BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210034-EI

Petition for rate increase by
Tampa Electric Company.
_________________________________/

DOCKET NO. 20200264-EI

Petition for approval of 2020
depreciation and dismantlement study
and capital recovery schedules, by
Tampa Electric Company.
_________________________________/

VOLUME 4
PAGES 716 - 925

PROCEEDINGS: HEARING

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

DATE: Thursday, October 21, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 10:24 a.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	901	901
2-60	As identified on the CEL	901	901

P R O C E E D I N G S

(Transcript follows in sequence from Volume 3.)

(Whereupon, prefiled direct testimony of Dylan W. D'Ascendis was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

DYLAN W. D'ASCENDIS, CRRA, CVA

ON BEHALF OF TAMPA ELECTRIC COMPANY

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PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

DYLAN W. D'ASCENDIS, CRRA, CVA

ON BEHALF OF TAMPA ELECTRIC COMPANY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DYLAN W. D'ASCENDIS, CRRA, CVA

ON BEHALF OF TAMPA ELECTRIC COMPANY

I. INTRODUCTION AND PURPOSE

Q. Please state your name, affiliation, and business address.

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. On whose behalf are you submitting this testimony?

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

Q. Please summarize your educational background and professional experience.

A. I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

I have offered expert testimony on behalf of investor-owned utilities in over 25 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, and one American Arbitration Association panel on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation of "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation of "Certified Valuation Analyst" by the NACVA in 2015.

The details of my educational background and expert witness appearances are provided in Document No. 1 of Exhibit No. (DWD-1).

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

A. The purpose of my direct testimony is to present evidence on behalf of Tampa Electric and recommend a return on equity ("ROE") to be used for ratemaking purposes in this proceeding.

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

A. Yes. My analyses and conclusions are supported by the data presented in Document Nos. 2 through 13 of Exhibit No. (DWD-1), which have been prepared by me or under my direction and supervision.

II. SUMMARY

Q. What is your recommended ROE for Tampa Electric?

A. I recommend that the Commission authorize Tampa Electric the opportunity to earn an ROE of 10.75 percent on its jurisdictional rate base. The ratemaking capital structure and cost of long-term debt is sponsored by Tampa Electric witnesses Jeffrey S. Chronister and Kenneth McOnie.

Q. Please summarize the support for your recommended ROE for Tampa Electric.

A. My recommended ROE of 10.75 percent is summarized in Document No. 2. To support my ROE recommendation, I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Tampa Electric. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established by the United States Supreme Court in two cases: (1) *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) *("Hope")*; and (2) *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) *("Bluefield")*. No proxy group can be <u>identical</u> in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of the Utility Proxy Group whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to the Non-Price Regulated Proxy Group as discussed further below. The results derived from each are summarized in Document No. 2.

As shown in Document No. 2, I adjusted the indicated common equity cost rate to reflect the effect of flotation costs, as well as the company's business risks associated with its smaller relative size and lack of geographic diversification as compared to the Utility Proxy Group. These adjustments resulted in a company-specific indicated range of common equity cost rates between 10.30 percent and 11.30 percent. Given the Utility Proxy Group and company-specific ranges of common equity cost rates, and the company's high customer growth and level of capital investment plans, my recommended ROE for the company is 10.75 percent.

Q. Please summarize the company’s proposed capital structure.

A. The company is proposing a capital structure which includes a 55.00 percent common equity ratio. That common equity ratio is consistent with the company’s historical equity ratios, and the equity ratios maintained by the Utility Proxy Group and their operating subsidiary utility companies.

III. GENERAL PRINCIPLES

Q. What general principles have you considered in arriving at your recommended common equity cost rate of 10.75 percent?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that a utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit a utility to attract needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases. Consequently, marketplace data must be relied on in assessing a common equity cost rate appropriate for ratemaking purposes. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

Business Risk

Q. Please define business risk and explain why it is important for determining a fair rate of return.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risks.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risks is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, the vagaries of weather, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to specifically and numerically quantify the effect of any individual risk on investors' required return, *i.e.*, the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

Financial Risk

Q. Please define financial risk and explain why it is important in determining a fair rate of return.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.*, failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. Can bond and credit ratings be a proxy for a firm's combined business and financial risks to equity owners (*i.e.*, investment risk)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[1] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

Q. Do rating agencies account for company size in their bond ratings?

A. No. Neither Standard & Poor's ("S&P") nor Moody's Investor Services ("Moody's") have minimum company size requirements for any given rating level. This means, all else being equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

IV. TAMPA ELECTRIC AND THE UTILITY PROXY GROUP

Q. Are you familiar with the company's operations?

A. Yes. Tampa Electric's electric division provides generation, transmission, and distribution electric service to approximately 800,000 retail customers in Florida.[2] Tampa Electric has long-term issuer ratings of A3 from Moody's and BBB+ from S&P.[3] The company is not publicly traded as it comprises an operating subsidiary of TECO Energy, Inc., whose ultimate parent is Emera Incorporated ("Emera" or the

"Parent"). Emera has electric generation, transmission, and distribution operations, natural gas transmission and distribution operations, and non-regulated energy marketing operations in Canada, the United States, and the Caribbean.[4]

Page 1 of Document No. 3 contains comparative capitalization and financial statistics for Tampa Electric for the years 2015 to 2019.[5] During the five-year period ending 2019, the historically achieved average earnings rate on book common equity for the company averaged 10.77 percent. The average common equity ratio based on total permanent capital (excluding short-term debt) was 55.44 percent, and the average dividend payout ratio was 99.71 percent.

Total debt to earnings before interest, taxes, depreciation, and amortization for the years 2015 to 2019 ranges between 2.65 and 3.82 times, with an average of 3.10 times. Funds from operations to total debt range from 20.92 percent to 32.22 percent, with an average of 25.46 percent.

Q. Please explain how you chose the companies in the Utility Proxy Group.

A. The companies selected for the Utility Proxy Group met the following criteria:

- They were included in the Eastern, Central, or Western Electric Utility Group of *Value Line* (Standard Edition);
- They have 70.00 percent or greater of fiscal year 2019 total operating income derived from, and 70.00 percent or greater of fiscal year 2019 total assets attributable to, regulated electric operations;
- They are vertically integrated (*i.e.*, utilities that own and operate regulated generation, transmission, and distribution assets);
- At the time of preparation of this direct testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.*, one publicly traded utility merging with or acquiring another) or any other major development;
- They have not cut or omitted their common dividends during the five years ending 2019 or through the time of preparation of this direct testimony;
- They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Betas;
- They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and
- They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following 13 companies met these criteria: ALLETE, Inc. (ALE); Alliant Energy Corporation (LNT); Ameren Corporation (AEE); Duke Energy Corporation (DUK); Edison International (EIX); Entergy Corporation (ETR); IDACORP, Inc. (IDA); NorthWestern Corporation (NWE); OGE Energy Corporation (OGE); Otter Tail Corporation (OTTR); Pinnacle West Capital Corporation (PNW); Portland General Electric Company (POR); and Xcel Energy, Inc. (XEL).

Q. Please describe Document No. 3, page 2.

A. Page 2 of Document No. 3 contains comparative capitalization and financial statistics for the Utility Proxy Group for the years 2015 to 2019.

During the five-year period ending 2019, the historically achieved average earnings rate on book common equity for the Utility Proxy Group averaged 8.92 percent, the average common equity ratio based on total permanent capital (excluding short-term debt) was 48.93 percent, and the average dividend payout ratio was 53.55 percent.

Total debt to earnings before interest, taxes, depreciation, and amortization for the years 2015 to 2019 for the Utility Proxy Group ranges between 3.96 and 5.30 times, with an average of 4.52 times. Finally, funds from operations to total debt for the Utility Proxy Group range from 15.01 percent to 23.50 percent, with an average of 19.71 percent.

V. CAPITAL STRUCTURE

Q. What is Tampa Electric's requested capital structure?

A. The company's requested capital structure (investor sources) consists of 45.00 percent long-term debt and 55.00 percent common equity. Tampa Electric's requested capital structure is its projected capital structure at the end of the test year, as testified to by Mr. McOnie.

Q. Does Tampa Electric have a separate capital structure that is recognized by investors?

A. Yes. Tampa Electric is a separate corporate entity that has its own capital structure and issues its own debt. Tampa Electric's actual capital structure is reflected in registrations of its debt issuances with the United States Securities and Exchange Commission.

Q. What are the typical sources of capital commonly considered in establishing a utility's capital structure?

A. Common equity and long-term debt are commonly considered in establishing a utility's capital structure because they are the typical sources of capital financing for a utility's rate base.

Q. Please explain.

A. Long-lived assets are typically financed with long-lived securities, so that the overall term structure of the utility's long-term liabilities (both debt and equity) closely match the life of the assets being financed. As stated by Brigham and Houston:

> In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term sources.[6]

Whereas short-term debt has a maturity of one year or less, long-term debt may have maturities of 30 years or longer. Although there are practical financing constraints, such as the need to "stagger" long-term debt maturities, the general objective is to extend the average life of long-term debt. Still, long-term debt has a finite life, which is likely to be less than the life of the assets included in rate base.

Common equity, on the other hand, is outstanding into perpetuity. Thus, common equity more accurately matches the life of the going concern of the utility, which is also assumed to operate in perpetuity. Consequently, it is both typical and important for utilities to have significant proportions of common equity in their capital structures.

Q. Why is it important that the company's requested capital structure, consisting of 45.00 percent long-term debt and 55.00 percent common equity, be authorized in this proceeding?

A. In order to provide safe, reliable, and affordable service to its customers, Tampa Electric must meet the needs and serve the interests of its various stakeholders, including its customers, shareholders, and bondholders. The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong credit ratings, and a supportive regulatory environment, so that the company has access to capital on reasonable terms in order to make necessary investments.

Safe and reliable service cannot be maintained at a reasonable cost if utilities do not have the financial flexibility and strength to access competitive financing markets on reasonable terms. As Mr. McOnie explains, an appropriate capital structure is important not only to ensure long-term financial integrity, it also is critical to enabling access to capital during constrained markets, or when near-term liquidity is needed to fund extraordinary requirements. In that respect, the capital structure, and the financial strength it engenders, must support both normal circumstances and periods of market uncertainty. The authorization of a capital structure that understates the company's actual common equity will weaken the financial condition of its operations and adversely impact the company's ability to address expenses and investments, to the detriment of customers and shareholders. Safe and reliable service for customers cannot be sustained over the long term if the interests of shareholders and bondholders are minimized such that the public interest is not optimized.

Q. How does the company's requested common equity ratio of 55.00 percent compare with the common equity ratios maintained by the Utility Proxy Group?

A. The company's requested ratemaking common equity ratio of 55.00 percent is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy

Group. As shown on pages 3 and 4 of Document No. 3, common equity ratios of the Utility Proxy Group companies range from 36.11 percent to 58.04 percent for fiscal year 2019.

I also considered the *Value Line* projected capital structures for the Utility Proxy Group companies for 2023-2025. That analysis shows a range of projected common equity ratios between 37.50 percent and 59.00 percent (*see*, pages 2 through 14 of Document No. 4).

In addition to comparing the company's actual common equity ratio with current and projected common equity ratios maintained by the Utility Proxy Group companies, I also compared the company's actual common equity ratio with the equity ratios maintained by the utility operating subsidiaries of the Utility Proxy Group companies. As shown on page 5 of Document No. 3, common equity ratios of the utility operating subsidiaries of the Utility Proxy Group range from 47.47 percent to 65.22 percent for fiscal year 2019.

Q. Is Tampa Electric's equity ratio of 55.00 percent appropriate for ratemaking purposes given these measures cited above?

A. Yes, it is. The company's equity ratio of 55.00 percent is appropriate for ratemaking purposes in the current proceeding because it is within the range of the common equity ratios currently maintained, and expected to be maintained, by the Utility Proxy Group and their utility operating subsidiaries.

VI. COMMON EQUITY COST RATE MODELS

Discounted Cash Flow Model

Q. What is the theoretical basis of the DCF model?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate, *i.e.*, the total common equity return rate expected by investors.

Q. Which version of the DCF model did you rely on?

A. I used the single-stage constant growth DCF model in my analyses.

Q. Please describe the dividend yield you used in applying the constant growth DCF model.

A. The unadjusted dividend yields are based on the Utility Proxy Group companies' dividends as of January 29, 2021, divided by the average closing market price for the 60 trading days ended January 29, 2021 (*see*, Column 1, page 1 of Document No. 4).

Q. Please explain your adjustment to the dividend yield.

A. Because dividends are paid periodically (*e.g.*, quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half of the annual dividend growth rate in the dividend yield component, or

$D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Document No. 4 were adjusted upward to reflect one-half of the average projected growth rate shown in Column 6.

Q. Please explain the basis for the growth rates you apply to the Utility Proxy Group in your constant growth DCF model.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. Please summarize the constant growth DCF model results.

A. As shown on page 1 of Document No. 4, the application of the constant growth DCF model to the Utility Proxy Group results in a wide range of indicated ROEs from 6.28 percent to 11.20 percent. The adjusted mean of those results is 9.03 percent, the adjusted median result is 8.85 percent, and the average of the two is 8.94 percent. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF.

The Risk Premium Model

Q. Please describe the theoretical basis of the RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debtholders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, the investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. Please explain how you derived your indicated cost of common equity based on the RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the Predictive Risk Premium Model ("PRPM"), and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

Q. Please explain the first risk premium method (*i.e.*, the PRPM).

A. The PRPM, published in the *Journal of Regulatory Economics*,[7] was developed from the work of Robert F. Engle III, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[8] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Furthermore, Engle discovered that the volatility of prices and returns cluster over time and is, therefore, highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an <u>estimate</u> of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term United States Treasury securities through January 2021. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series (*see*, Columns 1 and 2, page 2 of Document No. 5) and a GARCH coefficient (*see*, Column 4, page 2 of Document No. 5). Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[9] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.31 percent (*see*, Column 6, page 2 of Document No. 5.) to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip Financial Forecasts ("Blue Chip")*.[10]

As shown on page 2 of Document No. 5, the mean PRPM indicated common equity cost rate for the Utility Proxy Group is 10.47 percent, the median is 10.24 percent, and the average of the two is 10.36 percent. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the

Utility Proxy Group PRPM to calculate a cost of common equity rate of 10.36 percent.

Q. Please explain the second risk premium method (*i.e.*, the total market approach RPM).

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a Beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for electric utilities.

Q. Please explain the basis of the expected bond yield of 3.66 percent applicable to the Utility Proxy Group.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2022, and *Blue Chip*'s long-term projections for 2022 to

2026, and 2027 to 2031. As shown on line 1, page 3 of Document No. 5, the average expected yield on Moody's Aaa-rated corporate bonds is 3.06 percent. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.50 percent, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds (as shown on line 2 and explained in note 2 on page 3 of Document No. 5). Adding that recent 0.50 percent spread to the expected Aaa-rated corporate bond yield of 3.06 percent results in an expected A2-rated public utility bond yield of 3.56 percent. Since the Utility Proxy Group's average Moody's long-term issuer rating is A3, another adjustment to the expected A2-rated public utility bond is needed to reflect this difference in bond ratings. An upward adjustment of 0.10 percent, which represents one-third of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the A2 prospective bond yield applicable to an A3-rated public utility bond (as shown on line 4 and explained in note 3 on page 3 of Document No. 5). Adding the 0.10 percent to the 3.56 percent prospective A2-rated public utility bond yield results in a 3.66 percent expected bond yield applicable to the Utility Proxy Group as shown on page 3 of Document No. 5.

Q. Please explain how the Beta-derived equity risk premium is determined.

A. The components of the Beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the Beta coefficient. The derivation of the Beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, on page 8 of Document No. 5. The total Beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. How did you derive a market equity risk premium based on long-term historical data?

A. To derive an historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2020 ("SBBI - 2020")[11] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2019. Using holding period returns over a long period of time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.83 percent and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.05 percent (as explained in note 1, page 9 of Document No. 5). As shown on line 1, page 8 of Document No. 5, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.78 percent.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in <u>SBBI - 2020</u>.[12] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a <u>constant</u> rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. Please explain the derivation of the regression-based market equity risk premium.

A. To derive the regression-based market equity risk premium of 9.30 percent shown on line 2, page 8 of Document No. 5, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta(R_{Aaa/Aa})$$

Q. Please explain the derivation of the PRPM equity risk premium.

A. I applied the same PRPM approach described above to the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through January 2021.[13] Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 9.65 percent (*see*, line 3, page 8 of Document No. 5).

Q. Please explain the derivation of a projected equity risk premium based on *Value Line* data for your RPM analysis.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 9 of Document No. 5. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended January 29, 2021, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (as explained in note 1, page 2 of Document No. 6).

The average median expected price appreciation is 35.00 percent, which translates to a 7.79 percent annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.04 percent, equates to a forecasted annual total return rate on the market of 9.83 percent. The forecasted Moody's Aaa-rated corporate bond yield of 3.06 percent is deducted from the total market return of 9.83 percent, resulting in an equity risk premium of 6.77 percent, as shown on line 4, page 8 of Document No. 5.

Q. Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 14.10 percent. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.06 percent results in a 11.04 percent projected equity risk premium as shown on line 5, page 8 of Document No. 5.

Q. Please explain the derivation of an equity risk premium based on Bloomberg data.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 17.78 percent. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.06 percent results in a 14.72 percent projected equity risk premium as shown on line 6, page 8 of Document No. 5.

Q. What is your conclusion of a Beta-derived equity risk premium for use in your RPM analysis?

A. I gave equal weight to all six equity risk premiums based on each source – historical, *Value Line*, and Bloomberg – in arriving at a 9.54 percent equity risk premium as shown on line 7, page 8 of Document No. 5.

