BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 1

Direct Testimony of Christine M. Martin

Topics: **Overview of Rate Case Filing**
Principal Reasons for Rate Case Filing

Dated: September 30, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christine M. Martin. My business address is 827 Hausman Road, Allentown, PA 18104.

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

A. I am employed as the President of PPL Electric Utilities Corporation ("PPL Electric"), a subsidiary of PPL Corporation.

Q. What are your responsibilities as President of PPL Electric?

A. I am responsible for overseeing all aspects of the Company's strategy, financial performance and provision of electric service to approximately 1.5 million customers in eastern and central Pennsylvania through electric distribution and transmission facilities spanning approximately 10,000 square miles and serving a population of more than 3 million people.

Q. What is your educational background?

A. I have a Bachelor of Arts in Political Science/International Studies with minors in Economics and French from Indiana University of Pennsylvania and a Master of Public Administration from The Pennsylvania State University.

Q. Please describe your professional experience.

A. My career with PPL Corporation spans more than two decades with a focus on public affairs, energy and regulatory policy, and strategy. Before becoming President of PPL Electric in September 2023, I was PPL Corporation's Senior Vice President–Public Affairs and Chief Sustainability Officer, overseeing the corporation's advocacy and policy development, corporate communications and sustainability efforts across the enterprise. I also held the position of VP-State Government Relations, leading PPL Corporation's government relations and energy policy for multiple states with a primary focus in Pennsylvania.

Before coming to PPL, I was the deputy secretary for water management in Pennsylvania's Department of Environmental Protection ("DEP"). In that role, I was responsible for statewide water resources management and policy. I also served as senior policy manager for environmental, infrastructure, energy and regulatory issues for Governors Tom Ridge and Mark Schweiker.

Q. What is the purpose of your testimony?

A. I will provide an overall summary of the rate case filing as well as the principal reasons for this filing. I will also explain how PPL Electric continues to provide excellent value for the service we offer to our customers. I will share my perspective on significant changes in the energy industry and the Company's unwavering commitment to serving all customers at reasonable rates.

Q. Are you sponsoring any exhibits or schedules in this proceeding?

A. Yes, I am sponsoring Schedules A-1 in Exhibits Historic 1, Future 1, Fully Projected Future 1.

II. <u>OVERVIEW OF RATE CASE FILING & PRINCIPAL REASONS FOR RATE CASE FILING</u>

Q. Before providing an overview of the Company's rate case filing, could you please describe PPL Electric's overall strategy and goals?

A. PPL Electric continually strives to provide adequate, efficient, safe, reliable, and reasonable electric transmission and distribution service to approximately 1.5 million customers at reasonable rates, while offering programs and resources to support customers in saving energy and managing their bills. To that end, the Company works diligently to be efficient in its capital investments and operation and maintenance ("O&M") expenses, recognizing the impact of those costs on customers' rates as well as the importance of those expenditures in maintaining and improving its electric service. This focus on efficiency and affordability has enabled the Company to stay out of a base rate case filing for 10 years and has kept PPL Electric's distribution rates among some of the lowest in Pennsylvania. Most notable is the Company's focus on automation, which has eliminated outages and reduced the need to roll trucks.

However, as explained later in my testimony, PPL Electric must increase its distribution rates to continue to serve customers safely and reliably. Many factors were considered in this decision, including changing weather patterns and the increased frequency and intensity of storms, the need for continued reliability investments, electric demand and forecasted load changes, and the need for tariff changes or updates. These factors are significant enough to warrant a rate case to support PPL Electric's continued efforts to strengthen the grid against future storms and incorporate advanced technology that allows the Company to work smarter and more efficiently while delivering a better experience for PPL Electric's customers.

Q. What focus do you and the Company place on its commitment to the community it serves?

A. The Company has been, and continues to be, a valuable community partner for more than a century, giving back to its communities and neighbors in powerful ways. PPL Electric and its parent company, PPL Corporation, are both headquartered in Allentown, and make substantial financial contributions to the 29 counties served by PPL Electric throughout central and eastern Pennsylvania. A breakdown of these efforts is provided in the Statement of Reasons and reproduced below:

- **Volunteerism and board service:** PPL employees continually show up in the community spending more than 15,000 hours volunteering in the communities where they live and work in 2024. Our Pennsylvania employees support non-profit organizations by contributing their skills and expertise through service on local and statewide boards.
- **PPL Foundation Grants:** The PPL Foundation is an independent nonprofit funded by PPL Corporation. In 2025, the Foundation expects to award over $1 million in grants and scholarships in Pennsylvania. Since 2015, the Foundation has contributed more than $32 million to communities served by PPL Electric.

- **Employee-led Charitable Giving Campaign:** Pennsylvania employees and retirees of PPL, along with matching contributions from the PPL Foundation, contributed nearly $6.5 million in 2025 through an annual giving campaign which supports nonprofits throughout our Company's service territory.
- **Good Neighbor Energy Fund and Operation HELP:** The PPL Foundation increased its annual donation to the Good Neighbor Energy Fund to $400,000 in 2025, which assists low-income families in central and eastern Pennsylvania with their energy bills. In addition, PPL Electric also annually contributes approximately $600,000 a year for Operation HELP, which provides assistance to eligible customers struggling with their electric bills. This million-dollar annual financial commitment is just one of the ways that we are making a difference for our customers in need.
- **Education Improvement Tax Credit Funding:** In addition to grants funded by the PPL Foundation, PPL Electric also supports additional funding opportunities for eligible organizations. Education Improvement Tax Credit ("EITC") grants allow the Company to invest in projects that improve and enhance educational opportunities for Education Improvement and Pre-K organizations. In 2024, $750,000 in grants were awarded to over 200 organizations across 19 of our 29 counties.
- **NPP Contributions:** PPL Electric also supports its communities through the Pennsylvania Department of Economic Development's Neighborhood Partnership Program ("NPP"). Since 2015, PPL Electric has contributed over $4 million to community development programs in Allentown, Bethlehem,

Lancaster, Scranton, and Wilkes-Barre. These contributions support nonprofit agencies' affordable housing, crime prevention, job training, and other neighborhood assistance programs. PPL Electric contributes $400,000 annually to NPP partners.

- **Brighter Future Scholarships:** PPL Foundation partners with a network of schools in Pennsylvania to provide scholarships to students who are passionate about clean energy, sustainability, decarbonization, and grid reliability. Starting in 2024, PPL Foundation provides a total of $60,000 annually to four local institutions (Northampton Community College, Thaddeus Stevens College of Technology, Cedar Crest College, and Penn State Harrisburg). Scholarship winners are selected by a network of partner schools.

Q. How are economic development and load growth in the state impacting the Company's business?

A. Not all economic development is created equal as it pertains to the Company's distribution business. As explained in the Company's Statement of Reasons, PPL Electric has experienced and is expected to continue experiencing little or no growth in customers or sales due to slow economic growth and increased distributed generation. In 2024, Pennsylvania's GDP grew by 2.415% as compared to 2.796% nationally. Sales and revenues have been further eroded by increased interconnections of distributed generation and customer-generator net metering. This new distributed generation totals an additional 477 MW of capacity on PPL Electric's system since the Company's last base distribution rate case took effect in early 2016.

In addition, PPL Electric anticipates only marginal customer growth for customers taking distribution service below 69 kV (0.44% per year from 2025-2027 for residential customers). This is a slight decline from the 0.51% annual growth that the Company has seen from 2016 to 2024. In terms of total sales, the Company has seen only a 0.24% Total Compound Annual Growth Rate ("CAGR") across residential, small, and larger commercial and industrial customers, excluding new large load interconnections. With respect to the residential customer group, sales growth has been offset by distributed generation and energy efficiency, with the net effect being essentially flat growth over the next 5 years with a CAGR of only 0.45%.

While PPL Electric is anticipating more than doubling its system peak load over the next several years due to data center growth, not all load growth is created equally. In fact, data centers are not a significant contributor to distribution sales (demand or energy usage). A data center would take service from PPL Electric as a Large Commercial and Industrial customer under Rate Scheule LP-5. PPL Electric defines its distribution system as facilities operating below 69 kV. Because of this, LP-5 customers are primarily served by the Company's transmission system. This is why LP-5 customers only pay a monthly customer charge covering certain fixed costs to provide retail electric service under cost of service principles. Therefore, although the Company is projecting significant systemwide load growth from large load customers, these new large load customers do not contribute to higher demand or energy usage on the distribution system and, therefore, do not contribute to the Company's distribution revenue beyond the monthly customer charge. However, as discussed in the testimony of PPL Electric witness Joseph Lookup (PPL Electric St. No. 16), load growth from large load customers will result in significant reductions in customers' transmission rates. Nevertheless, this consumption growth data for the Company's distribution system has serious implications for PPL Electric's annual revenue and is a factor in the Company's request for rate relief in this proceeding.

Q. Please summarize the Company's filing for a distribution rate increase.

A. The filing requests Pennsylvania Public Utility Commission ("PUC" or the "Commission") approval of an approximately $356.3 million distribution rate increase, which would produce a system average increase in distribution revenues of approximately 33.42%, effective for service rendered on or after December 1, 2025. Assuming the standard seven-month suspension period for investigation and review, we anticipate an effective date of July 1, 2026, for the implementation of new rates. This level of rate relief is designed to provide the Company with an opportunity to earn an 8.56% overall rate of return on rate base, including a 11.30% return on common equity, on a claimed rate base of $5.818 billion.

Without the distribution rate increase requested in this filing, PPL Electric projects that in 2027 its return on common equity for the distribution business will fall to approximately 4.43%. Such a return clearly is deficient under any reasonable standard and would preclude the Company from obtaining capital on reasonable terms to finance infrastructure improvements needed to maintain reliable service to customers. The requested rate relief will allow the Company to continue its capital replacement strategy from a position of financial strength, which will result in continued reliability and in lower costs to customers over the long term.

This filing deals only with distribution base rates. Rates impacting default service and transmission service are not part of this proceeding. The revenues and expenses associated with these services are recovered through the Generation Supply Charge ("GSC") and Transmission Service Charge ("TSC"), respectively. In addition, all revenues and expenses from the Company's other automatic adjustment clauses, with the exception of the Distribution System Improvement Charge ("DSIC"), have been removed from the calculation of the requested revenue requirement. In accordance with prior Commission orders, the Company proposes to roll-in revenues collected under its DSIC mechanism and to reset the DSIC to zero.

Q. Could you please provide an overview of the witnesses submitting testimony on behalf of the Company and the subject matters of their testimony?

A. Yes. Below I have provided a list of the Company's other witnesses and the subject matters of their direct testimony. Collectively, the Company's testimony and exhibits fully support Commission approval of PPL Electric's proposed increase in distribution base rates and its other proposals in this proceeding.

- PPL Electric St. No. 2 – Dennis A. Urban, Jr. (Senior Director, Finance Transformation of PPL Services Corporation). Mr. Urban describes the current financial condition of the Company, the actual results of operations from July 1, 2024, through June 30, 2025, and the capital and operating budgets for the period of July 2025 through June 2026 and July 2026 through June 2027. Mr. Urban also addresses Act 40 of 2016.
- PPL Electric St. No. 3 – Christopher Garrett (Vice President – Financial Strategy and Chief Risk Officer for PPL Services Corporation). Mr. Garrett describes and supports

the calculation of support group costs and employee benefit costs developed by PPL Services and included in PPL Electric's 2025, 2026 and 2027 budgets. He also testifies about the Company's request to capitalize certain Information Technology ("IT") software implementation costs.

- PPL Electric St. No. 4 – Charles R. Schram (Vice President, Energy Supply and Analysis for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU")). Mr. Schram explains the development of the Company's forecast of sales, customers, and billed demands in addition to the annualization of sales and revenues.
- PPL Electric St. No. 5 – Bethany L. Johnson (Senior Director of Regulatory of PPL Services Corporation). Ms. Johnson provides an overview of the Company's revenue requirement increase proposed in this proceeding, the cost of service study utilized to allocate that increase to the customer classes, and PPL Electric's proposed design of distribution rates to recover that allocated revenue increase.
- PPL Electric St. No. 6 – Daniel S. Dane (President of Concentric Energy Advisors, Inc.). Mr. Dane presents and supports the revenue requirement model that developed the proposed revenue requirement for the Fully Projected Future Test Year ("FPFTY"), including a detailed description of the revenue requirement, the determination of rate base, the breakdown of revenues and expenses in and excluded from the calculations, adjustments made to such revenues and operating expenses, and compliances and regulatory considerations.
- PPL Electric St. No. 7 – Bickey Rimal (Vice President of Concentric Energy Advisors, Inc.). Mr. Rimal addresses the Company's cost of service studies in this proceeding,

including the purpose of an allocated cost of service study ("ACOSS"), the model used to conduct the Company's cost of service studies, the various principles of cost allocation, the factors that influence the cost allocation framework, the cost allocation methodology and basis used in the Company's cost of service studies, the studies of relative costs and other analyses used to assign costs, the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from the ACOSS, and the method used to apportion the Company's revenue deficiency to the various rate classes.

- PPL Electric St. No. 8 – Jennifer E. Nelson (Vice President of Concentric Energy Advisors, Inc.). Ms. Nelson presents evidence and provides a recommendation for PPL Electric's return on equity ("ROE"). She also discusses the Company's capital structure in comparison to the proxy group companies supporting her analysis.
- PPL Electric St. No. 9 – Julissa Burgos (Assistant Treasurer of PPL Services Corporation). Ms. Burgos testifies about PPL Electric's capital structure, cost of long-term debt and credit ratings in this proceeding. She also addresses how the Company's cost of long-term debt is calculated and how credit ratings affect the Company's cost of long-term debt and ultimately its cost of capital.
- PPL Electric St. No. 10 – Steven W. Wishart (Assistant Vice President of Concentric Energy Advisors, Inc.). Mr. Wishart describes and supports PPL Electric's proposed rate design in this proceeding. He explains how the Company has applied well-established ratemaking principles – cost causation, gradualism, customer understanding, and administrative feasibility – to design fair, reasonable, and understandable rates for all customer classes. He also testifies about how the results of the ACOSS inform the proposed rates, provides the required proof of revenues and bill impact analyses, and

presents the Company's proposals for updates to residential, general service, lighting, and standby tariffs.

- PPL Electric St. No. 11 – John J. Spanos (President of Gannett Fleming Valuation and Rate Consultants, LLC). Mr. Spanos testifies about the depreciation studies conducted under his direction and supervision for the utility plant of PPL Electric.
- PPL Electric St. No. 12 – Andrew W. Elmore (Vice President – Tax of PPL Corporation). Mr. Elmore's testimony and accompanying exhibits describe and support PPL Electric's calculation of certain tax-related ratemaking adjustments to the retail rate base and operating expenses contained in the Historic Test Year ("HTY"), Future Test Year ("FTY"), and FPFTY retail rate base and operating expenses. In addition, his testimony describes the impacts to PPL Electric of significant federal tax legislation that has been enacted since the filing of the last rate proceeding.
- PPL Electric St. No. 13 – Katelyn Arnold (Manager – Regulatory Strategy & Rates of PPL Services Corporation). Ms. Arnold testifies about the Company's cash working capital, the roll-in of various riders into base rates (including the revenues and plant associated with the Distribution System Improvement Charge ("DSIC")), the elimination of the Company's Competitive Enhancement Rider ("CER"), the Company's uncollectible accounts (including their relation to the Purchase of Receivables ("POR") Program and Merchant Function Charge ("MFC")), the Company's modifications to its Storm Damage Expense Rider ("SDER"), and the Company's revenue forecast.
- PPL Electric St. No. 14 – Gregory Olsen (Supervisor – Distribution Interconnection & Tariff Rules of PPL Electric). Mr. Olsen sponsors and supports the Company's

proposed retail tariff and testifies about the Company's Street Light Replacement Program.

- PPL Electric St. No. 15 – Andrew Castanaro (Energy Procurement Manager of PPL Services Corporation). Mr. Castanaro testifies about the Company's proposal to assign default supply customers on the Generation Supply Charge ("GSC") to Rate GSC-1 and Rate GSC-2 based on their maximum registered peak load, as defined by the Company's proposed retail tariff submitted in this proceeding.
- PPL Electric St. No. 16 – Joseph Lookup (Vice President – Transmission and Distribution Panning and Asset Management of PPL Services Corporation). Mr. Lookup explains the Company's reliability performance, describes proposals aimed at improving reliability performance, discusses trends that the Company is seeing with respect to storms, and describes how PPL Electric is meeting the challenges associated with interconnecting new large load customers.
- PPL Electric St. No. 17 – Nicole Howell (Manager – Vegetation Management & Program Management of PPL Electric). Ms. Howell describes the Company's current vegetation management program and proposed enhancements to that program.
- PPL Electric St. No. 18 – Lisa Norden (Vice President Customer Services of PPL Electric). Ms. Norden addresses the Company's customer service performance and planned initiatives to maintain and improve that level of performance. She also discusses changes to the Company's customer services IT investments to improve the Customer Information System ("CIS") and Customer Experience ("CX") systems. Additionally, she testifies about PPL Electric's proposals to include the cost of payment transaction fees in base rates, include the internal universal service employee salaries

and wages to the universal service program rider, and eliminate the Customer Assistance Program ("CAP") cost recovery offset. Finally, she describes the Company's proposed changes to its supplier tariff, which include charging suppliers for the cost of electronic data interchange ("EDI") costs incurred to support them and adjusting the POR write off discount.

- PPL Electric St. No. 19 – Daniel Johnson (Senior Vice President, Chief Information Officer of PPL Services Corporation). Mr. Johnson explains the current state of the Company's IT infrastructure and discusses the need for upgrades to modernize and streamline this infrastructure. He also will report on the state of the Company's customer-facing, business-facing, operations, and cybersecurity IT systems, as well as the Company's multi-year assessment of the operational risks of the current systems. He also will address why investment in upgrades to IT systems is necessary to secure critical infrastructure, streamline customer service and billing processes, ensure cost efficiency across all systems, and better evaluate and leverage new technologies in the future.
- PPL Electric St. No. 20 – James Conrad (Senior Director of T&D Smart Grid & Automation of PPL Services Corporation). Mr. Conrad describes the Company's proposed Electric Vehicle ("EV") Time-of-Use ("TOU") Charging Rebate Program, which is designed to help ensure that the distribution system is prepared to handle the challenges presented by EV charging.
- PPL Electric St. No. 21 – Jason Hunt (Manager of Business and Economic Development of PPL Services Corporation). Mr. Hunt testifies about the Company's economic

development proposal, which will help support communities and spur economic development in PPL Electric's service territory.

- PPL Electric St. No. 22 – Sharon Leskowsky (Assistant Controller of PPL Corporation). Ms. Leskowsky testifies about how she is sponsoring or co-sponsoring certain of the Company's filing requirements and exhibits in this case, particularly those concerning PPL Electric's accounting and financial records and the Company's pro forma adjustments for interest on certain amounts, such as customer deposits.

Q. What are the principal reasons that led to this rate filing?

A. As explained in more detail in the Statement of Reasons, the filing, to a very large degree, reflects the current business environment faced by the Company, particularly to address its need to make significant capital investments to help ensure that its reliability performance remains strong for customers today and in the future. The Company's principal reasons for filing the base rate case include: (1) little to no growth in customers or sales due to slow economic growth and increased distributed generation; (2) increased capital investment that is necessary to maintain and improve system reliability, such as an additional $4 billion in capital investments in the distribution system from 2025-2029 that will include additional storm hardening measures to strengthen the distribution system, protect against increasing weather-related outages, and improve customer experience; (3) the Company's commitment to providing the highest quality, safe, and affordable service to its customers; (4) the Company's significant Information Technology ("IT") infrastructure investments that are designed to, among other things, provide long-term security and stability to PPL Electric's IT infrastructure and enhance customer experience; and (5) the need to set rates based on the full class cost of service. Each of these issues is discussed in detail in the Statement of Reasons.

In addition, the Company forecasts that its return on common equity for the distribution business will fall to approximately 4.43% in 2027 based on current rates. This return is inadequate by any standard. In light of the business environment described above, PPL Electric believes that its requested return on equity is the minimum required to attract needed capital under reasonable terms. Such access to the capital markets will allow the Company to continue its capital replacement strategy, which will result in continued reliability and in lower costs to customers over the long term. Further, the requested rate relief also will permit the Company to pursue efforts to improve its bond ratings, which, if achieved, would further lower the cost to serve customers.[1]

Q. Does this conclude your direct testimony?

A. Yes, it does.

[1] As explained in Ms. Burgos's direct testimony (PPL Electric St. No. 9), PPL Electric's credit ratings have improved since the last rate case in 2015.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 2

Direct Testimony of Dennis A. Urban, Jr.

Topics: **Current Financial Condition**
July 1, 2024 through June 30, 2025 Actual Results of Operations
July 2025-June 2026 & July 2026-June 2027 Capital and Operating Budgets
Act 40 of 2016

Dated: September 30, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis A. Urban, Jr., and my business address is 645 Hamilton Street, Suite 9, Allentown, PA 18101.

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

A. I am employed by PPL Services Corporation ("PPL Services"), a subsidiary of PPL Corporation and an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company"). I hold the position of Senior Director, Finance Transformation.

Q. What are your responsibilities as Senior Director, Finance Transformation?

A. I am responsible for the financial planning and analysis and budgeting functions for PPL Corporation's utility operating companies. In addition, I am responsible for the ongoing activities of the Transformation Management Office.

Q. What is your educational background?

A. I have an Associate degree in Electrical Technology from the Dean Institute of Technology, a Bachelor of Science degree in Accounting from Point Park University, and a Master of Business Administration degree from Robert Morris University.

Q. Please describe your professional experience.

A. In 1982, I began my career with Duquesne Light Company ("Duquesne"), a Pittsburgh, PA based electric utility. Through 1996, I held various bargaining unit operations and maintenance positions, including as a journeyman lineworker. In 1997, I moved into a management role in the accounting department where I held the position of Senior Accountant until May 1999. From June 1999 to October 2001, I held the position of Manager of Financial Reporting where I had responsibility for all internal and external financial reporting requirements. In November of 2001, I was transferred to Duquesne's parent company, DQE, Inc., as the Manager of Corporate Development where I had responsibility for the development and recommendation of strategic alternatives. In May of 2004, I was promoted to Director of Corporate Development with the additional responsibility for the development of a strategic energy sourcing strategy to fulfill Duquesne's default service obligation. In June 2007, after Duquesne was purchased by a group of private equity investors, I became Manager, Financial Planning and Risk Analysis where I had responsibility for Duquesne's budgeting, planning and financial forecasting functions as well as its risk management functions including internal audit and corporate insurance programs. I joined PPL Electric in November 2008 as Manager, Energy Acquisition where I had responsibility for the development and implementation of the functional requirements to fulfill its default service obligation. In November 2010, I assumed the role of Senior Director, Rates and Regulatory Affairs. In January 2013, I was promoted to Vice President, Finance and Regulatory Affairs. In November 2015, I joined National Grid as Chief Financial Officer of its New England and Federal Energy Regulatory Commission ("FERC") jurisdictional operations. I subsequently rejoined PPL Services in February 2023 in my current role.

Q. Have you previously testified as a witness in other Pennsylvania Public Utility Commission ("Commission" or "PUC") proceedings or any other jurisdiction's proceedings?

A. Yes. I have testified before this Commission in PPL Electric's 2015 Distribution Rate case on topics similar to the purpose of this testimony.

Q. What is the purpose of your testimony?

A. My testimony will describe the current financial condition of the Company, the actual results of operations from July 1, 2024 through June 30, 2025, and the capital and operating budgets for the period of July 2025 through June 2026 and July 2026 through June 2027. I also will address the requirements of Act 40 of 2016.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring PPL Electric Exhibits DAU-1 and DAU-2 and portions of Parts I, II, V, and VI of the filing requirements as noted on their indexes.

II. CURRENT FINANCIAL CONDITIONS, ACTUAL RESULTS OF OPERATIONS, AND CAPITAL AND OPERATING BUDGETS

Q. PPL Electric is requesting an increase in electric distribution rates of approximately $356 million annually. Is this requested increase supported by data for a future or experienced test year?

A. The revenue requirement requested in this distribution base rate case is based primarily on data for a Fully Projected Future Test Year ("FPFTY") ending June 30, 2027, which is included in Exhibit Fully Projected Future 1. The Commission's regulations require that a public utility that uses a Future Test Year ("FTY") also must submit data for a Historic Test Year ("HTY"), consisting of the twelve months immediately preceding the FTY. As a result, PPL Electric has also submitted data for the FTY ending June 30, 2026 (Exhibit Future 1), and data for the HTY ended June 30, 2025 (Exhibit Historic 1).

Q. You have stated that the data in the HTY are for the 12 months ending June 30, 2025. What is the source for the data contained in Exhibit Historic 1?

A. The basic data in the HTY was derived from PPL Electric's actual general ledger for the 12 months ending June 30, 2025. These financial statements are prepared in accordance with generally accepted accounting principles ("GAAP"). They are audited annually by an independent certified public accounting firm. In addition, the FERC and PUC audit staffs conduct periodic audits via an independent third party.

Q. You have stated that the data in Exhibit Future 1 are for the 12 months ending June 30, 2026. What is the source for the data contained in Exhibit Future 1?

A. The basic data in Exhibit Future 1 was derived from PPL Electric's budget and forecast figures for the 12 months ending June 30, 2026. I will explain the procedures followed in preparing the Capital and Operating Budgets later in my testimony. In effect, the budget figures take the place of PPL Electric's actual book figures which serve as the basis for the June 30, 2025 data in Exhibit Historic 1.

Q. You have stated that the data in Exhibit Fully Projected Future 1 are for the 12 months ending June 30, 2027. What is the source for the data contained in Exhibit Fully Projected Future 1?

A. The basic data in Exhibit Fully Projected Future 1 was derived from PPL Electric's budget and forecast figures for the 12 months ending June 30, 2027. I will explain the procedures followed in preparing the Capital and Operating Budgets later in my testimony.

Q. Are you sponsoring any schedules in Exhibits Historic 1, Future 1 and Fully Projected Future 1?

A. Yes. I am sponsoring or co-sponsoring the following: Schedules B-1 through B-4, C-5, D-4, D-5, and D-12 of Exhibits Future 1 and Fully Projected Future 1. I note that PPL Electric witness Leskowsky is sponsoring or co-sponsoring those same schedules in Exhibit Historic 1, among other schedules.

Q. Mr. Urban, would you describe the material presented on Schedules B-1 through B-4 of Exhibits Historic 1, Future 1, and Fully Projected Future 1?

A. Schedules B-1 show the balance sheet of PPL Electric, excluding all its non-regulated subsidiaries, at June 30, 2025, June 30, 2026, and June 30, 2027, which includes the assets and liabilities related to the electric utility operations and investments in non-utility property.

Schedules B-2 contain a statement of electric utility operations showing the operating revenues and expenses and income for the years ended June 30, 2025, June

30, 2026, and June 30, 2027. Electric operating revenues shown on these schedules are set forth by source in Schedules B-3.

Schedules B-4 provide the operation and maintenance expenses of the electric utility operations by detailed accounts, including the major categories of expense: power production, transmission, regional market, distribution, customer accounts, customer service and informational, sales, and administrative and general. The expenses in the power production category represent the cost of purchased power and include, among other items, generation supply purchases to meet default service requirements and purchases from non-utility generation companies. Power production costs are not germane to the determination of the distribution revenue requirement in this filing.

All the data shown in Schedules B-1 through B-4 were taken from the books and records of PPL Electric, excluding all its non-regulated subsidiaries, for the 12 months ended June 30, 2025, or were derived from its operating and capital budget data for the 12 months ending June 30, 2026, and June 30, 2027.

Q. Please describe the source and method used to establish the book cost of plant shown in the accounts of PPL Electric.

A. The accounts of PPL Electric are kept in accordance with the Uniform System of Accounts prescribed by FERC, and adopted by this Commission, for Electric Utilities and Licensees. In several orders issued at Docket No. E.O.C. 34, the last dated December 30, 1947, the Commission determined the original cost of PPL Electric's plant as of November 30, 1947. Since that time, PPL Electric has recorded its plant transactions in accordance with the Commission's required system of accounts. PPL Electric's books, therefore, reflect the original cost of its plant at June 30, 2025.

Q. Are these accounts audited?

A. Yes. They are audited annually by an independent certified public accounting firm. In addition, FERC conducts periodic audits, and the PUC audit staffs conduct ongoing audits of PPL Electric's 1307 automatic adjustment clauses and performs Management Audits and Management Efficiency Investigations as required by regulation.

Q. How do you determine that all property reflected in Account 101, Plant in Service, as shown on page 1 of Schedule B-1, is actually in service?

A. The Asset Management Section of PPL Services maintains Fixed Asset Records for PPL Electric in an Asset Management System, which sets forth the detail of all property in service. The total dollar value of the Continuing Property Records in the Asset Management System is reconciled monthly to the balance in Account 101.

The Uniform System of Accounts requires that utilities record all construction and retirements of electric plant by means of work orders or job orders. In addition, the work order system must show the nature of each addition to, or retirement from, electric plant, the total cost thereof, and the plant account or accounts affected.

PPL Electric has maintained such a work order system since the establishment of its Continuing Property Records system. Under this system, an authorized capital work order is used for all work performed.

When any unit of property is taken out of service permanently, PPL Electric personnel record the removal under a work order and transmit that information to the Asset Management Section, where the necessary retirement accounting entry is made. Because many retirements can occur in connection with capital improvement projects, the retirement work is part of a construction authorization.

Costs of new construction are reported by work order number, and the Asset Management System accumulates, by work order, all costs associated with a specific job, as well as the appropriate retirement unit and utility account. At the completion of the job, PPL Electric personnel update the work order status to indicate the work order is in-service. This status change also is reflected in the Asset Management System. Based on this information and the costs accumulated under the work order, the property constructed is recorded in appropriate detail on PPL Electric's Continuing Property Records. With this system and its supporting detail, the costs comprising the total value of any item recorded as Plant in Service can be fully supported and verified.

Q. Mr. Urban, would you explain Schedules C-2, Electric Plant in Service – Original Cost in Exhibits Historic 1, Future 1, and Fully Projected Future 1?

A. Schedule C-2 of Exhibit Historic 1 represents electric plant in service and the accumulated reserve for depreciation at June 30, 2025, which were taken from PPL Electric's fixed asset records. Schedule C-2 of Exhibit Future 1 represents the projected electric plant in service and the accumulated reserve for depreciation at June 30, 2026. Schedule C-2 of Exhibit Fully Projected Future 1 represents the projected electric plant in service and the accumulated reserve for depreciation at June 30, 2027. The projected electric plant in service at June 30, 2026, is determined by adjusting the June 30, 2025 actual book balance for projects expected to be placed in service and projected retirements during the period of July 1, 2025, to June 30, 2026. The projected electric plant in service at June 30, 2027, is determined by adjusting the June 30, 2025 actual book balance for projects expected to be placed in service and projected retirements during the period of July 1, 2025, to June 30, 2027. The accumulated reserve for depreciation at June 30, 2026, was determined by adjusting the June 30, 2025 actual book balance for the provision for depreciation and amortization and the projected retirements for the period of July 1, 2025 to June 30, 2026. The accumulated reserve for depreciation at June 30, 2027, was determined by adjusting the June 30, 2025 actual book balance for the provisions for depreciation and amortization and the projected retirements for the period of July 1, 2025, to June 30, 2027.

Q. Mr. Urban, can you provide any background on how the FTY and FPFTY financial statements were prepared?

A. The FTY and FPFTY financial statements and data are based on information that PPL Electric used to prepare its 2025, 2026, and 2027 Operating and Capital Budgets and the Company's reforecasts of those budgets in the second quarter of 2025.

Q. Has PPL Electric's forecasting and budgeting processes been reviewed by the Commission?

A. Yes. The Commission conducted a Focused Management and Operations Audit of PPL Electric in 2015 with recommendations and findings reported in October 2016 at Docket

No. D-2016-2576052. With regard to PPL Electric's forecasting and budgeting processes, the Commission indicated that based on its review PPL Electric's processes are performed efficiently and effectively, and the audit report had no specific findings or recommendations for changes. The Commission also conducted a Management and Operations Audit of PPL Electric in 2023 with recommendations and findings reported in June 2024 at Docket No. D-2023-3039488. This report did not identify any specific recommendations or findings related to PPL Electric's forecasting and budgeting processes.

Q. Would you please explain how the capital budget process is carried out by PPL Electric?

A. Yes. PPL Electric's annual capital budgeting process is managed and governed by the Company's Finance group ("EU Finance"). The capital budget is reviewed throughout the year with the planning, evaluation, and prioritization of projects conducted by PPL Electric's Distribution planning team and Asset Management engineers. Prioritization occurs every month using a structured benefit-to-cost evaluation methodology. It considers prior year circuit performance, re-evaluation of prior plans, and proposed new projects to improve future circuit capacity and reliability performance. Some specific categories of capital, such as new customer connections (termed Provide Electric Service or "PES") and emergency response (termed Respond To Customers or "RTC") are not prioritized against other reliability and capacity projects, rather they are budgeted based on the forecasted demand for those services. The prioritized and budgeted portfolio of projects then is reviewed by PPL Electric's Asset Management and project management teams and subsequently submitted to EU Finance to enter the general budgeting process. Operations and Maintenance ("O&M") expenses related to capital also are estimated (certain capital projects require a component of O&M to implement under FERC accounting rules), and the capital budget is entered into the corporate budget system. This tentative capital budget is reviewed with EU Finance, PPL Electric's executive management, and the Company's President, including review of key operational (reliability and system performance) and financial indicators. Subsequently, the capital budget, like the O&M budget as described below, is reviewed by PPL Services' Financial Planning and PPL Corporation's executive teams before review and approval by PPL Corporation's Board of Directors. This budget is the key tool used by PPL Electric and its senior management to establish an operating plan for the upcoming year and for measuring actual results against this plan.

Q. Please describe PPL Electric Exhibit DAU-1.

A. PPL Electric Exhibit DAU-1 is a table that summarizes portions of PPL Electric's 2025-2029 Capital Budget which relate to the capital spending needs of the Company. At PPL Corporation, a five-year capital budget is prepared annually to identify the capital requirements of the corporation and to establish a basis for financial and manpower planning. Each of the corporation's business lines is responsible for identifying, evaluating, and approving projects for inclusion in its capital budget, and then forwarding all of that data to PPL Services' Financial Planning Department where the Capital Budget for PPL Corporation is reviewed and consolidated.

Q. Please describe the information listed on PPL Electric Exhibit DAU-1.

A. PPL Electric Exhibit DAU-1 summarizes the capital requirements related to the distribution system (transmission projects are not included in this table) and the capital requirements related to the Company's facilities, such as service centers, crew quarters, and office buildings. It also includes the capital requirements for the Company's Information Technology ("IT") investments. Supporting the annual amounts shown on PPL Electric Exhibit DAU-1 are lists and databases of projects, schedules for projects, and estimates of project costs. Those lists, schedules, and estimates provide the detailed information that is the basis of the estimates of property additions and retirements that appear in the Company's response to Question V-A-3 of Exhibit Regs., § 53.53, Part V-Plant and Depreciation Supporting Data, Including Related Depreciation Study Report ("Question V-A-3").

Q. Please describe the categories of expenditures listed in PPL Electric Exhibit DAU-1 that are specific to the distribution system.

A. The categories listed and a description of each is as follows:

1. "Provide Electric Service" includes projects to install new service for residential, commercial, and industrial customers (including service upgrades for existing customers to serve additional load) and purchases of distribution transformers. Work in this category is a function of customer requests. Also included in this category are funds for relocations due to highway improvements or other rights-of-way interferences. Forecasts of capital requirements for this category are based on recent spending history.

2. "Upgrade System Facilities" includes specific projects required to ensure and enhance system capacity and reliability. Projects are driven by forecasts of load growth and identified as a result of engineering studies that simulate system loadings under a variety of conditions.
3. "Maintain System Reliability" includes funding for the identification and remedy of deteriorated, obsolete, or failed equipment. Work in this category is a function of identifying a need as the result of inspection, testing, scheduled replacement, or failure. Forecasts of capital requirements reflect inspection and testing plans, the age of equipment, and previously observed conditions. This category includes items such as distribution pole replacements and reinforcements, underground cable curing and replacements, and other deteriorated or failed equipment replacements.
4. "Improve System Reliability" includes maintenance, engineering, and technology initiatives and programs to improve system reliability performance based on a variety of metrics or standards. This category consists of programs such as new Vacuum Circuit Reclosers ("VCRs"), distribution animal guarding, Low Tension Network ("LTN") upgrades and specific reliability improvement projects associated with tap fuses, tie lines, voltage regulators, re-conductor lines and relocation of lines from rights-of-way. This category also includes funds for storm hardening initiatives to improve reliability on worst performing circuits.
5. "Asset Optimization Strategy" ("AOS") includes funding to replace infrastructure that has reached the end of its useful life including deteriorated transformers, 12 kV interrupting devices, and equipment protection and control devices. This category also includes funding for Predictive Failure Technology ("PFT") installations to

help identify infrastructure reaching the end of its useful life before failure. AOS funding includes additional resources, beyond the Maintain and Improve System Reliability categories described above, that target aging infrastructure based on equipment condition analysis studies to ensure continued reliability performance for customers.

6. "Information Technologies" includes projects in support of our Value Streams (Customer, Enterprise Technology, Field Ops, Grid), which include our largest strategic initiatives as well as our run-rate work (Cyber, Infrastructure, Data) and the initiatives related to those areas.
7. "Other" reflects small and miscellaneous items such as Independent Power Producer ("IPP") interconnection and upgrade requests, metering requirements, tools and equipment and vehicles.
8. "Respond To Customer" includes small projects to resolve customer concerns related to service outages, voltage complaints, street and area lighting problems, property damage, flickering lights, and other concerns. Also included in this category are funds for work performed during storm response. Forecasts of capital requirements are based on recent history.
9. "Facilities Management" includes projects related to selling, purchasing or construction of buildings, replacement projects for facilities and equipment that are outdated or can no longer be maintained and are required for the continued operation of a building, projects required to provide employees a safe and acceptable work environment, and projects required to meet state and local environmental regulations. Forecasts of capital requirements for Facilities Management are based

both on lists of specifically identified needs and on recent history that is trended as appropriate.

10. "DERMS Capabilities" includes projects to install remote monitoring devices to improve the function and performance of PPL Electric's grid by developing infrastructure to facilitate integration between PPL Electric's Distributed Energy Resource Management System ("DERMS") and customer solar systems for visibility and control of various functions from PPL Electric's command center.
11. Substation Connectivity" includes projects to provide communication paths from substations. This would include VIP Scada installations and upgrades and cell to fiber projects. Forecasts are based on analysis of fiber proximity and communication from substations to other devices to help restoration.

Q. Do the capital requirements set forth in PPL Electric Exhibit DAU-1 and the associated property additions and retirements that appear in the Company's response to Question V-A-3 represent, in your opinion, a necessary investment in facilities by PPL Electric?

A. Yes. The capital requirements set forth in PPL Electric Exhibit DAU-1 and the associated property additions and retirements that appear in the Company's response to Question V-A-3 are the result of careful engineering studies extending over many months, and of inspection and testing programs designed to monitor the condition of equipment, and to anticipate the need to replace or upgrade it. This forecast of capital requirements reflects PPL Electric's best estimate of the facilities needed to continue to provide safe and reliable electric service both now and in the future. This forecast also considers the need to provide new and upgraded facilities which are necessary to maintain and, where appropriate, improve the efficiency of operating personnel. I believe that this forecast is reasonable and represents a prudent level of investment.

Q. Would you please explain how the operating budget process is carried out by PPL Electric?

A. Yes. In explaining the budget process, I will be referring to PPL Electric Exhibit DAU-2 that supports my direct testimony. During the summer of each year, PPL Services' Financial Planning group and business line teams, including EU Finance, begin preparing a detailed operating budget for the 5-year planning horizon. Information used in compiling PPL Electric's operating budget comes from two primary sources: (1) PPL Electric direct costs; and (2) an assignment or allocation of service company support costs. I will describe the budget process for the first source, PPL Electric direct costs. The second source, service company support costs, is explained in the direct testimony of Christopher Garrett (PPL Electric St. No. 3).

The operating budget for PPL Electric direct costs is composed of two parts: (1) certain specialized costs, such as depreciation and amortization, financing and taxes; and (2) all other costs. The specialized data for the budget is provided by PPL Services' staff groups. For all other costs, data for the 2025, 2026 and 2027 Operating Budgets comes from various PPL Electric responsibility centers in the following four major business areas: President, Finance, Customer Service, and Transmission and Distribution Operations. Each business area is subdivided into functional groups that include organizational units referred to as responsibility centers. Each major business area has an assigned manager who is responsible for all costs incurred by that area, and each employee is assigned to a specific responsibility center.

Q. What type of data does the responsibility centers provide?

A. Each responsibility center provides a projection of its employee levels for the year that becomes the basis for projecting total wages and salaries. The responsibility centers also provide a budget of their other operating costs.

Q. Could you explain how the budget for wages is determined?

A. Yes. Each spring, PPL Services' Financial Planning department notifies the business line affiliates of the "Date of Estimate," which is the date at which the corporate budget system calculates the wages associated with the number of employees, and their associated wages, in each responsibility center. Any changes from the Date of Estimate starting point, including new hires, decreases due to retirements or work force reductions and changes in salary levels must be identified. Employee levels are reviewed and approved in conjunction with the overall budget review.

The corporate budget system automatically calculates a budget for wages based on the starting level of employees and their actual earnings and the employee changes inputs. The system then applies assumed management and bargaining unit wage changes and the projected cost of employee benefits.

As business units budget for their employee levels, they generally allocate their available manpower by functional activity. As part of this process, the business units designate capital or expense in accordance with GAAP. Wages identified as expense ultimately appear on Schedule B-2 of Exhibit Future 1 and Exhibit Fully Projected Future 1, PPL Electric's income statement, as an O&M expense.

Q. You mentioned the budget for other operating costs. What costs fall into this category?

A. The corporate budget system requires budgeting by category of expenditure referred to as budget items. The budget items are essentially related to the activity that causes the cost to be incurred.

Q. How are these budget items estimated?

A. Non-payroll requirements, such as rents, materials and contractors, generally are entered by budget item and functional activity, and in the month or months the expenses are anticipated to occur. Budgets for payroll and non-payroll items are summarized by department for review following the process described above.

Q. Please describe the review and approval processes for the PPL Electric's operating budget.

A. Each of PPL Electric's organizations prepares its own O&M budget along with the EU Finance team. As explained above, Mr. Garrett addresses the development of the budgets for the services companies. Once all of the components of the budget are assembled and approvals have been obtained, an integrated operating budget is prepared by the EU Finance team. This budget is reviewed with senior management and the President, including review of key operational and financial indicators. This budget is the key tool used by PPL Electric and senior management to establish an operating plan for the upcoming year and for measuring actual results against this plan.

Q. As part of the FTY and FPFTY data in the present rate filing, budget expenditures have been provided by FERC account. Do the departments also budget by FERC account?

A. No. Most of the budget is created by category of expenditure and by functional activity. PPL Corporation believes that it is more meaningful to budget and monitor expenditures by category of expense (e.g., payroll, employee expenses, material and supplies) than by FERC accounts. However, to satisfy the requirements for this rate case filing, PPL Electric has allocated expenditures into FERC accounts. This was accomplished by using a historic relationship between the budgeted functional activity and the FERC account to which each activity would be charged. Amounts were then summarized by the designated FERC accounts.

Q. How was the operating budget used in this rate case filing?

A. The operating budget was used as the basis for forecasting PPL Electric's Operating Income for the FTY ending June 30, 2026, and FPFTY ending June 30, 2027. See the response to Question II-E-1 of Exhibit Regs., § 53.53, Part II, Primary Statements of Rate Base and Operating Income ("Question II-E-1"). The forecasted data shown in the response to Question II-E-1 was reformatted to correspond to FERC account classifications and is shown in Schedule B-2 of Exhibits Future 1 and Fully Projected

Future 1 and throughout PPL Electric's responses to the Commission's filing regulations.

