planned purchases of spare transformers, which I believe could not be justified, and so I recommended reducing the total number of spare transformers, which results in a reduction of seven-and-a-half million dollars.

Q Thank you, Mr. Mara.

MR. WATROUS: And I tender the witness for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

Florida Rising/LULAC.

MR. MARSHALL: No questions. Thank you, Mr. Chairman.

CHAIRMAN LA ROSA: FIPUG.

MR. MOYLE: We have no questions.

CHAIRMAN LA ROSA: Great.

FEA.

CAPTAIN GEORGE: No questions. Thank you.

CHAIRMAN LA ROSA: Great. Thank you.

FRF.

MR. LAVIA: No questions. Thanks.

CHAIRMAN LA ROSA: Walmart.

MS. EATON: No questions.

CHAIRMAN LA ROSA: TECO.

MR. MEANS: No questions.

CHAIRMAN LA ROSA: Staff.

MR. MARQUEZ: No.

CHAIRMAN LA ROSA: No questions.

Commissioners, do we have any questions?

Commissioner Graham, you are recognized.

COMMISSIONER GRAHAM: Thank you, Mr. Chairman. Welcome.

THE WITNESS: Thank you, sir.

COMMISSIONER GRAHAM: I happened to notice that you attended the institution of higher learning in downtown Atlanta, is that correct?

THE WITNESS: That is correct.

COMMISSIONER GRAHAM: Did you happen to see the football scrimmage that they had last Saturday in Dublin, Ireland?

THE WITNESS: I did happen to see that game.

COMMISSIONER GRAHAM: I just wanted to make sure that you didn't miss out on it.

THE WITNESS: I did.

UNIDENTIFIED SPEAKER: I am thinking about objecting for the record.

COMMISSIONER GRAHAM: Thank you. That's all the questions I had.

CHAIRMAN LA ROSA: Did he attend Emory or Georgia Tech? Is it Emory or Georgia Tech? Oh, yeah. Yeah. Excellent.

All right. Let's send it back to OPC for redirect.

MR. WATROUS: Thank you. I would like to -- no redirect.

CHAIRMAN LA ROSA: Okay. Excellent.

All right. Well, let's then move over to exhibits, exhibits to be entered into the record.

MR. WATROUS: I would like to move Exhibits KJM-1 and KJM-2, which are Nos. 58 and 59 in the CEL. I would like to enter them into the record.

CHAIRMAN LA ROSA: Great. Is there objections?

Seeing none, show them entered into the record.

(Whereupon, Exhibit Nos. 58 & 59 were received into evidence.)

CHAIRMAN LA ROSA: Are there others, other exhibits that need to be entered into the record?

Seeing none, Mr. Mara, you are excused.

THE WITNESS: Thank you, sir.

CHAIRMAN LA ROSA: Thank you.

(Witness excused.)

(Transcript continues in sequence in Volume 11.)

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 4th day of October, 2024.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028