After calculating the average market equity risk premium of 9.54 percent, I adjusted it by the Beta coefficient to account for the risk of the Utility Proxy Group. As discussed below, the Beta coefficient is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Document No. 6, the average of the mean and median Beta coefficient for the Utility Proxy Group is 0.96. Multiplying the 0.96 average Beta coefficient by the market equity risk premium of 9.54 percent results in a Beta-adjusted equity risk premium for the Utility Proxy Group of 9.16 percent (see line 9, page 8 of Document No. 5).

Q. How did you derive the equity risk premium based on the S&P Utility Index and Moody's A-rated public utility bonds?

A. I estimated three equity risk premiums based on the S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.74 percent and monthly Moody's A-rated public utility bond yields of 6.53 percent from 1928 to 2019 to arrive at an equity risk premium of 4.21 percent (as shown on line 1, page 12 of Document No. 5.). I then used the same historical data to derive an equity risk premium of 6.83 percent based on a regression of the monthly equity risk premiums (as shown on line 2, page 12 of Document No. 5). The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to January 2021 to arrive at a PRPM-derived equity risk premium of 5.59 percent for the S&P Utility Index (as shown on line 3, page 12 of Document No. 5).

I then derived expected total returns on the S&P Utilities Index of 10.36 percent and 7.67 percent using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 3.56 percent (derived on line 3, page 3 of Document No. 5), which resulted in equity risk premiums of 6.80 percent and 4.11 percent, respectively (as shown on lines 4 and 5, respectively, on page 12 of Document No. 5). As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.51 percent as shown on line 6, page 12 of Document No. 5.

Q. How do you derive an equity risk premium of 5.92 percent based on authorized ROEs for electric utilities?

A. The equity risk premium of 5.92 percent shown on line 3, page 7 of Document No. 5 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 13 of Document No. 5. Page 13 of Document No. 5 contains the graphical results of a regression analysis of 1,179 rate cases for electric utilities which were fully litigated during the period from January 1, 1980, through January 29, 2021. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[14] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 3.56 percent, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.92 percent, which is shown on line 3, page 7 of Document No. 5.

Q. What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. The equity risk premium I apply to the Utility Proxy Group is 6.86 percent, which is the average of the Beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 9.16 percent, 5.51 percent, and 5.92 percent, respectively, as shown on page 7 of Document No. 5.

Q. What is the indicated RPM common equity cost rate based on the total market approach?

A. As shown on line 7, page 3 of Document No. 5, I calculated a common equity cost rate of 10.52 percent for the Utility Proxy Group based on the total market approach RPM.

Q. What are the results of your application of the PRPM and the total market approach RPM?

A. As shown on page 1 of Document No. 5, the indicated RPM-derived common equity cost rate is 10.44 percent, which gives equal weight to the PRPM (10.36 percent) and the adjusted-market approach results (10.52 percent).

The Capital Asset Pricing Model

Q. Please explain the theoretical basis of the CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the Beta coefficient (β). A Beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a Beta coefficient greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the Beta coefficient. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta(R_m - R_f)$$

Where: R_s = Return rate on the common stock;

R_f	=	Risk-free rate of return;
R_m	=	Return rate on the market as a whole; and
β	=	Adjusted Beta coefficient (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the Beta coefficient is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[15]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding the figure in Document No. 12, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[16]

In addition, Morin observes that while the results of these tests support the notion that Beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[17]

* * *

Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x(R_M - R_F) + (1-x)\ \beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [18]

Fama and French provide similar support for the ECAPM when they state:

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well

> as in more recent cross-section regressions tests, like Fama and French (1992).[19]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the highest beta is 16.8 percent per year; the actual is 13.7 percent.[20]

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. What Beta coefficients did you use in your CAPM analysis?

A. For the Beta coefficients in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg. While both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, *Value Line* calculates the Beta coefficient over a five-year period, while Bloomberg calculates it over a two-year period.

Q. Please describe your selection of a risk-free rate of return.

A. As shown in Column 5, page 1 of Document No. 6, the risk-free rate adopted for both applications of the CAPM is 2.31 percent. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2022, and long-term projections for the years 2022 to 2026 and 2027 to 2031.

Q. Why is the yield on long-term U.S. Treasury bonds appropriate for use as the risk-free rate?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital of public utilities measured by the yields on Moody's A-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

A. The basis of the market risk premium is explained in detail in note 1, page 2 of Document No. 6. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.09 percent was deducted from the SBBI - 2020 monthly historical total market return of 12.10 percent, which results in an historical market equity risk premium of 7.01 percent.[21] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2020. That regression analysis yielded a market equity risk premium of 9.98 percent. The PRPM market equity risk premium is 10.76 percent and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through January 2021.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.31 percent, discussed above, from the *Value Line* projected total annual market return of 9.83 percent, resulting in a forecasted total market equity risk premium of 7.52 percent. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 2.31 percent from the projected total return of the S&P 500 of 14.10 percent. The resulting market equity risk premium is 11.79 percent.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.31 percent from the projected total return of the S&P 500 of 17.78 percent. The resulting market equity risk premium is 15.47 percent. These six measures, when averaged, result in an average total market equity risk premium of 10.42 percent as shown on page 2 of Document No. 6.

Q. What are the results of your application of the traditional and empirical CAPM to the Utility Proxy Group?

A. As shown on page 1 of Document No. 6, the adjusted mean result of my CAPM/ECAPM analyses is 12.44 percent, the adjusted median is 12.28 percent, and the average of the two is 12.36 percent. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 12.36 percent.

Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. Why do you also consider a proxy group of domestic, non-price regulated companies?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group that is comparable in total risk to the Utility

Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. How did you select non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the Beta coefficients and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 48 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms were:

- They must be covered by *Value Line* (Standard Edition);
- They must be domestic, non-price regulated companies, *i.e.*, not utilities;
- Their Beta coefficients must lie within plus or minus two standard deviations of the average unadjusted Beta coefficients of the Utility Proxy Group; and
- The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted Beta coefficients must

lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Beta coefficients measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar Beta coefficients and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. Have you prepared a schedule which shows the data from which you selected the 48 domestic, non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Document No. 7.

Q. Did you calculate common equity cost rates using the DCF model, RPM, and CAPM for the Non-Price Regulated Proxy Group?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Document No. 8 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 11.52 percent.

Pages 3 through 5 of Document No. 8 contain the data and calculations that support the 12.67 percent RPM common equity cost rate. As shown on line 1, page 3 of Document No. 8, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the second quarter of 2022, and for the years 2022 to 2026 and 2027 to 2031, is 4.04 percent.[22] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa1, a downward adjustment of 0.15 percent to the projected Baa2-rated corporate bond yield is necessary to reflect the difference in ratings which results in a projected Baa1-rated corporate bond yield of 3.89 percent.

When the Beta-adjusted risk premium of 8.78 percent (as derived on page 5 of Document No. 8) relative to the Non-Price Regulated Proxy Group is added to the prospective A3/Baa1-rated corporate bond yield of 3.89 percent, the indicated RPM common equity cost rate is 12.67 percent.

Page 6 of Document No. 8 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.00 percent.

Q. What is the cost rate of common equity based on the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group?

A. As shown on page 1 of Document No. 8, the results of the common equity models applied to the Non-Price Regulated Proxy Group – which group is comparable in total risk to the Utility Proxy Group – are as follows: 11.52 percent (DCF), 12.67 percent (RPM), and 12.00 percent (CAPM). The average of the mean and median of these models is 12.03 percent, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VII. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. What is the indicated common equity cost rate before adjustments?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates attributable to the Utility Proxy Group before any relative risk adjustments is between 9.94 percent and 10.94 percent as shown in Document No. 2. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost rate results, I conclude that a range of common equity cost rates between 9.94 percent and 10.94 percent is reasonable and appropriate before any adjustments for relative risk differences between the company and the Utility Proxy Group are made. The bottom of the indicated range (*i.e.*, 9.94 percent) was calculated by averaging the average of all model results (10.94 percent) with the lowest model result (8.94 percent), and the top of the indicated range is the approximate average of all model results. I have chosen this indicated range of common equity cost rates applicable to the Utility Proxy Group as a conservative estimate of the required ROE.

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Flotation Costs

Q. What are flotation costs?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the company receives less than one full dollar in financing.

Q. Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred

to build utility plants, and fair regulatory treatment must permit recovery of these costs…

The simple fact of the matter is that common equity capital is not free… [Flotation costs] must be recovered through a rate of return adjustment.[23]

Q. Do the common equity cost rate models you have used already reflect investors' anticipation of flotation costs?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[24] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[25] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. How did you calculate the flotation cost allowance?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by Tampa Electric's parent, Emera, in its equity issuances since its acquisition of Tampa Electric. Based on the issuance costs shown on page 1 of Document No. 9, an adjustment of 0.13 percent is required to reflect the flotation costs applicable to the Utility Proxy Group.

Business Risk Adjustment

Q. What company-specific business risks did you consider in your recommended ROE?

A. As detailed below, I've considered the company's smaller size and lack of geographic diversification relative to the Utility Proxy Group in my ROE recommendation.

Q. Does the company's smaller size relative to the Utility Proxy Group companies increase its business risk?

A. Yes. The company's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

Q. Is the increased relative risk due to small size and the associated implications on the rate of return on common equity supported by financial literature?

A. Yes, it is. As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps' 2020 Valuation Handbook – U.S. Guide to Cost of Capital ("D&P – 2020") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Returns," D&P – 2020 states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of

> capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[26]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 14, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[27]

Based on this evidence, Fama and French proposed their three-factor model, which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[28] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.**[29] (emphasis added)

Consistent with the financial principle of risk and return discussed above, increased relative risk due to Tampa Electric's smaller size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of the company, including its smaller relative size, which is justified and supported above by evidence in the financial literature.

Q. Please describe the company's lack of geographic diversity and why that increases its relative risk?

A. Tampa Electric's service area in West Central Florida is extremely compact compared to other Florida investor-owned utilities. In the event of a substantial storm or other catastrophic event, the entire system and customer base of Tampa Electric is at risk for damage, outages, and other customer impacts. This is unlike other utilities in Florida, and more importantly, the Utility Proxy Group, which have more geographically diverse service areas or larger service territories, which may only have a portion of the system assets and customer base affected in the case of storms or other natural disasters or catastrophic events, allowing the unaffected areas and assets to help mitigate certain impacts and help sustain the utility while repairs are made in affected areas. Tampa Electric's smaller size and limited geographic diversity have also been recognized as key risks in the company's recent S&P and Moody's credit ratings reports.[30]

Q. Is there a way to quantify a relative risk adjustment due to the company's smaller size and lack of geographic diversity when compared to the Utility Proxy Group?

A. Yes. The company has greater relative risk than the average utility in the Utility Proxy Group because of its smaller size and lack of geographic diversity. As a proxy for its greater risk, I will use the difference in size between Tampa Electric and the Utility Proxy Group as measured by its estimated market capitalization of common equity.

As shown in Document No. 10, the company's estimated market capitalization is approximately $7,780 million, compared with the market capitalization of the average company in the Utility Proxy Group of $15,616 million. The average company in the Utility Proxy Group has a market capitalization approximately 2.00 times the size of the company's estimated market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates attributable to the Utility Proxy Group to reflect the company's greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2019 period. The average size premium for the Utility Proxy Group with a market capitalization of $15,616 million falls in the second decile, while the company's estimated market capitalization of $7,780 million places it in the third decile. The size premium spread between the second decile and the third decile is 0.23 percent.

Q. Since Tampa Electric is part of a larger corporation, why is the size of the total corporation not more appropriate to use when determining the size adjustment?

A. The return derived in this proceeding will not apply to Emera's operations as a whole, but only to Tampa Electric's. Emera is the sum of its constituent parts, including those constituent parts' ROEs. Potential investors in the parent company are aware that it is a combination of operations in each state, province, and country and that each geographic area's operations experience the operating risks specific to their jurisdiction. The market's expectation of Emera's return is commensurate with the realities of the corporation's composite operations in each of the geographic areas in which it operates.

Other Considerations

Q. Have you considered any other company-specific issues in your recommended ROE?

A. Yes, I have. In addition to the company's flotation costs and its smaller relative size, I have also considered the company's high customer growth, and level of capital expenditures compared to the Utility Proxy Group companies in my ROE recommendation.

Q. Please describe the company's high customer growth.

A. Tampa Electric's total number of retail customers has increased by 56,500 (*i.e.*, approximately 7.7 percent) over the past five years.[31] The increased customer growth in Tampa Electric's service territory necessitates increased and accelerated capital investment.

Q. Please briefly summarize the company's capital investment plans.

A. Tampa Electric currently plans to invest over $4.0 billion of additional capital over the 2021-2024 period,[32] which represents over 54.00 percent of its 2019 year-end net utility plant.[33] That amount includes investments required to support growth, and to maintain safe, sufficient, and reliable service in both its transmission and distribution facilities. As discussed by Mr. McOnie, the company will require continued access to the capital markets, at reasonable terms, to finance its capital spending plan. As the company moves forward with its capital spending plan, timely recovery of its capital costs is critical to mitigate the delay of capital recovery and execute its capital spending program.

Q. Do substantial capital expenditures directly relate to a utility being allowed the opportunity to earn a return adequate to attract capital at reasonable terms?

A. Yes, they do. The allowed ROE should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates, and to maintain its financial integrity in a variety of economic and capital market conditions. As discussed throughout my direct testimony, a return adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness. To the extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged. These requirements are of particular importance to a utility when it is engaged in a substantial capital expenditure program.

The ratemaking process is predicated on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that since utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors the current and expected financial conditions of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets.

Q. Do credit rating agencies recognize risk associated with increased capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long-term challenges for utilities' financial health including: heavy construction programs to address demand growth; declining capacity margins; and aging infrastructure and regulatory responsiveness to mounting requests for rate increases.[34] More recently, S&P noted:

> We assume that capital spending will remain a focus of most utility managements and strain credit metrics. It provides growth when sales are diminished by ongoing demanded efficiency from regulators and other trends, and it is welcomed by policymakers that appreciate the economic stimulus and the benefits of safer, more reliable service. The speed with which the regulatory process turns the new spending into higher rates to begin to pay for it is an important factor in our assumptions and the forecast. Any extended lag between spending and recovery can exacerbate the negative effect on credit metrics and therefore ratings.[35]

The rating agency views noted above also are consistent with certain observations discussed in my direct testimony: (1) the benefits of maintaining a strong financial profile are significant when capital access is required and become particularly acute during periods of market instability; and (2) the Commission's decision in this proceeding will have a direct bearing on the company's credit profile and its ability to access the capital needed to fund its investments.

Q. How do the company's expected capital expenditures compare to the Utility Proxy Group?

A. To reasonably make that comparison, I calculated the ratio of expected capital expenditures to net plant for each company in the Utility Proxy Group. I performed that calculation using Tampa Electric's projected capital expenditures during 2021 through 2024 relative to its net plant for the year ended December 31, 2019. As shown in Document No. 11, Tampa Electric has the highest ratio of projected capital expenditures to net plant relative to the Utility Proxy Group, approximately 39.00 percent higher than the Utility Proxy Group median.

Q. What are your conclusions regarding the effect of Tampa Electric's capital investment plan on its risk profile and cost of capital?

A. It is clear that Tampa Electric's capital investment plan relative to net plant is larger than the median of the Utility Proxy Group companies. It also is clear that equity investors and credit rating agencies recognize the additional risks associated with substantial capital expenditures.

Q. What is the indicated cost of common equity after your company-specific adjustments?

A. Applying the 0.13 percent flotation cost adjustment and the 0.23 percent business risk adjustment to the indicated range of common equity cost rates between 9.94 percent and 10.94 percent results in a company-specific range of common equity rates between 10.30 percent and 11.30 percent. In consideration of both of these indicated ranges in addition to the company's high customer growth, and its substantial capital expenditure program, I recommend an ROE of 10.75 percent for Tampa Electric in this proceeding.

IX. CONCLUSION

Q. What is your recommended ROE for Tampa Electric?

A. Given the discussion above and the results from the analyses that I have performed, I recommend that an ROE of 10.75 percent is appropriate for the company at this time.

Q. In your opinion, is your proposed ROE of 10.75 percent fair and reasonable to the company and its customers?

A. Yes, it is.

Q. In your opinion, is the company's proposed equity ratio of 55.00 percent fair and reasonable to the company and its customers?

A. Yes, it is.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Archibald D. Collins was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
ARCHIBALD D. COLLINS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ARCHIBALD D. COLLINS

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

A. My name is Archibald D. Collins. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Emera Inc. and am seconded to Tampa Electric Company ("Tampa Electric" or "company") as President and Chief Operating Officer and will become Chief Executive Officer on May 3, 2021.

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

A. Today as President and Chief Operating Officer, I report to the Chief Executive Officer of Tampa Electric. I have overall responsibility for all aspects of the company including strategy development, operations of the company, safety, environment, customer experience, generation, transmission, distribution, construction, facility services and other shared services including Information Technology, Legal, Human Resources, Finance and

Procurement. All Tampa Electric Officers report to me, and together we lead a total of approximately 2,400 team members.

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

A. I graduated from St. Francis Xavier University with a diploma in Engineering and from Dalhousie University with a bachelor's degree in Chemical Engineering.

I have more than 30 years of experience in the energy industry. Prior to becoming Chief Operating Officer of Tampa Electric in 2018, and then President and Chief Operating Officer of the company in 2021, I held the position of President and Chief Executive Officer of Grand Bahama Power Co. and President and Chief Operating Officer of Emera Caribbean. In addition, I have served as Executive Vice President of Commercial Operations with Emera Energy, as Vice President of Operations at Emera Energy, and in senior roles with Nova Scotia Power.