Q. Are you aware of the requirement that a comparison of actual to budget data is to be supplied quarterly when a utility utilizes an FTY?

A. Yes. In preparation for complying with this requirement, PPL Electric Exhibit DAU-2 has been provided. This exhibit shows a breakdown of revenues and expenses for electric operations for the FTY into calendar quarters beginning in July of 2025 and ending June of 2026. PPL Electric will provide quarterly comparisons of actual results to the budget as shown in PPL Electric Exhibit DAU-2 as the actual data becomes available.

Q. You have stated that you previously testified in PPL Electric's 2015 distribution base rate case on similar topics. Please provide details on key changes to PPL Electric's investment strategy.

A. As explained in PPL Electric Statement No. 1, PPL Electric has generally maintained a consistent strategy in which it proactively identifies areas where it can most efficiently deploy system expenditures, whether capital or O&M, for maximum long-term reliability benefits, while considering the costs to customers. PPL Electric has utilized all its opportunities to do so, including its request for a DSIC Cap Waiver, which currently operates at the increased cap of 7.5%. Further, the Company has focused on O&M efficiencies since its last rate case. As an example, when PPL Electric submitted its 2015 rate case, PPL Electric's distribution O&M claim in that case was approximately $404,954,000 versus its claim in this rate case of approximately $434,922,000 (Schedule D-1, Column 8, Row 2 in Exhibit Fully Projected Future 1), an increase of only approximately $30 million or $7.4%, nominally, over a 10 year period. This is far less than even 1% per year. When considering inflation at 3.32% per annum, PPL Electric's current claim of approximately $434,922,000 compares to a 2015 inflation adjusted request of approximately $550,199,000 or approximately $108 million less. Although increases in the Company's O&M expenditures are not driven solely by inflation or affected by the same inflation factor, this comparison is notable given increasing storm events, supply chain challenges, customer expectations, technology changes, and inflation on materials and supplies. Over the time since the last rate case, the Company has largely absorbed O&M increases by using advanced technology and data analytics to drive process efficiencies and inform the strategic deployment of capital investment. This strategy is key to PPL Electric's ability to deliver reliable and affordable service, as discussed throughout this filing.

III. <u>ACT 40 OF 2016</u>

Q. Are you familiar with Section 1301.1 of the Public Utility Code, which is otherwise known as Act 40 of 2016?

A. Yes, I am. The legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania. Subsection (b) of Section 1301.1 requires a utility to demonstrate that it shall use at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment to support reliability or infrastructure related to the rate-base eligible capital investment and that the other 50 percent shall be used for general corporate purposes. However, it is also my understanding that this subsection (b) "shall no longer apply after December 31, 2025," under its own terms. 66 Pa. C.S. § 1301.1(c)(1). My understanding is predicated in part on the advice of counsel.

Q. Does the Company's rate base claim in this case support the conclusion that it is using at least 50% of that revenue requirement amount (associated with a consolidated tax savings adjustment) to support reliability or infrastructure related capital investments?

A. Yes, as presented on PPL Electric Exhibit DAU-1, PPL Electric's *pro forma* investment in capital additions for reliability or infrastructure projects in 2026 is $771 million and for 2027 is $783 million excluding the categories Information Technologies, Other and Facilities Management. This expenditure level is far greater than $12.76 million, which is 50% of the amount that would have been the consolidated tax savings adjustment under prior ratemaking principles. (*See* PPL Electric Exhibit AE-1, p. 1.)

Q. Does the Company's rate base claim in this case support the conclusion that it is using at least 50% of that revenue requirement amount to support general corporate purposes?

A. Yes. The Company's general corporate purpose expense will also exceed 50% of the tax benefit resulting from elimination of the consolidated tax adjustment. The Company anticipates an operating expense budget of more than $434 million to be used to render electric distribution service. By comparison, 50% of the consolidated tax adjustment revenue requirement would equate to only $12.76 million.

Q. Is the Company's presentation in this filing consistent with the Commission's and the Commonwealth Court's treatment of Act 40 of 2016?

A. Yes. I am advised by counsel that the Company's presentation in this filing is consistent with the Commission's determination on Act 40 in UGI Utilities, Inc. – Electric Division's 2018 Base Rate Proceeding at Docket No. R-2017-2640058 as well as the Commonwealth Court's order affirming the Commission's order on appeal.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PPL ELECTRIC UTILITIES CORPORATION

2025 - 2029 Distribution Capital Forecast
For Years Ended December 31,
(Millions of Dollars)

Budget Category	2025	2026	2027	2028	2029	Totals for 2025-2029
Provide Electric Service	135.9	121.8	124.1	129.4	130.9	642.2
Upgrade System Facilities	27.2	19.8	47.0	18.9	10.5	123.3
Maintain System Reliability	103.9	69.6	74.7	70.4	66.6	385.2
Improve System Reliability	53.3	380.4	354.0	403.7	418.8	1,610.2
Asset Optimization Strategy	91.8	92.0	91.6	76.8	73.5	425.7
Information Technologies	210.0	176.3	113.6	81.2	41.2	622.3
Other	23.4	29.2	26.3	24.0	24.1	127.0
Respond to Customer	68.4	76.4	80.3	78.8	80.7	384.6
Facilities Management	9.2	15.4	14.4	13.4	13.4	65.9
DERMS Capability	5.9	5.1	5.1	5.1	5.1	26.3
Substation Connectivity	3.0	6.5	6.5	6.8	3.7	26.5
Total	732.1	992.3	937.7	908.7	868.5	4,439.2
		(220.8)	(154.4)			
		771.4	783.3			

PPL ELECTRIC UTILITIES CORPORATION
Forecast July 2025 - June 2026
(Thousands of Dollars)

PPL Electric Consolidated	1st Q	2nd Q	3rd Q	4th Q	12 months
Operating Revenues					
Electric Revenue	$824,733	$831,595	$948,327	$780,973	$3,385,629
Wholesale Energy Marketing					
Intercompany Sales					
Total Operating Revenues	**824,733**	**831,595**	**948,327**	**780,973**	**3,385,629**
Operating Expenses					
Electric Fuel					
Energy Purchases - External	273,338	282,190	342,413	242,815	1,140,757
Energy Purchases - Internal					
Total Fuel & Energy Purchases	**273,338**	**282,190**	**342,413**	**242,815**	**1,140,757**
Other Operating Expenses - Direct	110,349	98,692	105,471	97,415	411,927
Other Operating Expenses - Intercompany	39,940	42,064	48,369	48,923	179,296
Total O&M Expense	**150,289**	**140,756**	**153,841**	**146,338**	**591,223**
Amort. of Transition Costs/Def Credits					
Depreciation	103,750	106,007	106,636	109,624	426,017
Taxes Other Than Income	35,740	36,498	41,348	32,438	146,024
Total Operating Expenses	**563,118**	**565,452**	**644,238**	**531,214**	**2,304,022**
Income from Operations	**261,615**	**266,143**	**304,089**	**249,759**	**1,081,607**
Other Income and (Deductions)	11,436	16,513	11,431	10,473	49,852
Interest Expense					
Long Term Debt	66,816	69,129	68,430	73,346	277,721
Preferred Securities	1,049	1,093	1,087	1,122	4,350
Short Term Debt & Other	2,350		96	326	2,772
Intercompany Interest					
AFUDC & Capitalized Interest	(3,709)	(3,541)	(2,853)	(3,166)	(13,270)
Total Interest Expense	**66,506**	**66,680**	**66,759**	**71,629**	**271,574**
Income Before Income Taxes	**206,545**	**215,976**	**248,761**	**188,603**	**859,885**
Income Taxes					
Federal Income Tax	13,576	16,317	23,426	11,211	64,530
State Income Tax	3,610	4,743	7,073	2,363	17,789
Deferred Income Taxes	34,991	33,786	28,680	29,244	126,701
Total Income Taxes	**52,178**	**54,845**	**59,179**	**42,819**	**209,020**
Income Before Extraordinary Item	**154,367**	**161,131**	**189,582**	**145,785**	**650,865**
Extraordinary Item, net of income taxes					
Net Income	**154,367**	**161,131**	**189,582**	**145,785**	**650,865**
Noncontrolling Interest					
Minority Interest					
Preferred Stock Dividend Requirements					
Net Income Attributable to Noncontrolling Interest					
Earnings Available for Common	**$154,367**	**$161,131**	**$189,582**	**$145,785**	**$650,865**

PPL ELECTRIC UTILITIES CORPORATION
Forecast July 2026 - June 2027
(Thousands of Dollars)

PPL Electric Consolidated	**1st Q**	**2nd Q**	**3rd Q**	**4th Q**	**12 months**
Operating Revenues					
Electric Revenue	$836,188	$850,275	$963,520	$798,960	$3,448,943
Wholesale Energy Marketing					
Intercompany Sales					
Total Operating Revenues	**836,188**	**850,275**	**963,520**	**798,960**	**3,448,943**
Operating Expenses					
Electric Fuel					
Energy Purchases - External	274,335	283,366	343,990	244,530	1,146,222
Energy Purchases - Internal					
Total Fuel & Energy Purchases	**274,335**	**283,366**	**343,990**	**244,530**	**1,146,222**
Other Operating Expenses - Direct	124,575	115,662	116,037	104,959	461,232
Other Operating Expenses - Intercompany	49,824	52,066	51,816	47,875	201,581
Total O&M Expense	**174,399**	**167,728**	**167,852**	**152,834**	**662,813**
Amort. of Transition Costs/Def Credits					
Depreciation	111,619	115,062	120,434	121,159	468,275
Taxes Other Than Income	39,378	40,154	45,086	36,266	160,884
Total Operating Expenses	**599,731**	**606,310**	**677,362**	**554,790**	**2,438,194**
Income from Operations	**236,457**	**243,965**	**286,158**	**244,170**	**1,010,749**
Other Income and (Deductions)	16,610	13,043	9,956	12,144	51,753
Interest Expense					
Long Term Debt	75,805	75,805	77,839	82,594	312,043
Preferred Securities	1,170	1,184	1,135	1,161	4,650
Short Term Debt & Other					
Intercompany Interest					
AFUDC & Capitalized Interest	(3,271)	(3,189)	(3,691)	(3,293)	(13,444)
Total Interest Expense	**73,704**	**73,799**	**75,284**	**80,462**	**303,249**
Income Before Income Taxes	**179,362**	**183,208**	**220,830**	**175,852**	**759,252**
Income Taxes					
Federal Income Tax	17,248	19,052	24,381	15,631	76,312
State Income Tax	4,691	5,386	6,087	2,956	19,120
Deferred Income Taxes	36,070	34,651	36,558	36,722	144,001
Total Income Taxes	**58,010**	**59,089**	**67,026**	**55,308**	**239,433**
Income Before Extraordinary Item	**121,352**	**124,119**	**153,804**	**120,544**	**519,819**
Extraordinary Item, net of income taxes					
Net Income	**121,352**	**124,119**	**153,804**	**120,544**	**519,819**
Noncontrolling Interest					
Minority Interest					
Preferred Stock Dividend Requirements					
Net Income Attributable to Noncontrolling Interest					
Earnings Available for Common	**$121,352**	**$124,119**	**$153,804**	**$120,544**	**$519,819**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 3

Direct Testimony of Christopher Garrett

Topics: **Support Group Costs**
Employee Benefit Costs
Capital Treatment of Certain Information Technology Costs

Dated: September 30, 2025

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Christopher Garrett. My business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223.

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

A. I am employed as Vice President – Financial Strategy and Chief Risk Officer for PPL Services Corporation ("PPL Services"), a subsidiary of PPL Corporation and an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company").

Q. What are your responsibilities as Vice President – Financial Strategy and Chief Risk Officer?

A. I am responsible for enterprise risk management as the Chief Risk Officer of PPL Corporation. This includes oversight of the financial risk management functions including credit, contract administration and insurance. Additionally, I help lead, develop, and support the financial strategy of PPL Corporation on various regulatory and accounting matters including the implementation of the new Enterprise Resource Planning ("ERP") solution. And lastly, I oversee the payroll function for the Kentucky subsidiaries of PPL Corporation.

Q. What is your educational background and professional experience?

A. A complete statement of my education and professional experience is attached to my direct testimony as Appendix A.

Q. What is the purpose of your testimony?

A. My testimony will describe and support the calculation of support group costs and employee benefit costs developed by PPL Services and included in PPL Electric's 2025, 2026 and 2027 budgets. Also, I will testify about the Company's request to capitalize certain Information Technology ("IT") software implementation costs.

Q. Are you sponsoring any exhibits or schedules in this proceeding?

A. Yes, I am sponsoring Exhibit Regs. II-D-8. I am also co-sponsoring Schedules D-14 in Exhibits Historic 1, Future 1, and Fully Projectetd Future 1.

II. SUPPORT GROUP COSTS

Q. Please describe the support costs you are sponsoring.

A. I am sponsoring the support group costs provided by PPL Services included in Exhibit Regs. II-D-8.

Q. Please describe PPL Services.

A. PPL Services is a Delaware corporation that provides various administrative and general services for PPL Electric and the other affiliates of PPL Corporation pursuant to a Comprehensive Utility Goods and Services Agreement approved by the Pennsylvania Public Utility Commission ("Commission" or "PUC") at Docket No. G-2023-3044914 through a Secretarial Letter issued on April 22, 2024. Under that Agreement, PPL Electric may provide or receive goods and administrative, management, supervisory, construction, engineering, accounting, legal, financial, operating, or similar services to or from its affiliates, including PPL Services, upon request. The Agreement also allows affiliates to provide other affiliates services by utilizing their personnel, such as executives, accountants, financial advisers, technical advisers, attorneys, and other professional persons with the necessary qualifications. Further descriptions of the services provided by PPL Services to PPL Electric are provided in Exhibit Regs. II-D-8. Also, the Company's filing at Docket No. G-2023-3044914 also included PPL Corporation's Cost Allocation Manual ("CAM"), which sets forth the methods, policies, and cost allocation procedures that all PPL Corporation affiliates follow in providing goods and services for other affiliated companies.

Q. Please describe how PPL Services support costs are determined.

A. In developing service group support costs for PPL Electric, each service group computes the level and expected costs of providing identifiable services (direct costs) to PPL Electric, utilizing cost assignment methods included in the PPL Corporation CAM. The service groups enter these direct support costs into the Corporate Budget System. Additionally, the service groups identify and enter into the Corporate Budget System budgeted costs that are not directly identifiable and chargeable to a specific PPL Corporation subsidiary but instead benefit various PPL Corporation subsidiaries (indirect costs). The Financial Planning Department has developed and incorporated into the Corporate Budget System an allocation methodology to distribute these indirect support costs to PPL Electric and other PPL Corporation subsidiaries. The allocation methodology was recommended by the Commission in its 2002 Management and

Operations Audit and was reaffirmed in its 2009 Management and Operations Audit, 2012 Management Efficiency Implementation Audit, 2015 Management and Operations Audit, and 2023 Management and Operations Audit.[1] The methodology is also set forth in the PPL Corporation CAM. The Corporate Budget System accumulates and incorporates all the direct and indirect support costs into PPL Electric's Operating Budget.

III. <u>EMPLOYEE BENEFIT COSTS</u>

Q. Please describe how employee benefit costs are determined.

A. PPL Services administers PPL Corporation's employee benefits plans. At the beginning of the budget cycle, the appropriate individuals on PPL Services' staff provide a summary of total PPL Corporation benefits and their expected costs to the appropriate staff in PPL Services' Financial Planning Department. The Financial Planning Department develops a corporate benefits loading rate as a percentage of total budgeted corporate payroll costs in each of PPL Corporation's subsidiaries to develop their respective benefits budget. I am supporting the calculation of the loading rates for PPL Electric and PPL Services.

---

[1] In the Commission's 2023 Management and Operations Audit Report, the Commission noted that PPL Corporation's CAM does not explicitly describe the services that PPL Electric provides to or receives from all affiliates. *See Management and Operations Audit*, Docket No. D-2023-3039488, pp. 26-27 (Report dated June 2024). PPL Electric's Implementation Plan explained that changes to the PPL Corporation CAM must be submitted to the Virginia State Corporation Commission for approval and that the Company will consider whether to include the requested documentation in a future CAM update. *See* Implementation Plan, Docket No. D-2023-3039488, p. 9 (June 2024).

IV. <u>CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY COSTS</u>

Q. Please describe the accounting treatment for software implementation costs under U.S. Generally Accepted Accounting Principles ("GAAP") and Federal Energy Regulatory Commission ("FERC") accounting guidance that must be expensed to operations and maintenance ("O&M").

A. Under both U.S. GAAP and FERC accounting guidance, certain software implementation costs must be expensed to O&M regardless of whether the IT system is located on-premises or off-premises via a cloud computing arrangement.[2] These costs include training, data conversion and migration, direct business or functional process reengineering incurred associated with strategic implementations, change management, preliminary project stage, hyper care, and cloud computing such as hosting and other fees during implementation.[3]

---

[2] See Accounting Standards Update (ASU) No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement* and FERC Docket No. AI 20-1-000, *Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract*.

FERC Docket No. AI-20-1-000 "Question: How should jurisdictional entities capitalize implementation costs related to cloud computing arrangements? Response: Implementation costs related to cloud computing arrangements are similar to the costs incurred to develop internal-use software and should be accounted for on the same basis. Jurisdictional entities have historically determined capitalizable internal-use software costs in a manner consistent with the requirements of ASC 350-40, which is an acceptable approach for accounting and financial reporting to the Commission. Accordingly, it is also appropriate for jurisdictional entities to determine capitalized implementation costs related to cloud computing consistent with ASC 350- 40."

[3] ASC 350-40-25-4 Training costs are not internal-use software development costs and, if incurred during this stage, shall be expensed as incurred.

ASC 350-40-25-1 Internal and external costs incurred during the preliminary project stage shall be expensed as they are incurred.

ASC 350-40-25-5 Data conversion costs, except as noted in paragraph 350-40-25-3, shall be expensed as incurred. The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, creation of new or additional data, and conversion of old data to the new system.

In this case, however, the Company is requesting Commission approval to record these costs as long-lived capital assets consistent with National Association of Regulatory Utility Commissioners ("NARUC") and Commission guidance discussed in detail below.

Q. What is the total amount of software implementation costs the Company is seeking to capitalize as part of this proceeding?

A. The total cost of these projects the Company is seeking to capitalize is approximately $53.9 million, inclusive of Allowance for Funds Used During Construction ("AFUDC") through the Fully Projected Future Test Year ("FPFTY"). These software implementation costs are related to shared IT platforms resulting from an organizational consolidation, including: (1) a cloud hosted, customer information system ("CIS"); (2) a cloud-hosted, Enterprise Resource Planning system ("ERP"); (3) consolidated work management systems; (4) an on premises, consolidated advanced distribution management system ("ADMS") platform; (5) a cloud hosted, consolidated geographic information system ("GIS"); and (6) other shared infrastructure services that are discussed in the testimony of PPL Electric witness Daniel Johnson (PPL Electric St. No.

ASC 720-45-25-2, *Other Expenses—Business and Technology Reengineering*, "The following third-party or internally generated costs typically associated with business process reengineering shall be expensed as incurred: c) Process reengineering—the effort to reengineer the entity's business process to increase efficiency and effectiveness. This activity is sometimes called analysis, determining best-in-class, profit and performance improvement development, and developing should-be processes."

ASC 350-40-25-6 Internal and external training costs and maintenance costs during the postimplementation-operation stage shall be expensed as incurred.

19). The $53.9 million discussed in my testimony is in addition to the IT capital investments described in Mr. Johnson's testimony.

Q. Why does the Company believe that these software implementation costs should be capitalized?

A. The Company believes that the costs should be capitalized and depreciated over the life of the systems that remain used and useful for numerous reasons. First, the new IT systems will provide benefits to customers over extended periods of time and not just the period in which the costs are incurred. In that respect, these investments are more akin to long-lasting capital investments as opposed to O&M expenditures. Second, similar implementation costs for non-IT related property, plant and equipment expenditures are eligible for capitalization under FERC accounting guidance.[4] In fact,

[4] Per the FERC Uniform System of Accounts, *Account 183, Preliminary Survey and investigation charges*:
"This account shall be charged with all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation. If construction results, this account shall be credited and the appropriate utility plant account charged."

Electric Plant Instruction 3.A.19 *Training:*
"When it is necessary that employees be trained to operate or maintain plant facilities that are being constructed and such facilities are not conventional in nature, or are new to the company's operations, these costs may be capitalized as a component of construction cost. Once plant is placed in service, the capitalization of training costs shall cease and subsequent training costs shall be expensed."

AI11-1-00 – *Capitalization of Allowance for Funds Used During Construction* defines the construction phase as including "activities that are necessary to get the construction project ready for its intended use are in progress."

Pennsylvania[5] and other state utility commissions[6] have approved capitalization treatment or regulatory asset accounting treatment. Lastly, such treatment is consistent with a resolution by NARUC,[7] in which NARUC encouraged state utility commissions to consider and adopt regulatory treatment for cloud computing arrangements that increased their use in an evolving market.

Q. Has the Company made pro forma adjustments to reflect this capitalization treatment for Pennsylvania ratemaking purposes?

---

[5] *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Joint Petition for Approval of Settlement of All Issues, Docket No. R-2021-3030218, et al., (Order entered June 24, 2022), *available at* https://www.puc.pa.gov/pcdocs/1749940.pdf ("For purposes of this Settlement, UGI Gas's as-filed capital treatment of certain information technology ('IT') costs is accepted. (See UGI Gas St. No. 3 at 22-23.) UGI Gas will capitalize IT costs that include internal labor, external consulting expenses, and other expenses related to the preparation of the vendor and system integrator requests for proposal. Other capitalizable costs include current state assessments, reengineering business processes to adapt to new systems, data conversion, data cleansing, and migration (including field verification and digitization of asset attributes required for accurate data and facility capture), pre-implementation training costs, cloud computing software implementation, and Hypercare.").

[6] *Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief*, Case No. 2021-00190, Order at 11 (Ky. PSC Dec. 28, 2021) ("[T]he Commission finds that Duke Kentucky [*sic*] should be authorized to establish a regulatory asset, for accounting purposes only, for the jurisdictional incremental costs for developmental Customer Connect and retirement CMS O&M expense because the costs are extraordinary expenses that over time will result in a saving that offsets the cost."); *see Alabama Power Company Petition For approval of Accounting Authorization Related to Software Expenditures*, Docket U-5285, Order (Al. PSC Feb. 5, 2019, *available at* https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=d95be406-0cce-4cb1-8c8a-fdba9ca0e07a ("As discussed below, the nature of software expenditures and the corresponding benefits realized from such investments do not align with applicable generally accepted accounting principles ('GAAP), creating uneven expense recognition patterns that do not serve as a benefit to customers. The Company therefore seeks the authority to establish a regulatory asset in which it would capitalize operations and maintenance ('O&M') costs associated with software projects, including cloud-based software solutions, and then amortize such costs for a period that is consistent with the lives of comparable plant-in-service capital assets. For the reasons set forth, the Commission finds that Alabama Power's request is reasonable and well-supported, and thus grants the accounting authorization.").

[7] "Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements" – Sponsored by the Committees on Critical Infrastructure, Gas, and Water. Recommended by the NARUC Board of Directors on November 15, 2016. Adopted by the NARUC Committee of the Whole on November 16, 2016.

A. Yes. First, Schedule C-1 in Exhibit Fully Projected Future 1 includes the following adjustments: an approximately $25.9 million[8] addition to Electric plant in service on Line 1a; an approximately $1.8 million addition to Reserve for depreciation on Line 2a; and an approximately $6.1 million addition to Accumulated deferred taxes on income on Line 9a. For budgeting purposes, the Company reflected the associated software implementation costs for which it is seeking capitalization treatment as regulatory assets (included in Other Noncurrent Assets) in accordance with FERC and GAAP accounting requirements. Thus, a pro forma adjustment was needed to reclassify the associated software implementation costs from a regulatory asset to Property, Plant, and Equipment ("PP&E") beginning in the FPFTY for Pennsylvania ratemaking treatment. Second, Schedule D-14 in Exhibit Fully Projected Future 1 reclassifies approximately $1.8 million in O&M expense to depreciation expense as a result of the regulatory asset treatment for budgeting purposes described above. The $1.8 million represents the associated amortization on the IT software implementation costs placed in-service prior to the conclusion of the FPFTY.

Q. Does this conclude your direct testimony?

A. Yes, it does.

---

[8] An additional approximately $28 million remains in construction work in progress ("CWIP"), bringing the total capital costs to approximately $53.9 million, inclusive of AFUDC through the FPFTY.

APPENDIX A

Christopher M. Garrett
Vice President – Financial Strategy and Chief Risk Officer
PPL Services Corporation
Vice President – Finance and Accounting
LG&E and KU Energy LLC
2701 Eastpoint Parkway
Louisville, Kentucky 40223
Telephone: (502) 627-3328

Previous Positions:

Vice President, Financial Strategy and Chief Risk Officer	Mar 2024 – present
Vice President, Finance and Accounting	Apr 2022 – present
Controller	Jan 2018 – Apr 2022
Director, Rates	Feb 2016 – Dec 2017
Director, Accounting and Regulatory Reporting	Dec 2012 – Jan 2016
Director, Financial Planning & Controlling	Feb 2010 – Nov 2012
Manager, Financial Planning	Nov 2007 – Feb 2010
Manager, Corporate Accounting	Jan 2006 – Oct 2007
Manager, Utility Tax	May 2002 – Jan 2006
Tax Analyst, various positions	Aug 1995 – May 2002

Education:

Eastern Kentucky University, Bachelor of Business Administration - Accounting, 1995
Graduated Magna Cum Laude
Certified Public Accountant, Kentucky, 1999

Professional Memberships:

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KYCPA)
Edison Electric Institute

Civic Activities:

The Louisville Free Public Library Foundation, Immediate Past Board Chair
Saint Joseph School, Past Board Chair
Leadership Louisville, Bingham Fellows 2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 4

Direct Testimony of Charles R. Schram

Topics: **Sales and Load Forecast**
Annualization of Sales and Revenue

Dated: September 30, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Charles R. Schram, and my business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223.

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

A. I am Vice President, Energy Supply and Analysis for LG&E and KU Services Company, which provides services to PPL Electric Utilities Corporation ("PPL Electric" or the "Company"); The Narragansett Electric Company d/b/a Rhode Island Energy ("RIE") in Rhode Island; Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") in Kentucky; and Old Dominion Power ("ODP") in Virginia. In this position, among other responsibilities, I oversee the preparation of the forecasts of electric sales, customers, and demands for the Company, RIE, LG&E, KU, and ODP, as well as the forecasts of gas sales, customers, and demands for RIE and LG&E. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. What are your responsibilities as Vice President, Energy Supply and Analysis?

A. I have five primary areas of responsibility: (1) sales forecasting and market analysis, (2) fuel procurement (coal and natural gas) and coal combustion residual marketing for the LG&E and KU generating stations, (3) real-time dispatch optimization of the generating stations to meet LG&E and KU's native load obligations, (4) wholesale market activities, and (5) generation planning for LG&E and KU. As it pertains to this proceeding, the Sales Analysis and Forecasting group prepared the electric sales forecast for the Company.

Q. What are the responsibilities of the Sales Analysis and Forecasting group?

A. The primary responsibility of the Sales Analysis and Forecasting team is to support decision-making within the Company through their forecasting and analysis activities. This begins with an understanding of how the Company's customers use electricity, obtained through economic and statistical analysis and research into factors that could change customers' future usage patterns. Though not a comprehensive list, this includes the following tasks:

- Analyzing key factors that influence customers' energy consumption, such as weather, the state of the economy, federal and state regulations, demand-side programs, end-use appliance efficiencies and saturations, distributed generation, electrification, and rates and rate design;
- Analyzing available interval data and aggregated calendar sales for specific rate classes;
- Analyzing sales variances against the forecast;
- Considering additional inputs that could aid or improve analysis or forecasting; and
- Documenting processes.

Q. Have you ever testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") or any other regulatory body?

A. I have not previously testified before the PUC. However, I have testified before numerous regulatory and legislative bodies. I have provided testimony before the Kentucky Public Service Commission on numerous occasions, including the most recent KU and LG&E Rate Cases (2025-00113 and 2025-00114) as well as Certificate of Public Convenience and Necessity filings in Case Nos. 2022-0402 and 2025-00045 and the LG&E and KU Integrated Resource Plan in Case No. 2024-00326. I have also provided testimony before the Virginia State Corporation Commission in Fuel Factor proceedings involving KU's Old Dominion Power subsidiary.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the development of the Company's forecast of sales, customers, and billed demands in addition to the annualization of sales and revenues.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am co-sponsoring Exhibit Regs. IV-C and sponsoring following exhibits:

- PPL Electric Exhibit CRS-1, which compares sales, customer counts, and billed demands in the historic test year ("HTY") to sales in the fully projected future test year ("FPFTY").

- PPL Electric Exhibit CRS-2, which details the annualization of sales and revenues for the HTY (July 2024 through June 2025), future test year ("FTY") (July 2025 through June 2026), and FPFTY (July 2026 through June 2027).

II. <u>SALES FORECAST</u>

Q. Please describe the development of the sales forecast set forth in PPL Electric Exhibit CRS-1.

A. The sales forecast is developed for the Residential, Small Commercial and Industrial ("Small C&I"), and Large Commercial and Industrial ("Large C&I") rate groups. These rate group forecasts were developed from models using regression analyses of historical sales data, economic data, end-use efficiency and saturation data, and weather data. Historical and forecasted economic data for the Commonwealth of Pennsylvania is obtained from Moody's Analytics. The weather (and more specifically temperature) data is obtained from the following airports: Lehigh Valley International, Harrisburg (Middletown), Wilkes-Barre/Scranton (Avoca), and Williamsport. Because the Company does not bill customers on a calendar month basis (bills are rendered based upon meter reads throughout the month), the revenue period (also referred to as "revenue month") heating degree days ("HDDs") and cooling degree days ("CDDs") are calculated for each revenue month. Forecasted weather is determined by calculating normal revenue month weather on an HDD and CDD basis for the past 20 years. The models use these inputs to generate a monthly sales forecast for each rate group.

Q. Has PPL Electric materially changed its approach to electric sales forecasting since the Company's 2015 rate case?

A. No. While I was not involved in the 2015 rate case, my understanding of PPL Electric witness Kimberly Golden's testimony (PPL Electric St. No. 3 from the 2015 rate case) is that the Company has a similar approach today as in 2015. The Company continues to look for ways to improve models and the forecast as a whole, but the overall approach to forecasting is consistent with that used in the prior rate case.

Q. How was the sales forecast set forth in PPL Electric Exhibit CRS-1 used in this rate filing?

A. The sales forecast is used to develop the FPFTY sales, which are a key input to the forecast of revenues, as discussed in the direct testimony of PPL Electric witness Katelyn Arnold (PPL Electric St. No. 13). The sales forecast is also part of the calculation of rates once cost allocations are determined.

Q. How are the Company's customer count and electricity sales expected to change in the FPFTY as compared to the HTY?

A. Changes by rate class from the HTY to the FPFTY are detailed in PPL Electric Exhibit CRS-1.

The residential class represents the majority of customer growth that has occurred historically and is projected to occur in the FPFTY, as shown in rows 27 and 37 of PPL Electric Exhibit CRS-1. With an annual growth rate of 0.44% per year from

2025-2027, forecasted customer growth is very similar to the 0.51% annual growth rate the Company has seen from 2016 to 2024.

Electricity sales to customers taking service under the residential service ("RS") and single-phase general service ("GS-1") rate schedules are forecast to be lower in the FPFTY than in the HTY, as shown in rows 28 and 11 of PPL Electric Exhibit CRS-1. This is primarily due to weather differences between the actual weather in the HTY versus the weather-normal based FPFTY as well as end-use appliance efficiency gains and distributed generation adoption that continue to reduce usage per customer.

Sales to non-data center customers taking service under the large general service ("LP-5") rate schedule are forecast to decrease in the FPFTY due to the loss of a few large customers, as shown in row 20 of PPL Electric Exhibit CRS-1. Sales to data center customers taking service under the LP-5 rate schedule are forecast to increase substantially in the FPFTY, as discussed later in my testimony and shown in row 23 of PPL Electric Exhibit CRS-1.

Q. Please identify the difference in weather between the HTY and the FPFTY.

A. Weather, and more specifically temperature, remains the most significant factor that drives the Company's sales variances on a near-term basis and thus is the main difference between the HTY and FPFTY, particularly for the weather-sensitive classes. As described below, actual weather in the HTY resulted in higher sales compared to sales under normal weather conditions.

Q. Please identify the variances in the CDDs and explain what those variances mean for sales projections during the summer.

A. The amount of actual CDDs in the HTY exceed the amount of normal CDDs in the FPFTY. This difference is most notable in July and August, which are typically the highest usage-per-customer months during the summer. This is shown in column G of Table 1 below.

Table 1: HTY and FPFTY Weather Comparison

		HTY		**FPFTY**		**FPFTY vs. HTY**			
	Revenue Month	**Revenue Month Actual (July 2024 - June 2025)**		**Revenue Month Forecast (July 2026 - June 2027)**		**Degree Day Difference**		**% Difference**	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
		HDD	**CDD**	**HDD**	**CDD**	**HDD**	**CDD**	**HDD**	**CDD**
[1]	**July**		317		252		(65)		-21%
[2]	**August**		315		290		(24)		-8%
[3]	**September**		162		181		19		12%
[4]	**October**	149		188		39		26%	
[5]	**November**	410		481		71		17%	
[6]	**December**	768		788		20		3%	
[7]	**January**	1,099		1,006		(93)		-8%	
[8]	**February**	1,075		1,003		(71)		-7%	
[9]	**March**	766		839		73		10%	
[10]	**April**	477		576		100		21%	
[11]	**May**	251		276		25		10%	
[12]	**June**		121		122		1		0%
[13]	**Total**	**4,995**	**915**	**5,158**	**845**	**163**	**(70)**	**3%**	**-8%**

Q. Please identify the variances in the HDDs and explain what those variances mean for sales projections during the winter.

A. The amount of actual HDDs in the HTY is less than the amount of normal HDDs in the FPFTY. However, focusing on the HDD differences in December through March, when usage-per-customer is typically at its highest, results in 71 more HDD in the HTY than in the FPFTY. This means that HTY temperatures in these months resulted in increased sales relative to the normal temperature assumptions in the FPFTY. This information is provided in column F of Table 1 above.

Q. Please provide an overview as to the differences in sales projected for the FPFTY relative to the HTY due to weather.

A. As described in Table 1 and discussed above, the HTY revenue months in which weather-sensitive usage is typically the greatest (January, February, July, and August) showed actual versus normal temperature differences that would suggest higher sales due to weather in the HTY. Overall, the normal temperature assumptions in the FPFTY result in fewer CDDs during the forecasted cooling months than actually experienced in the HTY and fewer HDDs in the January and February forecasted heating months than actually experienced in the HTY.

Q. Why does the Company use a 20-year period to calculate normal weather?

A. A 20-year normal provides an outlook of CDDs and HDDs that are calculated using temperature data from the past 20 years. The use of a 20-year normal results in less volatility from one forecast to the next as compared to a weather normal calculated over a shorter period, such as 10 years. Additionally, the sales forecasts are developed on a monthly basis, and the sales forecast impact of a normal weather assumption calculated over a shorter period of time would vary depending on the month. Evaluating the historical temperature data, the impact of using a shorter period for normal weather would generally be reduced sales during the heating months and increased sales during the cooling months. Therefore, as a result of this seasonal offsetting, there would be very little change in total annual sales. For example, a 10-year normal weather assumption would reduce annual sales by 0.5% for RS and 0.2% for GS as compared to the same forecast using a 20-year normal.

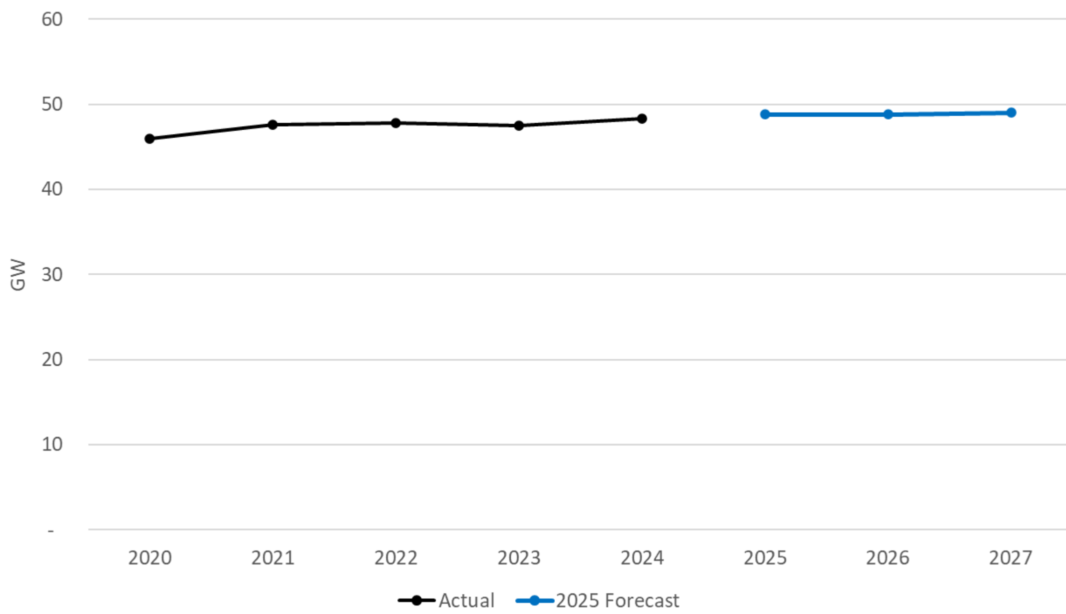
Q. For the rates that have demands as a billing determinant, how does weather affect demands in the HTY?

A. While monthly sales are highly correlated to changes in monthly degree days, demands are set based on only a 15-minute period in each revenue month, so demands are influenced more by intra-month temperature extremes versus total monthly degree days.

Q. Why is the Company's forecast of billed demands reasonable?

A. The figure below demonstrates that the recent trend in historical billed demands is closely aligned to both last year's forecast and this year's forecast. This year's forecast continues the slightly increasing trend since 2020 in total billed demands.

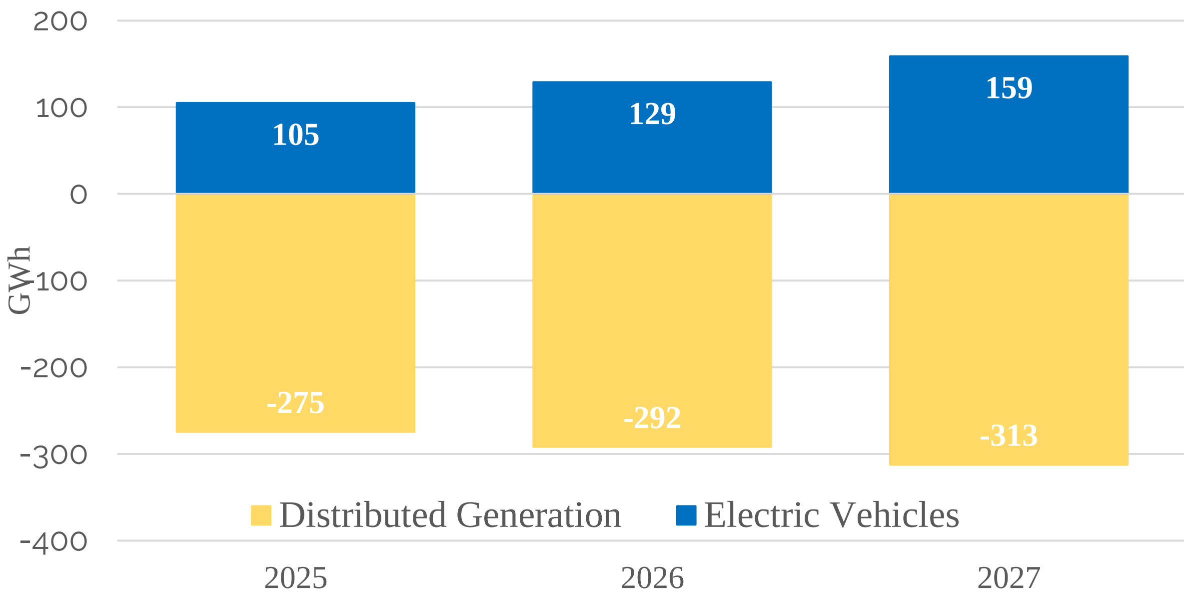
Figure 1: Total Billed Demands (GW)



Q. Does the sales forecast reflect the impact of distributed generation and electric vehicles?

A. Yes. As detailed below in Figure 2, energy produced from distributed generation reduces sales more than energy consumed by EVs increases sales. The net impact of distributed generation and EVs represents roughly 0.5% of total sales, excluding new large load customers, in the HTY and FPFTY.

Figure 2: Annual Sales Impacts of Distributed Generation and EVs



Q. How are new large load customers included in the sales forecast?

A. The Company included large load customers with executed Letters of Agreement ("LOAs") or Electric Service Agreements ("ESAs") with the Company at the time of the development of the sales forecast. The expected impacts of new large load customers are discussed more fully in PPL Electric witness Joseph Lookup's testimony (PPL Electric St. No. 16).

Q. What impact, if any, will new large load customers have on the Company's distribution revenues?

A. The large load customers projected to come online during the FPFTY are data center customers forecasted to take service under the LP-5 rate schedule. These customers are transmission-level customers, so the only distribution revenue impact from LP-5 customers is a customer charge. The LP-5 rate class's projected load growth in the FPFTY due to data center customers is based on input from Mr. Lookup's team and is set forth in PPL Electric Exhibit CRS-1 at rows 21 and 23. As stated above, the expected impacts of new large load customers, and in particular the impacts of these interconnections on system planning, are discussed more fully in Mr. Lookup's testimony.

III. ELECTRIC LOAD FORECAST

Q. Please describe the development of the peak load forecast.

A. Consistent with prior forecasts, the Company relies upon PJM Interconnection LLC ("PJM") for the peak load forecast. This year's peak load forecast comes from the 2025 PJM Load Report, published January 24, 2025, for the PPL Zone.

Q. Was the updated Annual Resource Planning Report ("ARPR") filed on August 8, 2025 based on the same peak forecast?

A. Yes, with the exception of new large load customers. The difference in the peaks is solely related to large load assumptions that were updated between the original filing of the ARPR in May 2025, which used the PJM forecast, and the updated filing of the ARPR in August 2025.

V. ANNUALIZATION OF SALES AND REVENUE

Q. PPL Electric Exhibit CRS-2 reflects annualizations of sales and base rate revenues for the HTY, FTY, and FPFTY. Please explain how those adjustments were developed.

A. The annualization adjustment of sales and base rate revenues for the HTY ended June 30, 2025, has two components. The first component accounts for changes in the number of customers over the year, and the second component accounts for changes in customer usage over the year.

The change in the number of customers from June 30, 2024, to June 30, 2025 was computed for each rate class. One-half of that change for each rate class was multiplied by the average annual kWh usage per customer to obtain the sales adjustment associated with new customers entering the rate class. The average unit base rate for each rate class was applied to the resulting kWh sales levels to obtain the base rate revenue adjustments for distribution due to changes in the number of customers.

The second adjustment recognizes changes in kWh usage levels by existing customers. The average change over the past three years in average annual usage for each class was computed. One-half of the change in average use was multiplied by the year-end number of customers for each rate class to obtain the kWh sales adjustment. The incremental base rate for each rate class was applied to this sales adjustment to obtain the base rate revenue adjustment. Details of the HTY annualization adjustment are shown on page 1 of PPL Electric Exhibit CRS-2.

The annualization of FTY and FPFTY sales and revenues consisted of similar adjustments for changes in the numbers of customers and customer usage. The details of the FTY annualization adjustment are shown on page 2 of PPL Electric Exhibit CRS-2; the FPFTY annualization adjustment details are shown on page 3 of PPL Electric Exhibit CRS-2.

Q. Please explain the source of the customer load data used to develop the rate class demand allocators employed in the Company's cost allocation studies.

A. PPL Electric collects interval sales data for all customers in the residential and large C&I rate groups, and all FERC jurisdictional customers. For the Small C&I rate group, most customers have interval meters, with the exception of a small number of unmetered customers taking service under the GS-1 and lighting rate schedules. For these unmetered rate schedules, a load profile is used to estimate the interval data. The hourly demands are aggregated to a total rate class level to determine the rate class coincident and non-coincident peaks.

Q. Have you provided the billing determinants used to develop the annual revenue effects for each of the rates?

A. Yes. The Sales Analysis and Forecasting team provided billing determinants to the Rates and Financial Planning teams for input into their calculations. The billing determinants can be found in PPL Electric witness Steven Wishart's testimony (PPL Electric St. No. 8).

Q. Do you believe the forecasted billing determinants for the FPFTY period are a reasonable basis for developing revenue forecasts and setting rates?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

Charles R. Schram
Vice President, Energy Supply and Analysis
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Professional Experience

LG&E and KU

Vice President, Energy Supply and Analysis	2025 – Present
Director, Power Supply	2016 – 2025
Director, Energy Planning, Analysis & Forecasting	2008 – 2016
Manager, Transmission Protection & Substations	2006 – 2008
Manager, Business Development	2005 – 2006
Manager, Strategic Planning	2001 – 2005
Manager, Distribution System Planning & Eng.	2000 – 2001
Manager, Electric Metering	1997 – 2000
Information Technology Analyst	1995 – 1997

U.S. Department of Defense – Naval Ordnance Station

Manager, Software Integration	1993 – 1995
Electronics Engineer	1984 – 1993

Education

Master of Business Administration
University of Louisville, 1995

Bachelor of Science – Electrical Engineering
University of Louisville, 1984

E.ON Academy General Management Program: 2002-2003

Center for Creative Leadership, Leadership Development Program: 1998

Civic Activities

The Housing Partnership – Board of Directors, 2017 – Present

Leadership Louisville – Bingham Fellows class of 2020

Comparison of PPL Electric Customers, Billing Demand, and Energy by Rate Classes: Historical Test Year vs Fully Projected Future Test Year

	A	B	C	D	E	F	G	H
1					Historical Test Year	Fully Projected Future Test Year	Fully Projected Future Test Year	
2	**Rate**	**Category**	**Values**		**Revenue Period Actual (Jul '24 -Jun '25)**	**Revenue Period Forecast (Jul '26 - Jun '27)**	**Difference**	**% Difference**
3								
4	BL	Customers	Avg Number of Customers		40	42	2	3.8%
5		Energy	Sum of Volume	GWh	7	7	(0)	-0.4%
6	GH-2	Customers	Avg Number of Customers		1,516	1,477	(39)	-2.6%
7		Demand	Sum of Volume	MW	233	232	(1)	-0.6%
8		Energy	Sum of Volume	GWh	35	35	0	0.3%
9	GS-1	Customers	Avg Number of Customers		147,715	147,382	(333)	-0.2%
10		Demand	Sum of Volume	MW	9,375	9,139	(236)	-2.5%
11		Energy	Sum of Volume	GWh	1,901	1,843	(58)	-3.0%
12	GS-3	Customers	Avg Number of Customers		39,257	39,839	582	1.5%
13		Demand	Sum of Volume	MW	25,323	25,220	(103)	-0.4%
14		Energy	Sum of Volume	GWh	8,236	8,238	1	0.0%
15	LP-4	Customers	Avg Number of Customers		1,218	1,237	18	1.5%
16		Demand	Sum of Volume	MW	14,285	14,316	31	0.2%
17		Energy	Sum of Volume	GWh	6,083	6,032	(51)	-0.8%
18	LP-5_excluding_LLI*	Customers	Avg Number of Customers		162	156	(7)	-4.1%
19	LP-5_POLR_excluding_LLI	Demand	Sum of Volume	MW	74	71	(3)	-4.4%
20	LP-5_excluding_LLI	Energy	Sum of Volume	GWh	6,068	5,797	(271)	-4.5%
21	LP-5_LLI	Customers	Avg Number of Customers			11		
22	LP-5_POLR_LLI	Demand	Sum of Volume	MW				
23	LP-5_LLI	Energy	Sum of Volume	GWh		6,303		
24	LP-5_Total	Customers	Avg Number of Customers		162	166	4	2.4%
25	LP-5_POLR_Total	Demand	Sum of Volume	MW	74	71	(3)	-4.4%
26	LP-5_Total	Energy	Sum of Volume	GWh	6,068	12,100	6,032	99.4%
27	RS	Customers	Avg Number of Customers		1,288,046	1,300,277	12,231	0.9%
28		Energy	Sum of Volume	GWh	14,380	14,216	(164)	-1.1%
29	RTS	Customers	Avg Number of Customers		11,651	11,564	(87)	-0.7%
30		Energy	Sum of Volume	GWh	232	231	(1)	-0.4%
31	Street Lighting	Customers	Avg Number of Customers		1,764	1,781	17	1.0%
32		Energy	Sum of Volume	GWh	74	73	(1)	-1.3%
33								
34	Total Customers_excluding_EconDev	Customers	Avg Number of Customers		1,491,370	1,503,755	12,385	0.8%
35	Total Energy_excluding_EconDev	Energy	Sum of Volume	GWh	37,016	36,472	(544)	-1.5%
36								
37	Total Customers	Customers	Avg Number of Customers		1,491,370	1,503,765	12,395	0.8%
38	Total Energy	Energy	Sum of Volume	GWh	37,016	42,776	5,759	15.6%

*LLI = New Large Load Interconnections

Rolling Q2 2025 Annualization

Rate	Revenue $	Sales kWh	Incremental Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	Average Price $/kWh	Sales Adjustment - Customer Growth kWh	Customer Growth Revenue $	Total Sales Adjustment kWh	Total Revenue Adjustment $
RS	$ 666,896,766	14,380,026,832	$ 0.03248	(67,360,501)	$ (2,188,168)	$ 0.0464	48,368,989	$ 2,243,189	(18,991,513)	$ 55,021
RTS	$ 7,371,575	231,759,714	$ 0.02173	(1,728,033)	$ (37,551)	$ 0.0318	(437,636)	$ (13,920)	(2,165,669)	$ (51,471)
GS-1	$ 73,162,604	1,900,730,309	$ 0.00445	(5,136,574)	$ (22,848)	$ 0.0385	3,834,532	$ 147,598	(1,302,041)	$ 124,750
GS-3	$ 117,901,253	8,236,078,739	$ 0.00551	(61,004,525)	$ (336,394)	$ 0.0143	71,540,846	$ 1,024,123	10,536,321	$ 687,729
LP-4	$ 35,418,992	6,082,854,450	$ 0.00454	(11,967,081)	$ (54,324)	$ 0.0058	(77,382,595)	$ (450,580)	(89,349,677)	$ (504,904)
LP-5	$ 1,769,022	6,068,124,552	$ 0.00002	(27,764,229)	$ (573)	$ 0.0003	(93,499,608)	$ (27,258)	(121,263,837)	$ (27,831)
BL	$ 342,115	7,302,079	$ 0.04449	(11,802)	$ (525)	$ 0.0469	(1,723,472)	$ (80,748)	(1,735,274)	$ (81,273)
SA	$ 3,410,074	5,512,029	$ (0.00339)	-	$ -	$ 0.6187	-	$ -	-	$ -
SM	$ 286,932	1,301,257	$ 0.00013	(49,191)	$ (7)	$ 0.2205	(11,516)	$ (2,539)	(60,706)	$ (2,546)
SHS	$ 9,896,524	27,345,959	$ 0.00449	(318,844)	$ (1,433)	$ 0.3619	(60,648)	$ (21,948)	(379,491)	$ (23,381)
SE	$ 1,853,096	25,726,427	$ 0.07738	413,141	$ 31,969	$ 0.0720	(113,166)	$ (8,151)	299,975	$ 23,818
TS	$ 28,378	298,128	$ 0.09518	(585)	$ (56)	$ 0.0952	-	$ -	(585)	$ (56)
GH-2	$ 1,203,126	35,182,588	$ 0.01027	(268,986)	$ (2,762)	$ 0.0342	(174,028)	$ (5,951)	(443,014)	$ (8,713)
SLE	$ 8,014,460	14,224,363	$ (0.00635)	33,222	$ (211)	$ 0.5634	201,179	$ 113,350	234,400	$ 113,140
Total	$ 927,554,916	37,016,467,426		(175,163,988)	$ (2,612,882)		(49,457,122)	$ 2,917,165	(224,621,110)	$ 304,283

Excludes Company Use
Revenue is distribution revenue excluding STAS and riders

Rolling Q2 2026 Annualization

Rate	Revenue $	Sales kWh	Incremental Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	Average Price $/kWh	Sales Adjustment - Customer Growth kWh	Customer Growth Revenue $	Total Sales Adjustment kWh	Total Revenue Adjustment $
RS	$ 722,695,115	14,313,969,291	$ 0.03534	43,835,238	$ 1,549,050	$ 0.0505	(39,516,511)	$ (1,995,141)	4,318,727	$ (446,091)
RTS	$ 7,375,230	205,354,747	$ 0.02371	(4,316,273)	$ (102,328)	$ 0.0359	(150,443)	$ (5,403)	(4,466,716)	$ (107,731)
GS-1	$ 78,194,980	1,898,310,011	$ 0.00208	(309,255)	$ (642)	$ 0.0412	(15,655,519)	$ (644,880)	(15,964,774)	$ (645,523)
GS-3	$ 125,178,802	8,137,182,066	$ 0.00606	(128,921,038)	$ (780,781)	$ 0.0154	159,589,257	$ 2,455,050	30,668,219	$ 1,674,269
LP-4	$ 40,457,254	6,369,370,969	$ 0.00437	12,416,319	$ 54,274	$ 0.0064	202,765,490	$ 1,287,935	215,181,809	$ 1,342,209
LP-5	$ 1,883,630	6,281,993,248	$ (0.00000)	23,584,311	$ (2)	$ 0.0003	(79,560,864)	$ (23,856)	(55,976,554)	$ (23,858)
BL	$ 361,046	7,529,601	$ 0.04795	35,545	$ 1,704	$ 0.0480	1,713,322	$ 82,154	1,748,867	$ 83,858
Street Lighting[1]	$ 15,492,950	59,453,351	$ 0.26059	(979,624)	$ (255,280)	$ 0.2606	142,061	$ 37,020	(837,562)	$ (218,260)
GH-2	$ 1,355,694	35,420,079	$ 0.00994	245,107	$ 2,436	$ 0.0383	(528,479)	$ (20,227)	(283,372)	$ (17,792)
SLE	$ 9,345,771	15,193,411	$ 0.61512	107,648	$ 66,217	$ 0.6151	105,317	$ 64,783	212,965	$ 130,999
Total	$ 1,002,340,472	37,323,776,774		(54,302,022)	$ 534,647		228,903,632	$ 1,237,434	174,601,610	$ 1,772,080

[1]Street Lighting includes SA, SM, SHS, SE, and TS rates
Excludes Company Use
Revenue is distribution revenue excluding STAS and riders

Rolling Q2 2027 Annualization

Rate	Revenue $	Sales kWh	Incremental Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	Average Price $/kWh	Sales Adjustment - Customer Growth kWh	Customer Growth Revenue $	Total Sales Adjustment kWh	Total Revenue Adjustment $
RS	$ 723,522,983	14,319,793,225	$ 0.03534	80,121,117	$ 2,831,271	$ 0.0505	20,425,104	$ 1,032,000	100,546,221	$ 3,863,271
RTS	$ 7,210,947	198,903,342	$ 0.02371	(3,190,391)	$ (75,644)	$ 0.0363	(447,780)	$ (16,234)	(3,638,171)	$ (91,877)
GS-1	$ 77,988,150	1,892,462,222	$ 0.00209	9,694,903	$ 20,256	$ 0.0412	-	$ -	9,694,903	$ 20,256
GS-3	$ 126,302,233	8,198,877,197	$ 0.00591	(96,239,548)	$ (569,134)	$ 0.0154	94,761,908	$ 1,459,790	(1,477,640)	$ 890,656
LP-4	$ 40,702,597	6,418,610,292	$ 0.00427	14,105,022	$ 60,214	$ 0.0063	25,336,620	$ 160,668	39,441,642	$ 220,882
LP-5	$ 1,892,576	8,578,726,782	$ 0.00001	398,212,773	$ 2,218	$ 0.0002	27,033,803	$ 5,964	425,246,575	$ 8,182
BL	$ 360,842	7,525,356	$ 0.04795	65,599	$ 3,145	$ 0.0480	-	$ -	65,599	$ 3,145
Street Lighting[1]	$ 15,289,914	58,674,224	$ 0.26059	(444,910)	$ (115,939)	$ 0.2606	(2,832)	$ (738)	(447,742)	$ (116,677)
GH-2	$ 1,351,205	34,130,297	$ 0.00994	324,117	$ 3,223	$ 0.0396	(211,152)	$ (8,359)	112,966	$ (5,137)
SLE	$ 9,451,380	15,365,099	$ 0.61512	85,374	$ 52,516	$ 0.6151	142,502	$ 87,656	227,876	$ 140,171
Total	$ 1,004,072,827	39,723,068,036		402,734,058	$ 2,212,126		167,038,173	$ 2,720,748	569,772,231	$ 4,932,874

[1]Street Lighting includes SA, SM, SHS, SE, and TS rates
Excludes Company Use
Revenue is distribution revenue excluding STAS and riders

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 5

Direct Testimony of Bethany L. Johnson

Topics: **Overview of Revenue Requirement,**
Cost of Service, and Rate Design
Rate Case Expenses

Dated: September 30, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Bethany L. Johnson, and my business address is 827 Hausman Road, Allentown, Pennsylvania, 18104.

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

A. I am employed by PPL Services Corporation ("PPL Services"), an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company") which provides services to PPL Electric, as the Senior Director of Regulatory.

Q. What are your responsibilities as Senior Director of Regulatory?

A. I am responsible for PPL Electric's development of revenue forecasting and analysis, distribution rate design and administration, cost of service implementation, as well as transmission Federal Energy Regulatory Commission ("FERC") Formula Rates, development of rate case strategies and processes, and compliance with the regulatory requirements of the Pennsylvania Public Utility Commission ("Commission"), the FERC and other regulatory agencies, as necessary. Additionally, I oversee energy and utility policy and regulatory strategy for PPL Electric. As part of this function, I am responsible for the preparation, review, and technical oversight and guidance of the development, content, and structure of cost allocation and revenue requirement studies. In addition, I am responsible for all aspects of Rhode Island Energy's and PPL Electric's procurement of wholesale generation supply and scheduling and settlement activities with PJM Interconnection, LLC ("PJM") and ISO New England, Inc. I also prepare and present expert testimony regarding these and other cost-of-service and ratemaking-related issues.

Q. What is your educational background?

A. I graduated from King's College in 1999 with a Bachelor of Science Degree in Finance, and from Moravian College in 2003 with a Master of Business Administration.

Q. Please describe your professional experience.

A. In 2000, I was employed by PPL Global Operations, Inc. ("PPL Global Operations"), where I supported the accounting and financial reporting activities for PPL Global Operations' domestic operations. In 2001, as a result of corporate realignment, I joined PPL Generation, LLC. In this position, my responsibilities included cost control, budgeting, reporting, and management of the forecasting process for large construction projects, as well as the administration of construction and financing contracts. In 2004, I rejoined PPL Global Operations as a Senior Business Analyst with responsibility for maintaining, analyzing, consolidating, and presenting business plans and operational performance results for PPL Global Operations' international affiliates. In 2007, I joined PPL Energy Services Group, LLC as a Business Analyst providing financial modeling and analytical support for evaluations of acquisition, development, and divestiture opportunities. In 2009, I joined PPL Electric as a Project Controls Specialist providing advanced cost analysis for distribution and transmission projects. Later in 2009, I became the Financial Business Planning Specialist in the Regulatory Compliance Department. In August 2012, I was named Manager - Regulatory Compliance for PPL

Electric, and in October 2015, I was named Manager - Regulatory Operations, which included overseeing scheduling and settlement functions with PJM. During my time in this role, I also took responsibility for load and revenue forecasting and reporting as well as energy and utility policy, and company strategy. In September 2020, I was named Director - Regulatory Affairs. In December 2021, my role was transferred to PPL Services Corporation. In June 2023, I was promoted to Senior Director -– Regulatory for PPL Services Corporation.

Q. Have you previously testified as a witness in other Commission proceedings or any other jurisdiction's proceedings?

A. Yes, I have testified before this Commission in several proceedings. A list of the matters in which I have testified is attached as Appendix A.

Q. What is the purpose of your testimony?

A. I will provide an overview of the Company's revenue requirement increase proposed in this proceeding, the cost of service study utilized to allocate that increase to the customer classes, and PPL Electric's proposed design of distribution rates to recover that allocated revenue increase.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring Schedule D-6 in Exhibits Fully Projected Future 1, Future 1, and Historic 1 and portions of Parts I and II of the filing requirements as noted on their indexes.

II. OVERVIEW OF REVENUE REQUIREMENT, COST OF SERVICE, AND RATE DESIGN

Q. Could you please provide an overview of the Company's proposed revenue requirement increase?

A. PPL Electric proposes an increase in distribution base operating revenues of approximately $356 million, as set forth in the direct testimony of Christine Martin (PPL Electric St. No. 1) and Dan Dane (PPL Electric St. No. 6). To help derive this proposed increase in the Company's revenue requirement, PPL Electric retained Concentric Energy Advisors, Inc. ("Concentric"). Under my direction and supervision, PPL Electric's business units provided the necessary data for Concentric to develop the revenue requirement model and calculate the proposed increase of approximately $356 million. Based on my review, the revenue requirement schedules reflect and incorporate the Company's financial data and projections.

Q. Would you please provide an overview of the allocated cost of service study ("ACOSS") utilized by the Company in this proceeding?

A. Bickey Rimal from Concentric was tasked with preparing the ACOSS for this proceeding, which is utilized to allocate the Company's overall cost of service to each rate class in a manner that reflects the class's underlying cost of service. As explained in his direct testimony (PPL Electric St. No. 7), Mr. Rimal used the Concentric Cost of Service Model ("Concentric Model") to prepare the ACOSS based upon data provided by PPL Electric for the Fully Projected Future Test Year ("FPFTY") ending June 30, 2027, including the number of customers, sales, revenues by rate class, rate base items, operations and maintenance ("O&M") expenses, and taxes. As Mr. Rimal explains, those costs were then functionalized, classified, and allocated to each rate class.

The following Table 1 from Mr. Rimal's direct testimony summarizes the results of the ACOSS, particularly the return at current rates and relative rate of return:

Table 1: Rate of Return at Current Rates

Rate Class	Rate Code	Return at Current Rates	Relative Rate of Return
Residential	RS	4.32%	1.0
Residential-Thermal Storage	RTS	2.27%	0.5
Small General Service - Sec. Voltage	GS-1	4.03%	0.9
Large General Service - Sec. Voltage	GS-3	5.31%	1.2
Large General Service - 12 KV	LP-4	3.53%	0.8
Large General Service - 69 KV or Higher	LP-5	24.01%	5.4
Separate Meter General Space Heating Service	GH-2	4.50%	1.0
Street Lighting/Area Lighting	SL/AL	5.89%	1.3
Total System		**4.43%**	**1.0**

He then relies on these results to develop the proposed revenue allocation for each rate class, noting the goal to move all rate classes to their cost of service while taking into consideration other factors such as affordability and gradualism. In the following table, Mr. Rimal summarizes the revenues at present rates, revenues based on the ACOSS, and the proposed mitigated revenue requirement by rate class.

Table 2: Revenues at Present and Proposed Rates

Rate Class	Rate Code	Revenue at Current Rates	Revenue Requirement based on ACOSS	Mitigated Revenue Requirement	ACOSS Increase (%)	Mitigated Increase (%)
Residential	RS	$718,787,174	$969,168,276	$972,760,160	34.83%	35.33%
Residential-Thermal Storage	RTS	$7,930,469	$13,351,425	$12,071,032	68.36%	52.21%
Small General Service - Sec. Voltage	GS-1	$78,435,579	$107,441,939	$107,788,638	36.98%	37.42%
Large General Service - Sec. Voltage	GS-3	$128,618,149	$169,637,439	$170,381,820	31.89%	32.47%
Large General Service - 12 KV	LP-4	$38,791,942	$63,254,109	$59,045,537	63.06%	52.21%

Large General Service - 69 KV or Higher	LP-5	$1,940,349	$1,325,612	$1,940,349	-31.68%	0.00%
Separate Meter General Space Heating Service	GH-2	$1,301,175	$1,771,840	$1,777,874	36.17%	36.64%
Street Lighting/Area Lighting	SL/AL	$24,366,203	$30,491,845	$30,677,073	25.14%	25.90%
Total System		$1,000,171,041	$1,356,442,484	$1,356,442,484	35.62%	35.62%

Q. Could you please summarize the Company's proposed rate design in this proceeding?

A. The proposed rate design is addressed in detail in Steven Wishart's direct testimony (PPL Electric St. No. 8). As an overview, the Company proposes an increase in Rate Schedule RS's monthly fixed customer charge from $15.58 to $17.00 as well as an increase in Rate Schedule GS-1's monthly fixed customer charge from $22.00 to $30.00. I note that Rate Schedule RS's currently monthly fixed charged of $15.58 includes the Smart Meter Rider 2 ("SMR-2") and the Competitive Enhancement Rider ("CER") that PPL Electric proposes to eliminate as part of this case. I also note that the ACOSS would support increases in these monthly fixed customer charges to $42.96 and $43.05, respectively, given the fixed costs incurred by the Company to provide service to customers in these rate classes. For these reasons, and as further discussed in Mr. Wishart's direct testimony, the Commission should approve the Company's proposed rate design, including the requested increases in the Rate Schedule RS and Rate Schedule GS-1 monthly fixed customer charges.

Q. Is the Company proposing the elimination or restriction of any currently existing Rate Schedules?

A. Yes. The Company is proposing the elimination of two Rate Schedules – Residential Thermal Storage (RTS) and General Space Heating Service (GH-2) which are sub schedules of the Company's Residential (RS) and General Service-1 (GS-1) Rate Schedules, respectively. Mr. Rimal's and Mr. Wishart's analysis indicated that the RTS and GH-2 customers are not aligned with their respective class cost of service allocations and to do so would require a significant increase in rates for both classes, which have few customers. Additionally, Rate Schedule RTS has been restricted since 1995, and Rate Schedule GH-2 has been restricted since 1972. The Company believes that the time is ripe to move all remaining customers in these Rate Schedules to Rate Schedules RS and GS-1, respectively. These proposals are further discussed in the direct testimony of Steven Wishart (PPL Electric St. No. 8) and Gregory Olsen (PPL Electric St. No. 14).

Q. Based on your extensive background and experience with the Company, do you agree with the proposals set forth by Concentric in this case?

A. Yes, I believe that the proposals are reasonable. Concentric has worked closely with PPL Electric in development of the revenue requirement, cost of service, and rate design results. I have reviewed the analyses and support the recommendations, as I believe they align with the Company's position regarding balancing the need for investment, customer affordability, and fairness across customer class with deference to the

Commonwealth Court's decision in *Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006).

Q. Please describe Schedules D-6 in Exhibits Fully Projected Future 1, Future 1, and Historic 1.

A. Schedule D-6 in each of these exhibits provides the Company's claim for rate case expenses, which includes expert witnesses and costs related to rate case preparation. The estimated expenses are adjusted for what has been included in the Company's business plan for each respective period, resulting in the Company's rate case expense claim.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

As an employee of PPL Electric, PPL EU Services, or PPL Services Ms. Johnson has offered expert testimony in the following electric utility proceedings before state PUCs.

Rhode Island PUC:

1. Docket No. D-21-29 – Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holding, LLC and Related Approvals

2. Docket No. 22-49-EL - The Narragansett Electric Company d/b/a Rhode Island Energy's Advanced Metering Functionality Case

Pennsylvania PUC:

1. Docket No. M-2012-2312472 – PPL Electric Utilities Corporation Final Generation Supply Charge-1 Reconciliation Report for the 12 Month Period May 1, 2011 through April 30, 2012

2. Docket No. C-2013-2367475 – Office of Small Business Advocate v. PPL Electric Utilities Corporation

3. Docket No. P-2013-2325034 – Petition of PPL Electric Utilities Corporation for Approval of a Distribution System Improvement Charge

4. Docket Nos. M-2010-2213754, et al. – PPL Electric Utilities Corporation Proposed Transmission Service Charge for the Twelve Months ending November 30, 2010

5. Docket No. P-2014-2417097 – Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period

6. Docket Nos. C-2013-2398440, et al. – PP&L Industrial Customer Alliance v. PPL Electric Utilities Corporation

7. Docket Nos. P-2014-2437081, et al. – Petition of PPL Electric Utilities Corporation for approval to Modify its Smart Meter Technology Procurement and Installation Plan and to Extend its Grace Period

8. Docket No. C-2014-2418167 – Loren J. Hulber v. PPL Electric Utilities Corporation

9. Docket Nos. R-2015-2469275, et al. – Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation

10. Docket No. M-2015-2515642 – Petition of PPL Electric Utilities for Approval of its Act 129 Phase III Energy Efficiency and Conservation Plan

11. Docket No. F-2016-2569470 – Stephen Kozeracki v. PPL Electric Utilities Corporation
12. Docket No. P-2019-3010128 – Petition of PPL Electric Utilities Corporation for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan
13. Docket No. C-2023-3042130 – Ed Frey v. PPL Electric Utilities Corporation
14. Docket Nos. P-2024-3048732, et al. – Petition of PPL Electric Utilities Corporation for a Waiver of the Distribution System Improvement Charge Cap of 5% of Billed Revenues
15. Docket No. P-2024-3049223 – Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 6

Direct Testimony of Daniel S. Dane

Topics:	**Revenue Adjustments**
	Rate Base Adjustments
	Expense Adjustments
	Revenue Requirement

Dated: September 30, 2025

I. INTRODUCTION

Q. Mr. Dane, please state your full name and business address.

A. My name is Daniel S. Dane. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

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

A. I am the President of Concentric Energy Advisors, Inc. ("Concentric").

Q. Please describe Concentric and your principal responsibilities in your position.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. As President of Concentric, my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory, financial, and accounting related issues.

Q. Please describe your educational background and business experience.

A. I have a Master of Business Administration degree from Boston College and a Bachelor of Arts degree in Economics from Colgate University. I am also a certified public accountant. My curriculum vitae is included as Appendix A to this pre-filed direct testimony.

Q. Have you previously testified as a witness on ratemaking-related issues?

A. Yes. My testimony listing is included as Appendix B to this pre-filed direct testimony.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony supports the Company's request for an increase in base rates for electric distribution service provided by PPL Electric Utilities Corporation ("PPL Electric"), a subsidiary of PPL Corporation, as calculated in the accompanying revenue requirement model, Exhibit D, and as set forth in the Company's Exhibit Historic 1, Exhibit Future 1, and Exhibit Fully Projected Future 1. In particular, my testimony explains the development of the Company's Pennsylvania-jurisdictional revenue requirement for the Fully Projected Future Test Year ("FPFTY") ending June 30, 2027, in accordance with the Pennsylvania Public Utility Code (66 Pa. C.S. §§ 1301 et seq.) and the regulations and policies of the Pennsylvania Public Utility Commission ("PUC" or the "Commission").

Q. How is your testimony organized?

A. Section I of this testimony provides an introduction and background information. Section II summarizes the purpose of my testimony. Section III discusses the test year period used to calculate the proposed revenue requirement. Section IV summarizes the Company's revenue requirement. Section V provides a detailed description of the computation of the revenue requirement and explains the determination of rate base. Section VI discusses the breakdown of revenues and operating expenses included in and excluded from the calculations, as well as the adjustments made to such revenues and operating expenses.

Section VII addresses compliance and regulatory considerations including the treatment of riders and surcharges within the revenue requirement. Section VIII is the conclusion.

Q. Are you sponsoring any exhibits in conjunction with your testimony?

A. Yes. I am sponsoring PPL Electric Exhibit DSD-1 for the Historic Test Year ("HTY") and Future Test Year ("FTY"), and FPFTY. I am also co-sponsoring Schedules D-4 through D-19 in Exhibit Historic 1, Exhibit Future 1, and Exhibit Fully Projected Future 1.

III. TEST YEAR

Q. What is the test year used to calculate the proposed revenue requirement?

A. The FPFTY used to calculate the proposed revenue requirement is the 12-month period ending June 30, 2027. The analysis reflects the Company's expected financial and operational conditions during that time. The test year was selected in accordance with Act 11 of 2012 and Act 40 of 2017, to align rates with anticipated future expenses and investments. Exhibits for the HTY, FTY, and FPFTY have been prepared using the same format and methodology. When referring to the exhibits, my testimony will focus on the FPFTY.

IV. SUMMARY OF REVENUE REQUIREMENT

Q. What is the basis for the Company's proposed revenue requirement?

A. The Company's filing is based on the cost of providing safe and reliable electric distribution service to Pennsylvania customers, excluding transmission and non-jurisdictional activities. The revenue requirement presents pro forma revenue, expense and rate base data for the HTY ended June 30, 2025, the FTY ended June 30, 2026, and the FPFTY ended June 30, 2027. Data for the HTY was obtained from the Company's books and records. The FTY and FPFTY reflect the Company's budgeted operating income and expenses, adjusted to reflect the conditions anticipated in those periods. The Company's rate base includes the estimated net utility plant in service as of June 30, 2027.

Q. Please describe the methodology used to calculate the revenue requirement.

A. The revenue requirement reflects the Company's reasonable costs of providing distribution services, including a fair and reasonable return on investment in distribution infrastructure to provide that service. Costs that are recovered through continuing automatic adjustment clause mechanisms and existing non-base rate charges for distribution service and transmission service are excluded from the revenue requirement, while the costs recovered under other automatic adjustment clause mechanisms are being rolled into base rates as explained by PPL Electric witness Katelyn Arnold (PPL Electric St. No. 13).

To present a distribution-only revenue requirement, all transmission plant, expenses, and revenues, as well as costs and revenues associated with existing non-base rate charges, are removed from the revenue requirement, per PUC requirements. PPL Electric Exhibit DSD-1 shows the removal of transmission related rate base, revenues, and expenses from "Total T&D Operations" of Schedule C-1 and the "T&D Pro Forma at Presents Rates" (column 5) of Schedule D-1 and reflect the roll-in of certain automatic adjustment clause mechanisms into base rates in the FPFTY. Costs are assigned to the correct function and class using business units and FERC accounts. The rate base for the FPFTY is developed by quantifying gross distribution plant expected to be in service as of

June 30, 2027, and associated accumulated depreciation. Adjustments are then made for working capital determined through a lead-lag study (see the direct testimony of Katelyn Arnold (PPL Electric St. No. 13)), accumulated deferred income taxes ("ADIT"), contributions in aid of construction ("CIAC"), customer advances, and customer deposits. The weighted average cost-of-capital ("WACC") using the Company's actual capital structure is applied to the resulting rate base to determine a fair return for investors.

Next, the operating revenues at current rates are adjusted for normalization and unbilled revenue. Operating expenses are normalized and adjusted for known and measurable changes. Depreciation and amortization are calculated on the projected plant balances using the depreciation rates as determined in a depreciation study (see the direct testimony of PPL Electric witness John Spanos (PPL Electric St. No. 11)). Lastly, income taxes are determined by using a blended Pennsylvania corporate tax rate (to account for the Pennsylvania corporate income tax phase down) and the federal rate after accounting for normalization, flow through adjustments, and deferred taxes. Income tax expense is then adjusted for excess deferred tax amortizations and investment tax credits amortizations (see the direct testimony of PPL Electric witness Andrew Elmore (PPL Electric St. No. 12)).

Analysis of the above inputs results in the revenue requirement needed to provide distribution service, including a fair and reasonable return on investment in distribution infrastructure to provide that service.

Q. Does the cost of service include costs incurred by PPL Corporation or its affiliates, on behalf of the Company?

A. Yes. PPL Corporation provides administrative functions through its service company subsidiary (i.e., PPL Services Corporation ("PPL Services")), which are allocated to PPL Electric based on the methods, allocations and requirements detailed in the PPL Corporation's Cost Allocation Manual (II-D-8). The cost of service for PPL Electric includes two types of affiliate charges from affiliates: (1) "direct charges" that are billed for costs incurred and work performed by personnel directly related to the Company; and (2) "common costs" that are allocated among the respective subsidiaries benefitting from the service based on the methods, allocations, and requirements detailed in the PPL's Cost Allocation Manual (II-D-8). Therefore, where applicable, costs incurred on behalf of, or allocated to, the Company are included in the HTY, FTY and FPFTY, as adjusted pursuant to the discussion in the direct testimony of PPL Electric witness Dennis Urban (PPL Electric St. No. 2).

Q. How are the costs that PPL Services and other affiliates incurred to perform services for PPL Electric reflected in the Company's cost of service calculations?

A. Those costs are incorporated into the rate base and operations and maintenance ("O&M") expense or other expense categories included in the test year's cost of service. In addition, the Company has included applicable charges from affiliates in the individual normalizing and known and measurable adjustments to the cost of service, to the extent that those adjustments also represent normalizing or known and measurable changes to the HTY, FTY and FPFTY cost of service.

Q. What evidence has the Company provided in this filing to demonstrate that the revenue requirement reflects the cost of serving customers, including capital costs, appropriate staffing levels, and prudent and efficient management?

A. As outlined herein and throughout the direct testimony accompanying the Company's rate case filing, PPL Electric's proposed increase in its operating revenues is necessary to provide the Company with a fair opportunity to earn a just and reasonable return of and on its investments to provide electric distribution service. In particular, the Company has provided evidence regarding the appropriateness and reasonableness of its budgeting process, the Company's policies to achieve cost efficiencies, the steps taken to ensure its staffing levels are appropriate and its compensation is market-based, the Company's approach to achieving operational effectiveness, and that the costs the Company bears are necessary for the provision of safe and reliable electric distribution service to customers. Further discussion on the Company's capital and O&M budgeting process can be found in the direct testimony of PPL Electric witness Dennis Urban (PPL Electric St. No. 2).

Q. What is the Company's proposed cost of service?

A. The Company's proposed operating revenues, including other operating revenues, to recover its cost of service is $1,422,171,692 (Schedule D-1, Column 8, Line 1 in Exhibit Fully Projected Future 1) including a weighted cost of capital of 8.56 percent on rate base of $5,817,887,791, as presented in Schedule C-1 of Exhibit Fully Projected Future 1.[1]

[1] There are negligible rounding differences between the FPFTY values in the revenue requirement model and the FPFTY values in the Allocated Cost of Service Study ("ACOSS") model.

Q. Are the proposed distribution rates designed to recover the Company's revenue requirement?

A. Yes. The Company's proposed distribution rates are designed to recover the Company's FPFTY revenue requirement, net of other operating revenue. A summary of the revenue requirement is provided on Schedule D-1 of Exhibit Fully Projected Future 1. This schedule reflects the required increase of distribution revenue, as well as the proposed rolling into base rates of the Competitive Enhancement Rider ("CER"), the Distribution System Improvement Charge ("DSIC"), the Tax Cuts and Jobs Act Temporary Surcharge ("TCJA"), and the Smart Meter Rider ("SMR") as well as amortization of excess ADIT. The budgeted operating revenue for PPL Electric, net of other operating revenues, before the reflection of the required increase, is $1,005,771,603, as shown on Schedule D-3, Line 6. The base revenue increase required is $356,271,009, as shown on Schedule D-1, Line 1. Thus, the total revenue requirement to be recovered through distribution rates (excluding other operating revenues) is $1,362,042,612, which includes revenues currently being recovered through riders of $53,469,710, for a net customer increase of $302,801,299.

Q. What is the proposed revenue deficiency in this proceeding?

A. Revenue deficiency is the shortfall between the amount of revenue a company currently collects through its rates and the amount it needs to recover its full cost of service, including operating expenses, capital costs, and a reasonable return. The proposed revenue deficiency in this proceeding is the difference between the current base revenue and the revenue requirement calculated by the Company, as summarized in Schedule D-1 of Exhibit Fully

Projected Future 1. The Company is seeking to address a revenue deficiency of $356,271,009 over the level of base revenue generated at current base distribution rates.

Q. Please summarize the other aspects of the Company's proposal.

A. Items that have been recovered through recovery mechanisms outside of base rates are excluded from the Company's HTY and FTY. Those items include the Act 129 Compliance Rider ("ACR"), the CER, the DSIC, Generation Service Charge ("GSC"), Merchant Function Charge ("MFC"), Purchase of Receivables ("POR"), the SMR, State Tax Adjustment Surcharge ("STAS"), Storm Damage Expense Rider ("SDER"), the TCJA, Transmission Service Charge ("TSC"), and Universal Service Rider ("USR"). The adjustment mechanisms for these items will continue to be utilized to recover the designated costs on a current, reconciling basis during the FPFTY, apart from the CER, SMR and TCJA, which the Company is proposing to include in base rates as discussed in the direct testimony of PPL Electric witness Katelyn Arnold (PPL Electric St. No. 13). For the recovery mechanisms that are proposed to be rolled into base rates, the expenses are included in the calculation of operating income at present rates, and any related plant-in-service is included in rate base for the FPFTY. In accordance with statutory requirements, DSIC expenses are factored into the calculation of operating income at present rates, and the corresponding plant-in-service is incorporated into the rate base. Amounts currently recovered under the DSIC mechanism are included in the revenue deficiency in base rates. As of the effective date of new base rates established in this proceeding, the DSIC will be reset to zero.

The Company's revenue requirement is allocated among the rate classes based on the results of an allocated cost of service study ("ACOSS") and other considerations. The proposed distribution rates are designed to collect the proposed amount from each rate class based on test year billing units – such as the number of bills, kilowatts, billing demand, among others – as supported by the direct testimony of PPL Electric witness Bickey Rimal (PPL Electric St. No. 7).

V. COST OF SERVICE AND RATE BASE

Q. Have you prepared an exhibit to support your revenue requirement calculations?

A. Yes. The revenue requirement is supported by a cost-of-service analysis contained in Section D of Exhibit Fully Projected Future 1. This section of the exhibit includes supporting schedules for each component, including the normalizing and known and measurable adjustments to test year data.

Q. Please describe the organization of the supporting schedules contained within Section D.

A. Section D is organized in a series of schedules as follows:

Schedule D-1 – Operating Income Pro Forma at Present and Proposed Rates

Schedule D-2 – Adjustments to Income

Schedule D-3 – Adjustments to Operating Revenue

Schedule D-4 – Adjustment to Operating Revenues for Unbilled Revenue

Schedule D-5 – Adjustment to Wages and Benefits

Schedule D-6 – Adjustment for Rate Case Expense

Schedule D-7 – Adjustment for Economic Development Proposal

Schedule D-8 – Adjustment for Competitive Enhancement Rider Roll-in to Base Rates

Schedule D-9 – Adjustment for Deferred Storm Outage Costs

Schedule D-10 – Adjustment for Deferred IIJA-Related Incremental Expenditures

Schedule D-11 – Adjustment for Universal Service Rider (USR) Salaries

Schedule D-12 – Adjustment for Interest Expense on Customer Security Deposits

Schedule D-13 – Adjustment for Company Use Generation Supply Purchases

Schedule D-14 – Adjustment for Certain IT Expenditures Requested to Be Treated as Capital

Schedule D-15 – Adjustment to Annual Depreciation Expense

Schedule D-16 – Adjustment to Taxes Other Than Income Taxes

Schedule D-17 – Computation of Income Taxes

Schedule D-18 – Adjustment to Deferred Income Taxes

Schedule D-19 – Adjustment to Amortization of Deferred Investment Tax Credit

Q. Please describe Schedule D-1 "Operating Income Pro Forma at Present and Proposed Rates."

A. Schedule D-1 provides the computation of the revenue requirement for the FPFTY at present and proposed rates. The total amount per books in column (1) is determined by the total transmission and distribution budget for the 12 months ending June 30, 2027, including riders. Column (2) shows the adjustment to the budget to eliminate specified riders. All related expenses that will continue to be recovered through riders, and not rolled into base rates, along with the corresponding operating revenues are removed in column (2), to develop a transmission and distribution operating income schedule, net of riders shown in column (3). The Company then adjusts for pro forma adjustments in column (4) to reflect the normalization of income and the impacts of known and measurable changes for transmission and distribution expenses to arrive at an adjusted transmission and distribution operating income at present rates in column (5). Column (6) presents only the distribution portion of the operating income regulated by the PUC. See PPL Electric Exhibit DSD-1 for the determination of the PUC jurisdictional pro forma revenue at current rates. Column (7) shows the projected revenue deficiency and corresponding increases in O&M expenses, taxes other than income taxes ("TOTI"), and income taxes that will result with the rate increase. The result in Column (8) of that schedule provides the operating income calculation at proposed rates.

As shown on Schedule D-1, the resulting operating revenue deficiency is $356,271,009. The operating revenue deficiency was computed by comparing the earned rate of return of 4.43 percent at current rates to the required rate of return of 8.56 percent and multiplying that difference by the rate base and grossing up that product for income taxes, gross receipts taxes, regulatory commission fees, and uncollectible accounts expense.

Q. Please explain Schedule D-2 "Adjustments to Income."

A. This schedule shows a summary of all the pro forma adjustments related to revenues, expenses, and taxes claimed by the Company. Further detail for each of these adjustments is found in Schedules D-3, Adjustments to Operating Revenue, and D-4, Adjustment for Unbilled Revenue.

Q. Please explain Schedule D-5 "Adjustment to Wages and Benefits."

A. The number of employees that PPL Electric employs can vary throughout any given year. This, in turn, impacts the wages and benefits incurred or projected for that period. Schedule D-5 annualizes transmission and distribution wages, payroll taxes, and benefits based on the number of T&D-related employees to be employed at the end of the test year, and the corresponding average monthly T&D-related wages per employee. The distribution segment receives an allocation of 91.63 percent of labor costs as determined by the allocated cost of service study (see direct testimony of PPL Electric witness Bickey Rimal (PPL Electric St. No. 7).

Q. Please explain Schedule D-6 "Adjustment for Rate Case Expense."

A. The Company has submitted Schedule D-6 to reflect the adjustment needed for expenses related to the filing of the distribution rate case. The adjustment shows the total rate case expense normalized over three years and offset by the amounts included in the budget.

Q. Please explain Schedule D-7 "Adjustment for Economic Development Proposal."

A. The adjustment on Schedule D-7 is made to reflect the expenses associated with the Economic Development Proposal discussed in the direct testimony of PPL Electric witness Jason Hunt (PPL Electric St. No. 21).

Q. Please explain Schedule D-8 "Adjustment for Competitive Enhancement Rider Roll-In to Base Rates."

A. The adjustment on Schedule D-8 is made to reflect the expenses associated with the Company's proposal to eliminate the Competitive Enhancement Charge and recover the expenses through base rates as discussed in the direct testimony of PPL Electric witness Katelyn Arnold (PPL Electric St. No. 13).

Q. Please explain Schedule D-9 "Adjustment for Storm Costs."

A. The adjustment on Schedule D-9 is made to adjust for the amortization of the regulatory asset for storm damage expense incurred over the maximum amount permitted to be recovered through the SDER as discussed in the direct testimony of PPL Electric witness Katelyn Arnold (PPL Electric St. No. 13).