Q. What are the purposes of your direct testimony?

A. Tampa Electric is requesting that the Florida Public

Service Commission ("Commission") approve a $294.9 million increase in the company's retail base rates and to reduce its miscellaneous service revenues by $6.6 million. Our filing also proposes Generation Base Rate Adjustments ("GBRA") in 2023 and 2024, for approximately $102.2 and $25.6 million, respectively. The purposes of my direct testimony are to (1) describe Tampa Electric's key actions since our last request for rate relief in 2013 and how they have benefitted customers; (2) explain how our strategic focus on our customers, cost control, and decarbonization, all enabled by our employees, has positioned our company to keep customer bills at about the same level they were in 2013; (3) describe significant investments planned or underway to meet customers' needs; and (4) summarize the company's request for rate relief. I will also introduce the other witnesses who have filed direct testimony in support of the company's petition and briefly describe the subject matter each witness will cover.

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

A. Yes. Exhibit No. ADC-1, entitled "Exhibit of Archibald D. Collins" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of the four documents:

Document No. 1	List of Tampa Electric Witnesses and Purpose of their Direct Testimony
Document No. 2	List of Minimum Filing Requirement Schedules Sponsored by Archibald D. Collins
Document No. 3	CO_2 Emissions (Short Tons / Year)
Document No. 4	Generation Mix

OVERVIEW OF TAMPA ELECTRIC

Q. Please describe Tampa Electric.

A. Tampa Electric was incorporated in Florida in 1899 and was reincorporated in 1949. Tampa Electric is a wholly owned subsidiary of TECO Energy, Inc. ("TECO Energy") and became a wholly owned subsidiary of Emera Inc. ("Emera") in 2016 when Emera purchased all common stock of TECO Energy, Inc. Tampa Electric is an investor-owned utility regulated by the Commission and the Federal Energy Regulatory Commission.

Tampa Electric currently provides retail electric service to approximately 800,000 customers over an approximate 2,000 square mile service territory within Hillsborough and portions of Polk, Pasco, and Pinellas counties. We serve these customers with approximately 2,400 employees and the utility facilities described below. Most of our team members work in the areas of Energy Supply, Electric Delivery, and Customer Experience, along with others who work in support areas like Information Technology, Accounting and Finance, Human Resources, and Regulatory Affairs.

The company maintains a diverse portfolio of generating facilities with a net winter capacity of approximately 5,790 megawatts ("MW"). Tampa Electric operates three electric generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, and an integrated gasification combined cycle unit. These units are located at Big Bend Power Station, H.L. Culbreath Bayside Power Station, and Polk Power Station. As of January 1, 2021, the company operated 655 MW of solar generation at 13 facilities located throughout its retail service territory and 12.6 MW_{ac} capacity of battery storage. For the full year 2020, these solar facilities provided approximately 6.0 percent of the company's total energy sales and represented 11.8 percent of the company's installed generating capacity.

Tampa Electric's transmission system consists of nearly 1,350 circuit miles of overhead facilities, including approximately 25,400 transmission poles and structures, and approximately nine circuit miles of underground facilities. The company's distribution system consists of approximately 6,300 circuit miles of overhead facilities, approximately 414,000 poles, and 5,500 circuit miles of underground facilities. Our transmission and distribution systems are connected through 216 substations throughout its service territory.

Q. Please describe Emera.

A. Emera is a geographically diverse energy and services company headquartered in Halifax, Nova Scotia, with approximately $31 billion CAD (Canadian dollars) in assets and 2020 revenues of more than $5.5 billion CAD. The company primarily invests in regulated electric and gas utilities, with a strategic focus on transformation from high carbon to low carbon energy sources. Emera has investments throughout North America and in four Caribbean countries.

Q. Please describe the purchase of TECO Energy by Emera and how it has benefited Tampa Electric's customers.

A. Emera officially acquired Tampa Electric in July 2016, as the successful bidder in a competitive process led by TECO Energy and its advisors. Emera is pleased to be part of the Florida business community and to have the opportunity to operate a safe and customer-focused business in the Tampa Bay region and in the state through Tampa Electric and its sister company, Peoples Gas System. Our customers have benefited in many ways since Emera's arrival, including Emera's continued commitment to the community. Recent examples of our community focus are our drive to reduce coal consumption and reduce emissions of CO_2, SO_2, and NO_X and our focus on supporting our customers during the COVID-19 pandemic. Emera has brought a disciplined focus on impact and results, the success of which is shown in our reliability improvements, safety results, and JD Power customer service satisfaction scores. During 2020, we achieved our lowest safety incident rate ever. Tampa Electric has invested in technology to modernize customer billing systems and Advanced Metering Infrastructure ("AMI"), the modernization of Big Bend Unit 1, and significant amounts of utility-scale renewable solar generation for the benefit of customers. Tampa Electric's improvements to its grid infrastructure are reducing the number and length of disruptions. The company is accomplishing these enhancements through a focus on prudent investments, providing services customers desire, and cost containment, and Emera has improved business stability by ensuring access to equity.

Q. Please describe Tampa Electric's leadership and management philosophy as part of Emera.

A. Since Emera acquired Tampa Electric in 2016, the company has focused on three strategic priorities – improving safety, improving the customer experience, and reducing our environmental impact. This was accomplished while focusing on cost control, efficiency, and prudent management.

Tampa Electric's Transformation

Q. Please describe Tampa Electric's key actions since 2013.

A. Tampa Electric last requested a general base rate increase eight years ago in 2013. Since then, the company has been operating under two Commission-approved general base rate settlement agreements, which were entered into in 2013 and in 2017. These agreements limited our ability to request base rate relief while allowing us to continue making sound investments to serve our customers and communities. These investments, combined with disciplined cost management, have enabled us to begin transforming and modernizing the company while maintaining customer rates that are among the lowest in Florida and well below the national average.

These agreements created a constructive regulatory framework for Tampa Electric, promoted rate stability and predictability, and delivered important benefits to our customers.

The agreements allowed the company to begin transforming its generation fleet; become a solar energy leader in Florida; improve safety, reliability, and the customer experience; maintain a strong financial profile; take advantage of low natural gas prices and reduce fuel expenses; make the company's generation mix cleaner, greener, and less carbon intensive; and keep operations and maintenance expenses relatively flat.

Q. How has Tampa Electric begun transforming its generation fleet?

A. The 2013 agreement allowed the company to harness the energy associated with waste heat at its Polk Power Station by converting Polk Units 2 through 5 into a highly efficient combined cycle generating unit. Under the 2017 agreement, the company built and recovered the cost of its investments in 600 MW of cost-effective photovoltaic solar generating capacity and, during its term, began important transformational projects such as construction of the Big Bend Modernization Project. By December 31, 2020, the Polk and solar projects reduced the company's carbon emissions and saved our customers over $184 million in fuel costs. Tampa Electric witness David A. Pickles provides additional details regarding the company's generation plant changes since 2013, including the Big Bend Modernization construction status, timeline, and expected cost. Tampa Electric witness J. Brent Caldwell presents the analysis demonstrating the Big Bend Modernization project's prudence and the savings it will provide customers.

Q. Does Tampa Electric plan to expand its solar generation portfolio?

A. Yes. Tampa Electric is one of Florida's solar energy leaders. Our existing solar generating assets power more than 100,000 homes, businesses, and schools. We are planning to build another 600 MW of "Future Solar" in three tranches of approximately 225 MW, 225 MW, and 150 MW, which will allow all customers to enjoy the benefits of solar generation. Adding 600 MW of solar generation enhances our system fuel diversity and provides fuel savings and environmental benefits to customers. When we complete these Future Solar projects, nearly 14 percent of our energy will come from the sun. This cost-effective long term energy solution will power more than 200,000 homes, promote price stability for customers, increase our fuel diversity, and reduce carbon emissions. Tampa Electric witness Jose A. Aponte explains why 600 MW is the optimal amount of Future Solar to add to our system over the next three years and demonstrates the cost-effectiveness of the solar projects. Tampa Electric witness C. David Sweat describes the Future Solar projects, their costs, and benefits of building them over the next three years.

Q. How has Tampa Electric improved the efficiency of its generating fleet?

A. Tampa Electric's average net system heat rate (Btu/kWh), which reflects the efficiency of our generating fleet, has improved from about 9,200 in 2013 to 7,600 in 2020, an improvement of about 17 percent. A more efficient generation fleet means less fuel is required to generate the same amount of energy. This is important because it saves customers money through reduced costs of fuel, and it reduces emissions.

Q. How has Tampa Electric improved the company's safety?

A. We have committed ourselves to achieving World Class safety, and to the beliefs that (1) all injuries are preventable and (2) no business consideration can take priority over safety. In 2018, we began implementation of a 10-element comprehensive safety management system founded on employee ownership and engagement in safety initiatives. Having a safe work environment and understanding that safety is the top value at Tampa Electric creates a sense of ownership among employees for all outcomes of the business. Tampa Electric reported its lowest OSHA recordable incident rate ever during 2020. Even though our incident rate (the number of work-related recordable injuries and illnesses per 100 full-time employees in a one-year period) has improved significantly in recent years, we believe our safety work is not done, and we continue to aspire to live and work injury-free.

Q. How has Tampa Electric improved the customer experience?

A. Tampa Electric has improved the customer experience through investments in new technology, process improvements, and training for employees. Our investments in technology, like our Customer Relationship and Billing system ("CRB"), AMI, and other digital enhancements, provide customers more convenience, choice, and self-service offerings. We now offer alerts and notifications through a customer's channel of choice, *e.g.*, phone, text, or website, and a customer self-service portal that allows customers to conduct business with us at their convenience. We also enhanced our outage map and outage communications so customers know more about outages and resolution time and can report them more easily. Tampa Electric also made internal process improvements and transactional enhancements that make it easier for customers to do business with us. We also implemented new training programs that will allow customers to be served more efficiently and consistently, getting them the information they need without unnecessary hand-offs. These investments in technology, process, and training allowed us to improve our service levels, including average speed of answer and call handle time when customers reach us through the contact center. Tampa Electric witness Melissa L. Cosby describes our customer experience improvements in greater detail.

Q. Has Tampa Electric improved distribution reliability?

A. Yes. We have steadily improved distribution reliability since 2013 through investments in our distribution infrastructure, as evidenced by improvements in two main reliability indices: System Average Interruption Duration Index ("SAIDI") and Momentary Average Interruption Frequency Index ("MAIFI"). Implementation of our annual distribution reliability plan and operational changes such as additional troublemen, dispatchers, and flex crews have contributed to reduce outage times when they occur. These actions have resulted in significant improvements in system reliability, and compared to 2013, outages during 2020 were 20% percent shorter in duration (SAIDI), and flickers were 36% percent less frequent (MAIFI). Tampa Electric witness Regan B. Haines describes these investments and reliability improvements in his direct testimony.

Q. Have the company's efforts improved customer satisfaction?

A. Yes. Our investments and programs have improved the company's safety, reliability, efficiency, and overall customer experience. Our efforts have resulted in higher customer satisfaction as measured by JD Power. Our JD Power ranking for residential customer overall satisfaction has improved from the fourth quartile in 2017 to the top of the second quartile in 2020, as described in the direct testimony of Ms. Cosby.

Q. How has the company's financial profile changed since 2013?

A. With more than 20 million residents, Florida is one of the nation's fastest growing states, and the Tampa Bay/I-4 Corridor is its fastest growing area. We now serve approximately 800,000 customers, up about 15 percent from approximately 695,000 customers in 2013. Our rate base investments have grown from about $4 billion in 2013 to $6.7 billion today and are expected to be approximately $7.9 billion in 2022. Our annual base revenues have increased from about $900 million in 2013 to approximately $1.2 billion in 2020, or by about 33 percent. Major portions of our rate base growth have helped us take advantage of low-cost natural gas as our primary fuel source as well as the addition of zero-cost-fuel solar generation, reducing the fuel expenses borne by our customers. We reduced our overall fuel expenses and delivered the value of lower natural gas prices to our customers through prudent construction of solar generation, expansion of dual-fuel capability at our coal-fired power plants, continued investments in efficient natural gas fired combined cycle technology as discussed in the direct testimony of Mr. Aponte, Mr. Caldwell, and Mr. Pickles.

Q. How have the company's fuel mix and carbon emissions changed since 2013?

A. Since 2013, we have made significant changes in our fuel mix by pivoting away from coal to natural gas and solar generation. First, we reduced our coal consumption by approximately 90 percent since 2015. In 2013, about 59 percent of Tampa Electric's electricity was generated using coal, about 41 percent was natural gas-fired, and we had no solar generation. By 2020, about five percent of our electricity was generated using coal, about 89 percent was natural gas-fired, and about 6 percent was from solar generation. As I previously stated, the direct testimony of Mr. Pickles provides additional information regarding the changes in the company's generation fleet since 2013.

Second, these changes in our fuel generation mix resulted in a significant reduction in our carbon emissions, which fell from 15.7 million tons in 2013 to about 8.8 million tons in 2020, a 44 percent reduction. By 2023, we will have reduced our carbon dioxide emissions by the equivalent of removing one million cars from local roadways. Document No.

3 of my exhibit shows CO_2 emissions over the last eight years and demonstrates our significant reduction in CO_2 emissions over that period.

Q. How have the company's O&M expenses changed since 2013?

A. Despite upward pressure on the costs of providing service from inflation and significant customer growth and the infrastructure improvements I discussed above, we have kept our operations and maintenance ("O&M") expenses essentially flat from 2013 to 2020. More details about management of operating costs are provided in the testimony of other Tampa Electric witnesses. The direct testimony of Mr. Pickles, Mr. Haines, and Ms. Cosby address management of O&M expenses for Energy Supply, Electric Delivery, and Customer Experience, respectively. The direct testimony of Tampa Electric witness Jeffrey S. Chronister also addresses management of O&M expenses.

Q. How do customer bills today compare with customer bills in 2013?

A. As a result of our actions to invest in assets and reduce fuel and O&M expenses and a focus on cost control, we kept customer bills stable, at about the same level since 2013.

Adding solar generation and transitioning away from coal allowed us to capture the value of declining natural gas prices and “no-fuel” solar to drive our typical monthly residential bill lower in 2020 than it was in 2013. Our typical monthly residential bill in 2013 was $102.58 and in 2020 was $97.69, a decrease of almost $5 a month. Our 2021 typical monthly residential bills are among the lowest in Florida and are 17 percent below the national average. We expect them to remain among the lowest in Florida and below the national average when including the current request for rate relief.

More Transformation and Customer Benefits to Come

Q. Does Tampa Electric have any significant projects currently underway or scheduled to begin in the next two years?

A. Yes. Tampa Electric is safer, cleaner and greener, and provides a better customer experience than in 2013; however, our work is not complete. To continue delivering the value our customers expect, we must plan for the long term and invest now to create an even cleaner, greener, and more efficient energy future. We constantly strive to identify and implement projects and strategies that will further improve our safety, reliability, customer experience, and environmental profile. The following projects - planned or currently underway - are vital to our vision for our customers and company:

1. <u>Big Bend Modernization (Units 1 and 2)</u>
   The company will retire Unit 2 and repower Unit 1 as a clean natural gas-fired two-on-one combined cycle generating facility. The repowered Unit 1 will be the most efficient generating unit in the company's fleet. Among other benefits, these changes will generate approximately $750 million in cumulative present value revenue requirement ("CPVRR") savings for our customers. This project is discussed in greater detail in the direct testimony of Mr. Caldwell.

2. <u>Retirement of Big Bend Unit 3</u>
   Retiring Unit 3 in April 2023 - rather than operating it on coal or natural gas until its planned retirement in 2041 - will reduce carbon emissions, provide operational benefits, and generate approximately $299 million in CPVRR savings for our customers, as described in the direct testimony of Mr. Caldwell.

3. <u>600 MW of Solar Generation</u>
   Through 2023, Tampa Electric plans to add an additional 600 MW of utility-scale solar generating

capacity ("Future Solar") through 11 specific projects across our service territory in three tranches of approximately 225 MW, 225 MW, and 150 MW. These cost-effective projects are expected to generate CPVRR savings of over $120 million. Mr. Sweat and Mr. Aponte describe these projects and the related cost savings.

4. Smart Grid and AMI

Tampa Electric has plans to further empower customers through technology via a multi-year project to build a smarter grid that delivers more reliable, affordable energy to our customers. The AMI implementation is a cornerstone of our grid modernization strategy. It includes installation of advanced meters, communication infrastructure, and data management systems, which taken together, provide the ability to offer new customer engagement programs and services. Mr. Haines provides more information about the modernization of the grid in his direct testimony. Additionally, we are investing in digital solutions to offer customers more personal choice in their service experiences, as explained in the direct testimony of Ms. Cosby.

Q. Are there any other innovative programs and projects that

Tampa Electric is currently exploring?

A. Yes. Tampa Electric is exploring new technologies and new ways to serve our customers. To support the growth of electric vehicles in our service territory, Tampa Electric requested and received approval to expand the availability of EV charging infrastructure with a 200-port charging pilot. The charging infrastructure pilot, along with customer education and working with fleet operators to support their conversion to EVs, will accelerate transportation electrification and decarbonization.

As Mr. Pickles describes, we implemented a 12.6 MW lithium-ion based battery energy storage system at Big Bend Station to study the benefits of this new technology. The Big Bend Battery project will examine how battery storage can increase reliability of power supplied to the grid, reduce peak demands, serve frequency regulation, and contribute to contingency reserves.

The company is currently seeking approval for an innovative new pilot program, a direct current micro-grid known as the Block Energy System with Emera Technologies, Metro Development Group, and Lennar Homes. This pilot will test the capability of the system to provide power to 37 residential homes using a high proportion of renewable energy as well as enhanced reliability and resiliency.