Q. Please explain Schedule D-10 "Adjustment for Deferred IIJA-Related Incremental Expenditures."

A. The adjustment on Schedule D-10 is made to adjust for the amortization of the regulatory asset for incremental expenditures incurred to prepare, apply, administer, and otherwise execute on Infrastructure Investment and Jobs Act ("IIJA") funding opportunities. For additional information on this adjustment, please see the direct testimony of PPL Electric witness Sharon Leskowsky (PPL Electric St. No. 22).

Q. Please explain Schedule D-11 "Adjustment for Universal Service Rider Salaries."

A. The adjustment on Schedule D-11 is made to reflect the removal of salaries from distribution base rates. USR salaries are proposed to be recovered through the USR as discussed in the direct testimony of PPL Electric witness Lisa Norden (PPL Electric St. No. 18).

Q. Please explain Schedule D-12 "Adjustment for Interest Expense on Customer Deposits."

A. The adjustment on Schedules D-12 shows the adjustment for interest related to customer deposits for projects. For additional information on this adjustment, please see the direct testimony of PPL Electric witness Sharon Leskowsky (PPL Electric St. No. 22).

Q. Please explain Schedule D-13 "Adjustment for Company Use Generation Supply Purchases."

A. Beginning in 2011, PPL Electric began shopping for and purchasing its generation supply service from alternative energy suppliers for the facilities it owns, *i.e.*, offices, service centers, crew quarters, warehouses, etc. This schedule calculates the distribution operating expense for that portion of the generation supply costs that PPL Electric is expected to incur for its own use in the normal course of business.

Q. Please explain Schedule D-14 "Adjustment for Capital Treatment of Certain IT Expenditures."

A. PPL Electric is requesting capital treatment of certain information technology costs. For further discussion of this proposal, please see the direct testimony of Christopher Garrett (PPL Electric St. No. 3), and for additional information on this adjustment, please see the direct testimony of PPL Electric witness Sharon Leskowsky (PPL Electric St. No. 22).

Q. Please explain Schedule D-15 "Adjustment to Annual Depreciation Expense."

A. The Company engaged Gannett Flemming to perform a depreciation analysis, as discussed in the direct testimony of John J. Spanos (PPL Electric St. No. 11). The known and measurable adjustment to depreciation expense reflects the application of depreciation rates determined in the depreciation study to the utility plant in service balances at the end of the FPFTY. For additional information on this adjustment, please see the direct testimony of PPL Electric witness Sharon Leskowsky (PPL Electric St. No. 22).

Q. Please explain Schedule D-16 "Adjustment to Taxes Other Than Income Taxes."

A. The Company adjusted TOTI for known and measurable changes based on pro forma adjustments to the Pennsylvania Gross Receipts Tax ("GRT") and the Public Utility Realty Tax ("PURTA"). The GRT is calculated on tariff revenue including late charges with an adjustment for bad debts. PURTA is calculated on the taxable value of utility real property and is determined by the Commonwealth.

Q. Please explain Schedule D-17 "Computation of Income Taxes."

A. Schedule D-17 shows the Company's requested additional operating revenue from the proposed rate increase as well as an increase in uncollectible accounts, commission fees, and applicable GRT and income taxes related to the proposed rate increase. See the direct testimony of Andrew Elmore (PPL Electric St. No. 12) for a full discussion of income tax calculations in this application.

Q. Please explain Schedule D-18 "Adjustment to Deferred Income Taxes."

A. Schedule D-18 shows the adjustment for the annual provision of deferred income taxes due to accelerated depreciation and plant related basis adjustments.

Q. Please explain Schedule D-19 "Adjustment for Amortization of Deferred Investment Tax Credit."

A. The Company has chosen Option 2, the Cost-of-Service Reduction Method, to provide customers with the direct benefit of investment tax credits in the form of reduced tax expense in the cost of service. This schedule adjusts for the amortization of investment tax credits over the related asset's book life. Under this method, unamortized investment tax credits do not reduce rate base.

Q. How did the Company compute the rate base?

A. The Company's rate base calculation is provided in Schedule C-1. The Company computed its rate base in this proceeding using the balance at the end of the HTY, June 30, 2025, adjusted for certain items, including additions to and retirements from utility plant (and associated accumulated depreciation and ADIT) relating to estimated plant in service additions through the end of the FPFTY, June 30, 2027, as discussed below.

The rate base amount includes utility plant in service, plus materials and supplies, and a cash working capital allowance. Deductions from rate base include accumulated depreciation, an ADIT liability, an income tax (i.e., “FAS109”) regulatory liability, CIAC, customer advances, and customer deposits.

Q. Please discuss the computation of utility plant in service and other assets that are included in rate base.

A. Utility plant in service includes the Company’s distribution property in-service, and an allocation of general and intangible plant that supports the distribution segment, as of the end of the HTY, the FTY and the FPFTY. Plant balances in the FTY and FPFTY include estimated plant additions (adjusted for retirements). The Company has excluded $10,170,680,090 of transmission property in-service which includes an allocation of general and intangible plant that supports the transmission segment as shown in PPL Electric Exhibit DSD-1, p. 5, Line 1.

Q. Please discuss the reflection of FTY and FPFTY plant additions in rate base.

A. The Company reflected estimated distribution plant additions and retirements for the FTY and FPFTY in its FPFTY rate base. The impacts of the plant additions and retirements have been reflected in the calculations of accumulated depreciation and ADIT.

Q. What adjustments did the Company make to the FPFTY utility plant in service to which depreciation rates were applied?

A. The Company adjusted utility plant in service by $25,879,855 to reflect the capital treatment of certain investments in information technology, which I mentioned previously.

Q. Please discuss the other materials and supplies balance in rate base.

A. The balance of other materials and supplies is the cost of inventory used in providing service. Rate base reflects the Company's HTY 13-month average of materials and supplies.

Q. What is the cash working capital allowance?

A. The cash working capital allowance of $16,775,207 was developed through a lead-lag study. This study is discussed in more detail in the direct testimony of Katelyn Arnold (PPL Electric St. No. 13).

Q. What are ADIT liability balances?

A. ADIT represents timing differences that arise between when items are recognized for financial accounting purposes and when they are recognized for tax purposes. Because the Company calculates income tax expenses for ratemaking purposes using financial accounting taxable income and statutory tax rates, PPL Electric recognizes those "book/tax" timing differences in rate base. The primary contributor to those timing differences is depreciation expense, which generally is recognized on an accelerated basis for tax purposes as compared to its recognition for financial accounting purposes, resulting in an ADIT liability that reduces rate base.

Q. What normalizing adjustments did the Company make to ADIT?

A. ADIT was adjusted to reflect the proration of the accumulation of deferred income taxes over the FPFTY, pursuant to IRS normalization requirements. Furthermore, adjustments were made to increase ADIT by the balance in the reserve for uncertain tax positions ("UTP") associated with the book/tax timing differences.

Q. What known and measurable adjustment was made to ADIT?

A. As discussed above, ADIT was adjusted to reflect additional deferred taxes arising from differences in book and tax depreciation for FTY and FPFTY plant additions.

Q. Please discuss CIACs and customer advances.

A. The Company did not have any CIACs or customer advances as of the end of the HTY, therefore there is no reduction to rate base.

Q. Please discuss customer deposits.

A. Customer deposits at the end of the HTY of $6,553,654 are included as a deduction to rate base. Interest credited to customers is included as an operating expense in the computation of the revenue requirement.

VI. REVENUES AND OPERATING EXPENSES

Q. What schedule provides the calculations related to operating revenues?

A. Schedules D-3 and D-4 summarize the FPFTY revenues including adjustments for other normalizing items related to operating revenue and the removal of unbilled revenues.

Q. Please summarize the adjustments to revenue.

A. The Company adjusted book revenue to remove revenue from rider mechanisms from the HTY, FTY, and FPFTY. Further adjustments were made to remove transmission revenue in the HTY, FTY and FPFTY. Lastly, the Company made normalization and annualization adjustments to revenue and removed unbilled revenue to develop the FPFTY operating revenue used to calculate the revenue deficiency. Further discussion of the normalization and annualization adjustments is in the direct testimony of Charles R. Schram (PPL Electric St. No. 4). Unbilled revenue is removed to ensure only revenue billed is included in the analysis.

Q. Were adjustments made to Other Operating Revenue?

A. Yes. Other operating revenue was adjusted to remove other income related to riders and rent and other income related to the transmission segment.

Q. Please provide an overview of the cost-of-service calculations related to expenses.

A. The cost-of-service calculations related to expenses began with the expenses budgeted for the FPFTY. The Company made adjustments to remove expenses related to rider mechanisms in the HTY and FTY. Further adjustments were made to remove expenses that support the transmission segment from HTY, FTY, and FPFTY. For the FPFTY, rider expenses were removed for riders that will not be recovered in base rates as previously described. Lastly, the Company made known and measurable adjustments to expenses. These adjustments are presented in Schedules D-5 through D-19 as previously described.

Q. What adjustments did the Company make to the FPFTY expenses as a result of the capital treatment of certain investments in information technology?

A. The Company currently records these investments as a regulatory asset that is amortized into O&M expense. To reflect the capital treatment, as proposed in this filing, the Company has reclassified the amortization expense from O&M to depreciation expense. A complete description of this investment is in the direct testimony of Christopher Garrett (PPL Electric St. No. 3).

Q. Please summarize the impact of the known and measurable expense adjustments proposed by the Companies.

A. The adjustment to remove expenses related to cost recovery riders that will remain outside of base rates resulted in a decrease of $1,390,478,283. Other known and measurable adjustments presented in Section D supporting schedules increased adjusted FPFTY operating revenues by $4,723,116 and increased operating expenses by $28,602,000, which net to a $23,878,884 decrease in operating income as shown on Schedule D-2 After these adjustments, $977,436,587 of revenue and $419,635,986 expenses were allocated to the transmission segment as shown on PPL Electric Exhibit DSD-1, thereby decreasing operating income by expenses requested for recovery in this proceeding.

Q. Are there any expenses that the Company is not seeking to recover and are therefore excluded from operating expenses?

A. Yes. The Company does not seek to recover amounts paid for membership dues to social and service organizations, as well as lobbying expenses.

Q. What is the total level of FPFTY operating expenses in the revenue requirement?

A. The total FPFTY level of operating expenses included in the Company's revenue requirement is $808,452,014 at present rates, which is shown on Schedule D-1.

Q. What additional information did you use to compute the revenue increase?

A. In addition to the test year operating expenses, the computation of the revenue deficiency required analyses of rate base, return on rate base, and income tax expense.

Q. Please discuss the income tax calculation presented in Schedule D-17.

A. The income tax calculation involved five steps. First, the Company calculated pre-tax operating income before interest expense for the FPFTY by deducting adjusted FPFTY expenses from adjusted FPFTY revenues. Pre-tax operating income before interest expense under current rates totaled $275,520,023 for the Company. Second, the Company calculated synchronized interest expense by applying the Company's weighted average cost of debt to rate base. That resulted in synchronized interest expense of $129,738,898. Third, the Company deducted synchronized interest expense from pre-tax operating income before interest expense to calculate state pre-tax income of $145,781,125. Fourth, the Company adjusted for permanent temporary and flow through temporary differences to determine taxable income. Lastly, state and federal income tax expense were calculated by multiplying state pre-tax income by a blended statutory state income tax rate of approximately 7.17 percent for Pennsylvania, and the statutory income tax rate of 21.00 percent for federal income taxes. Further discussion of the tax adjustments made regarding the tax cost of service calculation can be found in the direct testimony of Andrew Elmore (PPL Electric St. No. 12). The resulting total state and federal income tax expenses for the distribution segment amounted to $18,071,354 for the FPFTY at present rates.

Q. Did you compute the return on rate base for revenue at current rates?

A. Yes. The return on rate base at current rates is 4.43 percent for the Company, as shown on Schedule C-1, Line 15 in Exhibit Fully Projected Future 1. Return on rate base equals after-tax net operating income divided by the rate base.

Q. What is the overall rate of return that the Company is requesting to include in the cost of service?

A. As shown on Schedule C-1, Line 17 in Exhibit Fully Projected Future 1, the proposed overall rate of return is 8.56 percent. This overall rate of return is presented in the direct testimony of PPL Electric witness Jennifer E. Nelson (PPL Electric St. No. 10) and is supported by the return on equity set forth in Ms. Nelson's direct testimony along with the cost of long-term debt and capital structure presented in the direct testimony of PPL Electric witness Julissa Burgos (PPL Electric St. No. 9).

Q. How did you compute the needed revenue increase?

A. The first step in computing the revenue increase needed, or revenue deficiency, is to compute the difference between the return on rate base for revenue at current rates, and the Company's cost of capital. The rate of return deficiency is 4.13 percent, which is calculated taking Schedule C-1, Line 17 less Line 15 in Exhibit Fully Projected Future 1. That difference is multiplied by the rate base to compute the net operating income ("NOI") deficiency.

The revenue increase required to produce the additional NOI of $240,562,527 is computed by grossing up the NOI deficiency to reflect income taxes, GRT, Commission expenses, and related uncollectible accounts expense on the additional revenue. The gross-up factor of 1.48 is computed to reflect an allowance for uncollectible accounts expense on the revenue deficiency, as well as income taxes, GRT, and Commission expenses. When multiplied by the NOI deficiency, the revenue deficiency, or required revenue increase, is computed to be $356,271,009.

VII. COMPLIANCE AND REGULATORY CONSIDERATIONS

Q. Are there any other matters that were considered when calculating the revenue requirement?

A. Yes. As part of this case, PPL Electric proposes to roll the following riders into base rates and eliminate or reset them as appropriate. This approach aligns with statutory requirements and regulatory precedents and ensures transparency and long-term rate stability.

Rider	Description
Competitive Enhancement Rider (CER)	Funded retail market enhancements and consumer education. Supported customer choice and competitive market participation. Proposal: Roll into base rates and eliminate the rider.
Distribution System Improvement Charge (DSIC)	Recovered costs for infrastructure improvements between rate cases. Enabled accelerated replacement of aging assets. Proposal: Roll into base rates and reset DSIC to zero, in compliance with Section 1307.
Tax Cuts and Jobs Act (TCJA) Rider	Passed through federal tax savings from the 2017 TCJA via a negative surcharge. Provided bill credits to customers; reconciled annually. Proposal: Roll into base rates and eliminate the rider, per PUC guidance.
Smart Meter Rider (SMR)	Recovers costs for smart meter deployment under Act 129. Funded infrastructure upgrades and customer interface improvements. Proposal: Roll into base rates and eliminate the rider.

Q. Does this conclude your direct testimony?

A. Yes, it does.

DANIEL S. DANE, CPA
PRESIDENT

Daniel S. Dane has more than 20 years of experience in the energy, utility, and financial services industries advising electric, gas, and water utilities, power generators, and natural gas pipelines in the areas of regulation and ratemaking, litigation, mergers and acquisitions, valuation, and regulatory accounting matters. Mr. Dane also provides expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on multi-year rate plans and earnings sharing mechanisms, corporate finance matters such as the cost of capital and capitalization, merger impacts, revenue requirements, lead-lag studies/cash working capital, and regulatory policy. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is also a certified public accountant.

- **REPRESENTATIVE PROJECT EXPERIENCE**

Ratemaking and Utility Regulation Assignments

Expert Testimony

Submitted expert testimony on behalf of utilities and other stakeholders in state and provincial administrative rate setting and merger approval proceedings regarding multi-year rate plans and earnings sharing mechanisms, corporate finance matters such as the cost of capital and capitalization, valuation of energy and utility assets, merger impacts, revenue requirements, lead-lag studies/cash working capital, and regulatory policy.

Regulatory Advisory

Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: performance-based ratemaking; cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; securitization and ratemaking policy.

Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.

Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation, natural gas pipeline facilities, and water/wastewater utilities.

- Regulatory policy, ring-fencing, and merger impacts advisory services including expert testimony, provided to U.S. and Canadian investor-owned utilities.

Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

Litigation Advisory Assignments

- Prepared economic and valuation analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

Management and Operations Consulting Assignments

- Performed prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear-generating capacity uprates and new nuclear facilities.
- Performed operations and financial performance benchmarking and studies of productivity programs.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
President and Vice Chair

CE Capital Advisors, Inc. (2004 – 2023)
A FINRA-Member broker-dealer subsidiary of Concentric Energy Advisors, Inc.

Ernst & Young (2000 – 2001, 2003 – 2004)
Staff Auditor and Database Management Associate

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College
M.B.A., 2003

Colgate University
B.A., Economics, 1996

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004
American Institute of Certified Public Accountants, 2011

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).
"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.
"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.
"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Public Service Commission				
Liberty Utilities	02/23	The Empire District Electric Company	Docket 22-085-U	Return on Equity Capital Structure
Connecticut Public Utilities Regulatory Authority				
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts Cost of Debt and Credit Quality
SJW Group and Connecticut Water Service, Inc.	04/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts Cost of Debt and Credit Quality
The United Illuminating Company	09/22	The United Illuminating Company	Docket No. 22-08-08	Multi-Year Rate Plan Revenue Requirements
The Southern Connecticut Gas Company and Connecticut Natural Gas Company	11/23	The Southern Connecticut Gas Company and Connecticut Natural Gas Company	Docket No. 23-11-02	Revenue Requirements
The United Illuminating Company	11/24	The United Illuminating Company	Docket No. 24-10-04	Revenue Requirements
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket No.	Rate Base Adjustments Earnings Attrition

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Unitil Corporation, Northern Utilities, Inc.	07/24	Request for Regulatory Approvals Related to a Merger of Bangor Natural Gas Company Into Unitil Corporation and Related Debt and Affiliate Arrangements (35-A M.R.S. §§ 707, 708, 901 & 902)	Docket No. 2024-00174	Utility valuation; Merger commitments; Rate base Valuation
Massachusetts Department of Public Utilities				
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Performance-Based Rate Plan Revenue Requirement
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017 Administrative and General Expense Allocations
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Performance-Based Rate Plan Revenue Requirement
National Grid	11/23	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 23-150	Performance-Based Rate Plan Revenue Requirement

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri Public Service Commission				
Liberty Utilities (Empire District Electric Company)	11/24	Liberty Utilities (Empire District Electric Company)	Case No. ER-2024-0261	Return on Equity Cost of Debt Capital Structure
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement Step Adjustments
Liberty Utilities (Granite State Electric) Corp.	05/23	Liberty Utilities (Granite State Electric) Corp.	Docket No. DG 23-039	Temporary Rates
Liberty Utilities (Granite State Electric) Corp.	05/23	Liberty Utilities (Granite State Electric) Corp.	Docket No. DG 23-039	Multi-Year Rate Plan Revenue Requirement
Nova Scotia Utility Board				
Nova Scotia Power, Inc.	01/22	Nova Scotia Power, Inc.	M10431	Earnings Sharing Mechanism, Storm Rider, and Demand Side Management Rider
Oklahoma Corporate Commission				
Liberty Utilities Co.	02/22	Liberty-Empire	Cause No. PUD 202100163	Return on Equity Capital Structure
Liberty Utilities Co.	06/22	Liberty-Empire	Cause No. PUD 202100050	Winter Storm Funding and Cost Recovery
Ontario Energy Board				
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Cost of Capital: Equity Thickness

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Ontario Power Generation	12/20	Ontario Power Generation	EB 2020-0290	Cost of Capital: Equity Thickness
Hydro One Networks Inc.	08/21	Hydro One Networks Inc.	EB 2021-0110	Productivity Framework Review
Enbridge Gas Inc. (Operating as Enbridge Gas Distribution Inc.)	10/22	Enbridge Gas Inc. (Operating as Enbridge Gas Distribution Inc.)	EB-2022-0200	Cost of Capital: Equity Thickness
Ontario Energy Association, Coalition of Large Distributors and Ontario Power Generation	07/24	Generic proceeding commenced by the Ontario Energy Board to consider the cost of capital parameters and deemed capital structure to be used to set rates	EB-2024-0063	Cost of Capital (ROE, Cost of Debt, and Capital Structure); Carrying Costs on Regulatory Deferrals; Carrying Costs on Cloud Computing Deferrals
Oregon Public Utilities Commission				
Northwest Natural Gas Company d/b/a NW Natural	05/25	Northwest Natural Gas Company d/b/a NW Natural	UG 520	Future Test Year; Rate Base Development
Rhode Island Division of Public Utilities and Carriers				
PPL Corporation	11/21	PPL Corporation and PPL Rhode Island Holdings, LLC	D-21-09	Merger Impacts
South Dakota Public Utilities Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity Capital Structure

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer Financial Capability and Credit Quality

LEAD-LAG AND CASH WORKING CAPITAL STUDIES

JURISDICTION	SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.
Regulatory Commission of Alaska	Golden Heart Utilities, Inc. and College Utilities Corporation	08/21	Golden Heart Utilities, Inc. and College Utilities Corporation	U-21-070 U-21-071
Regulatory Commission of Alaska	Golden Heart Utilities, Inc. and College Utilities Corporation	08/24	Golden Heart Utilities, Inc. and College Utilities Corporation	U-24-030 U-24-031
Connecticut Public Utilities Regulatory Authority	The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04
Connecticut Public Utilities Regulatory Authority	The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42
Connecticut Public Utilities Regulatory Authority	Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16
Kentucky Public Service Commission	Duke Energy Kentucky	06/25	Duke Energy Kentucky	2025-00125
Massachusetts Department of Public Utilities	National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170
Massachusetts Department of Public Utilities	National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120
Massachusetts Department of Public Utilities	National Grid	11/23	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 23-150
New Mexico Public Regulation Commission	El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT
Public Utility Commission of Texas	El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831

JURISDICTION	SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.
Public Utility Commission of Texas	El Paso Electric Company	06/21	El Paso Electric Company	Docket No. 52195
Railroad Commission of Texas	Atmos Pipeline – Texas (APT), a division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas (APT), a division of Atmos Energy Corporation	Case No. 00013758
Railroad Commission of Texas	Atmos Energy Corporation, West Texas Division	10/24	Atmos Energy Corporation, West Texas Division	Docket No. OS-24-00018879 (West Texas)

PPL ELECTRIC UTILITIES CORPORATION

Rate Base and Rate of Return
12 Months Ended June 30, 2025
(Thousands of Dollars)

Line No.	Title of Account	Total T&D Operations (Exhibit C-1)	Less: T Operations	PPUC Jurisdictional
	Electric Plant			
1	Electric plant in service (C-2)	$ 17,239,085	$ (10,032,320)	$ 7,206,765
1a	Electric plant in service (C-2) (IT Pro-forma)	-	-	-
2	Reserve for depreciation (C-2)	4,079,195	(1,496,447)	2,582,748
2a	Reserve for depreciation (C-2) (IT Pro-forma)	-	-	
3	Net electric plant in service	13,159,890	(8,535,873)	4,624,017
	Additions			
4	Plant held for future use (C-3)	-	-	-
5	Total electric plant	13,159,890	(8,535,873)	4,624,017
	Working Capital			
6	Cash working capital (C-4)	(1,872)	15,010	13,138
7	Materials and operating supplies (C-5)	109,289	(37,143)	72,146
8	Total working capital	107,417	(22,134)	85,283
	Deductions			
9	Accumulated deferred taxes on income (C-6)	2,438,999	(1,283,496)	1,155,503
9a	Accumulated deferred taxes on income (C-6) (IT Pro-forma	-	-	
10	Customer advances for construction (B-1)	-	-	
11	Customer deposits (B-1)	6,554	-	6,554
12	Total deductions	2,445,553	(1,283,496)	1,162,057
13	Rate Base (net)	$ 10,821,754	$ (7,274,511)	$ 3,547,243
	Pro forma return at present rates			
14	Amount (D-1, col. 6)			$ 337,148
15	Percent			9.50%
	Pro forma return at proposed rates			
16	Amount (D-1, col. 8)			$ 300,097
17	Percent			8.46%

PPL ELECTRIC UTILITIES CORPORATION

Operating Income
Pro Forma at Present and Proposed Rates
Year Ended June 30, 2025
(Thousands of Dollars)

Line No.		(1) T & D Pro Forma at Present Rates (Exhibit D-1)	(2) Less: T Pro Forma at Present Rates	(3) PPUC Jurisdictional Pro Forma at Present Rates
1	Operating Revenues	$ 1,935,642	$ (854,451)	$ 1,081,192
	Operating Expenses			
2	Operation and Maintenance	487,355	(68,042)	419,313
3	Depreciation	375,777	(184,819)	190,958
4	Regulatory Debits/Credits	3,990	(0)	3,990
	Provision for Taxes			
5	Taxes Other Than Income	74,940	(3,322)	71,618
	Income Taxes			
6	Federal	76,262	(40,516)	35,746
7	State	23,240	(9,913)	13,327
8	Deferred Income Taxes	80,553	(71,542)	9,011
9	Investment Tax Credit	65	16	81
10	Total Taxes	255,060	(125,278)	129,782
11	(Gain)/Loss from Disposition of Utility Plant	-	-	-
12	Total Operating Expenses	1,122,182	(378,139)	744,043
13	Operating Income	$ 813,460	$ (476,312)	$ 337,148

PPL ELECTRIC UTILITIES CORPORATION

Rate Base and Rate of Return
12 Months Ended June 30, 2026
(Thousands of Dollars)

Line No.	Title of Account	Total T&D Operations (Exhibit C-1)	Less: T Operations	PPUC Jurisdictional
	Electric Plant			
1	Electric plant in service (C-2)	$ 18,702,492	$ (10,769,080)	$ 7,933,412
1a	Electric plant in service (C-2) (IT Pro-forma)	-	-	
2	Reserve for depreciation (C-2)	4,393,823	(1,650,834)	2,742,990
2a	Reserve for depreciation (C-2) (IT Pro-forma)	-	-	
3	Net electric plant in service	14,308,669	(9,118,247)	5,190,422
	Additions			
4	Plant held for future use (C-3)	-	-	-
5	Total electric plant	14,308,669	(9,118,247)	5,190,422
	Working Capital			
6	Cash working capital (C-4)	(4,929)	16,065	11,136
7	Materials and operating supplies (C-5)	109,289	(37,143)	72,146
8	Total working capital	104,360	(21,078)	83,282
	Deductions			
9	Accumulated deferred taxes on income (C-6)	2,559,432	(1,373,681)	1,185,751
9a	Accumulated deferred taxes on income (C-6) (IT Pro-forma)	-	-	
10	Customer advances for construction (B-1)	-	-	
11	Customer deposits (B-1)	6,554	-	6,554
12	Total deductions	2,565,986	(1,373,681)	1,192,305
13	Rate Base (net)	$ 11,847,043	$ (7,765,644)	$ 4,081,398
	Pro forma return at present rates			
14	Amount (D-1, col. 6)			$ 357,015
15	Percent			8.75%
	Pro forma return at proposed rates			
16	Amount (D-1, col. 8)			$ 347,327
17	Percent			8.51%

PPL ELECTRIC UTILITIES CORPORATION

Operating Income
Pro Forma at Present and Proposed Rates
Year Ended June 30, 2026
(Thousands of Dollars)

Line No.		(1) T & D Pro Forma at Present Rates (Exhibit D-1)	(2) Less: T Pro Forma at Present Rates	(3) PPUC Jurisdictional Pro Forma at Present Rates
1	Operating Revenues	$ 1,978,979	$ (917,558)	$ 1,061,421
	Operating Expenses			
2	Operation and Maintenance	408,289	(69,184)	339,105
3	Depreciation	413,853	(190,579)	223,274
4	Regulatory Debits/Credits	3,990	(0)	3,990
	Provision for Taxes			
5	Taxes Other Than Income	70,409	(2,333)	68,076
	Income Taxes			
6	Federal	69,693	(35,597)	34,096
7	State	19,236	(7,228)	12,008
8	Deferred Income Taxes	111,551	(87,679)	23,872
9	Investment Tax Credit	(31)	16	(15)
10	Total Taxes	270,858	(132,821)	138,037
11	(Gain)/Loss from Disposition of Utility Plant	-	-	-
12	Total Operating Expenses	1,096,989	(392,584)	704,406
13	Operating Income	$ 881,989	$ (524,974)	$ 357,015

PPL ELECTRIC UTILITIES CORPORATION

Rate Base and Rate of Return
12 Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Title of Account	Total T&D Operations	Less: T Operations	PPUC Jurisdictional (Exhibit BR-1)
	Electric Plant			
1	Electric plant in service (C-2)	$20,346,907	$ (10,170,680)	$ 10,176,227
1a	Electric plant in service (C-2) (IT Pro-forma)	25,880	-	25,880
2	Reserve for depreciation (C-2)	4,741,901	(1,487,624)	3,254,277
2a	Reserve for depreciation (C-2) (IT Pro-forma)	1,826	-	1,826
3	Net electric plant in service	15,629,060	(8,683,056)	6,946,004
	Additions			
4	Plant held for future use (C-3)	0	-	-
5	Total electric plant	15,629,060	(8,683,056)	6,946,004
	Working Capital			
6	Cash working capital (C-4)	1,014	15,761	16,775
7	Materials and operating supplies (C-5)	109,289	(37,143)	72,146
8	Total working capital	110,303	(21,382)	88,921
	Deductions			
9	Accumulated deferred taxes on income (C-6)	2,622,001	(1,417,606)	1,204,395
9a	Accumulated deferred taxes on income (C-6) (IT Pro-forma)	6,088	-	6,088
10	Customer advances for construction (B-1)	-	-	-
11	Customer deposits (B-1)	6,554	-	6,554
12	Total deductions	2,634,643	(1,417,606)	1,217,037
13	Rate Base (net)	$13,104,720	$ (7,286,832)	$ 5,817,888
	Pro forma return at present rates			
14	Amount (D-1, col. 6)			$ 257,449
15	Percent			4.43%
	Pro forma return at proposed rates			
16	Amount (D-1, col. 8)			$ 498,011
17	Percent			8.56%

Operating Income
Pro Forma at Present and Proposed Rates
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.		(1) T & D Pro Forma at Present Rates (Exhibit D-1)	(2) Less: T Pro Forma at Present Rates	(3) PPUC Jurisdictional Pro Forma at Present Rates	(4) PPUC Jurisdictional Rate Increase	(5) PPUC Jurisdictional Pro Forma at Proposed Rates
1	Operating Revenues	$ 2,043,337	$ (977,436)	$ 1,065,901	$ 356,271	$ 1,422,172
	Operating Expenses					
2	Operation and Maintenance	501,190	(73,243)	427,947	6,974	434,922
3	Depreciation	490,002	(200,406)	289,596	0	289,596
4	Regulatory Debits/Credits	3,990	(0)	3,990	0	3,990
	Provision for Taxes					
5	Taxes Other Than Income	71,146	(2,299)	68,847	21,020	89,867
	Income Taxes					
6	Federal	14,884	(39,256)	(24,372)	63,947	39,575
7	State	(3,527)	(7,747)	(11,274)	23,767	12,493
8	Deferred Income Taxes	150,434	(96,702)	53,732	0	53,732
9	Investment Tax Credit	(31)	16	(15)	0	(15)
10	Total Taxes	232,906	(145,987)	86,919	108,734	195,653
11	(Gain)/Loss from Disposition of Utility Plant	-	-	-	0	0
12	Total Operating Expenses	1,228,088	(419,636)	808,452	115,708	924,160
13	Operating Income	$ 815,249	$ (557,800)	$ 257,449	$ 240,563	$ 498,011

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 7

Direct Testimony of Bickey Rimal

Topics: **Class Revenue Allocation**
Cost Allocation Studies

Dated: September 30, 2025

Direct Testimony of Bickey Rimal

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Bickey Rimal, and my business address is 1300 19th Street, Suite 620, Washington, DC 20036.

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

A. I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Vice President.

Q. Please describe your professional background and education.

A. I have over 15 years of experience in the utility industry. I hold a Bachelor of Arts degree from Colgate University. I hold a Masters in International Public Affairs with a focus on Energy Policy from the University of Wisconsin in Madison. I have provided expert testimony on cost allocation issues on multiple occasions for various electric, gas, water, and wastewater utility clients. A summary of my education and experience is provided as Appendix A.

Q. Have you presented expert testimony in other proceedings?

A. Yes. I have testified previously before the Regulatory Commission of Alaska, Arizona Corporation Commission, Connecticut Public Utilities Regulatory Authority, Indiana Utility Regulatory Commission, Maine Public Utilities Commission, Massachusetts Department of Public Utilities, Public Utilities Commission of Nevada, New York State Department of Public Service, and Nova Scotia Utility and Review Board.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of PPL Electric Utilities Corporation ("PPL Electric" or the "Company"), which is a wholly owned subsidiary of PPL Corporation.

Q. What is your assignment in this proceeding?

A. PPL Electric retained Concentric to conduct a fully allocated cost-of-service study ("ACOSS") to determine the embedded costs of serving its various retail electric distribution customers, and propose appropriate assignment of the proposed revenue requirement to each class. In this regard, I am sponsoring the jurisdictional cost of service study ("JCOSS") to allocate total PPL Electric system costs to the Federal and Pennsylvania Public Utility Commission ("PUC" or "Commission") jurisdiction, as well as the ACOSS that allocates the PUC Jurisdiction totals to the retail customer rate classes. Based on the results of these studies, I am also supporting the class revenue increase allocation.

Q. Please summarize the nature and purpose of your testimony.

A. My testimony addresses the Company's cost of service studies. First, I discuss the purpose of an ACOSS and describe the Concentric Cost of Service Model ("Concentric Model") used in conducting PPL Electric's electric cost of service studies.

Second, I discuss the various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in the Company's electric cost of service studies.

Third, I describe the studies of relative costs and other analyses employed to assign the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes.

Fourth, I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from PPL Electric's ACOSS. This presentation will include the resulting unit costs by class for customer, demand, and energy-related costs within the ACOSS.

Fifth, I describe the method used to apportion the Company's revenue deficiency to the various rate classes. In particular, I describe the principles and methods used to mitigate the impacts on those classes that would otherwise receive large rate increases if the unmitigated results of the ACOSS were to be used to apportion the revenue requirement and set the rates in this proceeding.

Q. Are you sponsoring any attachments?

A. Yes. I am sponsoring PPL Electric Exhibits BR-1 and BR-2 and portions of Parts II and IV of the filing requirements as noted on their indexes.

Q. Would you briefly describe the contents of PPL Electric Exhibits BR-1 and BR-2?

A. PPL Electric Exhibits BR-1 and BR-2 respond to Question 1 of Exhibit Regs., Part IV, Section E, and present fully distributed Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. PPL Electric Exhibit BR-1 is based on costs and operating conditions for the fully projected future test year ("FPFTY") ending June 30, 2027. This exhibit provides a summary of the results, cost assignment and allocation detail, and a very detailed result of the studies. I have also included additional details regarding the methodology used for the studies. Further, PPL Electric Exhibit BR-2 provides the results of studies used to functionalize and classify certain distribution plant of the Company. These studies are based on distribution plant data as of the historic test year ("HTY") ending June 30, 2025. The results of these studies were applied to distribution plant data for the FPFTY.

II. ALLOCATED COST OF SERVICE STUDY

A. Introduction to ACOSS

Q. Please describe the general approach used to develop the ACOSS.

A. The purpose of the ACOSS in this proceeding is to allocate PPL Electric's PUC Jurisdictional overall revenue requirement to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each customer class and help to determine the individual class's revenue responsibility. The results also provide useful guidance in terms of designing rates for each class.

To allocate costs to the various classes, I reviewed PPL Electric's expense and plant accounts and worked with various PPL Electric personnel to develop studies of the relative costs of providing facilities and services for each rate class and analyzed the key factors that cause the costs to vary.

Q. Please describe the Concentric Model that was used in conducting the ACOSS filed in this proceeding.

A. PPL Electric has selected the Concentric Model to conduct the electric ACOSS in this general rate case. The same model was used in PPL Electric's last rate case at Docket No. R-2015-2469275. Concentric has developed a proprietary model for the purpose of conducting allocated cost of service studies, and Concentric is using that model for purposes of conducting the electric ACOSS in this rate case. A brief description of the Concentric Model is provided with this testimony as <u>Appendix B</u>.

B. <u>Principles of ACOSS Preparation</u>

Q. What is the guiding principle that should be followed when performing an ACOSS?

A. The fundamental principle underlying an ACOSS is that cost allocation should follow cost causation. Cost causation addresses the question of which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a relationship between the services used by a utility's customers and the particular costs incurred by the utility in serving those customers.

Q. What are the steps to performing an ACOSS?

A. To establish the cost responsibility of each customer class, a three-step analysis of the utility's total operating costs must be undertaken. The three steps which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step is cost functionalization, where the plant investment costs and operating expenses are categorized by the operational functions with which they are associated. PPL Electric's primary functional cost categories associated with electric service include Primary Distribution, Secondary Distribution, and Customer Accounts and Services. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent their costs vary in response to different customer class characteristics. Indirect costs that support these functions, such as General and Intangible Plant, and Administrative and General Expenses, are allocated to functions using allocation factors related to plant and/or labor ratios.

Q. Please describe cost classification.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary driver of the costs. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the system; and (3) the amount of electricity consumed by customers. These classification categories have been identified, for purposes of the ACOSS, as (1) Customer Costs, (2) Demand Costs, and (3) Energy Costs, respectively.

Q. How are these three classification categories related to the amount of costs incurred by the Company?

A. *Customer* Costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs are largely a function of the number of customers served and continue to be incurred whether the customer uses any electricity or not. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. Demand costs are fixed in nature and do not vary with the number of customers or the amount of energy that customers consume.

Energy Costs are those costs which vary with the amount of kilowatt hours ("kWh") sold to customers. For example, included in the instant study are costs associated with the administration of the default service program, which are classified as fuel-related and allocated to classes based on the amount energy consumed. However, except for this specific cost, PPL Electric's costs are fixed with respect to energy usage. As a result, there are no costs classified as energy in the ACOSS.

Q. What is the process followed to appropriately classify costs as Customer, Demand, and Energy?

A. Usually, a determination of the classification of costs can be made simply by knowing the type of activities or assets that reside within a particular FERC account. In these instances, the entire account can be classified into a single category. However, for some FERC account functions, it is beneficial to conduct classification studies to determine which portion of an account is associated with each classification category. Further discussion of the classification studies used in PPL Electric's ACOSS is provided in the section discussing the studies of relative costs below.

Q. Please describe cost allocation.

A. The third and final step, cost allocation, is the allocation of each functionalized and classified cost element to the individual customer or rate class that causes the cost to be incurred. Customers generally are divided into customer classes based on the type and character of services that they require. Costs typically are allocated to these customer classes based on factors related to the number of customers and the amount of energy and capacity demanded by customers. For example, much of the plant and equipment cost depends upon the peak demand of the customers and these costs were allocated based on the peak demands of the rate class. Other portions of the cost depend upon the number of customers on the system, and these costs were allocated on a customer or weighted-customer basis. In addition, certain variable production costs as well as fuel and purchased power costs primarily depend upon the amount of energy consumed by customers. These costs were allocated based on the amount of energy consumed, adjusted for losses of energy that occur across the transmission and distribution system.

Q. How do you then establish the fully allocated costs related to various utility services?

A. To establish these relationships, one must analyze a utility's electric system design, physical configuration and operations, its accounting records, and its system and customer load data. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for each of the utility's plant and expense elements.

Q. Please explain the term "direct assignment."

A. The term "direct assignment" means the assignment of costs to a specific customer or class of customers based on that customer's or class's exclusive identification with the particular plant or expense at issue. Usually, costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or class of customer. Direct assignments best reflect the cost causative characteristics of serving individual customers or classes of customers. Therefore, in performing a cost of service study, one seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology based on an analysis of factors that affect the relative costs of serving particular customer classes.

Q. What prompts the need to perform a study of the relative costs?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, further analysis must be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned to a specific customer or certain customer classes?

A. No. The nature of utility operations is characterized by the existence of facilities used jointly or commonly by multiple customers and classes. To the extent that a utility's plant and expenses cannot be directly assigned to customer classes, allocation methods based on cost causation must be derived to assign or allocate the remaining costs appropriately to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors based on cost causation for cost allocation purposes.

Q. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform an ACOSS.

A. As stated above, to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

III. PPL ELECTRIC'S JCOSS AND ACOSS

A. Sources of the Underlying Data

Q. What is the source of the cost data analyzed in PPL Electric's JCOSS and ACOSS?

A. All cost of service data was obtained from the Company's total cost of service (i.e., the base rate revenue requirement) contained in this general rate case filing for the FPFTY. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and necessary information provided by relevant Company personnel.

Q. How did you determine PPL Electric's Pennsylvania jurisdictional costs?

A. PPL Electric's Pennsylvania jurisdictional costs were determined based on the JCOSS, which allocates the total cost of the Company between the Federal (transmission) and Pennsylvania (retail distribution) jurisdictions. Since PPL Electric's historic test year per books and its future and fully forecasted future test years per budget are at the combined transmission and distribution ("T&D") level, it is necessary to conduct a study to separate those costs between transmission and distribution. Section V of PPL Electric Exhibit BR-1 provides specific details regarding the assignment and allocation of the combined T&D

costs and the determination of the Pennsylvania jurisdictional distribution service revenue requirements, with a summary provided as Section III of the same exhibit. The method utilized for this jurisdictional study follows the same methods that are employed by PPL Electric when developing its quarterly earnings reports.

Q. How did you allocate PPL Electric's Pennsylvania jurisdictional costs to the individual rate classes?

A. I have used the results of the JCOSS as an input into the ACOSS to assign the Pennsylvania jurisdictional costs to the individual rate classes. Section II of PPL Electric Exhibit BR-1 presents the results of PPL Electric's ACOSS. Section IV of PPL Electric Exhibit BR-1 provides details regarding the assignment and allocation of Pennsylvania jurisdictional costs to the individual rate classes.

B. <u>Functionalization and Classification of Costs</u>

Q. How did you functionalize and classify PPL Electric's costs?

A. The process starts with the assignment of the Company's FERC accounts to a specific function. In some instances, the costs in an account are first split into separate functions or classifications if the costs in the account are incurred to perform more than one function, or the costs in an account can be said to vary significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits have been separated into two functions: primary distribution and secondary distribution. In addition, these costs, as well as line transformers have been further separated into demand and customer classifications. The functionalization and classification studies are provided as Section I of PPL Electric Exhibit BR-2.

Q. Please explain the primary-secondary study.

A. Since the costs associated with distribution facilities are not always identified in the financial accounting records as being Primary Distribution (480 V – 34.5 kV) or Secondary Distribution (< 480 V), the distribution costs in Accounts 364–367 have been assigned to Primary or Secondary distribution functions based on cost-related ratios that were developed from analyses of the distribution plant records.

Distribution poles were sub-functionalized between primary and secondary voltage using the information contained within the accounting system. The accounting system contained information regarding the investment and quantity of poles by voltage, and this information was used to determine the investment and quantity of poles that serve the primary system versus the secondary system. However, similar level detail by voltage was not available for conductors. As a result, special studies were conducted to sub-functionalize conductors between primary and secondary distribution.

Distribution conductors were functionalized between primary and secondary voltages by utilizing length of conductors and the replacement costs of conductors serving primary versus secondary distribution systems. Using PPL Electric's asset management system, the length of conductors carrying primary versus secondary voltage was obtained. For each conductor type, the length of the conductor was multiplied by the replacement cost of that conductor to obtain the total cost of that conductor type. For conductor types that are no longer used, a replacement conductor was identified, and the cost of that replacement conductor was used in the analysis. Using the total costs of all conductors by voltage, the ratio of primary conductors to secondary conductors was calculated.

Q. Is the classification of certain distribution assets (i.e., poles, conductors, and line transformers) between customer and demand components consistent with past PPL Electric cost studies?

A. Yes. PPL Electric has consistently classified poles, conductors, and line transformers between customer and demand components. Similar to prior cases, I have continued to rely on the "minimum system" method to determine the customer component of these assets.

Plant and O&M costs related to production, transmission and distribution generally can be assigned directly to specific functions, but various indirect costs related to overhead such as intangible plant and general plant, as well as administrative and general expenses are allocated to functions using "internal allocators" that are based on the relative amount of certain costs that have been directly assigned to each function. The specific functionalization allocators used to assign overhead costs have been selected to reflect the type of direct costs that each overhead account generally supports.

Q. Please explain the Minimum System Study.

A. The costs associated with a distribution system are related to both the peak amount of load that the system is designed to deliver and the number of customers and premises that it is designed to serve. Consequently, it is appropriate to allocate a portion of the distribution system costs on a demand-related basis and a portion on a customer-related basis. To classify a certain portion of the distribution system costs as demand-related or customer-related, a Minimum System Study was conducted which included an analysis for poles and an analysis for conductors. The minimum system analysis compares the cost of a hypothetical minimum system (i.e., a system sized to simply connect customers) to the total cost of the entire system. The minimum system cost represents the customer-related costs, whereas the total costs less the minimum system costs represent the demand-related costs (i.e., total cost is split between the customer component and the demand component).

The Primary and Secondary Analysis for poles described above provided the total cost and total count of primary and secondary poles. This total count of primary poles was multiplied by the embedded cost of a minimum sized primary pole to calculate the minimum system cost of primary poles. This was then compared to the total embedded cost of primary poles to determine the portion of primary poles that is customer-related and demand-related. A similar analysis was conducted for secondary poles.

The Primary and Secondary Analysis for conductors described above provided the total cost and total circuit miles of primary and secondary conductors. A hypothetical minimum system replacement cost was calculated by taking the total circuit feet of conductor associated with the primary system and multiplying it by the replacement cost of the minimum sized primary conductor. The minimum system replacement cost was then compared to the total system replacement costs to arrive at the customer related and demand related costs for primary conductors. A similar analysis was conducted for secondary conductors.

Q. How were direct costs functionalized?

A. The direct costs of distribution plant and O&M expenses are directly assigned to their proper function and classification. O&M costs that are readily-identified with a specific function are assigned directly to the corresponding function. Distribution Supervision and Engineering expenses (Accounts 580 and 590) are allocated to functions using factors based on direct distribution operation labor and direct distribution maintenance labor. Miscellaneous Distribution Expense (Accounts 588) and Rents (Account 589) are allocated to distribution functions using factors based on total distribution plant.

Q. How did the ACOSS functionalize distribution-related O&M expenses?

A. In general, these expenses were functionalized and allocated based on the cost allocation methods used for the Company's corresponding plant accounts. This is based on the assumption that a utility's distribution-related O&M expenses are generally thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of operating and maintenance cost (i.e., expenses by the utility to operate and maintain those facilities). Thus, the allocation basis for a particular expense account will be the same basis as that used to allocate the corresponding plant account.

Q. How are overhead costs functionalized?

A. Indirect plant costs are allocated to functions based on ratios derived from direct plant costs. For example, Intangible Plant and General Plant are assigned to functions using the "Direct Labor" allocator.

Administrative and General Expenses were allocated to various functions using two different allocators. First, Salaries, Office Supplies, Administrative Expenses Transferred, Outside Services Employed, Injuries and Damages, Employee Pensions and Benefits, and Maintenance of General Plant were allocated using the direct labor allocation factor. Second, Property Insurance, Regulatory Commission Expense, and General Advertising Expense were allocated using the plant-related ratios associated with each function.

Q. How were taxes other than income taxes assigned to functions?

A. All taxes, except for income taxes, were functionalized in a manner that reflects the specific cost associated with the particular tax expense category. Generally, taxes can be functionalized using the tax assessment method established for each tax category, (e.g., payroll, property, or sales taxes). Depending on the method of assessment, other taxes were assigned or allocated to functions using either: (1) direct labor ratios; or (2) plant ratios.

C. <u>Allocations to Rate Classes</u>

Q. What was the next step in the ACOSS?

A. After functionalizing and classifying the costs, the functionalized and classified costs were allocated to the individual rate codes or classes.

(1) Allocation of Demand-related Costs

Q. How were the demand-related costs allocated in the proposed ACOSS?

A. Consistent with prior PPL Electric rate case filings, I utilized a non-coincident peak demand method to allocate demand-related distribution system costs. "Non-coincident Peak" refers to the highest level of demand that an individual class experienced during the year or month. This non-coincident peak for a given class may coincide with the overall system peak but, generally, it occurs at other times than the system peak.

(2) Allocation of Customer-related Costs

Q. How have the customer-related costs been allocated in the ACOSS?

A. Because a significant portion of the distribution system costs are incurred simply to attach a customer to the system and are the same regardless of the amount of energy that the customer might consume, significant portions of the distribution system costs and customer-related costs are allocated to classes using allocators that are related to the number of customers in the class. However, because there generally is a very wide difference between the customer classes in terms of the level of customer-related costs required per customer, many of the allocations of customer-related costs are weighted to reflect the relative differences in the average cost per customer of providing customer-related facilities or services for particular rate codes or classes. Thus, customer-related costs, such as meters, service lines, and collection costs, are allocated based on the cost-weighted number of customers in each class. The billing and customer records costs are allocated based on the number of customers.

Q. How did you develop the meter allocator?

A. Every customer, except lighting customers, requires a meter, but Commercial and Industrial meters generally cost considerably more and require more equipment compared to Residential meters. For this reason, meter weights were developed for each customer class based on the number and type(s) of meters installed for each rate class and the associated costs of each type of meter. The analysis also accounted for the incremental cost associated with transformer rated meters. The total meter cost along with necessary equipment provided an estimate of the relative cost of providing metering service for each rate class. The relative-weight factor was then multiplied times the number of customers in the class to develop the meter allocation factors for the test year.

Q. How was the services allocator developed?

A. The service allocator is used to allocate the service-related cost contained in FERC Account 369. The service allocator was developed based on a sample of recent service installations. For each rate class, I was able to obtain the length and type of service installed using recent installation data from the Company. I calculate the total cost of service installation for each rate class by multiplying the length of each service installation by the replacement cost of that service type. I then calculated a cost per installation by each class and used this information to develop a weighting factor for each class. This weighting factor was ultimately used to develop the service allocator for the test year.

IV. RESULTS OF PPL ELECTRIC'S ACOSS

Q. Please describe the results of the ACOSS with respect to rate of return under the Company's rate classes.

A. The summary of the results of the ACOSS and the relative rates of return produced by each class for the FPFTY, are presented in PPL Electric Exhibit BR-1 and summarized in Table 1 below. As shown on line 23 on page 7 of this exhibit and table below, at present rates the ACOSS shows a wide variation in the rates of return by rate class.

Table 1: Rate of Return at Current Rates

Rate Class	Rate Code	Return at Current Rates	Relative Rate of Return
Residential	RS	4.32%	1.0
Residential-Thermal Storage	RTS	2.27%	0.5
Small General Service - Sec. Voltage	GS-1	4.03%	0.9
Large General Service - Sec. Voltage	GS-3	5.31%	1.2
Large General Service - 12 KV	LP-4	3.53%	0.8
Large General Service - 69 KV or Higher	LP-5	24.01%	5.4
Separate Meter General Space Heating Service	GH-2	4.50%	1.0
Street Lighting/Area Lighting	SL/AL	5.89%	1.3
Total System		**4.43%**	**1.0**

Q. What is the amount of the rate increase or decrease that each customer class would need in order for each class to produce the system average required rate of return?

A. Line 63 on page 9 of PPL Electric Exhibit BR-1 shows the amount of increase that would be required for each class to pay its fully-allocated cost of service under the proposed revenue requirement.

V. DESCRIPTION OF PROPOSED CLASS REVENUE REQUIREMENTS

Q. Have you examined the percentage rate increases that would be required for each rate class according to the ACOSS?

A. Yes. Line 5 on page 7 of PPL Electric Exhibit BR-1 presents normalized base rate revenues that PPL Electric can expect to recover from each rate class at current rates, while Line 62 on page 9 of that exhibit shows the allocated cost of service for each class. Column F on page 16 shows the percentage increase/decrease in base rates that would be required if unmitigated ACOSS results were to be applied. Even though the goal is to move all rate classes to their cost of service, the Company considered affordability for each of the customer classes and determined that the percentage rate increases experienced by individual rate classes should be mitigated to moderate the impacts on individual rate classes.

A. Mitigation of Class Impacts

Q. How did you go about mitigating the class rate increases?

A. The proposed revenue allocation to each rate class was derived based on discussion with the Company. The criteria used for the proposed revenue allocation are: (1) impose an increase cap of 1.5 times the overall system increase to any rate class; and (2) no rate class receives a rate reduction. I believe that this approach reduces the inter-class subsidies and moves classes closer to their cost of service, while ensuring that impacts on any one particular class is moderated and gradual.

Q. Please describe the results of your mitigation approach.

A. Column P on page 17 of PPL Electric Exhibit BR-1 shows the final mitigated revenue requirement by rate class. The pro forma rates of return that would be generated by each rate class at the proposed mitigated revenue requirements are shown on column Q on page 17 of PPL Electric Exhibit BR-1. The table below summarizes the revenues at present rates, revenues based on ACOSS and proposed mitigated revenue requirement by rate class.

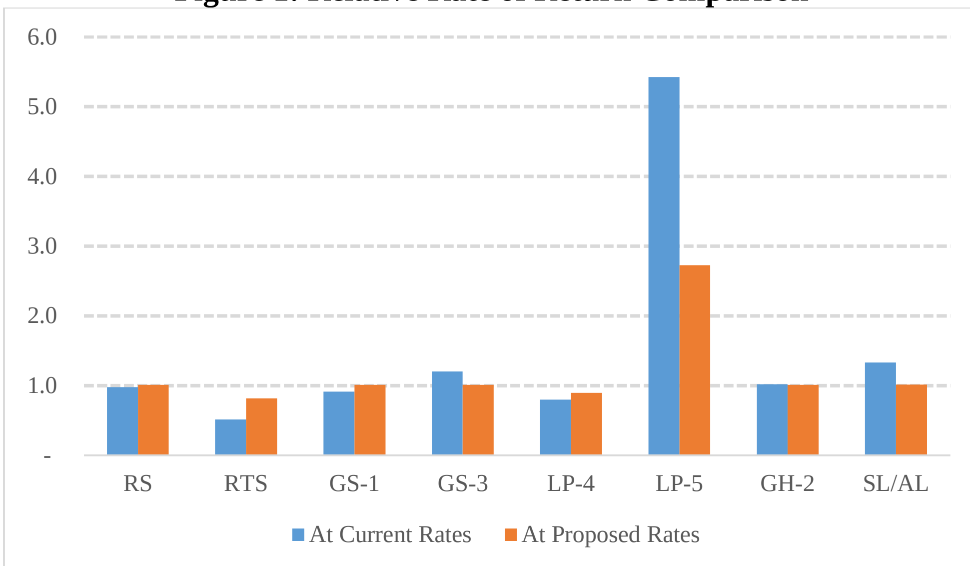
Table 2: Revenues at Present and Proposed Rates

Rate Class	Rate Code	Revenue at Current Rates	Revenue Requirement based on ACOSS	Mitigated Revenue Requirement	ACOSS Increase (%)	Mitigated Increase (%)
Residential	RS	$718,787,174	$969,168,276	$972,760,160	34.83%	35.33%
Residential-Thermal Storage	RTS	$7,930,469	$13,351,425	$12,071,032	68.36%	52.21%
Small General Service - Sec. Voltage	GS-1	$78,435,579	$107,441,939	$107,788,638	36.98%	37.42%
Large General Service - Sec. Voltage	GS-3	$128,618,149	$169,637,439	$170,381,820	31.89%	32.47%
Large General Service - 12 KV	LP-4	$38,791,942	$63,254,109	$59,045,537	63.06%	52.21%
Large General Service - 69 KV or Higher	LP-5	$1,940,349	$1,325,612	$1,940,349	-31.68%	0.00%
Separate Meter General Space Heating Service	GH-2	$1,301,175	$1,771,840	$1,777,874	36.17%	36.64%
Street Lighting/Area Lighting	SL/AL	$24,366,203	$30,491,845	$30,677,073	25.14%	25.90%
Total System		$1,000,171,041	$1,356,442,484	$1,356,442,484	35.62%	35.62%

Q. Does your proposed mitigation improve the relative rate of return from each class?

A. Yes. I compared the index of rate of return by class at present and proposed rates. As the graph below indicates, the index of return improves for each rate class under the proposed mitigated rates as compared to the present rates.

Figure 1: Relative Rate of Return Comparison



VI. SUPPORT FOR RESIDENTIAL CUSTOMER CHARGE

Q. Have you performed any analyses to determine the customer-related costs for the residential and small commercial class?

A. Yes. Using the results of the ACOSS, I have determined the customer-related costs per customer per month. I isolated the costs that were classified as being customer-related for RS and GS-1 customer class and calculated a per unit cost by dividing that total cost by the number of bills in each class. The table below presents the build-up of the customer unit cost by function.

Table 3: Customer Cost Build-up

Function	RS	GS-1
Deposits and Advances	-$78,001	-$60,237
Distribution Primary	$231,718,896	$26,207,249
Distribution Secondary	$70,009,993	$7,918,082
Line Transformers	$22,324,026	$2,524,832
Services	$74,274,570	$8,656,757
Meters	$35,161,156	$6,370,987
Lighting	$0	$0
Meter Reading	$8,767,619	$991,612
Customer Service	$92,367,142	$9,104,365
Billing and Collections	$135,799,807	$14,436,672
Total Customer-Related Costs	**$670,345,209**	**$76,150,319**
Annual Bills (Customer Count * 12)	$15,603,324	$1,769,083
Unit Costs ($/Bill)	**$42.96**	**$43.05**

Q. What level of customer charge is supported by the ACOSS?

A. As shown by the table above, the ACOSS supports customer charges of $42.96 and $43.05 for RS and GS-1 classes, respectively.

Q. Is the Company proposing to recover all customer-related costs in the proposed customer charge?

A. No, as discussed in more detail in PPL Electric witness Steven Wishart's testimony (PPL Electric St. No. 8), the Company is proposing to only recover a portion of the customer-related costs in the customer charges for Rate Schedules RS and GS-1, even though the ACOSS provides justification for higher customer charges.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BICKEY RIMAL
VICE PRESIDENT

Mr. Rimal has over 17 years of progressive experience in the energy and environmental sector. He is a testifying expert on matters related to cost of service and rate design, and has contributed to engagements related to energy market assessments, valuations of energy assets, and utility performance benchmarking. His work often involves financial modeling, statistical analysis, and regulatory research. Mr. Rimal has provided expert testimony on cost allocation issues on multiple occasions on behalf of electric, natural gas, water, and wastewater utilities. He has extensively used Concentric's Excel-based macro-driven Allocated Class Cost-of-Service ("ACCOS") model for various electric, gas, and water utility clients, modifying and updating the model as needed to suit the specific needs of the clients. Mr. Rimal has a Masters in International Public Affairs with a focus on Energy Policy from the University of Wisconsin in Madison. Prior to enrolling in the graduate program, Mr. Rimal worked at a global energy and environmental consulting firm for three years. While there, Mr. Rimal was extensively involved in projects dealing with policy design and implementation, economic impact analysis, regulatory evaluation, and environmental risk assessment.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Proceedings and Litigation Support

Mr. Rimal has been involved in projects dealing with all aspects of regulatory ratemaking process. Mr. Rimal has extensively used Concentric's excel-based macro driven Allocated Class Cost-of-Service ("ACCOS") model for various utility clients. He has modified and updated the model as needed to suit the specific needs of the clients.

Representative engagements have included:

- Conducted various cost allocation studies, functional studies, and minimum system studies and filed testimony supporting those studies for a vertically integrated Midwest electric utility.
- Supported the development of an allocated class cost of service study and rate design for another vertically integrated Midwest electric utility. Mr. Rimal was directly involved in conducting special cost allocations and functional studies; developing cost of service studies; designing the rates and calculating the associated bill impacts.
- Supported the development of an allocated class cost of service study and rate design for a distribution only electric utility in Pennsylvania. Mr. Rimal modified Concentric's ACCOS model to incorporate three distinct test years simultaneously and automated the results creation process.
- Responsible for the development of various cost allocation studies for two electric utilities in New York as part of the cost of service study.

- Supported the developed revenue requirement model to comply with a new performance based formula ratemaking process for a Midwest electric utility.
- Supported cash working capital studies on multiple cases by conducting billing lag analysis involving extremely large data sets utilizing SPSS and R software.
- Created model in R to statistically compare hourly load data between two distinct types of meters to assist a utility in its load research program.
- Created an excel based benchmarking model that have been used on multiple occasions to assess performance of several utilities against various peer groups.
- Supported the development of a rate model to calculate the annual cost of service rates as well as a levelized rate for conversion of an oil pipeline into a natural gas pipeline.

Market Assessment and Asset Optimization Review

- Involved on projects, with two different gas utilities in the Northwest, that forecasted the evolution of demand for compressed natural gas and liquefied natural gas in the transportation sector in their respective territories. Mr. Rimal developed models to analyze the market penetration of different transportation fuels under various fuel price spread scenarios and other market dynamics.
- Estimated the impact on electricity prices due to pre-mature closure of certain nuclear facilities using regression analysis. Validated the price impacts by analyzing the generation supply curve for the location in question.
- Annual assessment of asset manager's performance on multiple occasions by conducting asset optimization analysis of client's natural gas portfolio consisting of both transportation and storage assets.

Valuation

- Created a Discounted Cash Flow ("DCF") model to value a generic regulated natural gas local distribution company ("LDC"). The model was customized to create valuation for any LDC covered by SNL Financial by automating the data retrieval process from SNL based on user input. The model had an added functionality of triggering a revenue enhancement when the earned ROE was outside certain pre-established thresholds.
- Created Discounted Cash Flow ("DCF") models to assess the profitability of various generic units operating in the New York Control Area for NYISO.

Capacity Price Forecasting

- Updated and modified Concentric's Capacity model used to forecast capacity prices for various regions within NYISO based on existing and planned generation, planned retirements, transmission constraints, market mitigation rules, gross and net CONE estimates, and other relevant demand curve parameters.

Relevant ICF Experience

- While at ICF, Mr. Rimal was part of a team that assisted the EPA's Clean Air Market Division (CAMD) in analyzing the effect of environmental policies on power generation sector. As a part of this effort, he was significantly involved in executing as well as maintaining and updating the Technology Retrofit and Updating Model (TRUM). The TRUM model simulates the action of the electric utilities industry under a multi-pollutant emissions trading program.
- Assisted in the creation of an excel model that assessed the impacts of GHG mitigation policies on the competitiveness of the US manufacturing industries.
- Provided support to the Hours of Service regulation by analyzing different crash related data to identify main causes of fatigue among drivers by utilizing logistic regression models.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2011 – Present)
Vice President
Assistant Vice President
Senior Project Manager
Project Manager
Senior Consultant
Consultant
Assistant Consultant
Associate

ICF International (2006 – 2009)
Associate
Analyst
Research Assistant

EDUCATION

University of Wisconsin – Madison
M.A., International Public Affairs, 2011

Colgate University
B.A., Chemistry, Colgate University, 2006

ARTICLES AND PUBLICATIONS

Nemet Gregory F., Braden Peter, Cubero Ed, Rimal Bickey. Four decades of multiyear targets in energy policy: aspirations or credible commitments? WIREs Energy Environ. 2014, 3: 522-533.

AVAILABLE UPON REQUEST

Extensive client and project references, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
The Regulatory Commission of Alaska				
Golden Heart Utilities, Inc. and College Utilities Corporation	2024	Golden Heart Utilities, Inc. and College Utilities Corporation	Docket Nos. U-24-030 and U-24-031	Embedded Cost of Service and Rate Design; Weather Normalization Adjustment
Arizona Corporation Commission				
Epcor Water Arizona Inc.	2020	Epcor Water Arizona Inc.	Docket No. WS-01303A-20-0177	Embedded Cost of Service, Rate Design and Rate Consolidation; Weather Normalization Adjustment
Epcor Water Arizona Inc.	2022	Epcor Water Arizona Inc.	Docket No. WS-01303A-22-0236, et al.	Embedded Cost of Service, Rate Design, and Rate Consolidation
Epcor Water Arizona Inc.	2024	Epcor Water Arizona Inc.	Docket No. WS-01303A-24-0130	Embedded Cost of Service and Rate Design
Connecticut Public Utilities Regulatory Authority				
The Connecticut Water Company	2021	The Connecticut Water Company	Docket No. 20-12-30	Allocated Cost of Service, Rate Design and Rate Consolidation
The United Illuminating Company	2022	The United Illuminating Company	Docket No. 22-08-08	Allocated Cost of Service and Rate Design
Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company	2023	Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company	Docket No, 23-11-02	Allocated Cost of Service and Rate Design
The United Illuminating Company	2024	The United Illuminating Company	Docket No. 24-10-04	Allocated Cost of Service and Advanced Rate Design
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Co.	2015	Northern Indiana Public Service Co.	Cause No. 44688	Cost Allocation
Northern Indiana Public Service Co.	2018	Northern Indiana Public Service Co.	Cause No. 45159	Cost Allocation

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Indianapolis Power & Light Co.	2019	Indianapolis Power & Light Co.	Cause No. 45211	Cost Allocation as it relates to a Special Contract
AES Indiana	2023	AES Indiana	Cause No. 45911	Embedded Cost of Service and Rate Design
Duke Energy Indiana	2024	Duke Energy Indiana	Cause No. 46038	Minimum System Study
AES Indiana	2025	AES Indiana	Cause No. 46258	Embedded Cost of Service and Rate Design
Maine Public Utilities Commission				
Central Maine Power Company	2022	Central Main Power Company	Docket No. 2022-00152	Embedded Cost of Service Study
Massachusetts Department of Public Utilities				
Boston Gas Company d/b/a National Grid	2020	Boston Gas Company d/b/a National Grid	DPU 20-120	Embedded Cost of Service and Rate Design
The Berkshire Gas Company	2022	The Berkshire Gas Company	DPU 22-20	Embedded Cost of Service
Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty	2025	Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty	DPU 25-85	Embedded Cost of Service and Rate Design
Public Utilities Commission of Nevada				
Great Basin Water Co.	2024	Great Basin Water Co.	Docket No. 24-12003	Embedded Cost of Service, Rate Design, and Rate Consolidation
New York State Department of Public Service				
New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation	2022	New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation	Case 22-E-0317	Embedded Cost of Service
National Fuel Gas Distribution Corporation	2023	National Fuel Gas Distribution Corporation	Case 23-G-0627	Embedded Cost of Service
St. Lawrence Gas	2024	St. Lawrence Gas	Case 24-G-0668	Embedded Cost of Service and Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation	2025	New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation	Cases 25-E-0375, 25-G-0378, 25-E-0379, and 25-G-0380	Embedded Cost of Service and Standby Rate Design

Attributes of the Concentric Class Cost of Service Model

The Concentric Energy Advisors ("Concentric") allocated cost of service model (the "Model") contains many features that promote ease of use, efficiency and adaptability. These include:

- **Information linked, not transferred** – Rather than transferring or copying tables of data between worksheets, the Concentric model uses the linking capabilities of the software to directly reference information in one area that is used later in the cost of service process.

- **Color Coding** – Cells are shaded specific colors to indicate factor related inputs, data related inputs, data transferred from another worksheet, data checking and formulas that shouldn't normally be modified.

- **Expandable customer class specification** – The model is configured to allow up to 19 rate classes. Additional customer classes can be created with minor modifications to the model.

- **Centralized inputs** – Instead of having external input data located throughout the model, inputs have been centralized to three worksheets. This has been done to simplify data entry and to help prevent the user from forgetting to update information in a particular file or worksheet.

- **Automated functionalization, classification, and allocation** – The model automatically changes the allocation percentages whenever the user changes a functionalization, classification, or allocation factor of an account. There is no need to recode the allocation percentages or change cell formulas.

- **Cost tracking** – Costs can be tracked on a functional basis allowing for the calculation of functional revenue requirements and functional unit rates. Additional functional categories can be created with minor modifications to the model.

- **User-friendly buttons for running macros** – Instead of having to remember commands to run the macros to calculate the model and print various pages, the macros run off of clicking buttons in CONTROLS.

Concentric COS: Overview of Important Concepts

A. Worksheet overview

The Model contains 14 worksheets as follows:

1. CONTROLS – Contains buttons to run the macros to calculate the model and print various worksheets.
2. INPUTS – Provides for the user to specify customer classes, functional factors and classification factors.
3. CLASSIFIERS – Contains areas for data input of external classifiers based on user specified classifications on the INPUTS worksheet.
4. EXTERNAL – Contains areas for data input of user specified external allocators.
5. INTERNAL – Provides for the specification of internal allocation factors.
6. ACCOUNTS – Contains sections for the user to specify plant and expense information by account for the test year. The user can assign functions, classification,n and allocation factors to the various cost elements in this sheet.
7. CLASS – Takes line item cost data and factor information from ACCOUNTS and spreads them out over classification factors.
8. FUNCALLOC – Takes cost data from CLASS and spreads it out to functional/allocation factor categories.
9. CLASS ALLOC – Takes the functional/allocated plant and expense totals and spreads them to customer classes.
10. ACCT DETAIL – Shows, by account, the allocation factor used and the resulting allocation of costs by rate class and cost classification.
11. ACCTFAC – Calculates the factors needed for ACCT DETAIL.
12. REV REQ – The REV REQ sheet calculates the income tax as needed for the SUMMARY. Taking specific lines of data from CLASSALLOC and INPUTS, it calculates income taxes based on the fully functionalized, classified, and allocated costs.
13. SUMMARY – Summarizes results of functionalization, classification and allocation of data into total cost of service, functional rate base, functional revenue requirements and unit costs at equalized rates of return.
14. ErrorCheck – Produce a report of error conditions by row from four worksheets.

B. *Explanation of functional/ allocation factors*

One of the ways the revised model has achieved efficiencies while tracking functionalization is through the use of combined functional/allocation factors for grouping costs before spreading to customer classes.

In ACCOUNTS all cost items that are not assigned an internal factor are assigned a functional factor, classification factor, and allocation factor by which the cost will be distributed to the customer classes. Each cost item is carried into CLASS, which separates each cost into the assigned classification categories (e.g., 100% to DEM) and a macro creates the functional/allocation factor combinations for each cost item. These combinations are the name of the functional factor, an underscore, and the name of the allocation factor (e.g., F_PRODU_CP) assigned to that cost item. At the top of FUNCALLOC there are column headings which contain all of the possible functional/allocation factor combinations. Each cost item is then carried into FUNCALLOC and the portion of the costs associated with each functional/allocation factor is entered into the correct column. The rate base and expense totals in each functional/allocation factor column are pulled into CLASSALLOC, where the grouped costs are split into customer classes based on the allocation factor portion of the combined functional/allocator. The functionalization factor portion of the combined functional/allocation factors allows for subtotaling rate base and expenses by function that will be used throughout the rest of the model. Therefore, tracking grouped costs using the functional/allocators allows for calculating functionalized revenue requirements and unit costs.

All external and internal allocation factors must be assigned a name. In addition, each external allocation factor must be assigned a classification. Use of an unnamed allocation factor will cause an error condition which will be flagged in the orange "Check" column and reported on the ErrorCheck worksheet when the user runs the error check macro. Using an allocation factor in a different classification column on ACCOUNTS than that specified for the allocator on EXTERNAL may cause an error condition. To avoid any potential problems do not use allocator for more than one classification. Instead, create a second allocator with a different name. There are no problems that occur if an allocator on EXTERNAL or INTERNAL is not used. However, creating unnecessary allocation factors expands the size of the model.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 8

Direct Testimony of Steven W. Wishart

Topics: **Rate Design**
Standby Service Tariff (Rule 6 and 6A)
Proof of Revenues
Proposed Rates
Bill Impacts

Dated: September 30, 2025

I. INTRODUCTION

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

A. My name is Steven W. Wishart. I am an Assistant Vice President with Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Finance and a Master of Science in Resource Economics from the University of Arizona, and I have completed all coursework toward a Ph.D. in Applied Economics at the University of Minnesota. I have worked in the energy industry for more than 20 years. Prior to joining Concentric in 2023, I worked at Xcel Energy for nearly two decades, where I held leadership roles in Pricing and Regulatory Analytics as well as Resource Planning. In those positions, I was responsible for rate design, cost allocation, forecasting, and resource planning analyses in support of numerous regulatory filings. In my current role at Concentric, I advise utilities and other energy sector clients on rate design, cost allocation, affordability, and related regulatory matters.

Q. Have you previously testified before regulatory commissions?

A. Yes. I have testified in more than 35 proceedings before state commissions and the Federal Energy Regulatory Commission on topics including rate design, class cost of service, affordability, and resource planning.

Q. On whose behalf are you presenting this testimony?

A. I am presenting this testimony on behalf of PPL Electric Utilities Corporation ("PPL Electric" or the "Company").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and support PPL Electric's proposed rate design in this proceeding. My testimony explains how the Company has applied well-established ratemaking principles—cost causation, gradualism, customer understanding, and administrative feasibility—to design fair, reasonable, and understandable rates for all customer classes. I also explain how the results of the Allocated Cost of Service Study ("ACOSS") inform the proposed rates, provide the required proof of revenues and bill impact analyses, and present the Company's proposals for updates to residential, general service, lighting, and standby tariffs.

Q. How is your testimony organized?

A. Following this introduction, my testimony proceeds as follows:

Section II outlines the principles of rate design, the results of the ACOSS, and the billing determinants for the Fully Projected Future Test Year ("FPFTY").

Section III presents the Company's proposed residential rate design, including changes to the fixed monthly customer charge, energy charges, and protections for low-income customers.

Section IV addresses the proposed rate design for General Service classes, including the treatment of volunteer organizations.

Section V discusses the Company's proposed updates to lighting schedules.

Section VI introduces the proposed Standby Service Tariff, which consolidates existing standby provisions and ensures that customers with on-site generation pay appropriately for the resources they use.

Section VII provides a proof of revenues that demonstrates that the proposed rates result in the total distribution revenue requirement that the Company is proposing.

Through this testimony, I demonstrate that PPL Electric's proposals represent a balanced approach that moves rates toward cost-based levels while respecting gradualism and maintaining customer protections.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, attached to my testimony as PPL Electric Exhibit SWW-1, which provides detailed average customer bill analysis that demonstrates the overall impact of the Company's proposal, and portions of Part IV of the filing requirements as noted on its index.

II. RATE DESIGN OVERVIEW

Q. What principles did you apply in developing PPL Electric's proposed rate design?

A. In designing PPL Electric's proposed rates, I applied several well-recognized ratemaking principles. First and foremost, rates should reflect cost causation, meaning that customers' rates are based on the cost of service and, therefore, compliant with the *Lloyd* decision by the Commonwealth Court of Pennsylvania.[1] Second, the principle of gradualism recognizes that movement toward cost-based rates should occur in a measured way that

[1] *Lloyd v. Pa. PUC*, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006) (stating that the "polestar" in designing rates is the "cost of providing service").

avoids abrupt or excessive bill impacts. However, as recognized by the Court in *Lloyd*, gradualism cannot trump all other ratemaking concerns, including cost of service.[2] Third, rates should promote customer understanding, so that customers can see how their usage and demand decisions affect their bills. Finally, rate structures must meet the standard of administrative feasibility—that is, they must be implementable through the Company's billing systems and straightforward to administer.

Q. How have you emphasized these principles in this case?

A. The Company's rate proposals are grounded in cost of service. However, where appropriate, PPL Electric has moderated certain outcomes to respect gradualism and customer impacts. For example, the residential fixed monthly charge supported by the ACOSS and minimum system analysis is more than twice the proposed charge. Recognizing the potential for bill shock, PPL Electric has proposed a more moderate increase that moves toward cost-based recovery without imposing an abrupt shift. Similarly, while the ACOSS indicates higher customer charges for certain general service classes, the Company's proposals temper these increases to avoid disproportionate customer impacts.

Q. How does the ACOSS inform your rate design proposals?

A. The ACOSS, sponsored by PPL Electric witness Bickey Rimal (PPL Electric St. No. 7), establishes the revenue responsibility for each major customer class. My rate design begins with these class revenue requirements. Within each class, I have then designed rates that

---

[2] *See id.*

move recovery toward the class's cost of service, while balancing the principles of gradualism, customer understanding, and administrative feasibility. In short, the cost of service study tells us *how much* revenue should be collected from each class, and my testimony addresses *how* those revenues should be collected. Table 1 below aligns the major rate schedules in PPL Electric's tariff with the corresponding classes in the ACOSS.

Table 1 – Customer Class to Rate Schedule Mapping[3]

Customer Class	**Rate Schedule**
Residential	RS (Residential Service) RTS (Residential Thermal Storage) *To be eliminated*
Small General Service - Sec. Voltage	GS-1 (Single-Phase General Service) GS-1 (Volunteer Fire, Non-Profit Rescue, etc.) GH-2 (Separate Meter General Space Heating) *To be eliminated*
Large General Service - Sec. Voltage	GS-3 (Three-Phase General Service) GS-3 (Volunteer Fire, Non-Profit Rescue, etc.)
Large General Service - 12 KV	LP-4 (Large General Service – 12 kV)
Large General Service - 69 KV or Higher	LP-5 (Large General Service – 69 kV or higher)
Street Lighting/Area Lighting	SA (Private Area Lighting) SM(R) (Mercury Vapor Street Lighting) SHS (High Pressure Sodium Street Lighting) SLE (LED Street Lighting) SE (Energy Only Street Lighting) TS (Traffic Signal Lighting)

Q. What is the Company proposing with respect to Smart Meter Rider – Phase 2 ("SMR-2"), the Tax Cuts and Jobs Act Rider ("TCJA"), the Distribution System Improvement Charge ("DSIC"), the Competitive Enhancement Rider ("CER"), the

[3] The Company is also proposing to eliminate the Power Service to Electric Propulsion tariff, Rate Schedule LPEP. This change will have no impact as there are currently no customers taking service under that rate schedule.

State Tax Adjustment Surcharge ("STAS"), and the Storm Damage Expense Rider ("SDER")?

A. As explained in PPL Electric witness Katelyn Arnold's direct testimony (PPL Electric St. No. 13), the Company proposes to roll the SMR-2, TCJA, and DSIC rider mechanisms into base rates. Consequently, the DSIC will then be reset to zero in accordance with Section 1358(b)(1) of the Public Utility Code, and the SMR-2 and TCJA will be eliminated. Also, for the CER, the Company is proposing to eliminate it and, instead, to rely on base rates to recover the costs of administering the Eligible Customer List ("ECL"). Further, upon the effective date of new rates, the STAS and SDER will be reset to zero.

Q. Are these proposals reflected in the rates that you have designed in this proceeding?

A. Yes.

Q. What billing determinants did you rely on in preparing your rate design?

A. I relied on billing determinants developed for the fully projected future test year ("FPFTY") ending June 30, 2027. These determinants include customer counts, kilowatt-hour ("kWh") sales, and kilowatt ("kW") billing demands by class. They were developed from the Company's metering data, load research, and forecasting processes, and reflect expected levels of customer usage and demand in the FPFTY. These determinants form the foundation for the proof of revenues at proposed rates and the customer bill impact analyses presented later in my testimony.

Q. Do the Company's proposals comply with the Pennsylvania Public Utility Commission's filing requirements?

A. Yes. The Pennsylvania Public Utility Commission's ("Commission") regulations, specifically 52 Pa. Code § 53.53, require utilities to provide a proof of revenues at present and proposed rates and, bill frequency and bill impact analyses, and tariff sheets in both clean and blackline form. My testimony, together with the accompanying exhibits and workpapers, provides each of these elements. This ensures that the Commission has the information necessary to evaluate both the revenue adequacy of PPL Electric's proposed rates and their effect on customers.

Q. How do the Company's proposals impact customer bills on average?

A. As discussed in more detail later in my testimony, the average customer bill impacts are largely driven by the class revenue allocations from the ACOSS. For most customer classes, base distribution charges increase more significantly than total bills, since distribution charges represent only a portion of a customer's total bill. Table 2 below summarizes the average bill impacts for major rate schedules.

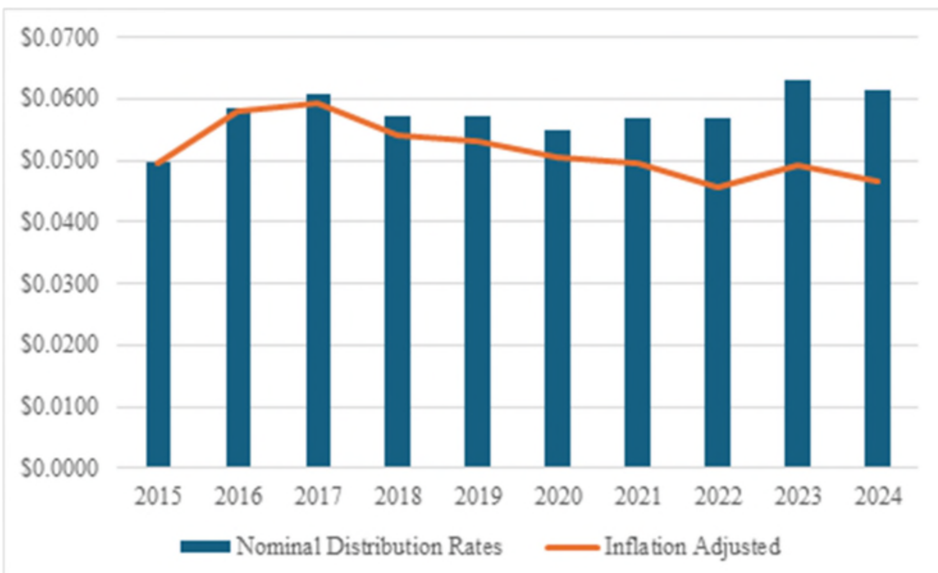
Table 2 – Average Bill Impacts by Rate Schedule

Average Bill Impacts	Base Rates	Total Distribution Rates	Total Bill
Residential	34.5%	19.9%	7.0%
GS-1	35.2%	23.5%	6.8%
GS-3	31.8%	20.9%	2.8%
LP-4	51.5%	28.4%	2.6%
LP-5	-2.1%	-0.7%	0.0%
Lighting	18.4% - 20.4%	19.0%-19.7%	6.5%-18.3%

Q. How have PPL Electric's residential delivery rates trended over the past decade?

A. PPL Electric's residential delivery rates have remained relatively stable over the last 10 years. Based on U.S. Energy Information Administration ("EIA") Form 861 data,[4] PPL Electric's average residential delivery rate increased at an average annual rate of only 0.6 percent over the period 2016 through 2024. Adjusted for inflation, however, PPL Electric's average residential delivery rate actually declined by approximately 19.7 percent over this period. This means that while customers have seen modest nominal increases in their delivery rates, in real terms the cost of delivery service has been falling since the Company's last rate case. Figure 1 illustrates this trend.

Figure 1 – PPL Electric Residential Delivery Rates 2015–2024

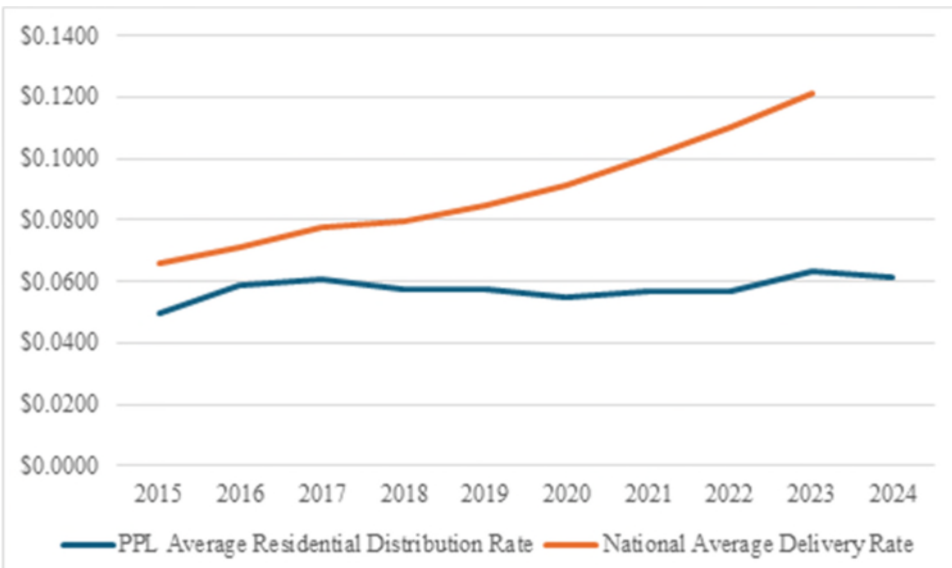


[4] EIA Form 861 divides total sales and revenue data between bundled service volumes and unbundled (delivery) volumes. The data reflects revenue from state and local income taxes, energy or demand charges, customer service charges, environmental surcharges, franchise fees, fuel adjustments and other miscellaneous charges applied to end-use customers during normal billing operations.

Q. How do PPL Electric's residential delivery rates compare to the national average?

A. PPL Electric's residential delivery rates are well below the national average and have become increasingly competitive over time. In 2015, PPL Electric's average residential delivery rate was approximately 24.7 percent below the national average. By 2023, the gap had widened to 47.9 percent. This widening differential demonstrates that even with the increases proposed in this proceeding, PPL Electric's residential delivery rates will remain substantially lower than the national average. Figure 2 provides a comparison of PPL Electric's average residential delivery rates to the national average.

Figure 2 – PPL Electric vs. National Average Residential Delivery Rates



III. RESIDENTIAL RATE DESIGN

Q. Is PPL Electric proposing an increase in the residential fixed monthly customer charge?

A. Yes. The Company is proposing a modest increase in the residential customer charge from $15.58 to $17.00. This proposed increase is intended to better align the residential customer charge with the underlying fixed costs of connecting and serving residential customers. Customer-related costs include the service drop, meter, billing, and customer service functions. These costs do not vary with usage. Instead, they are driven by the number of customers on the system. Under current rates, these fixed costs are not fully recovered through the residential customer charge, which means they are instead recovered through volumetric charge. This design results in a cross-subsidy where higher-use customers bear a disproportionate share of fixed costs, while lower-use customers contribute less than their cost of service. Increasing the fixed charge reduces this subsidy, improves cost alignment, and enhances bill stability and revenue adequacy.

Q. What customer charge is supported by the ACOSS?

A. The ACOSS and the accompanying minimum system study support a residential customer charge of $42.92 per month. However, recognizing the principle of gradualism, the Company has proposed a lower charge of $17.00 per month in this case. This amount represents a reasonable step toward cost-based rates while mitigating customer bill impacts.

Table 3 – Residential Fixed Monthly Customer Charge

Current	$15.58
Proposed	$17.00
Cost Based Charge	$42.92

Q. How does the Company propose to structure residential rates under the new design?

A. Under the proposal, residential customers will see increases in both the fixed customer charge and the per-kWh energy charge. However, the changes to base distribution rates are complicated by the roll-in of SMR-2, TCJA, and DSIC, the elimination of CER, and the resetting of the SDER and STAS to zero, which affects the apparent magnitude of the increase. Table 4 provides a comparison of current and proposed residential charges, showing the impact of adjustments to the SMR-2, TCJA, DSIC, CER, and STAS.