Q. Please describe Tampa Electric's long term goals to continue to reduce greenhouse gas emissions.

A. In February, Emera announced its commitment to achieving net zero carbon emissions by 2050. This commitment complements our goal to generate as much clean power as we can without compromising affordability or reliability. Tampa Electric's reductions of greenhouse gas emissions will contribute to achieving the Emera commitment. Tampa Electric's goals are being developed and, our first milestone goal is 60 percent GHG reduction by 2025 relative to 2000, which will be achieved with the addition of our cost-effective Big Bend Modernization project and Future Solar projects. Tampa Electric is committed to producing clean energy, which will contribute to a brighter future for our community and the global reduction of greenhouse gas emissions, as well as significant fuel savings benefits for our customers.

Q. How has Tampa Electric helped customers during the pandemic and economic downturn?

A. Tampa Electric is aware of the impact that the pandemic has had on our customers and the communities we serve. Since the onset of the pandemic in early 2020, Tampa Electric, its sister company Peoples Gas System, and our employees have donated over $2 million to local organizations providing pandemic relief. In addition to financial assistance, Tampa Electric has taken several other steps to assist our customers. As a result of these efforts, our customers received bill payment assistance totaling more than $10 million in 2020. Ms. Cosby describes our assistance to customers in more detail.

Major Factors Necessitating a General Base Rate Increase

Q. Why is a general base rate increase necessary?

A. To continue delivering the value our customers expect and knowing that our customers' expectations continue to evolve based on the service they receive from non-energy companies, we must plan for the long term and invest now to create an even cleaner, more efficient, and more reliable energy future. The major factors driving the need for a rate case include continued growth in rate base and associated depreciation expense, modest increases to O&M expenses to meet customer expectations, and revenue growth that has not kept pace with the needs of our system.

Q. What are the major factors driving the need for rate relief?

A. The major factors causing the need for rate relief are as follows.

1. The company's investment in rate base assets has grown 68 percent since 2013 to $6.7 billion today and is expected to be $7.9 billion in 2022. Some of this rate base growth has been addressed through incremental GBRA and Solar Base Rate Adjustment ("SoBRA") revenues, but general revenue growth will not be sufficient to allow the company to recover the costs associated with important projects like the Big Bend Modernization, Smart Grid/AMI, the Future Solar generation capacity described earlier in my testimony, and the general capital needs associated with our growing system.

2. Our investment in Energy Supply assets (production plant) will have increased by approximately $2 billion from 2013 to 2022. All have improved efficiency and environmental performance, are cost-effective, and are in the long-run best interests of our customers. They include the Polk Units 2 through 5 conversion, 655 MW of solar generating capacity in service by January 2021, and the capital costs associated with major planned outages at Big

Bend, Bayside, and Polk Power Stations, as well as the first phase of the Big Bend Modernization and 225 MW of Future Solar projects.

3. Since 2013, we have expanded our Electric Delivery system to serve new load and have become stronger and more resilient in the process. Our major capital spending in Electric Delivery from 2013 to 2022 includes transmission and distribution system enhancements to serve new customers, preventive maintenance, and the AMI implementation.

4. Our rate base growth has been accompanied by a commensurate increase in depreciation expense, which has grown from about $215 million in 2013 to $310 million in 2020.

5. We filed a depreciation and dismantlement study on December 30, 2020 in accordance with the 2017 Agreement. Depreciation expense during 2022 will be approximately $430 million, of which $46 million will be attributable to the higher depreciation rates in the study. Although the depreciation study filing moratorium in the 2013 and 2017 agreements reduced cost pressures during the term of the agreements by deferring rate-driven depreciation expense

increases, delaying depreciation and dismantlement studies had the predictable effect of pushing a material depreciation expense increase into the 2022 test year. Tampa Electric witnesses Davicel Avellan, Jeffrey S. Kopp, and Charles R. Beitel provide detail regarding depreciation and dismantlement.

6. Our December 30, 2020 depreciation and dismantlement filing also outlines a need to establish capital recovery schedules for the undepreciated net book value on December 31, 2021 of our investment in: (a) the portions of Big Bend Units 1 through 3 to be retired and (b) the AMR meters to be retired in conjunction with our Smart Grid initiative. The company has proposed that the net book value of these assets be amortized over ten years at an annual total cost of $63 million, $47 million of which are costs for base rate assets, and $16 million of which represents assets recovered through the environmental cost recovery clause. The direct testimony of Mr. Avellan discusses the need for capital recovery for these assets.

7. Tampa Electric has invested in Information Technology ("IT") to improve its customer experience and comply with new regulations and customer privacy requirements. These improvements include our CRB system and the infrastructure

that will support AMI. The costs we have incurred for IT have been influenced by requirements of the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Sarbanes-Oxley Act of 2002, as well as increased customer cybersecurity and privacy demands. Our IT investments and projects are described in greater detail in the direct testimony of Tampa Electric witness Karen M. Mincey.

8. Although the company has been able to keep its overall O&M expense levels essentially flat since 2013 through the smart use of technology and prudent cost management practices, the costs of labor, contractors, materials, insurance, and health care benefits are accelerating at a pace that is causing the company’s O&M expenses to increase. These increases are offset by lower tax and debt expense (as explained in the direct testimony of Mr. Chronister) and reasonable levels for employee compensation (as explained in the direct testimony of Tampa Electric witness Marian C. Cacciatore).

9. As explained in the direct testimony of Tampa Electric witness Edsel L. Carlson Jr., we are not seeking an annual accrual for the company's storm reserve and propose to continue the storm cost recovery method specified in the

company's previous two base rate settlement agreements. Tampa Electric witness Steven P. Harris describes our storm-related risk in his storm study and direct testimony.

10. Although the Tax Cuts and Jobs Act of 2017 benefitted our customers by reducing our federal income tax rate, it also eliminated "bonus" depreciation for federal income tax purposes. The combination of the loss of bonus depreciation and the required re-valuation of our accumulated deferred income tax balances has reduced the amount of zero-cost capital in our capital structure, thus requiring additional equity. More detail regarding this topic is provided in the direct testimony of Mr. Chronister.

11. An appropriate return on common equity ("ROE") is essential for a regulated utility to competitively attract the capital necessary to make long-term investments, maintain and improve the company's quality of service, and achieve lower costs for customers over the long term. Tampa Electric currently projects that its earned ROE in 2022 without rate relief will be below five percent which will not provide the level of financial integrity needed to maintain unrestricted access to cost-effective capital in the market and is not in the best interest of customers or shareholders. Tampa Electric requests that the Commission

approve an authorized ROE of 10.75 percent, with a range of plus or minus 100 basis points. Tampa Electric witness Dylan W. D'Ascendis supports the company's request for an authorized ROE of 10.75 percent.

12. Tampa Electric requests a capital structure of 55 percent equity and 45 percent debt to maintain Tampa Electric's financial integrity and credit ratings. Maintaining an equity ratio that supports financial integrity enables the company to access capital at competitive rates for the investments needed to provide customers with reliable service at reasonable rates. Witness Kenneth D. McOnie will present the company's proposed equity ratio for the 2022 test year and describe how the company's proposed capital structure and revenue increase will help preserve the company's overall financial integrity.

Our Request for New Rates and Charges

Q. Please summarize the company's requested base rate increase.

A. The company requests a $294.9 million general base rate increase and to reduce its miscellaneous service charge revenues by $6.6 million, both effective as of January 2022.

This increase will effectively recover the reasonable costs of providing service and allow the company an opportunity to earn an appropriate return on rate base. The revenue requirement is addressed in greater detail in the direct testimony of Tampa Electric witness A. Sloan Lewis.

The 2022 test year request addresses Phase One of the Big Bend Modernization, our investment in AMI, and approximately 225 MW of our planned Future Solar capacity. Instead of requesting larger general base rate increases for 2023 and 2024, the company requests authorization to implement GBRAs in 2023 and 2024. The 2023 GBRA of $102.2 million recovers costs for Phase Two of the Big Bend Modernization and approximately 225 MW of additional solar generation. The $25.6 million GBRA for 2024 will recover costs for about 150 MW of solar capacity. These base rate increases will be partially offset by fuel savings.

Tampa Electric's proposed rate design accurately reflects the cost to serve each of the various rate classes. Tampa Electric witness Lorraine L. Cifuentes presents the company's 2022 test year customer, energy sales, and peak demand forecast. Tampa Electric witness William R. Ashburn describes our proposed rate design, rates, and charges, and revised tariff sheets, and Tampa Electric witness Lawrence

J. Vogt provides the cost of service and jurisdictional separation studies.

We continue to design our rates so that it is less expensive to consume under 1,000 kilowatt-hours ("kWh") in a month, which benefits our low-income customers. Our 2022 residential bill will be only 5 percent higher than in 2009, will be 17 percent lower than they were in 2009 on an inflation-adjusted basis, will still be among the lowest in Florida, and will remain below the national average.

Actions Taken to Avoid a Retail Base Rate Increase

Q. What actions have you taken to avoid a retail base rate increase?

A. Since 2013, Tampa Electric has worked diligently to keep its costs low. The company continues to pursue efficiency improvements and cost reductions in all areas of its operations. Here are some of the steps we have taken to avoid seeking a general base rate increase:

- Since 2013, we have voluntarily limited our ability to request general base rate increases by entering the 2013 and 2017 agreements. These agreements have provided demonstrable benefits to our customers.

- We reduced base revenues by approximately $107.0 million without delay to give our customers 100 percent of the expense savings from federal and state tax rate reductions.

- The company has used cost discipline, process and system improvements, smart asset management, and has controlled O&M expenses since 2013. This results in proposed O&M expense levels for our 2022 test year that will be significantly below the Commission's benchmark, as described in the direct testimony of Mr. Chronister.

- We have captured the benefit of lower borrowing costs for our customers. The company has refinanced higher cost debt at lower rates, issued new debt at historically low rates, and adjusted our short-term borrowing portfolio to optimize the use of instruments with the lowest attainable rates.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony describes the prudent ways we have invested to reduce our environmental impact and improve our customers' experience, all while controlling our costs.

Tampa Electric has implemented a strategy of reducing fuel expense through replacement of older and higher cost generation with newer, cost effective renewables and other lower-carbon generation. Up to now, the costs of these capital investments have been offset by lower fuel expense and reduced operating costs associated with the investments as well as some GBRA and SoBRA revenues included in our 2013 and 2017 agreements. Tampa Electric has kept O&M expenses relatively flat over a period of years. We sought and implemented efficiencies, controlled costs, made prudent investments, and improved customer satisfaction over the last several years. These efforts have allowed Tampa Electric to avoid a general base rate increase since 2013.

My direct testimony describes how Tampa Electric is requesting a $294.9 million increase in base rates and reduction of miscellaneous service charge revenues of $6.6 million effective January 2022, based on a 2022 projected test year. This increase will cover the reasonable costs of providing service and allow the company an opportunity to earn an appropriate return on rate base. To promote regulatory efficiency and avoid larger general base rate increases for 2023 and 2024, the company also requests approval for GBRAs in 2023 and 2024. The 2023 GBRA is $102.2

million, and the 2024 GBRA request is $25.6 million.

I also introduce the other company witnesses and list the topics discussed in their direct testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of J. Brent Caldwell was inserted.)

ERRATA SHEET

DIRECT TESTIMONY OF J. BRENT CALDWELL[1]

Bates Numbered Page	Column	Original	Revised
43	$52	PPA CC	CTs -> CC
	$62	CTs -> CC	PPA 30yr Solar
	$126	PPA 30yr Solar	PPA 10yr Solar A
	$166	PPA 10yr Solar A	PPA 10yr Solar B
	$257	Mkt Asset	PPA Peaking
	$338	PPA System	PPA CC
	$340	PPA 10yr Solar B	Mkt Asset
	$350	PPA Peaking	PPA System

[1] Document No. 03307-2021, filed April 9, 2021 in Docket No. 20210034-EI.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
J. BRENT CALDWELL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Planning and Fuels.

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

A. My responsibilities include the long-term planning of Tampa Electric's energy resources to meet customer demand in an economic and reliable manner. I also oversee the optimization and trading associated with the planning and commitment of the system assets on a day-ahead basis.

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

A. I received a bachelor's degree in electrical engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 25 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In 2017, I assumed responsibility for Portfolio Optimization, which includes unit commitment, near-term maintenance planning, and natural gas and wholesale power trading. In December 2018, I assumed the role of Director, Planning and Fuels, which added responsibility for long-term planning to my existing responsibilities.

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

A. Yes. I submitted written testimony in the annual fuel docket from 2011 through 2019. In 2015, I testified in Docket No. 20150001-EI regarding natural gas hedging. I have also testified before the Commission in Docket No. 20120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project and filed testimony in Docket No. 20130040-EI regarding fuel inventory levels in Tampa Electric's last rate case.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to describe and explain the prudence of constructing the company's Big Bend Modernization Project ("Big Bend Modernization"). This project is part of the company's ongoing process to promote safety, improve the customer experience, and become a cleaner and greener utility. I will describe the company's Big Bend Generating Station, the analysis we undertook before beginning Big Bend Modernization, why the project is prudent, and how the project will improve our customer experience and benefit our customers and the communities we serve. I will also explain why it is prudent to retire Big Bend Unit 3 in April 2023.

Q. How does your direct testimony relate to the direct testimony of other Tampa Electric witnesses?

A. My direct testimony addresses the prudence of Big Bend Modernization and the early retirement of Big Bend Unit 3. Tampa Electric's witness David A. Pickles describes how the Big Bend Modernization Project and early retirement of Big Bend Unit 3 fit into the company's overall Resource Plans and the costs and project status of Big Bend Modernization. He also describes the units of property associated with Big Bend Units 1, 2, and 3 that will be retired and the items of inventory that will become obsolete when our plans for Units 1, 2, and 3 have been executed.

Mr. Pickles will describe the changes underway at Big Bend Power Station. Tampa Electric witness Davicel Avellan will explain how those changes affect our depreciation and dismantlement rates and create a need to recover the undepreciated net book value of the portions of Big Bend Units 1, 2, and 3 to be retired and related obsolete inventory via capital recovery schedules.

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

A. Yes. Exhibit No. JBC-1, entitled "Exhibit of J. Brent Caldwell" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of four documents, as follows:

Document No. 1: Big Bend Modernization Photos and Artist Renderings

Document No. 2:	Big Bend Modernization Options Considered and Relative CPVRR Savings without Emissions Cost Savings
Document No. 3:	CPVRR by Component for Big Bend Modernization
Document No. 4:	CPVRR by Component from Big Bend Unit 3 Early Retirement

OVERVIEW OF BIG BEND GENERATING STATION

Q. Please describe Tampa Electric's generation assets.

A. Tampa Electric has three centralized thermal generation stations: Big Bend Station, Polk Power Station ("Polk"), and the H.L. Culbreath Bayside Power Station ("Bayside"). Big Bend Station, Polk and Bayside use fossil steam units, combined cycle units ("CC"), combustion turbine peaking units ("CT"), and an integrated gasification combined cycle unit ("IGCC") to generate electricity. Tampa Electric also has a fleet of solar photo voltaic ("PV") generation sites distributed across the service territory and a small battery energy storage device near Big Bend Station.

Q. Please describe Tampa Electric's Big Bend Power Station ("Big Bend").

A. Big Bend consists of four steam turbines and an aero-derivative combustion turbine. The steam turbine units were originally designed to operate on high-sulfur, pulverized coal from the Illinois Basin. The units became operational in 1970, 1973, 1976, and 1985 for Units 1, 2, 3, and 4, respectively. The company's last depreciation study in 2011 contemplated that each of the steam turbine units would be retired after useful lives of 65 years.

Q. What types of equipment are needed to support these pulverized coal generating units?

A. Big Bend has equipment to receive, unload, store, blend, and pulverize coal that is received by barge or by rail. Each unit also has emission control equipment, such as precipitators to capture particulate matter, flue gas desulfurization ("FGD") scrubbers to capture sulfur oxides, and selective catalytic reduction units ("SCR") to capture nitrous oxides. Big Bend Unit 4 was originally designed and built with most of this emission control equipment in 1985. The company later retrofitted Big Bend Units 1, 2, and 3 to add this equipment.

Q. Have the Big Bend units evolved in other ways?

A. Yes. The four Big Bend pulverized coal units were originally designed and built to consume high-sulfur, low-cost Illinois Basin coal. This fuel choice provided significant fuel cost savings to Tampa Electric customers because, historically, Illinois Basin coal was the lowest cost delivered fuel. However, since international demand for U.S. coal increased and non-conventional shale gas production caused the price of natural gas to decrease, natural gas became a more competitively priced option for electric generation.

In 2015, Tampa Electric first took advantage of the greater availability and lower price of natural gas and replaced oil with natural gas as the fuel used to start up Big Bend Units 1 through 4. This change significantly reduced the cost of fuel associated with unit startup.

In 2017, Tampa Electric went a step further by adding natural gas burners so that each unit could be partially operated on natural gas. Tampa Electric added additional natural gas burners to Big Bend Units 1, 2, and 3 so that those units can operate close to maximum dependable capacity ("MDC") on natural gas. This dual-fuel capability enabled the company to run the Big Bend units on natural gas when available and the pricing is advantageous. The ability to co-fire on natural gas also improved unit and system reliability since the Big Bend units do not need to be taken offline in the event of a coal handling issue.

Mr. Pickles provides additional details about the transformation of Big Bend Station in his direct testimony.