Table 4 – Residential Rate Comparison: Current vs. Proposed Charges

	Current Rates	Proposed Rates	Change
Customer Charge (without riders)	$14.09/Bill	$17.00/Bill	
TCJA	-8.0%		
SMR 2	$1.50/Bill		
CER	-$0.01/Bill		
DSIC	7.5%		
STAS	-0.28%		
Total Base Customer Charge	$15.49/Bill	$17.00/Bill	9.7%
Energy Charge (without riders)	$0.03534/kWh	$0.04965/kWh	
TCJA	-8.0%		
ACR 4	$0.00220/kWh	$0.00220/kWh	
USR	$0.01111/kWh	$0.01111/kWh	
SDER	$0.00184/kWh		
DSIC	7.5%		
STAS	-0.28%		
Total Base Energy Charge	$0.05109/kWh	$0.06296/kWh	23.2%

Q. What is the impact of these changes on average residential bills?

A. While the Company is proposing to increase base distribution charges, these charges represent a relatively small portion of a customer's total bill. On average, the proposed changes increase residential base rates by 34.5 percent, but total residential bills increase by only 7.0 percent. Table 5 illustrates this impact for an average residential customer using 918 kWh per month.

Table 5 – Average Residential RS Bill Impact

	Current Rates	Proposed Rates	Change
FPFTY Ave. Monthly Use	918 kWh		
Base Rates	$46.52	$62.56	34.5%
Distribution Riders	$15.86	$12.21	-23.0%
Distribution Subtotal	$62.38	$74.78	19.9%
Energy Supply	$114.62	$114.62	0.0%
Total Bill	$177.01	$189.40	7.0%

Q. How does the proposed design balance cost causation and gradualism?

A. By setting the residential customer charge at $17.00 rather than the full cost-based amount of $42.92, PPL Electric is striking a balance between the goal of cost causation and the need for gradualism. This approach reduces cross-subsidies among residential customers while avoiding sudden or excessive bill increases for lower-use households. It also improves bill stability by ensuring that a larger share of fixed costs is recovered through fixed charges, thereby reducing reliance on usage-driven revenues.

Q. What is PPL Electric proposing for the Residential Thermal Storage (RTS) rate schedule?

A. The Company is proposing to eliminate Rate Schedule RTS in this proceeding. RTS has been closed to new customers since December 31, 1995, and the Company currently has 11,509 residential customers taking service through this rate. Customers currently taking service through RTS will be migrated to schedule RS when the new rates established in this proceeding become effective.

Q. What are the expected bill impacts for Rate Schedule RTS customers migrating to Rate Schedule RS?

A. On average, RTS customers will experience an overall increase in total monthly bills of about 12.4 percent. These bill impacts demonstrate that while RTS distribution rates are moving closer to cost-based levels, the overall effect on customer bills remains moderate.

Table 6 – Average Residential Thermal Storage (RTS) Bill Impact

	Current RTS Rates	Proposed RS Rates	Change
FPFTY Average Monthly Use	1,664 kWh		
Base Rates	$57.45	$99.63	73.4%
Distribution Riders	$27.84	$22.15	-20.4%
Distribution Subtotal	$85.29	$121.78	42.8%
Energy Supply	$207.86	$207.86	0.0%
Total Bill	$293.15	$329.64	12.4%

IV. GENERAL SERVICE RATE DESIGN

Q. How did you approach rate design for the General Service rate classes?

A. For the General Service rate schedules, I began with the class revenue responsibilities identified in the ACOSS sponsored by PPL Electric witness Bickey Rimal. Within each rate class, I designed rates that align fixed charges more closely with customer-related costs while ensuring that demand and energy charges recover demand- and energy-related costs, respectively. In doing so, I applied the principles of cost causation, gradualism, and customer understanding. Where the ACOSS supported materially higher customer charges than current levels, I moderated the increases to avoid excessive bill impacts while still moving toward their cost of service.

Q. What is PPL Electric proposing for Rate Schedule GS-1 (Single-Phase General Service)?

A. The customer charge for GS-1 is proposed at $30.00 per month, compared to $43.18 per month supported by the ACOSS. This moderation recognizes the principle of gradualism, while still moving recovery of fixed costs in the right direction. Because the proposed customer charge is below cost-based levels, the associated demand charge has been increased slightly more than proportionately to ensure that class revenues meet the ACOSS target.

Table 7 – Current and Proposed Charges for GS-1

	Current Rates	Current Rates With Roll-In Riders	Proposed Rates	Change	ACOSS Based Results
Customer Charge	$22.00/Bill	$24.93/Bill	$30.00/Bill	20.3%	$43.18/Bill
Demand Charge	$4.361/kW	$4.301/kW	$5.846/kW	35.9%	$3.333/kW

Q. How will the proposed rates for Rate Schedule GS-1 impact customers' bills?

A. Because generation and transmission charges represent a relatively large portion of GS-1 customers' bills, the impact of the Company's proposal on total bills is relatively small. The increase in distribution charges for the average GS-1 customer bill is 23.8%, which translates to only a 6.8% increase in total customer bills.

Table 8 – Average GS-1 Bill Impact

	Current Rates	Proposed Rates	Change
FPFTY Average Monthly Use	5.25kW & 1,051kWh		
Base Rates	$44.88	$60.67	35.2%
Distribution Riders	$5.53	$1.75	-68.4%
Distribution Subtotal	$50.41	$62.41	23.8%
Energy Supply	$127.36	$127.36	0.0%
Total Bill	$177.77	$189.78	6.8%

Q. What is PPL Electric proposing for Rate Schedule GH-2(R) (Separate Meter General Space Heating Service)?

A. Similar to the proposal for RTS, the Company is proposing that Schedule GH-2(R) be eliminated and that any customers taking service under that rate be migrated to Schedule GS-1. About 1,500 customers currently take service through GH-2(R) and their annual energy use represents about 2% of the total load in the GS-1 customer class.

Q. What are the expected bill impacts for Rate Schedule GH-2(R) customers migrating to Rate Schedule GS-1?

A. On average, GH-2(R) customers will have 34.8% higher distribution charges and total bill increases of 8.8%.

Table 9 – Average GH-2(R) Bill Impact

	Current GH-2(R) Rates	Proposed GS-1 Rates	Change
FFTY Average Monthly Use	13.1kW & 1,991kWh		
Base Rates	$73.71	$106.44	44.4%
Distribution Riders	$7.73	$3.30	-57.3%
Distribution Subtotal	$81.44	$109.74	34.8%
Energy Supply	$241.19	$241.19	0.0%
Total Bill	$322.63	$350.93	8.8%

Q. What is PPL Electric proposing for Rate Schedule GS-3 (Three-Phase General Service)?

A. For Rate Schedule GS-3, PPL Electric proposes to set the monthly customer charge at $78, which is slightly higher than the $73 level supported by the ACOSS. This proposal balances the increase to customer and demand charges in Rate Schedule GS-3. As a result, the proposed demand charge increases slightly more than the customer charge, ensuring that the rate class's revenue responsibility is met in a way that balances cost alignment and customer impacts.

Table 10 – Current and Proposed Charges for GS-3

Rate Design	Current Rates	Current Rates With Roll-In Riders	Proposed Rates	Change	ACOSS Based Results
Customer Charge	$60.00/Bill	$62.41/Bill	$78.00/Bill	25.0%	$72.96/Bill
Demand Charge	$3.985/kW	$3.930/kW	$5.272/kW	34.1%	$5.369/kW
TCJA	-8.0%				
SMR 2	$3.03/Bill				
CER	-$0.01/Bill				
SDER	$0.00092/kWh				
DSIC	7.5%				

Q. How will the proposed rates for Rate Schedule GS-3 impact customer's bills?

A. Because generation and transmission charges represent a relatively large portion of GS-3 customer bills, the impact of the Company's proposal on total bills is relatively small. The increase in distribution charges for the average GS-1 customer bill is 23.8%, which translates to only a 6.8% increase in total customer bills.

Table 11 – Average GS-3 Bill Impact

	Current Rates	Proposed Rates	Change
FPFTY Average Monthly Use	53kW & 17,231 kWh		
Base Rates	$270.22	$356.12	31.8%
Distribution Riders	$47.19	$28.60	-39.4%
Distribution Subtotal	$317.42	$384.72	21.2%
Energy Supply	$2,087.33	$2,087.35	0.0%
Total Bill	$2,404.74	$2,472.07	2.8%

Q. How are rates determined for volunteer organizations, such as Volunteer Fire Companies, Non-Profit Senior Citizen Centers, Non-Profit Rescue Squads, and Non-Profit Ambulance Services?

A. Under PPL Electric's tariff, these organizations may elect to take service under either the GS-1 or GS-3 schedules, but their charges are set equal to the residential rate schedule. Specifically, they pay the same monthly customer charge and per-kWh distribution charge as residential customers. This treatment reflects the public service nature of these organizations and ensures they are billed at levels consistent with residential customers, rather than the peak demand charges applicable to other General Service customers.

Q. What is PPL Electric proposing for Rate Schedule LP-4 (Large General Service – 12,470 volts)?

A. For Rate Schedule LP-4, PPL Electric proposes a customer charge of $235 per month, which is higher than the $209 charge supported by the ACOSS. This adjustment recognizes that even with a higher fixed charge, the demand component remains the predominant driver of LP-4 revenues. In this case, a modestly higher customer charge provides greater revenue stability without materially shifting cost responsibility among customers in the class.

Table 12 – Current and Proposed Charges for LP-4

	Current Rates	Current Rates With Roll-In Riders	Proposed Rates	Change	ACOSS Based Results
Customer Charge	$169.80/Bill	$350.67/Bill	$235.00/Bill	-33.0%	$209.70/Bill
Demand Charge	$2.547/kW	$2.519/kW	$3.881/kW	54.5%	$3.907/kW
TCJA	-8.0%				
SMR 2	$63.12/Bill				
CER	-$0.01/Bill				
SDER	$123.10/Bill				
DSIC	7.5%				
STAS-D	-0.28%				

Q. What is PPL Electric proposing for Rate Schedule LP-5 (Large General Service – 69 kV or higher)?

A. Rate Schedule LP-5 is unique in that its base distribution charges consist entirely of a monthly customer charge. Based on the ACOSS results, the Company is proposing to reduce this charge slightly, from $994 per month under current rates to $973.44 per month. This reduction reflects cost causation and ensures that LP-5 customers pay no more than their allocated cost responsibility.

Table 13 – Current and Proposed Charges for LP-5

	Current Rates	Current Rates With Roll-In Riders	Proposed Rates	Change	ACOSS Based Results
Customer Charge	$994.00/Bill	$1,079.09/Bill	$973.44/Bill	-9.8%	$973.44/Bill
TCJA	-8.0%				
SMR 2	$63.12/Bill				
CER	-$0.01/Bill				
SDER	$101.50/Bill				
DSIC	0.0%				

V. STREET AND AREA LIGHTING RATE DESIGN

Q. Please describe the street and area lighting rate schedules offered by PPL Electric.

A. PPL Electric offers several street and area lighting schedules. These schedules include Schedule SA (Private Area Lighting), Schedule SM(R) (Mercury Vapor Street Lighting), Schedule SHS (High Pressure Sodium Street Lighting), Schedule SLE (Light Emitting Diode Street Lighting), Schedule SE (Energy-Only Street Lighting), and Schedule TS(R) (Traffic Signal Service). In total, there are approximately 80 distinct fixture and service options across these schedules, reflecting different fixture types, wattages, lumen outputs, and maintenance requirements.

Q. How did the Company develop proposed rates for these lighting schedules?

A. In this proceeding, the Company did not conduct a fixture-by-fixture cost analysis to establish separate net book values or unit costs for each of the 80 lighting options. Instead, PPL Electric relied on the class level results of the ACOSS. The ACOSS indicated that overall lighting class revenues should increase by 19.9 percent, inclusive of the distribution riders that are being incorporated into base rates. PPL Electric applied that uniform class-wide increase to existing lighting charges. This approach maintains the current price differentials between various fixture types and schedules, thereby preserving customer expectations and avoiding abrupt changes in the relative costs of different lighting technologies.

Q. Is this approach consistent with the treatment of lighting rates by other Pennsylvania utilities?

A. Yes. For example, in PECO Energy Company's ("PECO") most recent electric base rate case, PECO applied a proportional adjustment to all lighting rates based on the class revenue requirement, rather than attempting a detailed lamp-by-lamp cost study. Similarly, UGI Utilities, Inc. – Electric Division ("UGI Electric") adopted an approach in which the lighting class increase was set based on ACOSS results, without recalculating costs for each individual fixture. These precedents confirm that applying a uniform adjustment at the class level is a reasonable and administratively feasible method for updating lighting rates.

Q. What are the expected bill impacts for lighting customers?

A. I have calculated that the impact of the proposed new lighting rates on total distribution charges will range from 19.0% to 19.7%. The range is due to the application of the various distribution riders. The overall bill impact, including energy supply charges, ranges from 6.5% to 18.3%. This range is larger due to the wide range of energy use by the various lighting types.

VI. STANDBY SERVICE TARIFF (RULE 6 AND 6A)

Q. What is the Company proposing with respect to standby service?

A. The Company is proposing to replace its existing standby service provisions under Rule 6 and Rule 6A with a new consolidated standby service, which is set forth in its proposed retail tariff (PPL Electric Exhibit GEO-1). The new tariff will apply to non-residential customers with on-site generation facilities greater than 3 MW and to other non-residential customers with on-site generation who do not qualify for net metering service.

Q. Why is the Company proposing this change?

A. The existing standby service provisions are complex and rely on rules that have not been comprehensively updated in many years. The proposed tariff simplifies the structure by consolidating the Company's standby service obligations into a single schedule. More importantly, the new tariff ensures that customers with on-site generation pay appropriately for the system resources they require, including capacity that must be available to serve them when their generation is not operating.

Q. How will the new standby tariff operate?

A. Customers will be required to enter into a Standby Service Contract with the Company specifying three contractual quantities: (1) Supplementary Contract Demand—the portion of the customer's demand expected to exceed their on-site generation capability; (2) Back-Up Contract Demand—the portion of the customer's demand served by their on-site generation, which the Company must stand ready to serve in the event of an unplanned outage; and (3) Total Contract Demand—the sum of supplementary and back-up contract demand.

Supplementary power will be billed at standard tariff rates. Back-up power will be subject to a monthly reservation charge and, when used, to demand charges that vary depending on whether the outage occurs in on-peak or off-peak months. Maintenance power, available during scheduled outages in off-peak months, will be priced at no additional cost for capacity.

Q. How does the proposed standby service compare to the current provisions under Rules 6 and 6A?

A. The proposed tariff eliminates the duplicative and outdated language in Rules 6 and 6A and replaces it with a clear, modern framework. The Company's proposal more clearly distinguishes between supplementary, back-up, and maintenance power, and provides price signals that encourage customers to schedule maintenance during off-peak periods and minimize reliance on back-up service during peak months.

Q. What is the ratemaking justification for this proposal?

A. The proposed standby service ensures that customers with on-site generation contribute appropriately to the cost of system resources required to serve them, thereby preventing cross-subsidization from other customers. At the same time, the simplified structure will improve customer understanding and administrative feasibility.

VII. PROOF OF REVENUES

Q. What is a proof of revenues, and why is it required in this proceeding?

A. A proof of revenues is a reconciliation required by the Commission's regulations. It demonstrates that the revenues to be collected under proposed rates align with the total distribution revenue requirement established in the ACOSS. The proof of revenues compares expected revenues at present rates with riders rolled into base rates to the revenues expected under proposed rates in the FPFTY. This comparison provides assurance to the Commission and stakeholders that the Company's proposed rates are designed to recover, but not materially exceed, the required revenue requirement.

Q. Please present the Company's proof of revenues.

A. Table 14 below compares total revenues by rate schedule in the FPFTY under (1) current rates including riders that are proposed to be rolled into base rates and (2) proposed rates. The table also shows the resulting changes in total revenue for each schedule.

Table 14 – Proof of Revenues

	Current Revenue Including Riders to be Rolled Into Base Rates	**Total Revenue Under Proposed Rates**	**Change in Total Revenue**	
RS Residential Service	$789,757,365	$984,902,533	$195,145,168	24.71%
GS-1 Single Phase General Service	$86,919,657	$108,369,547	$21,449,890	24.68%
GS-1 Volunteer / Non-Profit	$828,990	$1,064,293	$235,303	28.38%
GS-3 Three Phase General Service	$138,063,109	$170,249,019	$32,185,909	23.31%
GS-3 Volunteer / Non-Profit	$98,908	$128,569	$29,661	29.99%
LP-4 Large General Service at 12,470 Volts	$42,497,721	$59,048,155	$16,550,434	38.94%
LP-5 Large General Service at 69,000 Volts or Higher	$2,069,447	$1,940,352	-$129,095	-6.24%
SA Private Area Lighting Service	$3,796,032	$4,554,830	$758,799	19.99%
SM(R) Mercury Vapor Street Lighting Service	$253,167	$302,887	$49,719	19.64%
SHS High Pressure Sodium Street Lighting Service	$9,771,778	$11,712,519	$1,940,740	19.86%
SLE Light Emitting Diode (LED) Street Lighting Service	$9,695,377	$11,621,686	$1,926,309	19.87%
SE Energy Only Street Lighting Service	$2,045,464	$2,452,776	$407,312	19.91%
TS (R) Municipal Traffic Signal Lighting Service	$31,261	$36,821	$5,560	17.79%
Incremental Revenue BL Borderline Service		$132,981	$132,981	
Total	$1,085,828,276	$1,356,516,966		
ACOSS Total Revenue Requirement		$1,356,442,484		
Difference Due to Rate Rounding		$74,482		

Q. How should the differences across rate schedules be interpreted?

A. The range of revenue changes across the rate schedules primarily reflects how the ACOSS results have changed between this rate case and PPL Electric's last base rate case in 2015. In addition, the differences are partially attributable to changes in how the costs associated with riders such as SMR2, CER, TCJA, and DSIC are allocated when they are rolled into base rates. Moving these costs into base rates can also shift how they are charged to customers, resulting in variations across classes and schedules.

Q. What is the significance of the $74,482 difference between the total revenues at proposed rates and the ACOSS revenue requirement?

A. The total revenue under proposed rates is $1,356,516,966, which is $74,482 higher than the ACOSS revenue requirement of $1,356,442,484. This very small difference is due to necessary rounding conventions in rate design: energy charges are set to five decimal places, demand charges to three decimal places, and customer charges to two decimal places. These rounding rules ensure customer bills are calculable and consistent, while the minor variance does not materially affect recovery.

Q. Does this conclude your direct testimony?

A. Yes.

PPL Electric Utilities Corporation
Rate Schedule: RS Residential Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$14.09/Bill	1 Month	$14.09	$17.00/Bill	1 Month	$17.00	$2.91	20.7%
Energy Charge	$0.03534/kWh	918 kWh	$32.43	$0.04965/kWh	918 kWh	$45.56	$13.13	40.5%
Demand Charge								
TCJA	-8.0%		-$3.72				$3.72	-100.0%
SMR 2	$1.50/Bill	1 Month	$1.50				-$1.50	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00220/kWh	918 kWh	$2.02	$0.00220/kWh	918 kWh	$2.02	$0.00	0.0%
USR	$0.01111/kWh	918 kWh	$10.20	$0.01111/kWh	918 kWh	$10.20	$0.00	0.0%
SDER	$0.00184/kWh	918 kWh	$1.69				-$1.69	-100.0%
DSIC	7.5%		$4.36				-$4.36	-100.0%
Distribution Subtotal			$62.56			$74.78	$12.22	19.5%
State Tax Adjustment	-0.28%		-$0.18				$0.18	-100.0%
Total Distribution Charges			$62.38			$74.78	$12.40	19.9%
GSC-1	$0.09166/kWh	918 kWh	$84.12	$0.09166/kWh	918 kWh	$84.12	$0.00	0.0%
TSC	$0.03324/kWh	918 kWh	$30.51	$0.03324/kWh	918 kWh	$30.51	$0.00	0.0%
Energy & Transmission Subtotal			$114.62			$114.62	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$114.62			$114.62	$0.00	0.0%
Total Average Monthly Bill			$177.01			$189.40	$12.40	7.0%

PPL Electric Utilities Corporation
Rate Schedule: RTS Residential Thermal Storage
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$18.06/Bill	1 Month	$18.06	$17.00/Bill	1 Month	$17.00	-$1.06	-5.9%
Energy Charge	$0.02367/kWh	1,664 kWh	$39.39	$0.04965/kWh	1,664 kWh	$82.63	$43.24	109.8%
Demand Charge								
TCJA	-8.0%		-$4.60				$4.60	-100.0%
SMR 2	$1.50/Bill	1 Month	$1.50				-$1.50	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00220/kWh	1,664 kWh	$3.66	$0.00220/kWh	1,664 kWh	$3.66	$0.00	0.0%
USR	$0.01111/kWh	1,664 kWh	$18.49	$0.01111/kWh	1,664 kWh	$18.49	$0.00	0.0%
SDER	$0.00184/kWh	1,664 kWh	$3.06				-$3.06	-100.0%
DSIC	7.5%		$5.97				-$5.97	-100.0%
Distribution Subtotal			$85.53			$121.78	$36.25	42.4%
State Tax Adjustment	-0.28%		-$0.239				$0.24	-100.0%
Total Distribution Charges			$85.29			$121.78	$36.49	42.8%
GSC-1	$0.09166/kWh	1,664 kWh	$152.54	$0.09166/kWh	1,664 kWh	$152.54	$0.00	0.0%
TSC	$0.03324/kWh	1,664 kWh	$55.32	$0.03324/kWh	1,664 kWh	$55.32	$0.00	0.0%
Energy & Transmission Subtotal			$207.86			$207.86	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$207.86			$207.86	$0.00	0.0%
Total Average Monthly Bill			$293.15			$329.64	$36.49	12.4%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Single Phase General Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$22.00/Bill	1 Month	$22.00	$30.00/Bill	1 Month	$30.00	$8.00	36.4%
Energy Charge								
Demand Charge	$4.361/kW	5.25 kW	$22.88	$5.846/kW	5.25 kW	$30.67	$7.79	34.1%
TCJA	-8.0%		-$3.59				$3.59	-100.0%
SMR 2	$3.03/Bill	1 Month	$3.03				-$3.03	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00166/kWh	1,051 kWh	$1.75	$0.00166/kWh	1,051 kWh	$1.75	$0.00	0.0%
USR								
SDER	$0.00092/kWh	1,051 kWh	$0.97				-$0.97	-100.0%
DSIC	7.5%		$3.53				-$3.53	-100.0%
Distribution Subtotal			$50.55			$62.41	$11.87	23.5%
State Tax Adjustment	-0.28%		-$0.142				$0.14	-100.0%
Total Distribution Charges			$50.40			$62.41	$12.01	23.8%
GSC-1	$0.08956/kWh	1,051 kWh	$94.16	$0.08956/kWh	1,051 kWh	$94.16	$0.00	0.0%
TSC	$0.03158/kWh	1,051 kWh	$33.20	$0.03158/kWh	1,051 kWh	$33.20	$0.00	0.0%
Energy & Transmission Subtotal			$127.36			$127.36	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$127.36			$127.36	$0.00	0.0%
Total Average Monthly Bill			$177.77			$189.78	$12.01	6.8%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Volunteer & Non-Profit Organizations
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$14.09/Bill	1 Month	$14.09	$17.00/Bill	1 Month	$17.00	$2.91	20.7%
Energy Charge	$0.03534/kWh	2,533 kWh	$89.52	$0.04965/kWh	2,533 kWh	$125.77	$36.25	40.5%
Demand Charge								
TCJA	-8.0%		-$8.29				$8.29	-100.0%
SMR 2	$1.50/Bill	1 Month	$1.50				-$1.50	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00220/kWh	2,533 kWh	$5.57	$0.00220/kWh	2,533 kWh	$5.57	$0.00	0.0%
USR	$0.01111/kWh	2,533 kWh	$28.14	$0.01111/kWh	2,533 kWh	$28.14	$0.00	0.0%
SDER	$0.00184/kWh	2,533 kWh	$4.66				-$4.66	-100.0%
DSIC	7.5%		$10.14				-$10.14	-100.0%
Distribution Subtotal			$145.33			$176.49	$31.16	21.4%
State Tax Adjustment	-0.28%		-$0.41				$0.41	-100.0%
Total Distribution Charges			$144.92			$176.49	$31.57	21.8%
GSC-1	$0.08956/kWh	2,533 kWh	$226.87	$0.08956/kWh	2,533 kWh	$226.87	$0.00	0.0%
TSC	$0.03158/kWh	2,533 kWh	$80.00	$0.03158/kWh	2,533 kWh	$80.00	$0.00	0.0%
Energy & Transmission Subtotal			$306.87			$306.87	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$306.87			$306.87	$0.00	0.0%
Total Average Monthly Bill			$451.79			$483.36	$31.57	7.0%

PPL Electric Utilities Corporation
Rate Schedule: GH-2(R) Space Heating
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$22.00/Bill	1 Month	$22.00	$30.00/Bill	1 Month	$30.00	$8.00	36.4%
Energy Charge								
Demand Charge	$3.955/kW	13.08 kW	$51.71	$5.846/kW	13.08 kW	$76.44	$24.73	47.8%
TCJA	-8.0%		-$5.90				$5.90	-100.0%
SMR 2	$3.03/Bill	1 Month	$3.03				-$3.03	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00166/kWh	1,991 kWh	$3.30	$0.00166/kWh	1,991 kWh	$3.30	$0.00	0.0%
USR								
SDER	$0.00092/kWh	1,991 kWh	$1.83				-$1.83	-100.0%
DSIC	7.5%		$5.70				-$5.70	-100.0%
Distribution Subtotal			$81.67			$109.74	$28.07	34.4%
State Tax Adjustment	-0.28%		-$0.229				$0.23	-100.0%
Total Distribution Charges			$81.44			$109.74	$28.30	34.8%
GSC-1	$0.08956/kWh	1,991 kWh	$178.31	$0.08956/kWh	1,991 kWh	$178.31	$0.00	0.0%
TSC	$0.03158/kWh	1,991 kWh	$62.87	$0.03158/kWh	1,991 kWh	$62.87	$0.00	0.0%
Energy & Transmission Subtotal			$241.18			$241.18	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$241.19			$241.19	$0.00	0.0%
Total Average Monthly Bill			$322.63			$350.93	$28.30	8.8%

PPL Electric Utilities Corporation
Rate Schedule: BL Borderline Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge								
Energy Charge	$0.04795/kWh	14,512 kWh	$695.85	$0.06690/kWh	14,512 kWh	$970.84	$274.99	39.5%
Demand Charge								
TCJA	-8.0%		-$55.67				$55.67	-100.0%
SMR 2	$3.03/Bill	1 Month	$3.03				-$3.03	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00166/kWh	14,512 kWh	$24.09	$0.00166/kWh	14,512 kWh	$24.09	$0.00	0.0%
USR								
SDER	$0.00092/kWh	14,512 kWh	$13.35				-$13.35	-100.0%
DSIC	7.5%		$51.05				-$51.05	-100.0%
Distribution Subtotal			$731.69			$994.93	$263.24	36.0%
State Tax Adjustment	-0.28%		-$2.05				$2.05	-100.0%
Total Distribution Charges			$729.64			$994.93	$265.29	36.4%
GSC-1	$0.08956/kWh	14,512 kWh	$1,299.69	$0.08956/kWh	14,512 kWh	$1,299.69	$0.00	0.0%
TSC	$0.03158/kWh	14,512 kWh	$458.29	$0.03158/kWh	14,512 kWh	$458.29	$0.00	0.0%
Energy & Transmission Subtotal			$1,757.98			$1,757.98	$0.00	0.0%
State Tax Adjustment	0.001%		$0.02	0.001%		$0.02	$0.00	0.0%
Total Energy & Transmission Charges			$1,758.00			$1,758.00	$0.00	0.0%
Total Average Monthly Bill			$2,487.64			$2,752.92	$265.29	10.7%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Three Phase General Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$60.00/Bill	1 Month	$60.00	$78.00/Bill	1 Month	$78.00	$18.00	30.0%
Energy Charge								
Demand Charge	$3.985/kW	52.75 kW	$210.22	$5.272/kW	52.75 kW	$278.12	$67.89	32.3%
TCJA	-8.0%		-$21.62				$21.62	-100.0%
SMR 2	$3.03/Bill	1 Month	$3.03				-$3.03	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00166/kWh	17,231 kWh	$28.60	$0.00166/kWh	17,231 kWh	$28.60	$0.00	0.0%
USR								
SDER	$0.00092/kWh	17,231 kWh	$15.85				-$15.85	-100.0%
DSIC	7.5%		$22.21				-$22.21	-100.0%
Distribution Subtotal			$318.29			$384.72	$66.43	20.9%
State Tax Adjustment	-0.28%		-$0.891				$0.89	-100.0%
Total Distribution Charges			$317.39			$384.72	$67.32	21.2%
GSC-1	$0.08956/kWh	17,231 kWh	$1,543.18	$0.08956/kWh	17,231 kWh	$1,543.18	$0.00	0.0%
TSC	$0.03158/kWh	17,231 kWh	$544.15	$0.03158/kWh	17,231 kWh	$544.15	$0.00	0.0%
Energy & Transmission Subtotal			$2,087.33			$2,087.33	$0.00	0.0%
State Tax Adjustment	0.001%		$0.02	0.001%		$0.02	$0.00	0.0%
Total Energy & Transmission Charges			$2,087.35			$2,087.35	$0.00	0.0%
Total Average Monthly Bill			$2,404.74			$2,472.07	$67.32	2.8%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Volunteer & Non-Profit Organizations
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$14.09/Bill	1 Month	$14.09	$17.00/Bill	1 Month	$17.00	$2.91	20.7%
Energy Charge	$0.03534/kWh	5,867 kWh	$207.33	$0.04965/kWh	5,867 kWh	$291.29	$83.95	40.5%
Demand Charge								
TCJA	-8.0%		-$17.71				$17.71	-100.0%
SMR 2	$1.50/Bill	1 Month	$1.50				-$1.50	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00220/kWh	5,867 kWh	$12.91	$0.00220/kWh	5,867 kWh	$12.91	$0.00	0.0%
USR	$0.01111/kWh	5,867 kWh	$65.18	$0.01111/kWh	5,867 kWh	$65.18	$0.00	0.0%
SDER	$0.00184/kWh	5,867 kWh	$10.79				-$10.79	-100.0%
DSIC	7.5%		$22.06				-$22.06	-100.0%
Distribution Subtotal			$316.14			$386.37	$70.24	22.2%
State Tax Adjustment	-0.28%		-$0.89				$0.89	-100.0%
Total Distribution Charges			$315.25			$386.37	$71.12	22.6%
GSC-1	$0.08956/kWh	5,867 kWh	$525.43	$0.08956/kWh	5,867 kWh	$525.43	$0.00	0.0%
TSC	$0.03158/kWh	5,867 kWh	$185.27	$0.03158/kWh	5,867 kWh	$185.27	$0.00	0.0%
Energy & Transmission Subtotal			$710.70			$710.70	$0.00	0.0%
State Tax Adjustment	0.001%		$0.01	0.001%		$0.01	$0.00	0.0%
Total Energy & Transmission Charges			$710.71			$710.71	$0.00	0.0%
Total Average Monthly Bill			$1,025.96			$1,097.08	$71.12	6.9%

PPL Electric Utilities Corporation
Rate Schedule: LP-4 Large General Service at 12,470 Voltes
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$169.80/Bill	1 Month	$169.80	$235.00/Bill	1 Month	$235.00	$65.20	38.4%
Energy Charge								
Demand Charge	$2.547/kW	965 kW	$2,457.15	$3.881/kW	965 kW	$3,744.10	$1,286.94	52.4%
TCJA	-8.0%		-$210.16				$210.16	-100.0%
SMR 2	$63.12/Bill	1 Month	$63.12				-$63.12	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$1.057/kW	965 kW	$1,019.71	$1.057/kW	965 kW	$1,019.71	$0.00	0.0%
USR								
SDER	$123.10/Bill	1 Month	$123.10				-$123.10	-100.0%
DSIC	7.5%		$271.70				-$271.70	-100.0%
Distribution Subtotal			$3,894.42			$4,998.81	$1,104.38	28.4%
State Tax Adjustment	-0.28%		-$10.904				$10.90	-100.0%
Total Distribution Charges			$3,883.52			$4,998.81	$1,115.29	28.7%
GSC-1	$0.04734/kWh	406,485 kWh	$19,243.01	$0.04734/kWh	406,485 kWh	$19,243.01	$0.00	0.0%
TSC	$21.350/kW	965 kW	$20,596.87	$21.350/kW	965 kW	$20,596.87	$0.00	0.0%
Energy & Transmission Subtotal			$39,839.88			$39,839.88	$0.00	0.0%
State Tax Adjustment	0.001%		$0.40	0.001%		$0.40	$0.00	0.0%
Total Energy & Transmission Charges			$39,840.28			$39,840.28	$0.00	0.0%
Total Average Monthly Bill			$43,723.80			$44,839.09	$1,115.29	2.6%

PPL Electric Utilities Corporation
Rate Schedule: LP-5 Large General Service at 69,000 Volts or Higher
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$994.00/Bill	1 Month	$994.00	$973.44/Bill	1 Month	$973.44	-$20.56	-2.1%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-$79.52				$79.52	-100.0%
SMR 2	$63.12/Bill	1 Month	$63.12				-$63.12	-100.0%
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$1.057/kW	12,794 kW	$13,522.86	$1.057/kW	12,794 kW	$13,522.86	$0.00	0.0%
USR								
SDER	$101.50/Bill	1 Month	$101.50				-$101.50	-100.0%
DSIC								
Distribution Subtotal			$14,601.95			$14,496.30	-$105.65	-0.7%
State Tax Adjustment	-0.28%		-$40.885				$40.89	-100.0%
Total Distribution Charges			$14,561.06			$14,496.30	-$64.76	-0.4%
GSC-1	$0.04734/kWh	6,070,574 kWh	$287,380.99	$0.04734/kWh	6,070,574 kWh	$287,380.99	$0.00	0.0%
TSC	$56.378/kW	12,794 kW	$721,278.91	$56.378/kW	12,794 kW	$721,278.91	$0.00	0.0%
Energy & Transmission Subtotal			$1,008,659.91			$1,008,659.91	$0.00	0.0%
State Tax Adjustment	0.001%		$10.09	0.001%		$10.09	$0.00	0.0%
Total Energy & Transmission Charges			$1,008,669.99			$1,008,669.99	$0.00	0.0%
Total Average Monthly Bill			$1,023,231.06			$1,023,166.29	-$64.76	0.0%

PPL Electric Utilities Corporation
Rate Schedule: SA Private Area Lighting (LED)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$13.400/Fixture	1 Fixture	$13.40	$15.872/Fixture	1 Fixture	$15.87	$2.47	18.4%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-$1.07				$1.07	-100.0%
SMR 2								
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.026/Fixture	1 Fixture	$0.03	$0.026/Fixture	1 kW	$0.03	$0.00	0.0%
USR								
SDER	$0.014/Fixture	1 Fixture	$0.01				-$0.01	-100.0%
DSIC	7.5%		$0.93					
Distribution Subtotal			$13.28			$15.90	$2.61	19.7%
State Tax Adjustment	-0.28%		-$0.037			$0.000	$0.04	-100.0%
Total Distribution Charges			$13.25			$15.90	$2.65	20.0%
GSC-1	$1.380/Fixture	1 Fixture	$1.38	$1.380/Fixture	1 Fixture	$1.38	$0.00	0.0%
TSC	$0.487/Fixture	1 Fixture	$0.49	$0.487/Fixture	1 Fixture	$0.49	$0.00	0.0%
Energy & Transmission Subtotal			$1.87			$1.87	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$1.87			$1.87	$0.00	0.0%
Total Average Monthly Bill			$15.11			$17.77	$2.65	17.5%

** Sample bill based on the most common lighting type*

PPL Electric Utilities Corporation
Rate Schedule: SM(R) Mercury Vapor Street Lighting Service (Overhead, Wood Pole, 3,350 Lumens)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$12.225/Lamp	1 Lamp	$12.23	$14.479/Lamp	1 Lamp	$14.48	$2.25	18.4%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-$0.98				$0.98	-100.0%
SMR 2								
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.082/Lamp	1 Lamp	$0.08	$0.082/Lamp	1 Lamp	$0.08	$0.00	0.0%
USR								
SDER	$0.045/Lamp	1 Lamp	$0.05				-$0.05	-100.0%
DSIC	7.5%		$0.85					
Distribution Subtotal			$12.22			$14.56	$2.34	19.2%
State Tax Adjustment	-0.28%		-$0.034			$0.000	$0.03	-100.0%
Total Distribution Charges			$12.18			$14.56	$2.38	19.5%
GSC-1	$4.397/Lamp	1 Lamp	$4.40	$4.397/Lamp	1 Lamp	$4.40	$0.00	0.0%
TSC	$1.551/Lamp	1 Lamp	$1.55	$1.551/Lamp	1 Lamp	$1.55	$0.00	0.0%
Energy & Transmission Subtotal			$5.95			$5.95	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$5.95			$5.95	$0.00	0.0%
Total Average Monthly Bill			$18.13			$20.51	$2.38	13.1%

** Sample bill based on the most common lighting type*

PPL Electric Utilities Corporation
Rate Schedule: SHS High Pressure Sodium Street Light Service (Underground, Low Mount, =9,500 Lumens)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$20.360/Lamp	1 Lamp	$20.36	$24.123/Lamp	1 Lamp	$24.12	$3.76	18.5%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-$1.63				$1.63	-100.0%
SMR 2								
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.071/Lamp	1 Lamp	$0.07	$0.071/Lamp	1 Lamp	$0.07	$0.00	0.0%
USR								
SDER	$0.039/Lamp	1 Lamp	$0.04				-$0.04	-100.0%
DSIC	7.5%		$1.41					
Distribution Subtotal			$20.24			$24.19	$3.95	19.5%
State Tax Adjustment	-0.28%		-$0.057			$0.000	$0.06	-100.0%
Total Distribution Charges			$20.19			$24.19	$4.01	19.9%
GSC-1	$3.824/Lamp	1 Lamp	$3.82	$3.824/Lamp	1 Lamp	$3.82	$0.00	0.0%
TSC	$1.348/Lamp	1 Lamp	$1.35	$1.348/Lamp	1 Lamp	$1.35	$0.00	0.0%
Energy & Transmission Subtotal			$5.17			$5.17	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$5.17			$5.17	$0.00	0.0%
Total Average Monthly Bill			$25.36			$29.37	$4.01	15.8%

** Sample bill based on the most common lighting type*

PPL Electric Utilities Corporation
Rate Schedule: SLE Light Emitting Diode (LED) Street Light Service (Overhead, Wood Pole, =4,900 Lumens)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	$14.240/Lamp	1 Lamp	$14.24	$16.854/Lamp	1 Lamp	$16.85	$2.61	18.4%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-$1.14				$1.14	-100.0%
SMR 2								
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.043/Lamp	1 Lamp	$0.04	$0.043/Lamp	1 Lamp	$0.04	$0.00	0.0%
USR								
SDER	$0.024/Lamp	1 Lamp	$0.02				-$0.02	-100.0%
DSIC	7.5%		$0.99					
Distribution Subtotal			$14.14			$16.90	$2.75	19.5%
State Tax Adjustment	-0.28%		-$0.040			$0.000	$0.04	-100.0%
Total Distribution Charges			$14.11			$16.90	$2.79	19.8%
GSC-1	$2.325/Lamp	1 Lamp	$2.33	$2.325/Lamp	1 Lamp	$2.33	$0.00	0.0%
TSC	$0.820/Lamp	1 Lamp	$0.82	$0.820/Lamp	1 Lamp	$0.82	$0.00	0.0%
Energy & Transmission Subtotal			$3.15			$3.15	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$3.15			$3.15	$0.00	0.0%
Total Average Monthly Bill			$17.25			$20.04	$2.79	16.2%

** Sample bill based on the most common lighting type*

PPL Electric Utilities Corporation
Rate Schedule: SE Energy Only Street Lighting (Customer Owned Poles)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge								
Energy Charge	$0.06026/kWh	19,885 kWh	$1,198.25	$0.07254/kWh	19,885 kWh	$1,442.43	$244.18	20.4%
Demand Charge								
TCJA	-8.0%		-$95.86				$95.86	-100.0%
SMR 2								
CER	-$0.01/Bill	1 Month	-$0.01				$0.01	-100.0%
ACR 4	$0.00166/kWh	19,885 kWh	$33.01	$0.00166/kWh	19,885 kWh	$33.01	$0.00	0.0%
USR								
SDER	$0.00092/kWh	19,885 kWh	$18.29				-$18.29	-100.0%
DSIC	7.5%		$86.53				-$86.53	-100.0%
Distribution Subtotal			$1,240.21			$1,475.44	$235.23	19.0%
State Tax Adjustment	-0.28%		-$3.47			$0.00	$3.47	-100.0%
Total Distribution Charges			$1,236.74			$1,475.44	$238.71	19.3%
GSC-1	$0.08956/kWh	19,885 kWh	$1,780.87	$0.08956/kWh	19,885 kWh	$1,780.87	$0.00	0.0%
TSC	$0.03158/kWh	19,885 kWh	$627.96	$0.03158/kWh	19,885 kWh	$627.96	$0.00	0.0%
Energy & Transmission Subtotal			$2,408.83			$2,408.83	$0.00	0.0%
State Tax Adjustment	0.001%		$0.02	0.001%		$0.02	$0.00	0.0%
Total Energy & Transmission Charges			$2,408.85			$2,408.85	$0.00	0.0%
Total Average Monthly Bill			$3,645.59			$3,884.29	$238.71	6.5%

** Sample bill based on the most common lighting type*

PPL Electric Utilities Corporation
Rate Schedule: TS (R) Municipal Traffic Signal Lighting Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Per Watt Charge	$0.07496/watt	403 Watts	$30.18	$0.08967/watt	403 Watts	$36.10	$5.92	19.6%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-$2.41				$2.41	-100.0%
SMR 2								
CER	-$0.01/Bill	1 Watts	-$0.01				$0.01	-100.0%
ACR 4	$0.00121/watt	403 Watts	$0.49	$0.00121/watt	403 Watts	$0.49	$0.00	0.0%
USR								
SDER	$0.00067/watt	403 Watts	$0.27				-$0.27	-100.0%
DSIC	7.5%		$2.14					
Distribution Subtotal			$30.65			$36.59	$5.94	19.4%
State Tax Adjustment	-0.28%		-$0.086			$0.000	$0.09	-100.0%
Total Distribution Charges			$30.56			$36.59	$6.02	19.7%
GSC-1	$0.06543/watt	403 Watts	$26.34	$0.06543/watt	403 Watts	$26.34	$0.00	0.0%
TSC	$0.02307/watt	403 Watts	$9.29	$0.02307/watt	403 Watts	$9.29	$0.00	0.0%
Energy & Transmission Subtotal			$35.63			$35.63	$0.00	0.0%
State Tax Adjustment	0.001%		$0.00	0.001%		$0.00	$0.00	0.0%
Total Energy & Transmission Charges			$35.63			$35.63	$0.00	0.0%
Total Average Monthly Bill			$66.19			$72.21	$6.02	9.1%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 9

Direct Testimony of Julissa Burgos

Topics: **Capital Structure**
Embedded Cost of Capital

Dated: September 30, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Julissa Burgos. My business address is Two City Center, 645 Hamilton Street, Suite 9, Allentown, PA 18101.

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

A. I am employed by PPL Services Corporation ("PPL Services"), a subsidiary of PPL Corporation and an affiliate of PPL Electric Utilities Corporation ("PPL Electric" or the "Company"), which provides services to PPL Corporation and its subsidiaries. I hold the position of Assistant Treasurer. I also serve as Assistant Treasurer for PPL Electric.

Q. What are your responsibilities as Assistant Treasurer?

A. I am responsible for overseeing treasury activities including the execution of debt and equity capital market transactions for PPL Corporation and its subsidiaries, as well as maintaining rating agency and banking relationships, managing liquidity, financial risk management and overseeing investments and pensions.

Q. What is your educational background and professional experience?

A. My educational background and professional experience are set forth in my curriculum vitae attached as Appendix A.

Q. What is the purpose of your testimony?

A. I will testify about PPL Electric's capital structure, cost of long-term debt and credit ratings in this proceeding. I will address how the Company's cost of long-term debt is calculated and how credit ratings affect the Company's cost of long-term debt and ultimately its cost of capital.

Q. Are you sponsoring any exhibits or schedules in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- PPL Electric Exhibit JB-1: Moody's Rating Methodology, Regulated Electric and Gas Utilities, dated August 2024
- PPL Electric Exhibit JB-2: S&P General: Corporate Methodology dated January 7, 2024, republished July 7, 2025
- PPL Electric Exhibit JB-3: S&P General: Sector-Specific Corporate Methodology, dated July 7, 2025
- PPL Electric Exhibit JB-4: S&P Group Rating Methodology, dated July 2019, republished August 20, 2025

I am also co-sponsoring Schedules B-6 through B-8 of Exhibits Historic 1, Future 1, and Fully Projected Future 1 and sponsoring or co-sponsoring portions of Parts II and III of the filing requirements as noted on their indexes.

II. CAPITAL STRUCTURE

Q. Please describe the Company's capital structure.

A. PPL Electric targets a capital structure that optimizes the mix of debt and equity financing that balances the appropriate amount of risk and minimizes its weighted cost of capital, while maintaining credit metrics that support its strong investment-grade credit ratings. The strong investment-grade credit ratings provide the Company with the ability to access capital at more favorable borrowing rates as PPL Electric continues to make investments to strengthen grid reliability and resiliency without compromising affordability. For the fully projected test year ("FPFTY"), PPL Electric's debt-to-capitalization ratio is approximately 44 percent as reflected in Schedule B-7.

III. EMBEDDED COST OF CAPITAL

Q. Please describe PPL Electric's cost of debt.

A. The cost of debt reflects the interest rate payable on PPL Electric's long-term debt. Long-term debt is typically priced using the risk-free rate, a U.S. Treasury Bond for the applicable tenor (i.e., a 10-year bond would price using a 10-U.S. Treasury Bond) plus an applicable credit spread. The credit spread accounts for several market and issuer specific factors, including the issuer's credit rating. It also accounts for the additional return investors demand for investing in a corporate bond compared to the risk-free U.S. Treasury Bond.

The cost of debt for PPL Electric is determined by calculating the weighted average interest rate of the Company's existing long-term debt outstanding, including the discount or premium and amortized fees. For the FPFTY, PPL Electric's weighted average cost of long-term debt is forecasted to be 5.08% as reflected in Schedule B-6.

Q. Do you believe PPL Electric's cost of debt is reasonable?

A. Yes, I believe PPL Electric's cost of debt is reasonable. The Company's cost of debt is impacted by several factors including market conditions, overall investor sentiment at the time of issuance and credit spreads. Macroeconomic market conditions as well as investor sentiment on the bond market and the utility sector play a critical role in the execution of a debt transaction. Investor sentiment can drive demand for the Company's bonds as investors evaluate the different investment alternatives available to them across sectors compared to investing in PPL Electric. While most of these factors are beyond the Company's control, they have a significant impact on PPL Electric's cost of debt. The credit spread is also a major driver of the cost of debt and is the component of the cost that is specific to PPL Electric. As such, the Company aims to maintain strong investment grade credit ratings, which places PPL Electric in the best position to access capital when needed. The Company regularly works with banks to assess the factors that affect the cost of debt. The Company also has the benefit of insight into the cost of debt of its affiliates, along with other utility peers, which helps determine whether its cost of debt is appropriate given PPL Electric's individual attributes. Given the focus on achieving best execution at time of issuance and maintaining high credit quality, I believe that PPL Electric's cost of debt is reasonable.

Q. How do the Company's credit ratings impact the cost of debt?

A. The credit rating is a key consideration in determining the cost at which the Company can access capital. Many investors rely on the assessments done by the major ratings agencies, such as Moody's Investor Service ("Moody's") and S&P Global ("S&P").

The rating agencies evaluate a company's overall financial strength and credit worthiness, which includes an assessment of the company's liquidity, financial metrics, and environmental risks. They monitor key credit metrics with a focus on Cash Flow (Funds) From Operations to Debt (CFO/Debt) as well as Total Debt to Total Capitalization (Debt/Capitalization). In addition, for regulated utilities, the ratings agencies assess the regulatory environment given the critical importance it bears on the utility's financial performance. Companies with strong credit metrics have high credit quality, which typically results in a lower cost of borrowing, all else equal.

Q. Please explain the key considerations the rating agencies use to evaluate a utility's credit quality.

A. Moody's and S&P assess several qualitative factors, financial information and ratios as part of their rating methodologies. Moody's considers four key factors when evaluating regulated utilities: (1) the regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength.

The financial metrics Moody's evaluates in assigning a credit rating include the entity's CFO/Debt and the Debt/Capitalization ratios, amongst others. Moody's states, "High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in credit facilities or other financing agreements."

S&P evaluates creditworthiness using a top-down approach that considers the Business Risk Profile, which for regulated utilities like PPL Electric, is driven by regulatory advantage—not competitive position. It includes regulatory stability, tariff-setting procedures, financial stability and regulatory independence

S&P also determines the Financial Risk Profile, which is based on credit ratios such as FFO/Debt and Debt/EBITDA, reflecting the Company's ability to meet financial obligations. They also consider other factors, including capital structure, financial policy, liquidity, and group influence (e.g., support from parent company).

Q. What are PPL Electric's current credit ratings?

A. PPL Electric targets an "A" rating from Moody's and S&P. Presently, Moody's rating is A3 (with the first mortgage bonds rated A1), and S&P's rating is A (with first mortgage bonds rated A+). Short-Term Ratings are A-1 at S&P and P-2 at Moody's.

Q. Have the credit ratings changed since PPL Electric's last rate case? If so, what was the change and why?

A. Yes. In May 2022, S&P upgraded PPL Electric's issuer credit rating from 'A-' to 'A', with secured debt being upgraded to 'A+' from 'A' and short-term debt was upgraded to A1 from A2. The upgrade was the result of PPL Electric's stand-alone financial metrics at or above their respective upgrade threshold and the cumulative value of its insulating measures as prescribed in S&P's insulation assessment, which includes financial performance, funding arrangements, and operational independence.

Q. Do the existing credit ratings allow PPL Electric to compete for attractively priced capital for future investments in facilities to serve customers?

A. The Company maintains certain credit metrics to retain its strong investment-grade credit ratings, providing PPL Electric with greater flexibility to have access to capital. While the strong credit ratings are a critical component of the cost of capital, there may be other factors that may hinder the Company's ability to access capital at lower costs, including macro-economic factors as well investor sentiment on the utility sector at any given time.

IV. <u>RETURN ON COMMON EQUITY</u>

Q. Have you reviewed the testimony of PPL Electric witness Jennifer Nelson regarding return on common equity (PPL Electric St. No. 10)?

A. Yes, I have.

Q. Do you believe Ms. Nelson's proposed return on common equity is reasonable?

A. Yes, I do. I have reviewed her analyses that support her recommendation, and I find Ms. Nelson's proposed return on common equity of 11.3 percent to be fair and reasonable.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Julissa Burgos
Assistant Treasurer
PPL Services Corporation
Two City Center
645 Hamilton Street, Suite 9
Allentown, PA 18101-1179

Professional Experience

PPL Corporation

Assistant Treasurer	November 2024- Present
Director - Corporate Finance	July 2018 – November 2024
Manager - Investments and Pensions	July 2015 - July 2018
Finance Specialist - Investments & Pensions	November 2011 - June 2015
Supervisor - Cash Operations	January 2008 - October 2011
Analyst/Senior Analyst - Corporate Finance	July 2005 - December 2007
Staff Analyst - Cash Management	May 2001 - June 2005

Education & Credentials

Bachelor of Science Business Administration - Finance
University of Pittsburgh, Pittsburgh Pa
Certified Treasury Professional (CTP)

Professional Memberships

Association for Financial Professionals

Civic Activities

Treasurer- Board of Directors - Community Services for Children
Member- Investment Committee - DaVinci Science Center, Allentown, PA

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 10

Direct Testimony of Jennifer E. Nelson

Topics: **Return on Equity**
Capital Structure

Dated: September 30, 2025

I. INTRODUCTION

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

A. My name is Jennifer E. Nelson. I am a Vice President at Concentric Energy Advisors. Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts, 01752.

Q. On whose behalf are you testifying?

A. I am submitting this testimony to the Pennsylvania Public Utility Commission ("PUC" or the "Commission") on behalf PPL Electric Utilities Corporation ("PPL Electric", or the "Company"), which is an indirect, wholly owned subsidiary of PPL Corporation.

Q. Please describe your experience in the energy and utility industries and your educational and professional qualifications.

A. I have more than fifteen years of experience in the energy industry, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, and a petroleum economist for the State of Alaska. I completed utility regulatory training offered by New Mexico State University's Center for Public Utilities and have earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts based on my experience and successful completion of an examination. I hold a Bachelor's degree in Business Economics from Bentley University and a Master's degree in Resource and Applied Economics from the University of Alaska. A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as PPL Electric Exhibit JEN-1.

Q. Have you previously submitted testimony before the Commission?

A. No, I have not submitted testimony before the Commission. However, I have previously filed testimony before more than 20 state regulatory commissions, as detailed in PPL Electric Exhibit JEN-1. During my time as a consultant, I have supported the development of expert witness testimony and analyses regarding the Return on Equity ("ROE") and capital structure in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring portions of Part III of the filing requirements as noted on its index. Also, my analyses and recommendations are supported by the data presented in PPL Electric Exhibits JEN-2 through JEN-9, which have been prepared by me or under my direction. I sponsor the following exhibits:

PPL Electric Exhibit JEN-1	Résumé and Testimony Listing of Jennifer E. Nelson
PPL Electric Exhibit JEN-2	Constant Growth DCF Results

PPL Electric Exhibit JEN-3	Quarterly Growth DCF Results
PPL Electric Exhibit JEN-4	Expected Market Return Calculations
PPL Electric Exhibit JEN-5	CAPM and Empirical CAPM Results
PPL Electric Exhibit JEN-6	Bond Yield Plus Risk Premium Analysis
PPL Electric Exhibit JEN-7	Size Premium Adjustment
PPL Electric Exhibit JEN-8	Flotation Cost Adjustment
PPL Electric Exhibit JEN-9	Capital Structure Analysis

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation for PPL Electric's return on equity ("ROE"). My direct testimony also assesses the Company's capital structure in comparison to the proxy group companies supporting my analysis.

II. OVERVIEW AND SUMMARY

Q. Please summarize your recommendation regarding the appropriate cost of equity for PPL Electric.

A. In this proceeding, I recommend the Commission authorize an ROE of 11.30 percent for PPL Electric. To develop my ROE recommendation, I rely on the results of three widely used market-based financial models: (1) the constant growth and quarterly growth forms of the Discounted Cash Flow ("DCF") model, (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"), and (3) the Bond Yield Plus Risk Premium. These models indicate a cost of equity ranging from approximately 10.30 percent to 12.35 percent. An ROE of 11.30 percent reflects the approximate midpoint of the range of model results. Further, my recommendation is conservative as I do not make an additional adjustment for PPL Electric's planned capital expenditures, slightly smaller size compared to the proxy group, and flotation costs.

As to the capital structure, I conclude the Company's requested permanent capital structure consisting of 56.00 percent common equity and 44.00 percent long-term debt is reasonable and should be approved because it falls within the range of actual capital structures for the operating companies held by the proxy group companies.

Q. What factors do you consider in determining your ROE recommendation?

A. The cost of equity is an opportunity cost that cannot be precisely quantified. Therefore, it must be estimated through various financial models. Each of the ROE-estimation models is subject to limiting assumptions and each provides a different perspective on investors' return requirements under varying market conditions. The use of multiple financial models, therefore, enables a more robust and comprehensive assessment of the cost of equity instead of relying on one specific estimation model.

After reviewing the model results discussed later in the testimony, I assess the Company's risk profile relative to a group of proxy companies. As explained in more detail throughout my testimony, my recommendation considers: (1) the Company's significant capital investment needs; (2) the regulatory environment in which the Company operates; (3) the Company's smaller size compared to the size of the proxy group companies; (4) the impact of flotation costs; and (5) the current capital market environment. While I do not make any explicit adjustments to my ROE estimates for PPL Electric's business risks, I consider them when determining my ROE recommendation.

The low end of my range, 10.30 percent, is informed by the results of my Constant Growth and Quarterly Growth DCF analysis using mean growth rates and the average Bond

Yield Plus Risk Premium results. Additionally, low end of the range is supported by the CAPM and Empirical CAPM ("ECAPM") results using a long-term average historical market return. The high end of my recommended range, 12.35 percent, is informed by the average of the forward-looking CAPM and ECAPM analysis. Based on those considerations, it is my opinion that an ROE at the approximate midpoint of the range, or 11.30 percent, is a just and reasonable estimate of PPL Electric's cost of equity.

Q. Has the Commission previously acknowledged the importance of considering prevailing market conditions in determining the appropriate ROE?

A. Yes, in its July 2024 Opinion and Order for Pennsylvania American Water Company in Docket No. R-2023-3043189, the Commission considered the prevailing market conditions of increasing inflation, higher interest rates, and capital costs in approving an ROE that reflected the average of the DCF and CAPM results.[1] As explained in my Direct Testimony, these conditions persist, and are expected to persist, going forward.

Q. How is the remainder of your Direct Testimony organized?

A. The remainder of my Direct Testimony is organized as follows:

- <u>Section III</u> – Provides a summary of issues regarding the cost of equity estimation in regulatory proceedings, describes the regulatory guidelines pertinent to the development of the cost of capital, explains my selection of the proxy group used to develop my analytical results, and describes my analyses on which my ROE determination is based;

---

[1] Pennsylvania American Water Company, Docket No. R-2023-3043189, Opinion and Order, at 194 (July 11, 2024).

- Section IV – Discusses the specific business risks that have a direct bearing on the Company's cost of equity;
- Section V – Reviews the current capital market conditions and the effect on the cost of equity;
- Section VI – Compares the Company's proposed capital structure to the capital structures of the proxy group; and
- Section VII – Summarizes my conclusions and recommendations.

III. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Financial Considerations

Q. Before addressing the specific aspects of this proceeding, please explain the connection between the cost of capital and a utility's cost of service.

A. Under the cost-of-service ratemaking paradigm, the development of utility rates begins with determining the utility's total cost to serve customers. This is known as the revenue requirement, since the utility's revenues must be sufficient to recover its costs to serve customers. The revenue requirement consists of four components: (1) operating and maintenance ("O&M") expenses, (2) taxes, (3) the return *of* capital through depreciation expense, and (4) the return *on* capital through the regulated return on rate base. The return on rate base is calculated as the weighted average cost of capital multiplied by the rate base. The return on capital must be sufficient to allow the utility to repay its debt obligations and compensate equity investors for the use of their financial capital. From that important perspective, the return on capital reflects a cost to the utility just as any other component of the revenue requirement.

Q. Please explain the cost of capital conceptually.

A. The cost of capital is the return that investors require to commit capital to a firm. Investors will provide funds to a firm only if the return that they expect is equal to, or greater than, the return that they require to accept the risk of investing capital in the firm. Simply, the cost of capital is the expected rate of return prevailing in the capital markets on alternative investments of similar risk.[2] Conceptually, the cost of capital is: (1) forward looking and reflects an expected rate of return; (2) an opportunity cost; (3) determined in the capital markets, and (4) dependent on, and proportional to, the risk of the investment.[3]

Because the cost of equity is expectational and premised on the principle of opportunity costs, it cannot be precisely quantified. Instead, it must be estimated by applying market data to various financial models that are simplified representations of investor behavior and expectations. Moreover, equity investors have a subordinate claim to cash flows owed to debt investments and other claims; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. In the end, the cost of equity should reflect the return that investors require considering the subject company's risk profile and the returns available on comparable investments.

Q. How is the Cost of Equity estimated in regulatory proceedings?

A. Regulated utilities primarily use long-term capital (e.g., common stock and long-term debt) to finance their permanent rate base. The rate of return for a regulated utility is calculated

---

2 Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

3 *Id*.

as its weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective book values.

The ROE reflects the cost of raising and retaining equity capital and is estimated by using one or more market-based analytical approaches. Although quantitative models are used to estimate the ROE, the cost of equity cannot be precisely quantified through a strict mathematical exercise. As such, a reasonable and appropriate ROE reflects the financial, economic, and regulatory environment in which the estimate is developed, as well as the subject company's risk profile.

Q. Please briefly summarize the guidelines used in establishing the cost of capital for a regulated utility.

A. Public utility regulation is rooted in the principle that utilities receive a fair rate of return sufficient to attract the capital required to provide safe and reliable public utility service for customers at reasonable rates. The U.S. Supreme Court ("Supreme Court") established the guiding principles for establishing a fair return for capital in two seminal cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[4] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[5] In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the

---

4 *See Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U.S. 679, 692 (1923).

5 *See Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

> utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[6]

The Supreme Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Supreme Court reiterated the three primary standards for a regulated rate of return:

> [Th]e return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[7]

In summary, the Supreme Court has recognized that the fair return should be: (1) commensurate with returns investors expect to earn on other investments of similar risk (the "comparable return" standard); (2) sufficient to assure confidence in the company's financial integrity (the "financial integrity" standard); and (3) adequate to maintain and support the company's credit and to attract capital (the "capital attraction" standard). Importantly, a fair and reasonable rate of return satisfies all three standards.

---

[6] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*, 262 U.S. 679, 692 (1923).
[7] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

Q. Has the Commission also applied the *Hope* and *Bluefield* standards as guidance for setting rates?

A. Yes, it has. The Commission upholds the precedents of the *Hope* and *Bluefield* cases and regularly acknowledges that a utility is entitled to a fair and reasonable return. For example, in its November 2015 order approving the settlement in PPL Electric's last filed rate case, the Commission stated, "In determining what constitutes a fair rate of return, the Commission is guided by the criteria set forth in *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)."[8] Based on those standards, the authorized ROE should provide PPL Electric with the *opportunity* (which is not a guarantee) to earn a fair and reasonable return and should enable efficient access to external capital under a variety of market conditions.

Q. Why is it important for a utility to be allowed the opportunity to earn a return adequate to attract capital at reasonable terms?

A. Regulated utilities have a legal obligation to serve regardless of prevailing economic and capital market conditions. Unlike non-regulated firms, a regulated utility cannot decide to whom it provides utility service in its footprint, how much service it delivers, nor when it provides service. Because utilities are one of the most capital-intensive sectors, they must ensure they have access to external financial capital on efficient terms not only during times when markets are well-behaving, but also when markets are volatile or constrained (e.g.,

[8] *Pa. PUC v. PPL Electric Utilities Corp*., Opinion and Order, Docket No. R-2015-2469275, Public Meeting Held November 19, 2015, at 16.

during periods of high inflation and interest rates, global pandemics,[9] changes in government, and economic recessions). A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected for investments of similar risk.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have a reasonable opportunity to recover the return of, and the market-required return on, invested capital. To meet its legal obligation to serve, the allowed ROE should enable the subject utility to maintain its financial integrity in a variety of economic and capital market conditions. To preserve and enhance service reliability, PPL Electric must generate adequate cash flow from operations and have efficient access to external capital needed to undertake its capital investment plan regardless of the economic and capital market conditions at the time.

Further, the financial community carefully monitors utility companies' current and expected financial conditions, 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.[10] That

[9] E.g., the Commission rejected the opposing parties' argument that no rate increase should be granted during the COVID-19 pandemic. See *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Opinion and Order, Docket No. R-2020-3018835, at 42.

[10] *See, e.g.*, Moody's Investors Service, Rating Methodology: Regulated Gas and Electric Utilities, at 7 (August 6, 2024).

consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

The outcome of the Commission's order in this case, therefore, should provide PPL Electric with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms, (2) sufficient to ensure its financial integrity, and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent PPL Electric has a reasonable opportunity to earn its market-based cost of equity, neither customers nor shareholders are disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables PPL Electric to provide customers with safe, reliable service while maintaining its financial integrity.

Q. What are your conclusions regarding the regulatory principles pertaining to the cost of capital for a public utility?

A. Congruent to other costs in a utility's cost of service, the regulated return on rate base is a cost that PPL Electric incurs as part of its normal operations, including the need to compensate equity investors for the use of their capital. Under the *Hope* and *Bluefield* standards, the cost of equity authorized for PPL Electric in this proceeding should be: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments having similar risks.

Because utilities are capital intensive and investors have many investment alternatives, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions. The Commission's decision regarding the authorized ROE and capital structure in this proceeding will directly affect the Company's ability to attract the capital needed to maintain and enhance service to customers.

B. Proxy Group Selection

Q. Why is it necessary to select a group of proxy companies to determine the Cost of Equity for PPL Electric?

A. The cost of equity for a given enterprise depends on the attendant risks to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities that are inherent in the business sectors in which those units operate. Because the ROE is a market-based concept estimated by applying market data to various financial models, and PPL Electric is not a standalone, publicly traded entity, it is necessary to establish a group consisting of companies that are both publicly traded and reasonably comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. Please provide a summary profile of PPL Electric.

A. PPL Electric is an indirect wholly owned subsidiary of PPL Corporation and provides electric distribution and transmission service to approximately 1.5 million customers in Pennsylvania.[11] The Company's current long-term issuer credit ratings are as follows:

[11] Source: PPL Corporation, Form 10-K: Annual Report, 2024, Page 7.

Figure 1: PPL Electric's Current Long-term Issuer Credit Ratings[12]

Rating Agency	Current Credit Rating	Outlook
S&P Global Ratings	A	Stable
Moody's Investors Service ("Moody's")	A3	Stable

Q. Does the fact that PPL Electric is a subsidiary of PPL Corporation affect its cost of equity?

A. No. The cost of equity depends on the risk of a firm's operations and the assets supporting those operations. In other words, the cost of equity depends on the *use* of capital, not on the *source* of capital. Therefore, the Company's corporate structure, including whether it (or its parent) is privately held or publicly traded, does not affect the analysis. That is, the ROE is not determined by reference to PPL Electric's parent company.

Q. What criteria do you use to select the proxy group?

A. Because estimating the cost of equity is a comparative exercise, it is necessary to develop a proxy group of companies with risk profiles that are reasonably comparable to the subject company. As each company is unique, no two companies will have identical business and financial risk profiles. In selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by PPL Electric, while at the same time ensuring that there is a sufficient number of companies in the proxy group. To develop my proxy group, I began with the domestic companies that *Value Line* classifies as Electric Utilities and applied the following screening criteria:

[12] Source: S&P Global Ratings; Moody's, as of June 30, 2025.

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I exclude companies that do not consistently pay quarterly cash dividends, or have cut their dividend in the last two years;
- Because certain of the models assume that earnings grow over time, I exclude companies that do not have positive earnings growth rates from at least two sources;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;
- I exclude companies that do not have (or its primary regulated electric utility subsidiary does not have) an investment-grade issuer or senior unsecured bond credit rating from Standard and Poor's ("S&P") and Moody's;
- To incorporate companies that are primarily regulated electric utilities, I first exclude companies that have less than 60 percent of net operating income from regulated operations on average over the three years ended 2024. I then exclude companies within this group that have less than 60 percent of total regulated operating income from regulated electric operations, on average, over the three years ended 2024;
- I eliminate companies that have had recent significant merger activity or transactions or have had a recent significant financial event that could affect their market data or financial condition; and
- To avoid any circularity concerns, I exclude PPL Electric's parent company, PPL Corporation, from my proxy group.

Q. Which companies meet your screening criteria?

A. The criteria discussed above resulted in a proxy group of the following 24 companies:

Figure 2: Proxy Group Screening Results

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Eversource Energy	ES
Exelon Corporation	EXC
FirstEnergy Corporation	FE
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Public Service Enterprise Group Inc.	PEG
Southern Company	SO
Xcel Energy Inc.	XEL

The screening criteria results in a group of electric utilities that are comparable (but not identical) to the financial and operational characteristics of PPL Electric. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like

PPL Electric, are in sound financial condition. Additionally, the criterion screening on the percent of net operating income from regulated electric operations distinguishes between electric utilities that are subject to regulation and those with substantial unregulated operations and are exposed to higher risks. In my opinion, these screens collectively reflect key risk factors that investors consider in making investments in electric utilities.

C. Cost of Equity Models

Q. What analytical approaches do you use to determine the Company's ROE?

A. As noted earlier, I rely on the constant growth and quarterly growth forms of the DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach. The models that I apply are commonly used in practice,[13] as well as in regulatory proceedings. Additionally, each model provides a different insight into investors' views of risk and return. Therefore, the use of multiple methods provides a comprehensive and robust perspective on investors' return requirements.

1. Constant Growth Discounted Cash Flow Model

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplified form, the Constant Growth DCF model shown in Equation [1] below sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [1]$$

where:

k = the required ROE,

[13] See for example., Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

D_0 = the current annualized dividend,

P = the current stock price, and

g = the expected long-term annual growth rate.

Q. What assumptions underlie the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) dividends are paid annually, and the dividend payout ratio is stable; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current cost of equity will remain constant in perpetuity.

Q. What market data do you use to calculate the dividend yield in your Constant Growth DCF model?

A. I calculate the Constant Growth DCF result for each of the proxy companies using the following inputs:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended June 30, 2025, for the term P;
- The current quarterly dividend as of June 30, 2025 multiplied by 4, for the term D_0; and

- Long-term earnings per share ("EPS") growth rate projections as of June 30, 2025, reported by Zacks, S&P Capital IQ,[14] and *Value Line* for the long-term growth rate, *g*.

Q. Why do you use three averaging periods to calculate an average stock price?

A. I do so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the average period should reasonably reflect the conditions that have defined the financial markets over the recent past. Using 30-, 90-, and 180-trading day averaging periods reasonably balances those concerns.

Q. How do you calculate the expected dividend yield over the coming year?

A. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume dividend increases will be evenly distributed over calendar quarters. Therefore, I calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period.

---

[14] In prior testimonies, I have relied on analysts' consensus long-term EPS projections from First Call as reported by Yahoo! Finance. As of November 2024, Yahoo! Finance no longer publishes consensus long-term projected EPS growth rates. Therefore, I now rely on analysts' consensus EPS growth rate projections reported by S&P Capital IQ as a third source.

Q. Why is the projected EPS growth the appropriate measure of long-term growth in the Constant Growth DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [1] above) assumes a single expected growth estimate in perpetuity, which assumes a fixed payout ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. In the long run, dividend growth can only be sustained by earnings growth.

Further, academic studies have clearly and consistently shown that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[15] For example, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[16] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends.

Lastly, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely available estimates of growth further supports the conclusion that earnings growth is the most meaningful measure of growth among the investment community. For these reasons, earnings growth is the appropriate measure of long-term growth in the DCF model.

---

15 *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

16 *See* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. What are the results of your constant growth DCF analysis?

A. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean, and high Constant Growth DCF result for each proxy company using the low, mean, and high EPS growth estimate. The mean result combines the average of the three EPS growth rate estimates with each proxy company's expected dividend yield. The high DCF result adds the maximum EPS growth rate estimate with each proxy company's expected dividend yield. Similarly, the low DCF result adds the minimum EPS growth rate estimate for each proxy company to the expected dividend yield. I then calculate the mean and median low, mean, and high DCF results for the proxy group (*see* PPL Electric Exhibit JEN-2). In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results using the mean EPS growth rates (*see* Figure 3 below). By relying on the average of the mean and median proxy group results, I consider the individual DCF results of each proxy company while mitigating the effect of the highest and lowest estimates.

Figure 3: Constant Growth DCF Results Using Mean Growth Rates[17]

	Mean	Median	Average of Mean & Median
30-Day Average	10.26%	10.11%	10.19%
90-Day Average	10.23%	10.05%	10.14%
180-Day Average	10.30%	10.24%	10.27%

2. Quarterly Growth Discounted Cash Flow Model

Q. Please describe the Quarterly Growth DCF model.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly basis. Although the dividend yield adjustment discussed earlier is intended to reflect that assumption by increasing the observed dividend yield by one-half of the expected growth rate, it does not fully account for the quarterly receipt and reinvestment of dividends. Consequently, the Constant Growth DCF model likely understates the cost of equity. The Quarterly Growth DCF model specifically incorporates the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[18]

---

[17] *See* PPL Electric Exhibit JEN-2.
[18] Roger A. Morin, New Regulatory Finance, at 344 (2006).

Q. How is the dividend yield portion of the Quarterly DCF model calculated?

A. To reflect the timing and compounding of quarterly dividends, the model replaces the "D" component of the Constant Growth DCF model with the following equation:

$$D = d_1 (1 + k)^{0.75} + d_2 (1 + k)^{0.50} + d_3 (1 + k)^{0.25} + d_4 (1 + k)^{0} \quad [2]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.[19]

To calculate the expected dividends over the coming year for the proxy companies (*i.e.*, d_1, d_2, d_3, and d_4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the growth rate (*i.e.*, $1 + g$). To provide a spectrum of quarterly growth DCF-based ROE estimates, I calculate the low, mean, and high quarterly growth DCF result for each proxy company using the low, mean, and high EPS growth estimates. For the *P* component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis for each proxy company.

Q. What are the results of your Quarterly Growth DCF analyses?

A. My Quarterly Growth DCF results are summarized in Figure 4 below (see also PPL Electric Exhibit JEN-3). As with my Constant Growth DCF analysis, I rely on the average of the mean and median proxy group results using the mean EPS growth rates.

[19] Because the required ROE (*k*) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

Figure 4: Quarterly Growth DCF Results Using Mean Growth Rates[20]

	Mean	Median	Average of Mean & Median
30-Day Average	10.46%	10.28%	10.37%
90-Day Average	10.42%	10.22%	10.32%
180-Day Average	10.50%	10.41%	10.46%

3. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. Please describe the general form of the CAPM.

A. The CAPM is a risk premium method that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. As shown in Equation [3], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

K_e = the required market ROE for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

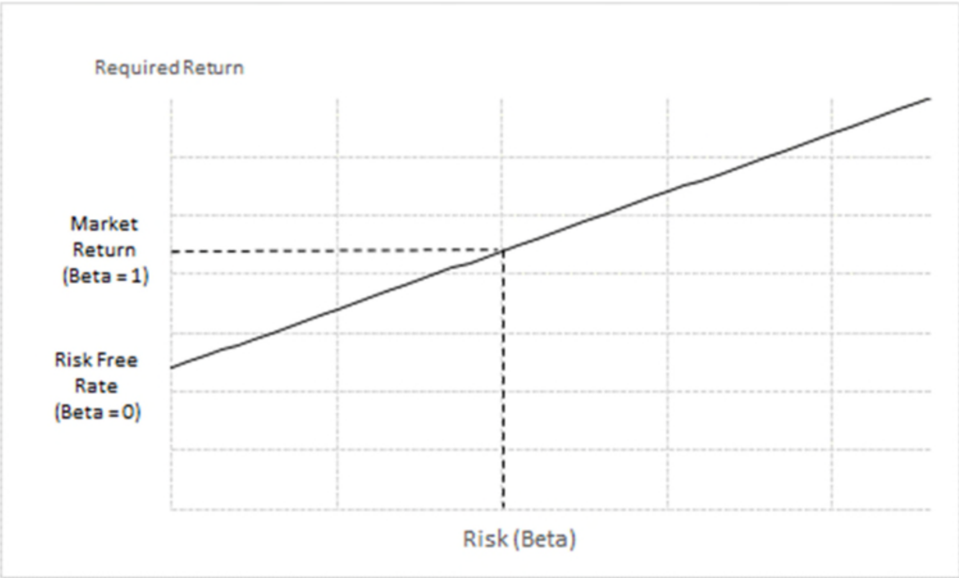
r_m = the required return on the market as a whole.

Equation [3] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, depicted in Figure 5 below. The intercept is the risk-free rate (r_f) which has a Beta coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). As shown in Figure 5, the SML is upward sloping, illustrating the principle that investments of higher risk require a higher return. By definition, r_m, the return on the market, has a

[20] *See* PPL Electric Exhibit JEN-3.

Beta coefficient of 1.00. A Beta coefficient of less than 1.00 generally indicates less market risk and a lower required return than the market; conversely, a company with a Beta coefficient greater than 1.00 has higher market risk, thereby warranting a higher required return than the market by investors.

Figure 5: Security Market Line



The CAPM assumes that all non-market (unsystematic) risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic risk. Systemic (or non-diversifiable) risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \text{ x } \rho_{j,m} \quad [4]$$

where σj is the standard deviation of returns for company "j," σm is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns between company *j* and the broad market.

The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. What risk-free rate assumptions do you include in your CAPM analysis?

A. I apply two different estimates of the risk-free rate: (1) the 30-day average yield on 30-year Treasury bonds as of June 30, 2025 (*i.e.*, 4.92 percent);[21] and (2) a projected 30-year Treasury yield (*i.e.*, 4.52 percent).[22]

Q. Why do you rely on the 30-year Treasury yield in the CAPM analysis?

A. In determining the security most relevant to the application of the CAPM, the term (or maturity) should approximate the life of the underlying investment. Electric utilities are typically long-term duration investments; therefore, the 30-year Treasury yield is most suitable for the risk-free rate applied in the CAPM.

Q. What Beta coefficients do you use in your CAPM model?

A. As shown in PPL Electric Exhibit JEN-5, my CAPM analyses rely on two estimates of the Beta coefficient. First, I use the average five-year Beta coefficients from *Value Line* and Bloomberg for each proxy company as of June 30, 2025. Beta coefficients from both services are calculated using weekly returns over a five-year period, adjusted to reflect the

---

21 Source: Bloomberg Professional Services.

22 The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q4 2026; and (2) the average long-term projected 30-year Treasury yield for the years 2027-2031 and 2032-2036 reported by Blue Chip Financial Forecast. *See* Blue Chip Financial Forecast, Vol. 44, No. 7, July 1, 2025, at 2 and Blue Chip Financial Forecast, Vol. 44, No. 6, June 2, 2025, at 14.

tendency of Beta coefficients to regress toward the market mean of 1.00. In addition, I also conduct the CAPM analyses using 10-year adjusted Beta coefficients from Bloomberg.

Q. What estimates of the expected market return do you use to calculate the market risk premium?

A. I consider two estimates of the expected market return. The first estimate calculates a forward-looking market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model to the S&P 500 Index, which results in expected market return estimates of 16.06 percent and 14.81 percent, as I describe further below. The second estimate is the long-run historical arithmetic average market return of 12.17 percent reported by Kroll (formerly Duff & Phelps) for the years 1926 to 2024.[23]

Q. Please further explain your forward-looking DCF approach to estimating the market return.

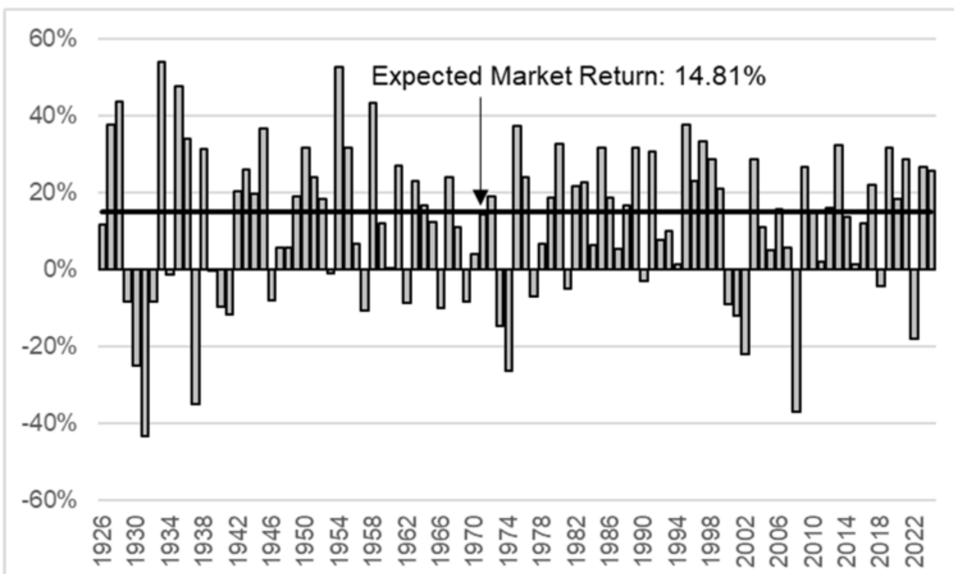
A. Using the Constant Growth DCF model described earlier, I develop two estimates of the expected market return by applying dividend yields from Bloomberg and projected earnings growth rates from Bloomberg and *Value Line*. I calculate a market capitalization-weighted dividend yield and projected earnings growth rate for the S&P 500 Index and apply those estimates to the Constant Growth DCF formula, using the same half-growth rate assumption described earlier. The expected market returns from Bloomberg and *Value Line* are 16.06 percent and 14.81 percent, respectively (*see* PPL Electric Exhibit JEN-4). To be conservative, I rely on the *Value Line* estimate of 14.81 percent.

[23] Source: Kroll, Cost of Capital Navigator.

Q. Is the market DCF-based estimate of 14.81 percent consistent with actual observed returns on the market?

A. Yes, it is. As shown in Figure 6 below, a market return of 14.81 percent or higher occurred in 50 of the last 99 years (i.e., more than half of the time). Since 2009, the annual market return has averaged 15.58 percent, and equaled or exceeded 14.81 percent in 10 of the last 16 years and 12 of the last 22 years. In other words, an annual market return of 14.81 percent, or higher, has occurred frequently and is not an outlier.

Figure 6: Annual Market Return (1926-2024)[24]



Q. Please explain the historical average return on the market of 12.17 percent as an alternate estimate of the expected market return.

A. I also consider the long-term average historical return on large capitalization stocks between 1926 and 2024 as reported by Kroll (12.17 percent).

---

[24] Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7 (years 1926-2022); Cost of Capital Navigator (2023-2024 data).

Q. With the risk-free rates and required market return estimates described above, how do you calculate the market risk premium?

A. I apply two estimates of the risk-free rate and two estimates of the expected market return. Combined, those variables produce four estimates of the market risk premium, ranging from 7.25 percent to 10.30 percent as shown below in Figure 7.

Figure 7: Market Risk Premium Estimates

	Current Risk-Free Rate (4.92%)	**Projected Risk-Free Rate (4.52%)**
Forward Looking DCF-based Expected Market Return (14.81%)	9.89%	10.30%
Long-Term Historical Average Market Return (12.17%)	7.25%	7.65%

Q. Do you consider another form of the CAPM?

A. Yes, I also consider the Empirical CAPM ("ECAPM") approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[25] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as expressed in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

where:

k_e = the required market ROE;

[25] *See, e.g.*, Roger A. Morin, New Regulatory Finance, at 189-190 (2006).

β = Adjusted Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

To calculate my ECAPM results, I apply the same market return, Beta coefficients, and risk-free rates described earlier to the ECAPM formula shown in Equation [5].

Q. What is the benefit of the ECAPM approach?

A. The ECAPM corrects the tendency of the CAPM to underestimate the cost of equity for companies, such as regulated utilities, with low Beta coefficients, and to overstate the cost of equity for companies with high Beta coefficients. As discussed below, the ECAPM recognizes academic research that indicates that the risk-return relationship is flatter than the relationship estimated by the CAPM, and that the CAPM underestimates the alpha, or the constant return term.[26]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML is not as steeply sloped as the SML predicted by the CAPM formula.[27] Fama and French found that the actual returns on the low Beta coefficient portfolios were higher than the CAPM-predicted returns, and vice versa for the high Beta coefficient portfolios.[28] Similarly, Dr. 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.

---

[26] *Id*. at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

[27] *Id*. at 175.

[28] Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

> ***
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,(R_M - R_F) + (1\text{-}x)\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[29]

Q. Does the application of adjusted Beta coefficients in the ECAPM address the empirical issues with the CAPM?

A. No, it does not. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the actual SML is not as steeply sloped as the SML predicted by the CAPM formula. To that point, Dr. Morin explains:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to

[29] Roger A. Morin, New Regulatory Finance, at 175, 190 (2006).

> Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[30]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

Q. Are you aware of academic studies that support the use of the ECAPM for utilities?

A. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities.[31] The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to *Value Line*'s approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

Q. What are the results of your CAPM analyses?

A. As shown in Figure 8, the average CAPM results range from 10.35 percent for the results using the long-term average market return to 12.35 percent for the results using the forward market return.

---

[30] *Id*. at 191.

[31] Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

Figure 8: Summary of CAPM and ECAPM Results[32]

	Current 30-Year Treasury Yield (4.92%)	**Projected 30-Year Treasury Yield (4.52%)**
CAPM Forward Market Return	12.05%	11.94%
ECAPM Forward Market Return	12.74%	12.66%
Average Forward Market Return CAPM	12.35%	
CAPM Historical Market Return	10.15%	10.04%
ECAPM Historical Market Return	10.65%	10.57%
Average Historical Market Return CAPM	10.35%	

4. Bond Yield Plus Risk Premium Approach

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to compensate for the residual risk associated with equity ownership. Risk Premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds.

Q. Please explain how you perform your Bond Yield Plus Risk Premium analysis.

A. I first define the equity risk premium as the difference between the authorized ROE and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield, using the authorized ROE for 1,824 electric utility rate proceedings between January 1, 1980, and June 30, 2025. To reflect the prevailing level of bond yields during the pendency of the proceedings, I

[32] PPL Electric Exhibit JEN-5. Results reflect the average of the proxy group mean and median for both 5-year and 10-year Beta coefficients.

calculate the average 30-year Treasury yield over the average period between the filing of the rate case and the date of the final order (approximately 202 days).

Because the data spans several economic cycles over more than four decades, the analysis incorporates changes in the equity risk premium over time. Prior research, for example, has shown that the equity risk premium is inversely related to the level of bond yields.[33]

Q. How do you analyze the relationship between bond yields and the Equity Risk Premium?

A. I estimate the relationship between bond yields and the equity risk premium by applying regression analysis, in which the observed equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I used the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta\,(\mathrm{LN}(T_{30})) \qquad [6]$$

where:

RP = the equity risk premium;

α = the intercept term;

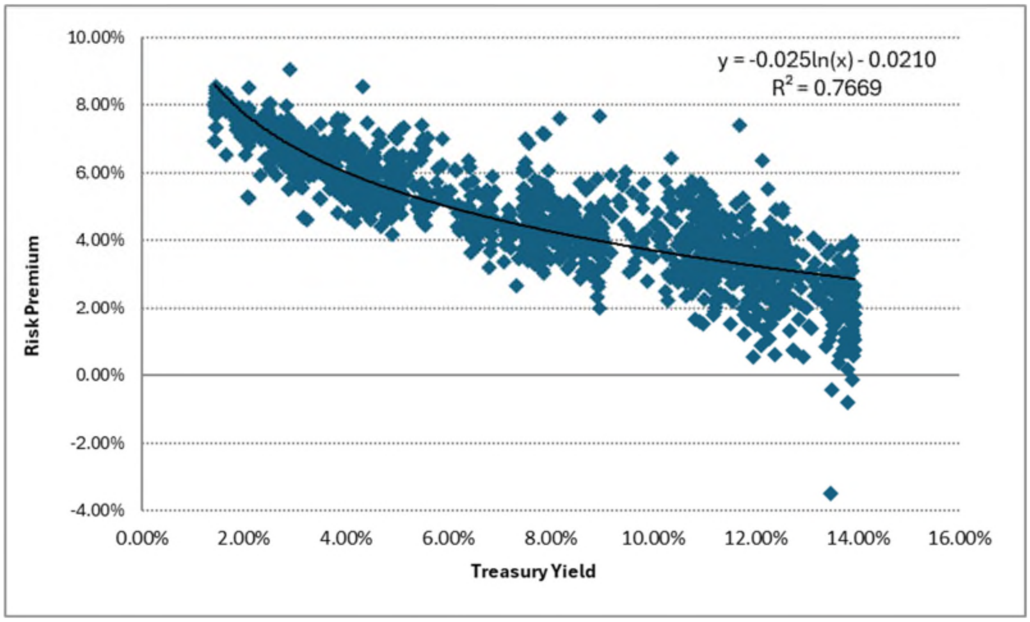
β = the slope term; and

---

[33] In other words, declines in the 30-year Treasury yield are related to an increase in the Equity Risk Premium and vice versa. *See, e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, (Spring 1985), at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

LN(T_{30}) = the natural log of the 30-year Treasury yield.