Overview of the Big Bend Modernization Project

Q. Please generally describe the Big Bend Modernization Project.

A. The Big Bend Modernization Project consists of three fundamental building blocks: (1) the retirement of Big Bend Unit 2 and all of its associated equipment, (2) the refurbishment of Big Bend Unit 1’s steam turbine and generator, and (3) replacement of Big Bend Unit 1’s boiler and coal processing equipment with two new GE 7HA.02 CTs and associated heat recovery steam generators (“HRSG”). Document No. 1 of my exhibit contains photographs and artist renderings of the project.

The Big Bend Modernization Project has two phases and will take approximately 42 months to complete. Mr. Pickles describes the activities and costs associated with the two phases and details of the project timeline in his direct testimony. He also explains that the project is on time and within budget.

Q. In general, what components of Big Bend Unit 1 will be retained and what components of Big Bend Units 1 and 2 will be retired?

A. Essentially all coal-related equipment and steam production equipment associated with Big Bend Unit 1 will be retired and all the equipment associated with the production of electricity from Big Bend Unit 1 will be retained. The equipment being retired from Big Bend Unit 1 includes coal mills, coal pulverizing equipment, coal injectors, the boiler, slag tanks, ash hoppers, precipitators, and the flue gas desulfurization scrubber.

The primary components being retained and modernized for Big Bend Unit 1 include the steam turbine, the generator, ductwork, fans, the cooling system, circulating pumps, and selective catalytic reduction equipment. With respect to Big Bend Unit 2, essentially all unit specific equipment will be retired.

Q. How will the capacity and heat rates for the modernized Big Bend Unit 1 compare to those of the original Big Bend

Units 1 and 2?

A. The Big Bend Modernization Project will increase the combined generating capacity for Big Bend Units 1 and 2 from approximately 800 MW to a winter capacity of 1,120 MW when the repowering is complete.

The Big Bend Modernization Project will also improve the generating efficiency at Big Bend. Prior to the Big Bend Modernization, Units 1 and 2 had operational heat rates of over 10,500 Btu/kWh. The modernized Big Bend Unit 1 will be the most efficient generating unit in the company's fleet, with an expected operational heat rate of approximately 6,350 Btu/kWh, an efficiency gain of 40 percent. This means lower natural gas fuel volumes, lower energy costs, and lower emissions, which will result in savings for customers.

Q. What other operational benefits will the Big Bend Modernization Project bring to Tampa Electric's system?

A. The modernizing of Big Bend Unit 1 will yield two other important improvements. First, Big Bend Unit 1 will have the ability to run in simple-cycle operation, combined-cycle operation, or a mix of the two, which will provide significant operating flexibility to meet rapidly changing system needs. In addition to flexible operational modes, the modernized Big Bend Unit 1 will be able to change its output much more quickly and vary its output over a much wider MW range than the existing Big Bend Units 1 and 2 can. With the evolving industry and changing load dynamics, having a unit with this amount of operational flexibility, especially as compared to 1970s-vintage pulverized coal steam turbines, will be critical for meeting current and future customer needs.

Second, the repowered unit will be more reliable. CTs are inherently more reliable than the pulverized coal units, and the ability to run in simple-cycle and combined-cycle modes enhances the reliability of the unit and facilitates scheduling of maintenance.

Mr. Pickles provides additional details about the operational benefits of Big Bend Modernization, including how the project will complement the company's solar generation facilities, in his direct testimony.

Q. Has Tampa Electric executed a project like Big Bend Modernization before?

A. Yes, the Big Bend Modernization is just the latest example of Tampa Electric refurbishing and integrating existing generation assets with new technology to cost effectively meet customer growth needs and improve overall system efficiency. Tampa Electric repowered Gannon coal units 5 and 6 into Bayside Units 1 and 2 in 2003 and 2004. Just like the modernization of Big Bend Unit 1, new natural gas combustion turbines and heat recovery steam generators were integrated with a refurbished existing steam turbine and electrical generator to create a more efficient, more reliable, and more flexible natural gas combined cycle ("NGCC") unit. When Bayside 1 and Bayside 2 came online, they became the most efficient and most reliable units on the Tampa Electric system.

Tampa Electric used this process again in 2017 at Polk Station. The four existing combustion turbines at Polk Station were integrated with new heat recovery steam generators, a new steam turbine, and a new electric generator. As was the case when the Bayside project went in-service, when the Polk Unit 2 NGCC became the most efficient and most reliable unit on the system when it came online. Tampa Electric has proven the concept of using existing assets to create a new NGCC at a lower cost than building a whole new unit. The Big Bend Modernization is exactly the same concept and, when it comes online as a NGCC unit, will be the most efficient unit on the system.

Analysis Leading to Big Bend Modernization

Q. Please describe the industry trends that initiated the analysis the company performed before beginning Big Bend Modernization.

A. Tampa Electric regularly reviews the retirement horizon of its generation units. In the early to mid-2010s, this review took on an added sense of urgency for several reasons.

First, numerous environmental initiatives such as the Mercury and Air Toxics Standards, the Clean Power Plan, and the Coal Combustion Residuals rule cast significant uncertainty on the long-term cost and viability of pulverized coal units.

Second, by then Units 1 and 2 were over forty years old, and while the units can operate for the remainder of their 65-year depreciation lives, annual budgeting activities revealed rising capital investment and operating cost to maintain sufficient performance, reliability, and safety for these units.

Finally, technology advancements yielding greater efficiency and lower costs for NGCC generation, coupled with relatively lower cost natural gas produced from non-conventional production technologies, caused efficient NGCC generation to supplant pulverized coal generation, even for existing units, as a more cost-effective and emission-friendly generation choice.

Q. Please describe the process the company used to identify, select, and evaluate Big Bend Modernization.

A. The company started with a screening of options available at the Big Bend Station site to identify and select the best alternative for assets at Big Bend. The screening process, conducted in 2016, looked at multiple options for Big Bend Station including various retirement scenarios, various repowering configurations, and new build options. The screening process determined that the retirement of Big Bend Unit 2 coupled with the modernization of Big Bend Unit 1 into a NGCC was the best option for Tampa Electric customers.

Q. What were the primary factors that supported identification of the Big Bend Modernization as the right choice for customers?

A. Three main factors supported Big Bend Modernization as the right choice.

The first factor was the cost of continuing to operate Big Bend Units 1 and 2 on pulverized coal. While Units 1 and 2 have provided Tampa Electric low-cost energy for decades, their relative inefficiency, recent increases in fuel costs, emissions intensity, and increasing levels of investment required to operate the units safely and reliably opened the door for a life-cycle review.

The second factor was the cost savings associated with retaining and reusing existing assets through repowering of a Big Bend unit. Using Big Bend Unit 1’s steam turbine, generator, cooling system, transmission infrastructure, land, and water rights made repowering both cost effective and executable.

The third factor was that the staged approach for bringing the two new CTs online in 2021 will (1) ease the operational challenges associated with removing 800 MW of generating capacity from service and (2) provide operational and reliability benefits to our system before the project will be finished.

Q. Once the modernization of Big Bend Unit 1 was selected for the Big Bend site, what other alternatives were considered?

A. Once the Big Bend Modernization Project was selected as the option at Big Bend, the Project was further tested against other resource alternatives available to the system. As it does each year, the company updated its load forecasts, fuel price forecasts, maintenance schedules, and other projections in the early summer of 2017 to prepare the company's 2018 projected fuel cost filing. The 2017 Ten-Year Site Plan with updated inputs became the base case for the analysis. Using these fully updated assumptions, the company compared Big Bend Modernization to the base case and several other expansion alternatives including options to build new generation and options to purchase power in the market.

Q. What did this comparison to other options show?

A. The comparison showed that the Big Bend Modernization Project is expected to provide $747 million of cumulative present value revenue requirement ("CPVRR") savings for customers compared to the base case. The evaluation also showed that the Big Bend Modernization Project was the lowest cost alternative by at least $50 million CPVRR.

Q. Please further describe the other alternatives considered.

A. The other alternatives analyzed by the company, and their savings relative to Big Bend Modernization, are shown in Document No. 2 of my exhibit.

The options included building combustion turbines without retiring any Big Bend units (the base case), retiring both Big Bend Units 1 and 2 and building combustion turbines and converting them to combined cycle, and the Big Bend Modernization Project. Of these build options, the Big Bend Modernization process was the most cost-effective option driven largely by the reuse of existing steam turbine and generation assets, leveraging existing water rights, circulating water cooling assets and transmission assets, and immediate fuel savings from improved efficiency of the system.

The options also included buying power or existing generation facilities from the wholesale power market. The wholesale market options ranged from peaking power to full-requirements system power and also included solar photovoltaic purchase power options. The Big Bend Modernization Project was more cost-effective than all of the wholesale market purchased power options. Like the alternate build options, the wholesale power purchase options cannot overcome Big Bend Modernization's advantages of using existing rights and assets. Additionally, wholesale power projects have the additional hurdles of paying for transmission capacity on neighboring systems, paying for ancillary and balancing services, and have uncertainty regarding timing and impact of changing transmission and network dynamics.

Q. What are some of the key insights from the analysis?

A. First, avoiding the ongoing capital, operating, and maintenance expense associated with Big Bend Units 1 and 2 provides the foundation of benefits to customers. Second, combined cycle energy with its high efficiency and low-cost generation was the type of resource needed by the system and provides significant fuel cost savings to customers. And third, because of the reuse of existing generation equipment, existing transmission rights and equipment, and existing water rights and equipment, the Big Bend Modernization Project was the most cost-effective option for customers.

Q. Are there other aspects of the Big Bend Modernization Project that make it beneficial beyond the cost effectiveness analysis?

A. Yes, there are several benefits from the Big Bend Modernization Project. First, the Tampa Electric transmission and distribution system has been built and operated with a large portion of the capacity and energy being sourced from the Big Bend Station location. Building a new resource at a different location or buying power that is imported into the system creates new flows and dynamics that will likely increase operational costs and complexities. Second, the Big Bend Modernization Project provided certainty of execution. Permitting water use rights and securing or building new transmission capability is challenging, both from a cost certainty standpoint and a time to complete standpoint. Whether building new generation or buying from the wholesale power market, all options besides modernizing Big Bend Unit 1 have a much higher level of cost and timing risk associated with permits and transmission. And, third, modernizing Big Bend Unit 1 so that the company keeps a large, spinning generator on its system provides “inertia” that helps maintain voltage regulation, frequency regulation, and other ancillary services that maintain system stability and integrity that is difficult and expensive to provide from outside the system.

Q. Did the company conduct a formal request for proposals from the Florida wholesale power market?

A. Tampa Electric included numerous wholesale power alternatives in the options it considered, but it did not conduct a formal request for proposals. Since the analysis showed that no build or purchase options were likely to be more cost effective than the modernization project, and the other options lacked the previously mentioned benefits of reusing the existing generation and transmission infrastructure, the company moved forward with the project to capture its benefits for customers more quickly rather than risking delay and cost from a request for proposals.

Q. Did the company consider the value of reduced emissions in the assessment of the project?

A. Yes. The company calculated CPVRR savings with and without avoided emission costs. Using an industry-recognized forecast of the cost associated with emissions of CO_2, SO_2, and NOx, the company estimates that the Big Bend Modernization Project will avoid approximately $108 million of emission costs. As shown on Document No. 3 of my exhibit, the company estimates that the total CPVRR savings from Big Bend Modernization are $855 million when avoided emissions costs are included.

Q. Could energy conservation, load management, or other demand-side management programs have deferred or avoided the need for the Big Bend Modernization Project?

A. No. Demand-side management programs simply could not be implemented with the magnitude or the certainty needed to replace 800 MW of baseload generation. Even if cost-effective at that magnitude, demand-side management programs could not provide the operational flexibility provided by the quick start, rapid ramp rates, and transmission network support associated with Big Bend Modernization.

Q. What approvals were requested and received for Big Bend Modernization?

A. First, Tampa Electric had to get approval from Emera, Inc.'s Board of Directors and the Emera Finance Committee to assure funding of the project by Emera. The Board approved the project on February 18, 2018, and the Finance Committee approved the project on May 24, 2018.

Second, Tampa Electric filed a Site Certification

Application with the Florida Department of Environmental Protection on April 18, 2018. After extensive discovery and five days of hearings on March 11 through 15 of 2019, the administrative law judge issued an order on May 30, 2019 recommending approval of the project. The Governor and cabinet sitting as the Power Plant Siting Board approved the project on July 25, 2019.

Q. What is the status of the project?

A. Big Bend Modernization is on schedule and within budget. The total project cost for which Tampa Electric is seeking recovery is projected to be $893 million, including AFUDC, three million less than the $896 million, including AFUDC, used in the cost-effectiveness analysis. At $893 million, the cost of the project is approximately $800 per kW which is lower than all recent, similarly sized projects in Florida, further supporting that the project is the right choice for customers. More details about the status of the project are included in the testimony of Mr. Pickles.

Building Big Bend Modernization is Prudent

Q. Is Big Bend Modernization prudent, and what benefits does it provide to Tampa Electric and its customers?

A. Yes. The Big Bend Modernization Project is prudent and provides numerous benefits to Tampa Electric and its customers. The benefits generally include avoided investments of capital and operating costs for two aging pulverized coal units, greater reliability and flexibility of the company's generating system, fuel savings from improved generating efficiency, lower emissions, reduced water consumption and wastewater, and, finally, continued support of the winter population of manatees. More specifically:

1. Construction and operation of Big Bend Modernization and the related replacement of the portions of Units 1 and 2 to be retired is prudent because the project and associated retirements was the best available option and will yield a $747 million CPVRR savings to customers compared to the base case, without avoided carbon emission costs and $855 million with.

2. The repowered Big Bend Unit 1 will be the most efficient generating unit in the company's fleet, with an expected operational heat rate of approximately 6,350 Btu/kWh. This means lower natural gas fuel volumes, lower energy costs, and lower emissions, which will result in savings for customers.

3. The retirement of portions of Big Bend Unit 1 and all of Big Bend Unit 2 will allow the company to avoid spending an estimated total of $293 million CPVRR of capital to keep Big Bend Units 1 and 2 operating for the remainder of their Commission-approved lives.

4. Having removed Big Bend Unit 1 from commercial service in June 2020, the company will avoid making the approximately $151 million CPVRR of capital expenditures needed to keep Big Bend Unit 1 in service in its current form until its planned retirement date of 2035.

5. Removing Big Bend Unit 2 from commercial service in December 2021 will allow the company to avoid making the approximately $142 million CPVRR of capital expenditures needed to keep Big Bend Unit 2 in service until its planned retirement date of 2038.

6. The project will re-use much of the existing Big Bend Unit 1 infrastructure such that it moderates the dollar value of retired assets subject to a special capital recovery schedule and related customer rate impacts.

7. The project will improve the company’s overall generating system reliability. It will also make the Big

Bend Station generating units more reliable on a stand-alone basis. The annual Net Equivalent Availability Factor (“EAF") for Units 1 and 2 in 2019 were less than 70 percent. The company expects the EAF for the repowered Big Bend Unit 1 to be approximately to be 93 percent in combined cycle mode and 98 percent in simple cycle mode.

8. The company will burn less coal, use less water, and generate less wastewater than under the status quo, making Tampa Electric cleaner and greener.

9. The project will lower the company’s emission of CO_2, SO_2, and NO_X relative to current levels and levels projected for the future.

10. The project will enable the company to moderate the amount of money it must spend on solid fuel before Big Bend Modernization is complete while maintaining an acceptable level of warm water discharge to the existing manatee sanctuary.

11. The project will complement the company’s approved solar projects by providing winter reserve margin, 24-7 energy, and regulation support for the solar generation, which is an intermittent resource. The flexibility and

"following" ability inherent in the repowered Big Bend Unit 1 will effectively complement the company's utility scale solar generation. The repowered Big bend Unit 1 will be able to quickly offset the variability of solar plants as weather conditions change by ramping up or reducing output.

12. The project will allow the company to reduce O&M expenses at Big Bend through staffing reductions and other means as explained further in the direct testimony of Mr. Pickles.

13. The project will enhance safety by making Big Bend an inherently safer work environment by eliminating the complex and aging equipment related to coal handling and coal generation associated with Big Bend Units 1 and 2.

Q. Did the company identify the costs of not moving forward with Big Bend Modernization, and, if so, what were they?

A. Yes. If the company chose not to modernize Big Bend, the alternative would be to serve customers using a traditional expansion plan that adds simple-cycle combustion turbines. Under this approach, Tampa Electric and its customers would incur additional costs of $747 million CPVRR. This approach would also impose other costs and burdens on Tampa Electric and its customers, such as greater water usage, higher emissions, and lower reliability. Perhaps most importantly, Tampa Electric and its customers may have missed out on the opportunity afforded by Big Bend Modernization, to advance the system with new, more efficient technology.

Q. How will Big Bend Modernization benefit Florida and the communities Tampa Electric serves?

A. Big Bend Modernization will benefit Florida and the communities Tampa Electric serves by materially improving the electrical grid with higher efficiency, lower emissions, greater reliability, and greater operational flexibility. The project achieves these benefits while reusing most of the existing Big Bend Unit 1 generation assets, water rights, and transmission infrastructure.

Q. How does the project complement the company's investment in utility scale solar?

A. Tampa Electric is committed to cost-effectively reducing its impact on the environment and solar PV generation is an important component of this commitment. Customers want Tampa Electric to incorporate as much cost-effective solar energy as can be managed reliably. By its very nature, solar energy is non-dispatchable, meaning it produces energy when the solar radiance is available, not necessarily when the utility needs it. Similarly, solar energy output is erratic, with wide, frequent swings as clouds pass overhead.

The Big Bend Modernization Project will replace two aging pulverized coal units that have limited output range and are slow to vary output with two state-of-the-art combustion turbines that can start quickly, ramp rapidly, and generate across a wide MW range. While the Big Bend Modernization Project is not solely intended to support solar, its presence on Tampa Electric’s system will improve our ability to use existing solar resources and add additional utility scale solar generation as discussed in the testimony of Mr. Sweat and Mr. Aponte.

Q. Will the project provide a capacity benefit for the company?

A. Yes. With a winter capacity of 1,120 MW, compared to about 800 MW for existing Big Bend Units 1 and 2, Big Bend Modernization will provide approximately 300 MW of incremental, reliable, and flexible generating capacity.

The cost of the modernization is more than offset by cost savings from using existing assets from Big Bend Unit 1, fuel savings from improved efficiency, and redeployment of capital and O&M to new technology instead of maintaining aging coal units.

Q. Will the Big Bend Modernization Project advance the company's three areas of strategic focus - safety, customer experience, and being cleaner and greener?

A. Yes. The project will support all three areas of strategic focus.

The project will enhance safety by making Tampa Electric's Big Bend Station an inherently safer work environment by removing complex aging equipment used for coal handling and coal-fired generation associated with Units 1 and 2.

The project will enhance the customer experience because customers will receive increased reliability and lower costs for their electrical service.

The project will allow the company to make significant progress on its goal of running a cleaner and greener generating fleet by replacing two pulverized coal units with a much more efficient, reliable, and flexible NGCC unit with lower emission levels, water consumption levels, and solid waste like coal combustion residuals. As I previously mentioned, the increased reliability and flexibility of repowered Big Bend Unit 1 will enhance the company's ability to accommodate increasing levels of zero-emission, zero fuel cost solar generation.

Q. Will Big Bend Modernization increase the company's need for natural gas?

A. Yes, but not as much as one might expect. First, Tampa Electric would need more gas pipeline capacity if the energy to be generated by the modernized Big Bend Unit 1 would be generated from existing, less efficient units. When Big Bend Units 1 and 2 are fueled with natural gas, it requires nearly twice as much natural gas commodity and pipeline capacity for the same amount of electrical energy from the modernized Big Bend Unit 1. Even if Big Bend Units 1 and 2 are operating on coal, their much lower availability factor means that frequently the energy they produce must be replaced with natural gas burned in the inefficient Big Bend units or in other gas units on the Tampa Electric system. While the very efficient and very reliable modernized Big Bend Unit 1 may increase the average daily need for natural gas supply and pipeline capacity, it eliminates the unpredictable spikes in gas supply and pipeline capacity demands associated with the units it replaces. Overall, Tampa Electric's reliance on natural gas increases with the project, but the ultimate management of that natural gas demand improves significantly.

Q. Is it prudent to retire portions of Big Bend Units 1 and 2 as part of Big Bend Modernization before the retirement date used when preparing the company's last-approved depreciation rates?

A. Yes. Early retirement of parts of Big Bend Unit 1 and all of Unit 2 are necessary parts of Big Bend Modernization, so the early retirement of portions of Big Bend Unit 1 and all of Unit 2 is prudent for the same reasons Big Bend Modernization is prudent. The early retirements associated with Big Bend Modernization will lower fuel costs, reduce future capital costs, and moderate operating costs at Big Bend. The cost effectiveness analysis benefits are over and above recovery of the remaining undepreciated value of the retired assets. It is clearly in Tampa Electric's customers' best interest to retire these assets before their planned retirement dates as part of the project.

The Big Bend Units 1 and 2 assets to be retired in conjunction with Big Bend Modernization, their undepreciated net book values, and the company's proposed accounting treatment for those assets are discussed in the direct testimony of Mr. Pickles and Mr. Avellan.

Q. How does the Project fit into the company's ten-year site plan?

A. The Big Bend Modernization Project strengthens the foundation upon which Tampa Electric provides energy for our customers as compared to the coal units that are being retired and modernized. In addition to improving the system's ability to accommodate solar, this improved foundation enables Tampa Electric's generation expansion plan to incorporate distributed energy resources such as solar photovoltaic, energy storage, and reciprocating engines more easily. These emerging technologies provide opportunities to improve reliability, improve resiliency, reduce emissions, reduce energy losses, adapt quickly to changing needs, and avoid transmission and distribution investments. The Big Bend Modernization Project improves the Tampa Electric generation portfolio now and into the future.

Early Retirement of Big Bend Unit 3 is Prudent

Q. Please describe Big Bend Unit 3.

A. Big Bend Unit 3 is a pulverized coal-fired steam unit. It was placed in service in May 1976. It has a name-plate capacity of 445.5 MW and has summer and winter capability of 395 MW and 400 MW, respectively. The expected retirement date reflected in the company's 2011 Depreciation Study is 2041.

Big Bend Unit 3 has been maintained, operated, and upgraded across those five decades to comply with ever evolving and increasingly demanding environmental constraints. Some of its primary emissions control equipment includes particulate matter collectors, flue gas desulfurization scrubbers, nitrogen oxide selective catalytic reduction equipment, pre- and post-water treatment plants, and coal combustion residual handling equipment. The company has replaced the heavy oil igniters on Big Bend Unit 3 with natural gas igniters and added additional natural gas burners to allow operation with natural gas as either a supplement or as an alternative to coal.

Despite this fuel flexibility and exceptional emission control, it is prudent to retire Big Bend Unit 3 in April

2023, which is before the retirement date used in the company’s 2011 depreciation study.

Q. How did the company conclude that it would be prudent to retire Big Bend Unit 3 earlier than planned?

A. As previously noted, the company began evaluating what actions would be in the best interest of its customers with respect to the future of the steam turbine units at Big Bend Station in 2016. The Big Bend Modernization Project was the culmination of this process. During that process, the retirement of Big Bend Unit 3 before its current expected retirement date was identified as another opportunity to benefit our customers.

The Integrated Resource Plan prepared by the company in late-2019 and early-2020 once again confirmed the early retirement of Big Bend Unit 3 and recommended the action. The decision and timing of the retirement of Big Bend Unit 3 was ultimately finalized in late 2020. In October 2020, the company concluded that it would be in the best interest of its customers to retire Big Bend Unit 3 in April 2023.

Q. Why is the early retirement of Big Bend Unit 3 prudent and in the best interest of customers?

A. Early retirement of Big Bend Unit 3 is prudent from an economic perspective, an environmental risk perspective, and an operational perspective.

Economically, Tampa Electric projects that customers will save nearly $299 million on a CPVRR basis from the retirement of Big Bend Unit 3, as shown in Document No. 4 of my exhibit. These savings come primarily from reduced investment needed to maintain and operate a 1970’s vintage coal-fired unit. Fuel savings and variable O&M expense reductions round out the overall economic benefit.

Environmentally, the energy that would be provided by Big Bend Unit 3 with a heat rate of about 11,000 Btu/kWh will instead be produced by a NGCC generator with a heat rate of about 7,000 Btu/kWh which is an efficiency improvement of over 35 percent. Since less fuel will be consumed, fewer emissions will be created. Due to the relative prices for natural gas and coal, Big Bend Unit 3 currently operates on natural gas. Emission reductions from the early retirement of Big Bend Unit 3 would be even greater compared to a scenario where Big Bend Unit 3 burns coal or if the replacement generation comes from solar or some other emission-free resource.

Operationally, Big Bend Unit 3, like all coal-fired steam turbine units, was built to be a baseload unit, meaning it is designed to be turned on and left on around-the-clock for multiple days or even months in a row. Changing energy use patterns by our customers and the addition of intermittent resources on our electric system require that the company's generation portfolio be more flexible, able to follow the variation in load, and react to changing output from solar resources. For these reasons and because aged, coal-fired assets are inherently less reliable compared to modern gas-fired generation technology, Big Bend Unit 3 no longer fits the operational needs of Tampa Electric and its customers' demands.

Q. What are the costs and proposed accounting treatments associated with the early retirement of Big Bend Unit 3?

A. The Big Bend Unit 3 assets to be retired in 2023, their undepreciated net book values, and the company's proposed accounting treatment for those assets are discussed in the direct testimony of Mr. Pickles and Mr. Avellan.

SUMMARY

Q. Please summarize your direct testimony.

A. The Big Bend Modernization Project is important to Tampa Electric and its customers. The project will provide $747 million of CPVRR savings compared to an optimized expansion plan that does not retire and calls for the continued refurbishment of existing coal-fired units. The project was identified and selected through an extensive screening and analytic process and is the most prudent option as compared to numerous other new construction and market options.

In addition to its compelling economics, Big Bend Modernization will improve system efficiency as it will be the most efficient dispatchable unit on the system. It will improve system environmental performance by significantly lowering air emissions, water consumption, and wastewater production. The project will improve overall system reliability and operational flexibility by replacing two 1970's vintage pulverized coal units with state-of-the-art, responsive, and reliable combustion turbines and heat recovery steam generator integrated with the Big Bend Unit 1 generation equipment. The Big Bend Modernization Project is a foundational element of Tampa Electric's plan to provide service to its customers in an affordable, reliable, and environmentally responsible manner.

Likewise, the early retirement of Big Bend Unit 3 is prudent from an economic perspective, an environmental risk perspective, and an operational perspective and will provide demonstrable benefits to Tampa Electric and its customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Jeffrey T. Kopp was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

DIRECT TESTIMONY AND EXHIBIT
OF
JEFFREY T. KOPP
ON BEHALF OF TAMPA ELECTRIC COMPANY

DOCKET NO. 20210034-EI
FILED: 04/09/2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEFFREY T. KOPP

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114. I am employed by 1898 & Co., which is the consulting group within Burns & McDonnell Engineering Company, Inc. ("1898 & Co."), as the Managing Director of the Utility Consulting Department.

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

A. The purposes of my prepared direct testimony are to (1) discuss the Fleet Decommissioning Cost Study ("Dismantlement Study" or "the Study") conducted for Tampa Electric Company ("Tampa Electric" or "company") and (2) support the reasonableness of the Dismantlement Study costs included in the company's rate request.

Q. Which Tampa Electric generating units does the Study assume will be dismantled?

A. The Study assumes that all units in Tampa Electric's generation fleet will be dismantled.

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

A. Yes. Exhibit No. JTK-1 was prepared under my direction and supervision. My exhibit consists of three documents, entitled:

Document No. 1	Fleet Decommissioning Cost Study
Document No. 2	Resume of Jeffrey T. Kopp
Document No. 3	List of Proceedings in Which Jeffrey T. Kopp Has Submitted Testimony

Q. Are there other witnesses submitting direct testimony in this proceeding that addresses dismantlement costs for Tampa Electric, and if so, how does their testimony relate to your testimony?

A. Yes. Tampa Electric witness Davicel Avellan 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. Additionally, witness Charles R. Beitel of Sargent & Lundy is testifying on behalf of the company as to the costs for selective demolition of Big Bend Units 1, 2, and 3.

EDUCATION AND BUSINESS EXPERIENCE

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

A. I have a bachelor's degree in Civil Engineering from the University of Missouri – Rolla (now the Missouri University of Science and Technology) and a Master of Business Administration degree from the University of Kansas. I am a professional engineer with more than 19 years of experience consulting to electric utilities. I have been involved in numerous dismantlement studies and served as project manager on the majority of them. I have helped prepare dismantlement studies on all types of power plants utilizing various technologies and fuels.

As the Managing Director of the Utility Consulting Department of 1898 & Co., I oversee a group of more than 110 engineers and consultants who provide consulting services to clients primarily in the electric power generation and electric power transmission industries, but also to other industrial and commercial clients. The services provided by this group include dismantlement cost studies, independent engineering assessments of existing power generation assets, economic evaluations of capital expenditures, new power generation development and evaluation, electric and water rate analysis, electric transmission planning, generation resource planning, renewable power development, and other related engineering and economic assessments.

In my role as a group manager, project manager, and project engineer, I have worked on and have overseen consulting activities for coal, natural gas, wind, solar, hydroelectric, and biomass power generation facilities.

Q. Do you hold any certifications?

A. Yes, I am a registered professional engineer in the states of Florida, Illinois, Indiana, and Missouri.

Q. Have you previously testified before state or federal regulatory commissions?

A. Yes. I have provided written or oral testimony in various proceedings listed in Document No. 3 of my Exhibit No. JTK-

1.

1898 & CO.

Q. What qualifies 1898 & Co. to prepare accurate estimates of dismantlement costs and why should the Florida Public Service Commission ("Commission") rely on these estimates?

A. Over the years, 1898 & Co. has worked closely with demolition contractors to develop decommissioning cost estimates that accurately estimate the costs for activities that the demolition contractors will perform. 1898 & Co. has prepared numerous decommissioning studies for various clients considering different technologies in different states and has provided services to clients on decommissioning project execution including review and evaluation of bids from demolition contractors. 1898 & Co. has utilized this experience preparing decommissioning estimates and reviewing demolition contractor bids to confirm the reasonableness of the cost estimates prepared by 1898 & Co.

At the time a utility decides to decommission the power plants included in the Study ("the plants"), means and methods will not be dictated to the contractor by 1898 & Co. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning and dismantling the plants at the lowest possible cost. However, based on 1898 & Co.'s experience with decommissioning projects and discussions with demolition contractors, the costs estimated by 1898 & Co. are reflective of what contractors would bid through a competitive bidding process given the option to select safe and efficient means and methods.

As indicated above, 1898 & Co. has vast experience in preparing decommissioning studies, overseeing demolition projects, and executing construction projects. In order to execute over $2 billion of construction projects on an annual basis, Burns & McDonnell Engineering Company, Inc., of which 1898 & Co. is a division, has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates. If we routinely estimated costs too high, we would not be successful in winning projects. If we routinely estimated costs too low, we would not be able to execute projects profitably and would no longer be active in this market. Our long history, large market presence, and top industry rankings demonstrate our ability to estimate costs effectively and accurately. In addition, we review competitive bids from demolition contractors for power plant demolition projects, and we have worked with demolition contractors over the years to refine our estimating process for decommissioning studies to align our costs with theirs.

SELECTIVE VS. FULL DISMANTLEMENT COSTS

Q. Please describe selective demolition and full dismantlement and how the selective demolition costs proffered by Mr. Beitel differ from the dismantlement costs included in your Study.

A. The costs included in my study are based on end-of-life costs for demolishing each power generating unit after all generating units have been taken out of service. This allows the use of explosives to fell boilers and other tall structures and then cutting them up on the ground, with no provisions made to protect operating equipment. This allows demolition contractors to select demolition methodologies that can be safely performed in an efficient and low-cost manner.

Selective demolition assumes that some generating units and related facilities will be demolished at a particular plant site, while others will remain in operation at the plant site where the demolition will take place. Costs for selective demolition at Big Bend Units 1, 2, and 3 were estimated separately by Sargent & Lundy, assuming that other equipment and facilities at the Big Bend site would remain in operation. This prohibits the use of explosives and limits the ability to drop large structures. In this selective demolition scenario, all demolition activities would need to be performed in a more controlled manner, which results in a higher demolition cost for these units.

1898 & CO. DISMANTLEMENT STUDY

Q. Please describe the purpose of the Dismantlement Study.

A. The company retained 1898 & Co. to provide it with a recommendation regarding the total cost, in 2020 dollars, of dismantlement of each company-owned generation unit at the end of its useful life, as well as the total cost of dismantlement of the common facilities at these generating plants. The total dismantlement cost as determined by 1898 & Co. and reflected in the Dismantlement Study is net of salvage value for scrap materials at each plant. 1898 & Co. had previously prepared a similar study for the company in 2011 in support of the company’s depreciation filing. The current Dismantlement Study serves to update the costs presented in the 2011 study for changes to market conditions, physical changes that have occurred at the plants, and incorporating new facilities that have been constructed or acquired since 2011.

Q. What level of dismantlement and demolition did 1898 & Co. assume was performed at each of the sites?

A. The basis of the 1898 & Co. cost estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility.

Q. What does restoring the sites for industrial use require?

A. The sites will have all above grade buildings and equipment removed, foundations removed to three feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use.

Q. What process did you follow in preparing the Dismantlement Study?

A. The estimates of dismantlement costs were prepared with the intent of most accurately representing what 1898 & Co. would anticipate contractors bidding to dismantle the equipment, address environmental issues, and restore the site through a competitive bidding process.

As outlined in the Dismantlement Study, we prepared these cost estimates by estimating quantities and then applying current market pricing for labor rates, equipment costs, scrap, and disposal costs specific to the area in which the work is to be performed. This results in the total cost of dismantlement for each site.

Q. Are there industry-standard methods or inputs used when preparing such a study and what are they?

A. Yes. We reviewed Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies, as a guide for preparing our study. We also incorporated the methodologies used in prior studies we prepared that have been approved by the Commission and other utility commissions throughout the country. Furthermore, many of the inputs in our estimates come directly from industry standard data sources and publications, including:

- RSMeans Heavy Construction Cost
    - o RSMeans is an industry standard publication of construction cost data that is used throughout North America by engineers to prepare construction and demolition cost estimates. The RSMeans database

includes adjustments to the base costs based on location, to provide a more accurate estimate for the area in which the project will take place. RSMeans includes data for all types of construction and demolition activities, including materials, labor, hauling, and disposal.

- Fastmarkets AMM
  - Fastmarkets AMM has been in business since they began as American Metal Market in 1882. They are the leading publication of metal pricing, including scrap metal pricing. They provide an independent market perspective on metal prices in North America, using data from market transactions.

Q. Did Tampa Electric provide data to you for use in the study?

A. Yes.

Q. What data did the company provide?

A. The company provided numerous drawings and equipment data for each of the sites evaluated in the study.

Q. Please describe the key assumptions of the Dismantlement Study.

A. As I stated earlier, the basis of the estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility. We also assumed that all units at each power station will be dismantled as part of a single demolition project, therefore, no selective demolition was included in the estimates. Additional assumptions are outlined in Sections 4.1 and 4.2 of the Study in Document No. 1 of Exhibit JTK-1.

Q. Please generally explain the types of costs reflected in the study?

A. The cost estimates reflected in the Dismantlement Study are inclusive of direct costs associated with dismantling the plant equipment and facilities and restoring the sites to an industrial-ready condition. The direct costs include environmental remediation costs for asbestos removal and other hazardous material handling and disposal, as well as costs for removing and disposing of contaminated soil around transformers. The Dismantlement Study does not include any estimates of indirect costs to be incurred by the company during dismantlement, nor any contingency costs. Indirect owner’s costs and contingency costs were applied by Tampa Electric separate from the study.

Q. How were the direct costs estimated for purposes of the study?

A. As part of the Dismantlement Study, site-specific cost estimates were developed using a “bottom-up” cost estimating approach, where cost estimates are developed from scratch through the development of site-specific quantity estimates and the application of unit pricing rates to the quantity estimates.

As outlined in the Dismantlement Study, 1898 & Co. prepared these cost estimates by estimating quantities for existing equipment based on visual inspections, review of engineering drawings, review of 1898 & Co.’s in-house database of plant equipment quantities and using 1898 & Co.’s professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each dismantlement effort. Current market pricing for labor rates and equipment were used to develop unit pricing rates for each task. These unit pricing rates were applied to the quantities for the plants to determine the total direct cost of dismantlement for each site. Additionally, unit pricing for scrap values was applied to the scrap quantities to determine anticipated salvage values, which were subtracted from the gross direct costs to arrive at a net project cost in 2020 dollars.

Q. Were any costs excluded from your study?

A. As discussed earlier, 1898 & Co. did not include any costs associated with selective demolition, which allows for units at the site to remain in operation during and subsequent to demolition activities. In particular, costs for selective demolition at Big Bend Units 1, 2, and 3 were estimated separately by Sargent & Lundy and are presented by Mr. Beitel. 1898 & Co. prepared costs for full demolition of all units and equipment at the Big Bend site assuming no selective demolition techniques would be required. However, the cost for Big Bend Units 1, 2, and 3 dismantlement included in Tampa Electric’s depreciation and dismantlement costs submitted to the Commission in Docket No. 20200264-EI on December 30, 2020 is based on the Sargent & Lundy costs, since selective demolition techniques will be required for those units.

Q. Is it your conclusion that the study results are reasonable estimates?

A. Yes, the study results and cost estimates are reasonable estimates and are useful for planning purposes. It is appropriate for the company to rely on these estimates for inclusion in their dismantlement reserve needs.

SUMMARY

Q. Please summarize your direct testimony.

A. The company retained 1898 & Co. to provide it with a recommendation regarding the total cost, in 2020 dollars, of dismantlement of each company-owned generation unit at the end of its useful life as well as the total cost of dismantlement of the common facilities at these generating plants. 1898 & Co. is qualified to prepare dismantlement cost estimates and has vast experience in preparing decommissioning studies, overseeing demolition projects, and executing construction projects. The estimates of dismantlement costs were prepared with the intent of most accurately representing what 1898 & Co. would anticipate contractors bidding through a competitive bidding process to dismantle the equipment, address environmental issues, and restore the site. The dismantlement study is consistent with Rule 25-6.04364, Florida Administrative Code, Electric Utilities Dismantlement Studies, incorporates the methodologies used in prior studies we prepared that have been approved by the Commission and other utility commissions throughout the country, and incorporates industry standard data. The study results and cost estimates are reasonable estimates and appropriate for the company to rely on for their dismantlement reserve needs.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Steven P. Harris was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: TAMPA ELECTRIC COMPANY’S

PETITION FOR AN INCREASE IN BASE RATES

AND MISCELLANEOUS SERVICE CHARGES

DIRECT TESTIMONY AND EXHIBIT

OF

STEVEN P. HARRIS

ON BEHALF OF TAMPA ELECTRIC COMPANY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

STEVEN P. HARRIS

ON BEHALF OF TAMPA ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Steven P. Harris. My business address is. ABSG Consulting, Inc. ("ABS Consulting"), 300 Commerce Drive Suite 150, Irvine, California 92602.

Q. Who is your employer and what is your position?

A. I am a Senior Consultant with ABS Consulting, a subsidiary of the ABS Group of Companies. I was formerly with EQECAT (an ABS Group Company), which was acquired by CoreLogic, Inc. Insurance & Spatial Services, Consulting Services Group in December 2013.

ABS Consulting is a global provider of catastrophic risk management services to insurers, corporations, governments, and financial institutions.

Q. Please summarize your educational background.

A. I received bachelor's and master's Degrees in engineering from the University of California at Berkeley. I am a licensed civil engineer in the State of California.

Q. Please describe your responsibilities as a Senior Consultant with ABS Consulting.

A. As a Senior Consultant with ABS Consulting, I provide catastrophic risk management consulting services to major insurers, reinsurers, corporations, government, and other financial institutions. These services provide catastrophic underwriting, pricing, risk management, and risk transfer model analytics that are used extensively in the insurance industry. These services provide the financial, insurance, and brokerage communities with a science and technology-based source of independent quantitative risk information.

Q. Please describe your prior work experience and responsibilities.

A. Over the past 30 years, I have conducted and supervised independent risk and financial studies for public utilities, insurance companies, and other entities, both regulated and unregulated. My areas of expertise include natural hazard risk analysis, operational risk analysis, risk profiling and financial analysis, insurance loss analysis, loss prevention and control, business continuity planning, and risk transfer.

I have performed or supervised windstorm (tropical storm or hurricane) loss, and reserve analyses for utilities including Tampa Electric Company ("Tampa Electric" or "company"), Florida Power & Light, Duke Energy Florida, Gulf Power Company, and others. Additionally, I have performed loss analyses for earthquake hazard for utilities including the Metropolitan Water District of Southern California, the Los Angeles Department of Water and Power, and the Sacramento Municipal Utility District.

For energy companies that have assets in a wide array of geographic locations, I have performed or supervised multi-peril analyses of transmission and distribution ("T&D") systems, power plants, solar farms, battery energy storage systems, and wind farms for natural hazards, including earthquakes, windstorms, and ice storms.

Q. Have you previously testified before this commission or other state public utility commissions?

A. Yes. I have submitted written testimony or testified before the Florida Public Service Commission ("FPSC" or "Commission") many times over the past 20 years. I have represented the Florida investor-owned utilities, including Tampa Electric, regarding T&D loss assessment and reserve coverage in each of these cases.

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

A. The purpose of my testimony in this proceeding is to present the results of ABS Consulting's independent analyses of the risk of uninsured hurricane loss to Tampa Electric's T&D assets. The study includes a Hurricane Loss Analysis and a Reserve Performance Analysis.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring Exhibit No. SPH-1, entitled "Exhibit of Steven P. Harris on Behalf of Tampa Electric Company", which was prepared under my direction and supervision. It consists of one document, "Hurricane Loss and Reserve Performance Analysis".

Q. Please briefly describe the studies performed for Tampa Electric.

A. ABS Consulting performed two analyses relative to the reserve: The Hurricane Loss Analysis (“Loss Analysis”) and The Reserve Performance Analysis (“Reserve Analysis”). The Loss Analysis is a probabilistic hurricane analysis that uses proprietary software to develop an estimate of the expected annual amount of uninsured hurricane losses to which Tampa Electric is exposed. The Reserve Analysis is a dynamic financial simulation analysis that evaluates the performance of the reserve in terms of the expected balance of the reserve and the likelihood of positive reserve balances over a five-year prospective period, given the potential uninsured losses determined from the Loss Analysis.

Q. Please summarize the results of your analyses.

A. The Hurricane Loss Analysis estimated the level of annual damage that Tampa Electric is exposed to from hurricanes. The Reserve Analysis tested the performance of the reserve against the potential hurricane losses determined from the Loss Analysis. The study estimated the total expected average annual uninsured cost to Tampa Electric from all hurricanes to be $27.3 million.

The Reserve Analysis demonstrated that the expected reserve balance would be a deficit of negative $21.4 million at year five of the simulation, with a probability of a negative reserve balance of 70.1 percent within the five-year simulation time horizon.

LOSS ANALYSIS

Q. Please summarize the Loss Analysis.

A. The Loss Analysis determined the expected annual amount of hurricane losses to Tampa Electric's T&D system. Hurricane losses included costs associated with service restoration and repair of Tampa Electric's T&D system due to hurricanes. Also included are estimates of the costs of hurricane insurance deductibles attributable to non-T&D assets.

Q. Please describe the computer software used to perform the Loss Analysis.

A. Risk Quantification and Engineering ("RQE®") is a probabilistic catastrophe simulation model designed to estimate damage due to the occurrence of hurricanes. The model computes probabilistic annual damage using the results of thousands of random variable hurricanes and develops annual damage estimates for assets and aggregates them to produce the overall portfolio damage amounts. RQE's climatological models are based on the National Oceanic and Atmospheric Administration's ("NOAA") National Weather Service ("NWS") Technical Reports. The RQE proprietary computer software model was evaluated and determined acceptable by the Florida Commission on Hurricane Loss Projection Methodology for projecting hurricane loss costs.

Q. Why are catastrophe simulation models used for hurricane loss projection?

A. Catastrophe simulation modeling is the process of using computer-assisted calculations to estimate the damage that could be sustained due to natural disasters such as hurricane events. Catastrophe simulation modeling combines actuarial science, engineering, meteorology, and computer science to allow loss estimation of infrequent events. The insurance industry and risk managers use catastrophe simulation modeling to assess and manage risks. Catastrophe simulation modeling is the current standard of risk assessment in the insurance industry.

Q. Does RQE take into account storm frequency and severity?

A. Yes. The analysis is based on storm frequency and severity distributions developed from the entire, over 100-year, historical hurricane record. RQE estimates the frequency of storms in the current period of heightened hurricane activity.

Q. Please describe the current period of heightened hurricane activity.

A. Hurricanes are known to occur in multi-year cycles. The recent decades of the 1970s through the mid-1990s had significantly lower activity than the over 100-year long-term average. Other decades have had periods of higher activity. NOAA has expressed its belief that we entered a period of increased hurricane formation around 1995.

There is the emerging consensus that changes in the El Niño/ Southern Oscillation and North Atlantic Oscillation variables indicate we have entered a more active period for hurricane formation, like that experienced in the 1920s and 1940s. The length of these active periods is thought to be about 25 to 40 years or more. Therefore, Tampa Electric may expect to experience higher damage to its T&D assets over the next several years than would be predicted by the long-term hurricane hazard. The Loss Analysis is based on hurricane frequency and severity distributions that are reflective of the relatively more active periods of the

1920s and 1940s.

The simulated hurricane events ABS Consulting analyzed therefore represent frequencies associated with the current period that may be associated with a higher frequency of hurricane formation. If the view held by NOAA and other meteorological experts is correct, we may expect to see larger numbers of hurricanes form and larger numbers of landfalls in the coming years than we have in the pre-1995 period.

Q. Do the storm frequency assumptions include the possibility of having multiple hurricane landfalls within Florida in any given year?

A. Yes. RQE includes the possibility of having multiple hurricane landfalls within Florida in any given year, including the impact of such landfalls on aggregate losses, similar to the 2004 hurricane season when multiple landfalls in Florida occurred.

Q. What were the results of the Loss Analysis?

A. The total expected annual uninsured cost to Tampa Electric's system from all hurricanes is estimated to be

$27.3 million.

Q. What does this expected annual loss estimate represent?

A. The expected annual loss estimate represents the average annual cost associated with damage to T&D assets, insurance deductibles for damage to other assets such as generating plants and substations, and service restoration activities resulting from hurricanes over a long period of time.

Q. Is the Loss Analysis performed for Tampa Electric the same analysis performed for insurance companies to price an insurance premium?

A. Yes. The natural hazards loss modeling and analysis is similar for an insurance company, electric utility, or other entity. The expected annual loss is also known as the "pure premium." When insurance is available, the pure premium is the insurance premium level needed to pay the expected losses. Although insurance companies would add their expenses and profit margin to the pure premium to develop the premium charged to customers, those additional costs are not reflected in ABS Consulting's analyses and results.

RESERVE PERFORMANCE ANALYSIS

Q. Please summarize the Reserve Analysis.

A. ABS Consulting performed a dynamic financial simulation analysis of the impact of the estimated hurricane losses on the reserve for specified fund parameters. The starting assumption for the Reserve Analysis was a reserve balance of $48.2 million. The Reserve Analysis includes 10,000 simulations of windstorm losses within the Tampa Electric service territory, each covering a five-year period, to determine the effect of the charges for loss on the reserve.

This analysis technique relies on repeated sampling to model multiple storm seasons and simulates variable hurricane losses consistent with the results of the Loss Analysis. The study includes 10,000 five-year simulations to estimate the performance of the reserve and ensure an adequate number of samples of rare storm events because storm seasons and losses are highly variable. ABS Consulting used these Monte Carlo simulations to generate damage samples for the analysis.

ABS Consulting used the simulations to generate loss samples consistent with the expected annual loss from the Loss Analysis results. The expected annual loss determined in the Loss Analysis is $27.3 million, and $23.7 million of this amount is assumed to be an obligation of the reserve annually. The analysis provides the expected balance of the reserve in each year of the simulation, accounting for losses, using a financial model.

Q. How are the results of the Loss Analysis used in the Reserve Analysis?

A. ABS Consulting used the likelihoods and amounts of uninsured annual losses determined in the Loss Analysis to simulate losses in each of the five years in the Reserve Analysis to determine the reserve balance and the likelihood of the reserve having positive balances.

Q. Please describe the assumptions that were included in the Reserve Analysis.

A. The initial reserve balance is $48.2 million. The analysis also assumed future growth of the customer base and system assets and inflationary cost increases for new T&D assets of 3.96 percent annually.

Based on the simulated hurricane loss distributions, the expected or mean reserve balance is a negative $21.4

million. There is also a 70.1 percent chance of the reserve balance reserve reaching zero or becoming negative in one or more years of the five-year simulation.

The analysis also provides estimates of the fifth percentile and ninety-fifth percentile reserve balances. At the fifth percentile reserve balance, only five percent of the simulated outcomes have smaller values. Similarly, for the ninety-fifth percentile reserve balance, only five percent of simulated outcomes have values which would be greater than that value. The fifth percentile represents an extremely adverse five years of storm experience where the reserve balance is a negative $137.8 million due to losses that would far exceed the reserve funds available. Conversely, the ninety-fifth percentile balance represents an extremely favorable five years of storm experience where only five percent of simulated reserve outcomes would be greater than the estimated balance, or five years of very small or no storm damage.

Q. Please summarize the results of your analyses.

A. The Loss Analysis demonstrated that the total expected annual damage to Tampa Electric’s system from all hurricanes is estimated to be $27.3 million.

The Reserve Analysis demonstrated that, assuming a $48.2 million initial reserve balance, and recovery of negative reserve balances due to storm losses over the following one-year period, the expected reserve balance would be a negative $21.4 million, and there would be a 70.1 percent probability of the reserve balance reaching zero or becoming negative in one or more years of the five-year simulation.

The $48.2 million reserve and one-year recovery of negative reserve balances are insufficient to pay for all the expected annual storm damage over the five-year period. Over the five-year simulation, the reserve balance would be expected to decline and have a negative balance.

Q. Does this conclude your direct testimony?

A. Yes.

CHAIRMAN CLARK: All right. Move on to exhibits.

MR. MURPHY: Staff has prepared a Comprehensive Exhibit List which includes Exhibits 1 through 60. The list and the identified exhibits have been provided to the parties, Commissioners and the court reporter.

Staff asks that the Comprehensive Exhibit List be marked as Exhibit No. 1, with all subsequent exhibits marked as identified on the list.

(Whereupon, Exhibit Nos. 1-60 were marked for identification.)

CHAIRMAN CLARK: The exhibits are so marked.

MR. MURPHY: Staff asks that Exhibits 1 through 60 be entered into the record at this time.

CHAIRMAN CLARK: Any objection? Seeing none, so ordered.

(Whereupon, Exhibit Nos. 1-60 were received into evidence.)

CHAIRMAN CLARK: All right. Let's move into our witnesses.

Mr. Wahlen, will you introduce your panel of witnesses?

MR. WAHLEN: Yes, sir. Thank you, and good morning again, Commissioners.

The consumer parties have assembled a panel of witnesses to answer any questions you have. They are seated here in front of you. They agreed to sit at the counsel table on the condition that they would not be confused as lawyers, so I hope that we can verify that at the beginning.

I would like to introduce them starting down on the end is Randy Futral. He is one of Public Counsel's experts. He is available to answer questions about the Clean Energy Transition Mechanism and other things.

Next to him is Jeff Chronister. He is the CFO and Controller of Tampa Electric Company. He can answer questions about the revenue requirement and GBRA, those sorts of things.

Next to him is Randy -- I am sorry, Kevin Higgins. Kevin is an expert who was retained by the Hospitals. He is here to talk if you have questions about cost of service and revenue allocations.

Next to me is Penelope Rusk. She's the Director of Regulatory Affairs for Tampa Electric. She's bed and cleanup, and can deal with any rate design questions and anything else that the other witnesses can't field.

So I would be glad to help direct traffic if you have a question and want some help getting to the right person, I am happy to do that or you can --

CHAIRMAN CLARK: Sounds good.

Let's swear these witnesses in first and then we will move from there.

Would you please stand and raise your right hand?

Whereupon,

PENELOPE RUSK
KEVIN HIGGINS
JEFFREY CHRONISTER
RANDY FUTRAL

were 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:

CHAIRMAN CLARK: Thank you, consider yourselves sworn in.

All right. Yeah, Mr. Wahlen, if you want to direct the traffic and we will open that up to questions at that point.

MR. WAHLEN: Very well. They are able for questions.

CHAIRMAN CLARK: All right. Staff, do you have any questions for the parties?

MR. MURPHY: No questions.

CHAIRMAN CLARK: All right. Commissioners, it's your turn. Who wants to start?

Commissioner Fay, you may begin.

COMMISSIONER FAY: Thank you, Mr. Chairman.

Mr. Wahlen, I will direct the question at you, but obviously any of the panel members can answer.

So the first question I have is the Clean Energy Transition Mechanism, it essentially -- I know it does a number of things, but I guess can you explain how it's consistent with Commission policy?

MR. WAHLEN: Well, I will take that kind of as a legal question to begin with, and then if there is some factual follow-up we can.

First of all, I think the Commission has a long history of allowing recovery of assets that are being retired early when there is a benefit associated with the retirement. And the record in this case shows that the Big Bend modernization program, after you consider the cost of the retired assets, still provides a huge positive revenue requirement benefit for customers.

The AMI project is also something that will save expenses, but more importantly is going to allow for new services and enable customers to manage their energy habits a little bit better in the future.

So essentially, the CETM is a cost recovery mechanism for retired assets. The Commission has a long history of allowing recovery for them.

Now, I will stop there, and if there is more, I can add in.

COMMISSIONER FAY: Can you just elaborate how the GBRA intertwines with that mechanism?

MR. WAHLEN: Sure, the GBRA.

The GBRAs the Commission has approved a number of times. In this case, the company provided prefiled direct testimony outlining all the solar projects that solar projects it was going to build, what they expect the cost to be and provided individual cost-effectiveness tests showing that each individual project was cost-effective. It's almost like all the work we did for the first three or four SoBRAs for Tampa Electric in our 2017 agreement.

But based on that, the parties, I believe, got comfortable that the plan to build the additional solar is solid, the projects are cost-effective. And rather than having additional rate cases in the future, we were able to agree to generation base rate adjustments that would allow base rates to increase in '23 and '24 to allow cost recovery for those assets.

COMMISSIONER FAY: Okay. And then maybe just briefly elaborate on the protections put in place for the consumers and/or cost overrun.

MR. WAHLEN: Well, I think on the -- on the GBRAs or the CETM?

COMMISSIONER FAY: Both, really. I mean, I think just holistically the idea of being if the costs extend beyond what's proposed in the settlement.

MR. WAHLEN: Okay. Well, in terms of the GBRA, if the projects cost more than projected, it's on the company. That's a pretty strong protection for the consumers. There is not a provision in the agreement to come back, you know, and increase the GBRA amounts if they cost more.

In terms of the SET -- CETM, except for a small part of the costs associated with the dismantlement of Big Bend, the costs have been identified. They are fixed and they are not going to change. The only thing that will change with the CETM is if the company's overall rate of return changes or the tax rate changes, the revenue requirement will be adjusted prospectively.

So that's a protection for the customers too. It will ensure that the company doesn't continue to earn at a higher level if its return on equity changes in the future.

COMMISSIONER FAY: Okay. Great.

And then one more question, Mr. Chairman. I know that everyone is probably tired of seeing the two lawyers with pink bow ties have a conversation here, so maybe this will go towards the experts.

Can you just elaborate on how you got to the ROE and what basis was used?

MR. WAHLEN: I guess maybe Mr. Chronister can talk about that a little bit. He is probably going to say it's a negotiated item, but he will be able to answer it.

WITNESS CHRONISTER: Yeah. The ROE midpoint was a negotiation among the parties.

COMMISSIONER FAY: We lost you.

WITNESS CHRONISTER: The ROE was a negotiated item among the parties.

COMMISSIONER FAY: Okay. And you don't want to speak to any of the process of how that's calculated? Just recognizing the Commission sees a range of numbers on these rate cases, and sometimes within these settlements, a number has fallen in there. I am not asking specifically to the decimal point why you got to there, but what foundation was used?

WITNESS CHRONISTER: Well, I think there was a combination of what the company had submitted in their prefiled testimony, and the thought process and reasoning behind what's happening in financial markets. And then in addition to that, you know what, as referred to earlier, what's happening around the country and what ROEs we are seeing being awarded by the Commissions across the country.

COMMISSIONER FAY: Okay. Great. Thank you for your answer.

MR. REHWINKEL: Mr. Chairman.

CHAIRMAN CLARK: Yeah, Mr. Rehwinkel.

MR. REHWINKEL: Just if I could add a little color that dogs not delve into the negotiations.

As we have all mentioned, this process took 10 months. The company ultimately filed ROE testimony. But as I mentioned, the Public Counsel and at least one other party brought their return on equity expert to the negotiation, which was first. And even though we did not get to file testimony because we settled the case, we had, from day one to day, was it 120 -- no, I can't do my math, 10 times -- day 300, ROE was fervently negotiated with the ROE experts on both sides working.

So it was -- it wasn't just sort of a back-of-the-envelope let's go walk in the park and negotiate it. It was rigorous, if that helps.

CHAIRMAN CLARK: All right. Other Commission questions?

Commissioner La Rosa.

COMMISSIONER LA ROSA: Thank you, Chairman.

And certainly -- I got a few questions, and I will jump into the CETM, we will look at what we were just talking and want to follow up on Commissioner Fay's questions.

Strong position or statements that you just made as far as, you know, some of this falling back to the company. Are there any unknowns or possibilities of an increase in the modernization of the Big Bend unit? Kind of -- I guess I am looking for specifics.

MR. WAHLEN: Well, I guess I will pass that to Ms. Rusk.

WITNESS RUSK: Yes, Commissioner. The Big Bend modernization project is on target and on time. And the cost of retiring the other Big Bend units, those assets have already been identified. They will not be changing.

The only piece that will be trued up other than the weighted average cost of capital and tax rate would be the dismantlement costs to take out those retiring assets, so customers will not pay more or less than the actual costs in the end to remove those units.

So there is really no significant opportunity for costs to increase there.

COMMISSIONER LA ROSA: Mr. Chairman, just a few other follow-ups.

As it relates to the ROE trigger mechanism, there was -- in the settlement it talked about not double counting for the impact of the trigger. Can you provide more details of really what that provision means and what it includes? That could be --

MR. WAHLEN: Yeah, give me just a second.

We responded to a data request on that pointed out -- Mr. Chronister can answer that question while I am looking for it.

WITNESS CHRONISTER: In the provision, we established the midpoint at 9.95 and then the range that will travel from 9 to 11. If the trigger occurs, the idea of not double counting is we are going to make sure that if the trigger occurs that the company is not able to capture the trigger revenue requirement, and then additionally, say, that we are below the bottom of the range and be able to trigger a rate. So the language of the provision protects the customers from being able to do both.

COMMISSIONER LA ROSA: A follow-up on that.

Was something like this included in the 2017 settlement?

MR. WAHLEN: I know it was in the 2013 agreement, and I believe it was in the 2017 agreement. But the difference is that in this trigger, there is a revenue increase that comes along with the trigger if the trigger occurs.

COMMISSIONER LA ROSA: Okay. I am going to switch gears to the economic development, the economic development riders.

Can you tell me where the company sits today as far as are you at capacity? Are you still entertaining new customers that would qualify under

the economic development rider?
MR. WAHLEN: That's a good question for Ms. Rusk.
WITNESS RUSK: Commissioner, we are actually ramping up our economic development efforts. We are hiring an additional staff person, at least one, to focus on that, and we have included some expenses in our rate case filing to account for that. So we -- we expect it to increase.
COMMISSIONER LA ROSA: Chairman, that's all I have.
CHAIRMAN CLARK: All right. Other questions?
Commissioner Passidomo.
COMMISSIONER PASSIDOMO: Thank you, Mr. Chairman.
Okay. So I kind of want to just follow up on Commissioner Fay and Commissioner La Rosa's questions -- I'm sorry -- regarding the CETM and GBRA. So I just -- can you please elaborate on how these work together to transform the company's power generation?
MR. WAHLEN: Well, I will give a simple answer, and then if it gets more complicated we are going to have to have an expert.
But in general, what the -- what the CETM,

C-E-T-M, and the GBRAs do, is help the company transition away from coal into solar. So the CETM covers the retirement of the coal assets and squares that away for the future. And then the GBRAs allow the company to get cost recovery for the Big Bend modernization program, which is a highly efficient combined cycle plant, and the 600 megawatts of solar.

So those are kind of pivotal pieces of the agreement that allows the company to become cleaner and greener in the future.

COMMISSIONER PASSIDOMO: So would you say those are the chief investments that the company is going to make as a result of those mechanisms?

MR. WAHLEN: During the term, yes, but there will be more to come in the future.

COMMISSIONER PASSIDOMO: And I just want to pivot just quickly to ROE. I mean, the majority of my questions were asked and adequately answered, so I appreciate that. I just want one follow up on the approximate bill impact of a residential customer for 1,000 kWh.

MR. WAHLEN: That's a good question for Ms. Rusk.

WITNESS RUSK: A new residential customer of typical monthly bill of 1,000 kWh will be $120.86, and that includes the updated clause amounts that the company has filed in those respective dockets.

COMMISSIONER PASSIDOMO: Okay. And maybe just one for the, just the settlement agreement revenue increase in 2022, I just, you know, if you could just kind of a quick elaboration on how the additional revenue increase benefits customers, in your opinion.

WITNESS RUSK: Sure.

The first phase of the Big Bend modernization is included in there, as well as the first tranche of our future solar, so 225 megawatts of solar. And it also covers any investments which we have made since 2013.

Not all of our investments have been included in rates because we only had adjustments in the 2017 agreement for SoBRAs. So only the solar assets under a SoBRA agreement were added.

In addition, the CETM is approximately $68.5 million annually. And so the total $191 million revenue requirement increase for '22, those are the main components of it.

COMMISSIONER PASSIDOMO: Thank you very much.

CHAIRMAN CLARK: All right. Any other

questions?

I guess I have a couple. I really want to make an observation and comment probably just to be on record.

My hat is off for coming up with the CETM acronym. I thought only government could come up with these kind of really cool ways to describe the mothball fund. I say that because I do have -- I do have concerns that this takes us continually in a direction that is putting us in a position that we are relying more and more on certain technologies.

I say that because I have some concern about winter capacity when it comes to solar. And I remember in your prefiled testimony, I can't remember who it was, but looking at Tampa Electric's projections out through I believe 2045, and how you switch from becoming winter peak -- summer peaking to a winter peaking facility over time.

I just want to make sure we are taking in the consideration the long-term aspects of what we're doing, especially right now as it comes to looking at our increasing gas prices that we are facing here in the very near term.

And I guess I transition that statement -- there is not a question in there anywhere -- over to the current rate proposals, the revised rate schedule for 2022. You show a 2.75, $2.75 increase, but that contemplates that you have done a -- we did an adjustment, a midcourse adjustment, I guess, several months ago, probably six months ago, you are staying out from a midcourse correction in January. When do you anticipate doing another fuel adjustment taking into account our current increase in fuel costs?

MR. WAHLEN: That's a good question for Ms. Rusk.

WITNESS RUSK: Chairman, the natural gas prices have increased, and we have been monitoring that closely. We decided to wait and see how the end of October and November looks before we made a suggestion of an adjustment.

If they continue at this rate, the company does plan to request an adjustment in the early part of 2022.

CHAIRMAN CLARK: Any projections on what that number would look like? We are looking at -- we are looking at a rate increase of some number?

WITNESS RUSK: Yes. It's currently being run through the models, so I don't have a right number for you yet.

CHAIRMAN CLARK: Sure. I understand.

I will conclude with I want to take my hat off to the parties as well. I think you guys did a tremendous job. I don't want to belittle what work that you have done. I just want to reiterate, I do continue to have concerns when it comes to fuel diversity, when it comes to the, what I consider to be currently overreliance on natural gas for production. But in general, I will say you did a commendable job of taking into consideration the ratepayers in this case.

I -- one thing I am going to give you a plus on the CET -- CETM, I think it's good that customers know what the cost is, and as we continue to see a demand for, an honest demand for clean energy transition, I think customers do see -- need to see the real cost of that. And I guess I can commend you for putting that number out there and saying, hey, you want it, here's what it's going to cost. And as long as that demand continues, I guess we will continue to consider that a positive benefit.

Any other comments from Commissioners?

All right. Let me find my place in the notes here.

All right. Parties, any concluding statements from the parties, Mr. Wahlen?

MR. WAHLEN: No thank you.

CHAIRMAN CLARK: Make this simple. Any concluding statements from any of the parties? Seeing none.

All right. Staff, other matters?

MR. MURPHY: Yes, Mr. Chairman.

Since all of the parties have signed the settlement, it is my understanding that no briefs will be filed. Therefore, staff suggests that this matter may be in a posture for a bench decision on whether the corrected 2021 settlement is in the public interest and the rates therein are fair, just and reasonable; whether to approve the corrected 2021 settlement agreement as clarified by TECO's letter on CETM revenue true-up filed on October 14th, 2021; whether to approve the settlement agreement tariff sheets filed on August 20th, 2021, to implement the settlement; and finally, whether to close the dockets.

CHAIRMAN CLARK: All right. Commissioners, are we ready to make a decision? Seeing no objections.

Staff, you mentioned and outlined some of the things that have to be considered -- that need to be considered before the motion occurs. Anything else in that regard?

MR. MURPHY: That is what you would have to do to approve the settlement and close the dockets.

CHAIRMAN CLARK: All right. I will entertain a motion.

Commissioner Fay.

COMMISSIONER FAY: Mr. Chairman, I will see if I can get this. So we would -- the Commission would move to approve the 2021 settlement as clarified in the TECO letter for the CETM true-up from October 14th, also include the tariffs as filed on August 20th, and that the settlement and the rates would be in the public -- the settlement would be in the public interest and the rates would be fair, just and reasonable, and we would close the dockets, Mr. Chairman.

CHAIRMAN CLARK: I believe he hit all of the key points there.

I will entertain a second.

COMMISSIONER GRAHAM: Second.

CHAIRMAN CLARK: I have a second.

Any of discussion on the motion?

All in favor, say aye.

(Chorus of ayes.)

CHAIRMAN CLARK: Opposed?

(No response.)

CHAIRMAN CLARK: The motion carries unanimously.

All right. Is there anything further that needs to come before the commission?

MR. WAHLEN: Mr. Chairman.

CHAIRMAN CLARK: Mr. Wahlen.

MR. WAHLEN: I just had a couple of things before we wrap up.

First, on behalf of Tampa Electric, and I think all the parties, we would like to thank staff again for their diligent work, not just in the rate case. As a result of the rate case filing, the cost recovery factors and all the clauses have had to be updated. So if you weren't lucky enough to participate in the rate case as a staff member, you got to play in the clauses, and so we recognize it's been a big effort coming from the whole staff.

Second, I want to thank the consumer parties for their work and professionalism. It's been said, but we started this about a year ago, and

J.R. Kelly was the Public Counsel, so he should get a little bit of credit. In fact, we have sort of decided informally if anything comes up in the next three years about this agreement that we don't like, we are just going to blame him. So that's part of the way we are going to show our affection for his participation.

The other thing I would like to do is remind people that this case has been about change, and there is a couple of retirements I would like to share with the Commission if you don't mind.

The first is Billy Stiles. Billy Stiles is going to be retiring at the end of the year. He spent most of his career around the Commission either as an employee or as a liaison for Tampa Electric Company. You have seen him at Agenda Conferences, Internal Affairs, workshops, hearings, he has just always been there. And he cares deeply about the Commission as an institution and has incredible respect for the role the Commission plays in the lives of Floridians. We will find a successor to Billy, but it will be difficult to find a replacement. So I hope that we can all celebrate his retirement.

The other retirement that's important is Jim

Beasley. Jim Beasley has been a lawyer at our law firm for his entire career, which is now 48 years, and he has represented Tampa Electric the whole time. He began practicing at the Commission when it regulated motor carriers and intrastate airlines. And he can tell you about the origin of the fuel adjustment clause if you want to hear about it.

I think it's interesting -- this is his last rate case with us. He will be retiring at the end of the year. One of his first jobs at the law firm was to deliver Tampa Electric's 1974 rate case filing to the Commission. And at the time it was in the Whitfield Building, which is the old Supreme Court Building, and the whole filing rode very nicely in one bankers box in the back seat of his Volkswagen Beetle. So that's some indication of how things have changed.

Jim has since then been involved in all of the 10 or 11 rate cases that Tampa Electric has had since then. He has been involved in all of the big electric cases since then. He has been a valuable resource to a lot of people, me in particular, and we are going to miss both Jim and Billy.

So I appreciate you giving me a chance to say those things publicly, because we are going to be losing two very important parts of our team.

CHAIRMAN CLARK: Thank you, Mr. Wahlen.

Let's give them a hand of congratulations.

(Applause.)

CHAIRMAN CLARK: Mr. Beasley, I thought for a minute that Mr. Wahlen was going to say you regulated horse and buggies. He was going way, way back in time there.

Also to Mr. Stiles, thank you both, we appreciate your service not only to the company that you have worked for, but to the state of Florida as well. Your contributions are noted, and you will be missed. It's been -- it's been really great getting to know both of you guys, and we wish you the very best in your retirement years as well.

All right. Any other business to come before the Commission?

Mr. Murphy.

MR. MURPHY: Yes, staff notes that a final order will be issued on or before November 10th.

CHAIRMAN CLARK: I assume we got a waiver on the briefs, everybody was good with not writing. All right. Thumbs up.

Anything else?

All right. We stand adjourned. Thank you.
(Proceedings concluded.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 1st day of November, 2021.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024