Figure 9: Equity Risk Premium[34]



As Figure 9 illustrates, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin cites several studies and concludes that, "beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[35] Applying the regression coefficients in Figure 9 produces ROE estimates of 10.22 percent to 10.41 percent, as can be seen on Figure 10 below (see also PPL Electric Exhibit JEN-6).

---

[34] *See* Exhibit JEN-6.

[35] Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 128 (2006).

Figure 12: Summary of Bond Yield Plus Risk Premium Results[36]

	30-Year Treasury Bond	Risk Premium	Return on Equity
Current 30-Year Treasury	4.92%	5.49%	10.41%
Projected 30-Year Treasury	4.52%	5.71%	10.22%

Q. What are the advantages of the Bond Yield Plus Risk Premium approach?

A. There are several advantages. First, authorized ROEs in other jurisdictions are a significant part of the market information that investors consider when evaluating their investment alternatives. Therefore, they are a direct measure of returns available to other electric utilities, as required under the comparable return standard of the *Hope* and *Bluefield* decisions. The level of authorized ROE also provides a signal to investors about the level of regulatory support that a company can expect regarding its ability to compete for capital and to ensure its financial integrity. An ROE below its peers for a given period may be an impediment to the Company's ability to attract capital and finance the infrastructure required to provide safe, reliable service to its customers.

Second, the use of the Bond Yield Plus Risk Premium model in conjunction with the DCF and CAPM approaches adds diversity to the model results, which enables a more robust and reliable ROE estimate. The fewer models that are relied upon, the more likely it is that model risk biases the ultimate ROE determination. For the same reasons that diversity is a wise and prudent investment strategy, diversity of the models used to estimate the ROE is similarly prudent, as it reduces the risk that the results of any single model may not reasonably reflect investors' return requirements.

[36] *See* PPL Electric Exhibit JEN-6.

A third advantage of the Bond Yield Plus Risk Premium approach is its simplicity and reliance on fewer contentious inputs.

Lastly, the Bond Yield Plus Risk Premium approach adds a measure of stability because it is less vulnerable to changes in market data. As shown in the regression equation in Figure 9, the change in the risk premium (and therefore the ROE estimate) as a result of a change in bond yields is less than one-to-one. For example, as shown in Figure 10 above, a 40-basis point increase in the bond yield (from 4.52 percent to 4.92 percent) results in a 19-basis point change in the ROE from 10.22 percent to 10.41 percent.

IV. <u>BUSINESS AND FINANCIAL RISKS</u>

Q. Are there factors specific to PPL Electric's risk profile that you also considered in developing your ROE recommendation?

A. Yes, there are several additional factors that have a direct bearing on PPL Electric's ability to earn a fair return and on the Company's riskiness relative to the proxy group. Those factors include: (1) the Company's capital expenditure program, the regulatory environment in which it operates, and the need to maintain access to capital; (2) the Company's size compared to the proxy group companies; and (3) the costs associated with issuing equity (or flotation costs). Those factors, which are discussed below, should be considered in terms of their overall effect on PPL Electric's business risk and, therefore, its cost of equity. However, as explained below, I have not made an explicit adjustment to account for these factors.

A. Capital Expenditures, Regulatory Environment, and Capital Access

Q. Do you have any preliminary thoughts on the importance of access to capital for electric utilities such as PPL Electric?

A. Yes, I do. As a capital-intensive enterprise, the authorized ROE should enable PPL Electric to finance capital expenditures and working capital requirements at reasonable costs and maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness to the benefit of customers.

Electric utilities are one of the most capital-intensive market sectors. On average, electric utilities generate less than one-third of the revenue per dollar of assets than the non-utility U.S. companies covered by *Value Line*. To fund the significant capital expenditures needed to maintain, expand, and modernize existing infrastructure, electric utilities require sufficient internally generated cash flow and ongoing access to investor supplied capital. Because electric utilities tend to be cash flow negative (i.e., cash spent on plant investment is more than cash flow received from operations), it is critical that regulation provide predictable, adequate, and achievable allowed returns that support the financial integrity of the utility.

Q. Please discuss PPL Electric's capital expenditure program.

A. The Company plans a major capital investment program over the 2025-2029 period, totaling approximately $4.4 billion of distribution capital expenditures.[37]

[37] PPL Electric's planned capital investment program is described by Company Witness Dennis A. Urban Jr.; see Exhibit DAU-1.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with higher levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[38]

Moody's also notes that growing power demand and the need to improve grid resilience are increasing capital expenditure pressure for utilities, widening cash flow deficits and weakening their financial strength:

> Credit pressure is emerging most acutely for companies with large, complex or multiyear projects or for those that are experiencing a delay in the recovery of investment costs. Unlike exogenous events of recent years – such as severe storms, commodity price spikes and the COVID-19 pandemic, which we viewed as temporary events – capital spending and related financings are core long-term financial policy issues.[39]

[38] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.
[39] Moody's Ratings, "High capital spending will weigh on credit quality without supportive company actions," October 21, 2024.

Regarding PPL Electric's credit profile, the credit rating agencies have identified heightened capital expenditures as a credit challenge for PPL Electric. Moody's notes a credit challenge of "[i]ncreasing leverage to support [sic] robust capital expenditure plan."[40] In noting a key risk, S&P similarly identifies that, in part, PPL Electric's ongoing capital spending will result in "[n]egative discretionary cash flow, leading to external funding needs."[41]

Therefore, to the extent that PPL Electric's rates do not permit the Company an opportunity to recover its full cost of doing business, PPL Electric will face increased recovery risk and thus increased pressure on its credit metrics. Maintaining access to capital markets on favorable terms is especially important for utilities and their customers during periods of significant capital investment.

Q. Please explain how the regulatory framework affects investors' risk assessments.

A. The ratemaking process is premised 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 invested capital and the market-required return on such capital. Regulatory commissions recognize that, because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, thereby balancing the long-term interests of investors and customers. In that respect, the regulatory framework in which a utility operates is one of the most important factors in both debt and equity investors' risk assessments.

---

[40] Moody's Ratings, "PPL Electric Utilities Corporation Update to credit analysis," June 14, 2024, at 2.
[41] S&P Global Ratings, "PPL Electric Utilities Corp.," June 25, 2024, at 1.

Because investors have many investment alternatives, even within a given market sector, the Company's authorized return must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Q. Does the regulatory environment influence utilities' access to capital?

A. Yes, it does. The regulatory environment is a key driver of investors' assessment of a utility's risk. Investors and rating agencies understand that a constructive regulatory environment is critical to support utilities' credit ratings and financial integrity, especially during adverse market conditions. Credit rating agencies also recognize the importance of the regulatory environment when assessing a utility's business risk profile.

Q. Please explain how credit rating agencies consider the regulatory framework in establishing a company's credit rating.

A. The overall regulatory framework is one of the most important factors Moody's, S&P, and Fitch consider in establishing credit ratings. Moody's establishes credit ratings based on four key factors:

Figure 113: Moody's Rating Factors[42]

Factor	**Weighting**
Regulatory Framework	25%
Ability to Recover Costs and Earn Returns	25%
Diversification	10%
Financial Strength	40%
Total	**100%**

[42] Moody's Investor Service, Rating Methodology, Regulated Electric and Gas Utilities, August 6, 2024, at 2.

Two of these factors (*i.e.*, regulatory framework and the ability to recover costs and earn returns) relate to the constructiveness of the regulatory environment such that 50 percent of Moody's overall assessment of a utility's business and financial risk depends on the regulatory environment.[43] Similarly, S&P has identified the regulatory environment as an important factor, stating, "we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most."[44] Moody's views the Commission's supportive regulatory framework as a "credit strength" for PPL Electric, however, it notes that "[a] rating downgrade could be considered if there is significant deterioration in the credit supportiveness of the regulatory environment."[45] S&P states that regulatory advantage is "of critical importance" because "[i]t defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.[46] S&P explains that it considers four subfactors when assessing a utility's ability to recover all its costs "on time and in full – and to earn a return on the capital it deploys".[47] Those four subfactors are (1) regulatory stability, (2) tariff-setting procedures and design, (3) financial stability, and (4) regulatory independence and insulation.[48] With respect to capital expenditures, S&P notes that a regulatory "framework's ability to attract long-term capital, and the availability of capital support during construction," support a utility's financial stability as they "alleviate funding and cash flow pressure when heavy investment is needed."[49] Thus, predictability and consistency of regulatory actions are

[43] *Id*. at 6.
[44] Standard & Poor's, Assessing U.S. Utility Regulatory Environments, March 11, 2010, at 2.
[45] Moody's Ratings, "PPL Electric Utilities Corporation Update to credit analysis," June 14, 2024, at 2.
[46] S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).
[47] *Id*.
[48] *Id*.
[49] *Id*.

among the primary concerns for the rating agencies, as is full and timely cost recovery, including recovery of capital costs.

The ROE determined in this proceeding will have a direct effect on the credit rating agencies' perspective of the Company's risk profile. Given the substantial amount of capital that will be required to serve PPL Electric's customers, it is critical that Pennsylvania's regulatory environment continue to be viewed as balanced, predictable, and constructive.

Q. What are your conclusions regarding the Company's capital expenditure plans, its need to maintain access to capital, and the effect of the regulatory environment on the company's risk profile?

A. The Company's capital expenditure program is substantial and emphasizes the importance of the Commission's decision in this proceeding, which will have a direct bearing on the Company's ability to maintain its financial profile and its access to the capital market at reasonable costs and terms.

PPL Electric will need to rely on external sources for funding critical investments to expand and enhance its assets to support the growing demand. The Company's ability to efficiently access the capital markets at favorable terms will depend on the strength of its balance sheet and financial integrity. For these reasons, it is important that the authorized ROE and capital structure be set at a level that allows PPL Electric to continue to attract both debt and equity under favorable terms under a variety of economic and financial market conditions.

B. <u>Size Effect</u>

Q. Please explain the risk associated with a company's size and scale.

A. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect."[50] Although empirical evidence of the size effect is often based on studies of industries beyond regulated utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, a senior consultant with Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[51]

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (i.e., the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and (2) fundamental business risks. As discussed below, relative to the proxy group, PPL Electric's operations are both smaller in size and less diversified.

Q. How does the size and scale of PPL Electric affect its business risks relative to the proxy group?

A. It is important to bear in mind that my ROE recommendation for PPL Electric is developed based on market data applied to a risk-comparable proxy group. Consequently, an evaluation of the Company's risk associated with its size and scale is necessarily based on

---

[50] *See* Mario Levis, *The Record on Small Companies: A Review of the Evidence*, <u>Journal of Asset Management</u> at 368-397 (Mar. 2002) for a review of literature relating to the size effect.

[51] Michael Annin, *Equity and the Small-Stock Effect*, <u>Public Utilities Fortnightly</u> (Oct. 15, 1995).

a comparison of its size relative to the proxy group, because, all else equal, size has a material bearing on risk.

In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. Any material changes to expected operations and maintenance expenses can have severe consequences on a company's level of operating leverage. Similarly, capital expenditures for non-revenue producing investments such as system maintenance and replacements will put proportionately greater pressure on customer costs, potentially leading to demand reduction. Taken together, these risks affect the return required by investors for smaller companies. For smaller companies, unpredictable and adverse events may affect revenues or expenses more acutely.

Q. Is there support in the financial community for the use of a small size premium?

A. Yes, there have been several studies that demonstrate the size premium. One of the earliest works in this area found that over a period of 40 years "the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[52] The author, who referred to that finding as the "size effect," suggested that the CAPM was mis-specified, in that on average, smaller firms had significantly larger risk-adjusted returns than larger firms. The author also concluded that the size effect was "most pronounced for the smallest firms in the sample."[53] Since then, additional empirical research has focused

[52] R. W. Banz, The Relationship Between Return and Market Value of Common Stocks, Journal of Financial Economics, 9, 1981 at 3-4.

[53] *Id.* at 16.

on explaining the size effect as a function of lower trading volume and other factors, but the proposition that Beta coefficients fail to reflect the risks of smaller firms persists.[54] In 1994, Fama and French also focused on the issue of whether the CAPM adequately explained security returns and proposed a "three factor" model for expected security returns. Those factors include: (1) the covariance with the market, (2) size, and (3) financial risk as determined by the book/market ratio. As explained by Morningstar, Fama and French "found that the returns on stocks are better explained as a function of size and book-to-market value in addition to the single market factor of the CAPM, with the company's size capturing the size effect and its book to market ratio capturing the financial distress of a firm."[55]

Simply put, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps (now Kroll) 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," Duff & Phelps 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)[56]

---

[54] *See, e.g.*, Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002.
[55] Morningstar, Ibbotson SBBI 2013 Valuation Yearbook, at 109.
[56] Duff & Phelps Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2020, at 4-1.

Q. Are you aware of other studies regarding the existence of size premium for regulated utilities?

A. Yes. A 2002 study by Thomas M. Zepp[57] concludes that size premia do exist for smaller utilities. Developed in response to a 1993 study by Annie Wong, the Zepp study focuses specifically on the utility industry and the effect of the size premium in a regulated environment. For example, one study reviewed by Zepp found that smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities, and the result was statistically significant at the 90.00 percent level.[58] Zepp concludes that "to the extent water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones."[59]

Additionally, a 2011 study by Stéphane Chrétien and Frank Coggins in the article "Cost of Equity for Energy Utilities: Beyond the CAPM" [60] considered the Fama-French three-factor model and a model similar to the Empirical CAPM I described earlier. In the article, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins show, the Beta coefficient on the size variable for a group of U.S. natural gas utilities was positive and statistically significant supporting the position that small size risk is relevant for regulated utilities.[61]

---

57 Thomas M. Zepp, *Utility stocks and the size effect – revisited*, Quarterly Review of Economics and Finance, 43 (2003) 578-582.

58 *Id*. at 580-581.

59 *Id*. at 582.

60 Chrétien, Stéphane, and Frank Coggins. *Cost Of Equity For Energy Utilities: Beyond The CAPM.* Energy Studies Review, vol. 18, no. 2, at 31.

61 *Id*.

Q. Is it appropriate to consider the risk associated with PPL Electric's size even though it is a subsidiary of a larger entity?

A. Yes. The widely accepted "stand-alone" regulatory principle treats each utility subsidiary as its own company. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. The opportunity cost concept applies regardless of the source of the funding. When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary competes for capital with the parent company's affiliates, and with other similarly situated utility companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return. It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective. From that perspective, the fact that PPL Electric is a subsidiary of PPL Corporation is not relevant to the consideration of the risk associated with PPL Electric's small size.

Q. How does PPL Electric compare in size to the proxy companies?

A. PPL Electric is smaller than the average of the proxy companies; as PPL Electric Exhibit JEN-7 shows, PPL Electric's implied market capitalization is approximately $12,941 million, or approximately 48 percent smaller than the proxy group median market capitalization, and approximately 63 percent smaller than the proxy group mean market capitalization.[62]

Q. How did you estimate the size premium for PPL Electric?

A. In its Cost of Capital Navigator, Kroll presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. An additional estimate of the size premium associated with PPL Electric, therefore, is the difference in the Kroll size risk premia for the proxy group median market capitalization relative to the Company's implied market capitalization.

As shown in PPL Electric Exhibit JEN-7, according to recent market data, the median market capitalization of the proxy group is approximately $24,988 million, which corresponds to the second decile of Kroll's market capitalization data. Based on Kroll's analysis, that decile corresponds to a size premium of 0.33 percent (or 33 basis points). As noted above, PPL Electric's implied market capitalization is $12,941 million, which falls within the third decile and corresponds to a size premium of 0.49 percent (or 49 basis points). The difference between those size premia is 16 basis points, as shown in PPL Electric Exhibit JEN-7.

[62] PPL Electric's implied market capitalization is calculated by applying the median Market/Book ratio for the proxy group of 1.90 to PPL Electric's total common equity of approximately $6,800 million as of June 30, 2025. *See* Exhibit JEN-7.

Q. Have you made an explicit adjustment to your ROE recommendation for PPL Electric's comparatively small size?

A. No, I have not. While I quantify the size effect for PPL Electric, I conservatively do not make an explicit adjustment to my ROE recommendation for the Company's size relative to the proxy group.

C. Flotation Cost Adjustment

Q. What are flotation costs, and how do they affect the cost of capital?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the utility's ability to attract adequate capital on reasonable terms. To estimate flotation costs, the DCF calculation is modified to provide a dividend yield that reimburses investors for issuance costs. Based on the proxy group actual issuance costs shown in PPL Electric Exhibit JEN-8, flotation costs for the proxy companies have equaled roughly 2.53 percent of gross equity raised. To properly reflect these issuance costs in my cost of capital estimates, it would be necessary to increase the authorized ROE by 10 basis points for PPL Electric, as shown in PPL Electric Exhibit JEN-8.

Q. Do academic and financial experts recognize the need to consider flotation costs in a utility's cost of equity?

A. Yes. Dr. Roger Morin summarizes:

> 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. [63]

According to Dr. Shannon Pratt, a published expert in cost of capital estimation:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[64]

Q. Has PPL Corporation recently issued common equity?

A. Yes. PPL Corporation issued 4.8 million shares of common equity through an at-the-market placement in March and April 2025.

Q. Do you make an explicit adjustment to your ROE recommendation for flotation cost recovery?

A. No, I do not. While appropriate to do so, in this case, I have conservatively not made an explicit adjustment to my ROE recommendation for flotation cost recovery.

---

[63] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 321.
[64] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

V. CAPITAL MARKET ENVIRONMENT

Q. Do economic conditions influence the required Cost of Capital and required return on common equity?

A. Yes. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. Each of the analytical models used to estimate the required ROE is influenced by current and expected capital market conditions. Therefore, an evaluation of current and projected market conditions is integral to any ROE recommendation.

Q. What are the key factors affecting the Cost of Equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utilities is currently affected by several key factors including (1) the interest rate environment and central bank monetary policy; (2) inflationary pressure and the longer-term outlook for inflation; and (3) uncertainty in the economic environment because of geopolitical events. As discussed below, although the Federal Reserve reduced the Federal Funds rate three times in 2024 as inflation stabilized and moved closer to the central bank's two percent target, interest rates and inflation are expected to remain above the levels experienced prior to the COVID-19 pandemic. Further, geopolitical events present significant uncertainties with respect to the near-term economic and capital market in which PPL Electric will be raising external capital.

Q. Please summarize the changes in capital market conditions since early 2020.

A. The COVID-19 pandemic had wide ranging impacts on markets, affecting all market sectors, including utilities. At the start of the pandemic, both the S&P 500 Index and the electric utility sector lost more than a third of their value.[65] At the same time, the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX", a measure of expected market volatility) tripled, from 25.03 on February 24, 2020, to 82.69 on March 16, 2020.[66] Treasury bond yields declined rapidly as the stock market became extremely volatile and investors sought the relative safety of government bonds, combined with the Federal Reserve's reduction in the Federal Funds rate to a target range of 0 percent to 0.25 percent. Because bond yields and bond prices are inversely related, as demand for safer bonds increases, investors bid up the price of bonds and bid down the yields. Since the decline in bond yields was caused by investors' increased aversion to equity market risk, the cost of equity did not decline commensurately with the decline in bond yields.

As the U.S. economy opened from the COVID-19 lockdowns, economic activity quickly rebounded, causing inflation to reach the highest levels seen in the previous 40 years. In response, the Federal Reserve tightened monetary policy at the fastest pace since the 1980s by increasing the Federal Funds rate by 525 basis points over the course of 11 consecutive Federal Open Market Committee ("FOMC") meetings between March 2022 and July 2023.

As Figure 12: Consumer 12 below illustrates, although the pace of inflation subsided from its peak reached in 2022, inflation remains above the Federal Reserve's 2.0

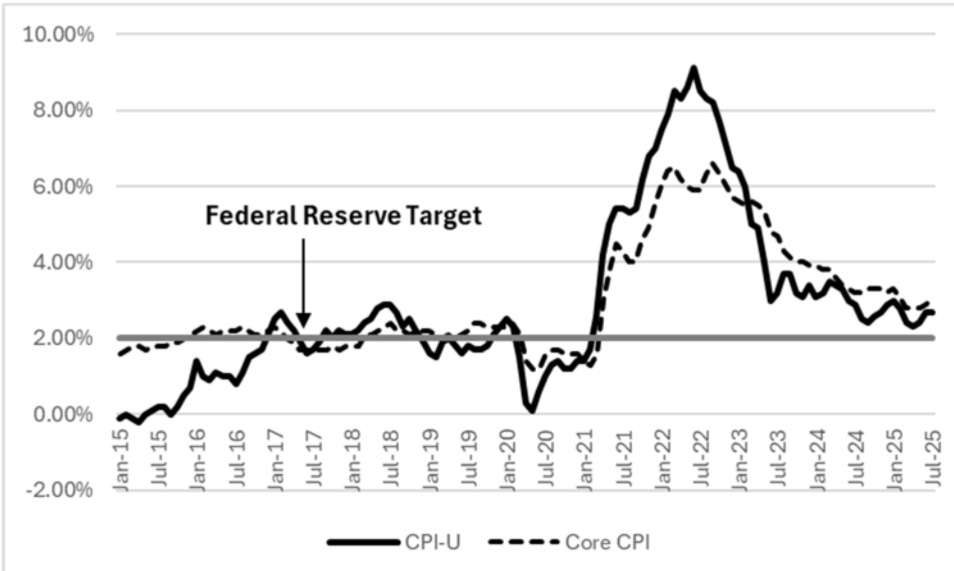
---

65 Source: S&P Capital IQ. Electric utility sector measured by the S&P 500 Electric Utilities Index.

66 Source: Federal Reserve Bank of St. Louis FRED Database.

percent target, ticking up to 2.70 percent for all items and 3.10 percent excluding food and energy ("core CPI") as of July 2025.

Figure 12: Consumer Price Index, 12-month Percentage Change[67]



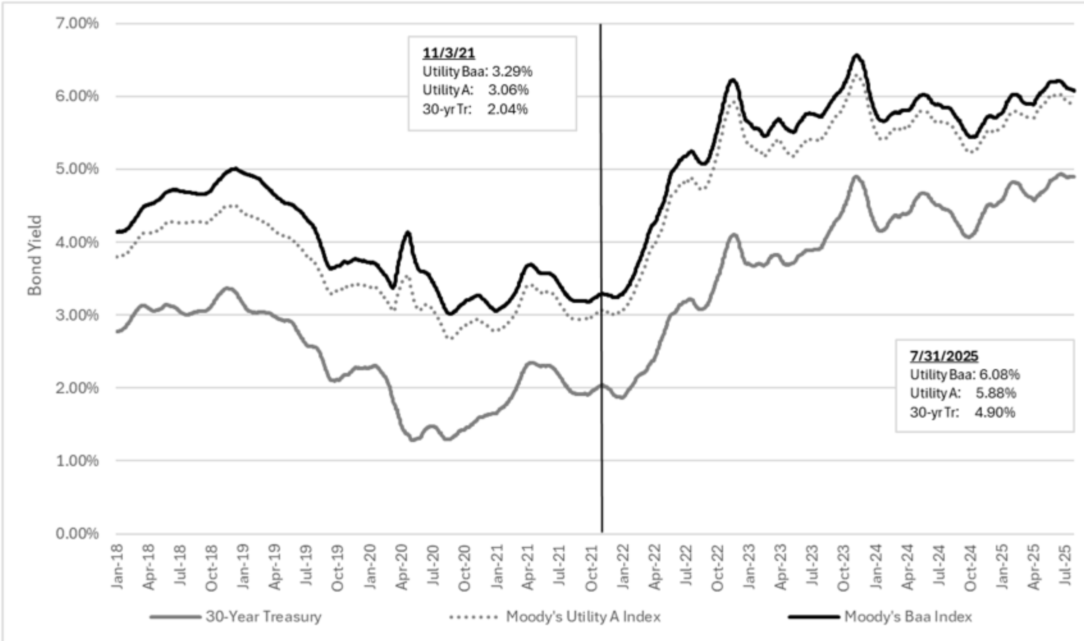
Q. How did government and utility bond yields respond to the Federal Reserve's monetary policy tightening?

A. As the U.S. economy improved in 2021 and the Federal Reserve moved aggressively to tighten monetary policy to fight stubbornly higher inflation, prevailing interest rates rose to their highest levels since 2010.[68] As shown in Figure 13 below, the 30-year Treasury yield has increased 286 basis points since November 3, 2021 when the Federal Reserve signaled it would begin tapering its asset purchases. Utility bond yields have increased by approximately 280 basis points over the same period.

[67] Source: Bureau of Labor Statistics, https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm.

[68] Source: Federal Reserve Bank of St. Louis, FRED Economic Database.

Figure 13: 30-Year Treasury Bond and Utility Bond Yields (2018-2025)[69]



Q. Please explain how higher bond yields affect the ROE estimates.

A. The 30-year Treasury bond yield is a direct input to both the CAPM and the Risk Premium models because, as explained earlier, the term of the security aligns with the long life of natural gas utility assets. As yields increase, the cost of capital generally increases, and the ROE estimates from those two models also increase, although not on a one-to-one basis. Further, while interest rates are not a direct input to the DCF model, dividend yields on utility stocks must compete with yields on Treasury bonds. As yields on government bonds increase, utilities must offer a higher dividend yield to attract and retain investors, signaling an increase in the cost of equity for utilities. All else equal, higher dividend yields produce higher ROE estimates in the DCF model.

---

69 Source: Federal Reserve Bank of St. Louis, FRED Economic Database; Bloomberg Professional.

Q. How have economic and financial market conditions changed in recent months?

A. At the end of 2024, financial markets were optimistic that the Federal Reserve was close to attaining a "soft landing" by taming inflation without a consequential rise in unemployment. Over the past few months, however, federal policy uncertainty has climbed sharply, and financial market volatility has increased. Since the announcement of the Administration's tariff policies in early April, data have shown a vulnerable and slowing economy with consumer and business sentiment declining and growing anticipation of higher inflation.[70]

While inflation has subsided from the elevated levels experienced in the wake of the COVID-19 pandemic, the era of record low interest rates and inflation has likely ended. As noted above, long-term interest rates have increased considerably since the Federal Reserve began tightening monetary policy, and expectations for interest rates are markedly higher than in the five years prior to the pandemic.

Furthermore, even though the pace of inflation has slowed, U.S. consumers continue to expect inflation to remain elevated. As the University of Michigan's Surveys of Consumers Director Joanne Hsu explains regarding consumer sentiment on inflation for July 2025:

> After four months of sharp increases to start 2025, long-run expectations fell for three consecutive months through July. This month's median is below the peak reading from mid-2022, but the three-month-moving average is currently above mid-2022. Expectations exhibit substantial uncertainty, particularly in light of ongoing developments and changes with economic policy and concerns that impacts on inflation are still to come.[71]

---

[70] *See, e.g.*, Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 1.

[71] University of Michigan, Survey of Consumers, "July 2025 Update: Current versus Pre-Pandemic Long-Run Inflation Expectations", August 1, 2025, https://www.sca.isr.umich.edu/files/px5web202506.pdf.

Lastly, cuts in 2024 to the Federal Funds rate by the Federal Reserve have had little effect on long-term government and utility bond yields. Long-term bond yields are less sensitive to the Federal Reserve's monetary policy, and as such have not declined as much as short-term yields, even as the Fed has reduced the Federal Funds rate. As shown in Figure 14 below, since the end of June 2024 (prior to the Fed's rate cuts), the 1-year and 2-year Treasury yields declined by 99 and 77 basis points, respectively, whereas the 10-year and 30-year Treasury yields had stayed relatively flat or actually *increased* (i.e., the 30-year Treasury yield increased by 38 basis points), respectively.

Figure 14: U.S. Treasury Yields (June 2024 vs. July 2025)[72]

	1-year Treasury	2-year Treasury	10-year Treasury	30-year Treasury
June 28, 2024	5.09%	4.71%	4.36%	4.51%
July 31, 2025	4.10%	3.94%	4.37%	4.89%
Change	-0.99%	-0.77%	+0.01%	+0.38%

Therefore, current long-term yields have not declined commensurate with reductions in the Federal Funds rate but have stayed relatively flat or increased. Since models used to estimate the just and reasonable ROE rely primarily on long-term yields, the market movement of short-term yields does not influence the ROE model results as the longer-term yields do.

[72] Source: Spot yields reported by Federal Reserve Board of Governors, H15 Selected Interest Rates. https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15.

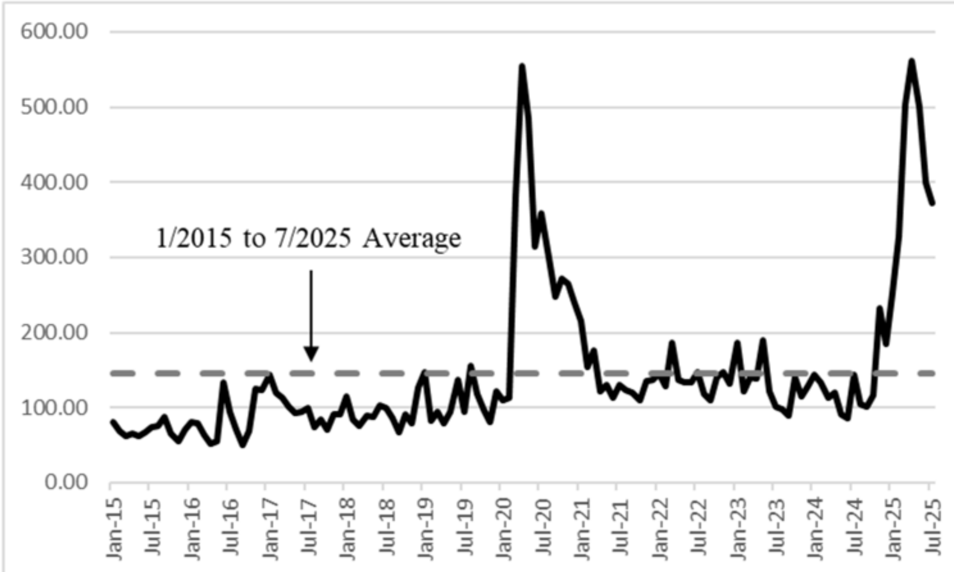
Q. Please discuss recent changes in U.S. trade policy.

A. During the first half of 2025, the Trump administration announced, implemented, or delayed implementation of tariffs on numerous U.S. trade partners. A highlight of this is when, on April 2, 2025, President Trump announced the administration would impose a 10 percent base tariff on all imports from nearly every country plus an additional "reciprocal" tariff customized for each of approximately 60 countries.[73] These reciprocal tariffs were subsequently paused, but significant uncertainty remains around the future course of U.S. trade policy and how it will affect the economy.

This created significant policy and market uncertainty; as can be seen in Figure 15 below, the Federal Reserve Bank of St. Louis' Economic Policy Uncertainty Index (the "Index") spiked to levels not seen since the COVID-19 pandemic. While the Index has partially subsided in recent months (to 372.15 as of July 2025), it is still significantly above the average level (145.23) and the level in November 2015 (55.51), when the Commission approved the settlement in PPL Electric's last filed rate case. This indicates that there is still significant uncertainty related to international trade and the economy. Uncertainty increases risk, which increases the cost of equity, all else equal.

[73] https://www.whitehouse.gov/presidential-actions/2025/04/regulating-imports-with-a-reciprocal-tariff-to-rectify-trade-practices-that-contribute-to-large-and-persistent-annual-united-states-goods-trade-deficits/.

Figure 15: Economic Policy Uncertainty Index January 1, 2019 – July 31, 2025[74]



Q. How might these changes in U.S. trade policy affect inflation and interest rates?

A. Although the effect of these tariffs on the economy remains uncertain, economists generally agree that higher tariffs increase inflation by increasing the cost of consumer goods. The tariffs could lead to higher inflation and reduced overall demand, as well as higher interest rates and a stronger dollar.[75] The Budget Lab at Yale University estimates that these tariffs would raise consumer prices by 1.8 percent before substitution, which would be equivalent to $2,400 in disposable income for the average household.[76]

In a recent article published by S&P Global Market Intelligence, economists noted the "enormous uncertainty" associated with the effect of tariffs on inflation and the economy. The article projected that if President Trump's tariffs are imposed as proposed,

[74] Federal Reserve Bank of St. Louis Economic Database (FRED), Economic Policy Uncertainty Index for United States (USEPUINDXD), https://fred.stlouisfed.org/series/USEPUINDXD.

[75] J.P. Morgan Asset Management, Market Insights "2025 Year-Ahead Investment Outlook," November 21, 2024.

[76] Yale Budget Lab, "State of U.S. Tariffs," August 7, 2025. https://budgetlab.yale.edu/research/state-us-tariffs-august-7-2025

they "would cause the core consumer price index[77] to run at a 6% annual pace on average over the next two years".[78]

Sustained inflation is complicating the Federal Reserve's unwinding of restrictive monetary policies,[79] bolstering long-term bond yields like the 30-year Treasury yield. In an April 16, 2025 speech, Federal Reserve Chair Jerome Powell stated that the Fed faces a "challenging scenario" in balancing the goals of controlling inflation and supporting the labor market, driven primarily by the risk of prolonged inflation and slower economic growth as a result of the tariff policies.[80]

Longer-term bonds like the 30-year Treasury bond are more sensitive to inflation expectations than shorter-term bonds because their value is influenced more by inflation due to their longer maturity holding period and reinvestment rate implications. Thus, as the value (price) of bonds declines due to higher inflation expectations, the yield increases. Because utilities are capital intensive enterprises, higher inflation and interest rates tend to have a negative effect on utility stocks. If realized, higher inflation and interest rates would suggest that the cost of capital for utilities may increase in the future.

Q. What conclusions do you draw from your review of the current capital market environment and its implications on the Company's cost of equity?

A. Over the last five years, the economic and financial market environment has operated under heightened uncertainty associated with the COVID-19 pandemic, the war in Ukraine,

---

77 As measured by the Personal Consumption Expenditures ("PCE") price index.

78 S&P Global Market Intelligence, "Tariffs projected to push US inflation near 2022 highs," April 9, 2025.

79 *See, e.g.*, S&P Global Market Intelligence, "Tariffs projected to push US inflation near 2022 highs," April 9, 2025.

80 Chair Powell's speech at the Economic Club of Chicago, Chicago, Illinois, April 16, 2025, https://www.federalreserve.gov/newsevents/speech/files/powell20250416a.pdf

stubborn inflation, uncertainty surrounding the economy and in the timing of the Federal Reserve's monetary policy, and more recently, economic policy uncertainty and geopolitical tensions. Although the Federal Reserve responded to easing inflation by cutting short-term rates in late 2024, it has since paused those cuts to assess how the effects of fluctuating trade policies affect the economy. These factors underscore the importance of using multiple models when determining PPL Electric's cost of equity to gain a comprehensive perspective of the effect of fluid and evolving market conditions on the cost of equity.

VI. CAPITAL STRUCTURE

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

A. As explained by Company Witness Burgos, the Company is requesting a permanent capital structure consisting of 56.00 percent common equity and 44.00 percent long-term debt, consistent with its recent actual capital structure.

Q. Please summarize the approaches to determining the appropriate capital structure for regulated utilities.

A. There are two primary approaches regulators use to determine the appropriate capital structure for ratemaking purposes. The most common approach is to use the subject utility's actual capital structure. This approach is preferred when the subject utility (1) issues its own debt, (2) has its own credit rating, and (3) its actual capital structure is within industry standards and practice.[81] When the subject utility does not issue its own debt and

[81] *See, e.g.*, Parcell, D.C. (2020). *The Cost of Capital: A Practitioner's Guide.* Society of Utility and Regulatory Financial Analysts; 154 FERC ¶ 61,004, Docket No. ER15-945-001, at 15.

have its own credit rating, or when the actual capital structure deviates substantially from industry practice, a hypothetical capital structure may be imputed.

Q. Does PPL Electric issue its own debt and have its own credit rating?

A. Yes. Therefore, the next step is to assess the reasonableness of its actual capital structure within the context of industry practice.

Q. What are the regulatory guidelines for determining whether a utility's capital structure is consistent with sound utility practice?

A. In a 2020 publication titled *A Cost of Capital and Capital Markets Primer for Utility Regulators*, NARUC advises that actual capital structure ratios should be used unless they "greatly diverge" from sound industry practice:

> A utility management must be permitted latitude, discretion, and flexibility in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments.
>
> Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios greatly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs.
>
> ***
>
> As increasing financial leverage shifts the weight from common equity to lower cost debt, it also increases both the cost of debt and the cost of

common equity. In practice, these offsetting impacts cancel each other out over a wide range of capital structure ratios".[82]

Further, James C. Bonbright explains in his seminal text *Principles of Public Utility Rates* that a hypothetical capital structure should be used only when actual capital structures are "clearly unsound" or "extravagantly conservative," reasoning that using hypothetical capital structures "substitutes an estimate of what the capital cost would be under non-existing conditions for what it actually is or will soon be under prevailing conditions."[83]

Q. How have you assessed whether PPL Electric's capital structure is consistent with industry standards?

A. The proxy group has been selected to reflect comparable companies in terms of business and financial risks. Therefore, it is appropriate to compare the financial capital structures of the proxy group companies to the financial capital structure requested by PPL Electric to assess whether the Company's capital structure is reasonable and consistent with industry standards for companies with commensurate risk. I calculated the average capital structure for each of the proxy group operating companies from 2022 through 2024. PPL Electric Exhibit JEN-9 shows that the Company's proposed common equity ratio of 56.00 percent is within the range of actual common equity ratios of 44.73 percent to 60.60 percent for the operating companies held by the proxy group over this period.

[82] NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), at 12 (emphasis added).

[83] James C. Bonbright, Principles of Public Utility Rates, at 243-44 (1961). Republished with permission by the Regulatory Assistance Project.

Q. Has the Commission previously accepted a utility's capital structure if it has been consistent with industry standards?

A. Yes, it has. For example, in PECO Energy Company – Gas Division's ("PECO Gas") 2021 rate case, the Commission adopted PECO Gas's and the Administrative Law Judge's recommendation to use PECO Gas's actual capital structure, noting that "if a utility's actual capital structure is within the range of a similarly situated proxy group of companies, rates are set based on the utility's actual capital structure."[84]

Q. What is your conclusion regarding the appropriateness of PPL Electric's capital structure in this proceeding?

A. Based on the analysis presented in PPL Electric Exhibit JEN-9, I conclude that the Company's proposed permanent capital structure of 56.00 percent common equity and 44.00 percent long-term debt is consistent with sound industry practice and is consequently reasonable and appropriate, especially given PPL Electric's substantial capital investment requirements and the uncertain economic environment in which it will need to raise capital going forward.

---

[84] *Pennsylvania Public Utility Commission, Office of Consumer Advocate, Office of Small Business Advocate Philadelphia Area Industrial Energy Users Group v. PECO Energy Company – Gas Division*, Opinion and Order, Docket No. R-2020-3018929, Public Meeting held June 17, 2021, at 144.

VII. CONCLUSIONS AND RECOMMENDATION

Q. What is your recommendation regarding the Company's cost of equity and capital structure in this proceeding?

A. As discussed throughout my Direct Testimony, it is important to consider a variety of quantitative and qualitative information in reviewing analytical results and arriving at ROE determinations. The results from three commonly used analytical approaches applied to a proxy group of 24 comparable electric utilities indicate an ROE in the range of 10.30 percent to 12.35 percent in today's capital market environment. Within that range, I recommend an ROE of 11.30 percent, which is the approximate midpoint of the range. Further, my recommendation does not include additional adjustments for PPL Electric's heightened capital expenditures, smaller size compared to the proxy group, and flotation costs. Lastly, I support PPL Electric's proposed financial capital structure of 56.00 percent common equity and 44.00 percent long-term debt as reasonable relative to the range of actual capital structures for the operating companies held by the proxy group companies.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JENNIFER E. NELSON
VICE PRESIDENT

Ms. Nelson is a Certified Rate of Return Analyst with more than fifteen years of experience in the energy industry. As an expert witness, she has testified to the cost of capital and alternative ratemaking proposals for electric, natural gas, and water utilities. In her time as a consultant, Ms. Nelson has provided consulting services on a variety of utility regulatory matters including ratemaking and regulatory policy, cost of service and revenue requirements, integrated resource planning, renewable power contracts, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. Ms. Nelson has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc., and a managing consultant at Sussex Economic Advisors, LLC. Prior to consulting, she was a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley University.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, Michigan, New Hampshire, New Mexico, North Carolina, South Carolina, Texas and Virginia regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Alaska, Florida, North Carolina, Ohio, Oregon, South Carolina, Utah, West Virginia, and Wyoming regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through research, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of electric utilities and a water utility before the Arkansas Public Service Commission regarding the utilities' proposed Formula Rate Plans.
- Submitted expert testimony on behalf of an electric utility before the Oklahoma Corporation Commission regarding the utility's proposed Formula Rate Plan.
- Submitted expert testimony on behalf of an electric and natural gas utility before the Delaware Public Service Commission regarding the utility's proposed performance-based rate plan.

- Submitted expert testimony on behalf of an electric and natural gas utility before the Montana Public Service Commission regarding the utility's proposed alternative rate mechanisms.
- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast U.S. natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported rebuttal testimony filed on behalf of an Alaska natural gas utility regarding the utility's gas supply planning standards.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.
- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Filed expert testimony before the California PUC regarding the benefits of financial flexibility and diversity in sources of financial capital associated with an electric utility's request to lease entitlements as a means of raising capital.
- Supported expert testimony on the appropriate level of remuneration associated with the Massachusetts electric utilities' long-term contracts for wind power through research, financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for utility acquisitions.

RELEVANT PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021-present)
Vice President
Assistant Vice President

ScottMadden, Inc. (2016-2021)
Director
Manager

Sussex Economic Advisors, LLC (2013-2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011-2013)
Economist, Electric Power Division

State of Alaska Department of Revenue, Tax Division (2007-2010)
Petroleum Economist

Federal Reserve Bank of Boston (2000-2002)
Research Assistant, Economic Research Department

EDUCATION AND RELEVANT COURSEWORK

University of Alaska
Master of Science, Resource and Applied Economics

Bentley University (formerly Bentley College)
Bachelor of Science, Business Economics
Graduated *magna cum laude*

New Mexico State University
Center for Public Utilities, Regulatory Basics

ISO New England
Wholesale Energy Markets (WEM-101)

Colorado School of Mines
Petroleum Engineering SuperSchool

EUCI
Course Instructor – Performance-Based Ratemaking

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts
Member, Society of Utility and Regulatory Financial Analysts

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	04/25	ENSTAR Natural Gas Company	TA-352-4	Cost of Capital
Arkansas Public Service Commission				
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Sponsored testimony evaluating the Return on Equity included in Rider FRP
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
California Public Utilities Commission				
Pacific Gas & Electric Co.	01/25	Pacific Gas & Electric Co.	A-24-03-009	Financial flexibility and capital diversity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/24	Delmarva Power & Light Company	24-0868	Alternative Ratemaking Proposal
Florida Public Service Commission				
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	05/22	Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	20220069-GU	Cost of Capital
State Corporate Commission of Kansas				
Evergy Kansas Central and Evergy Kansas South, Inc.	07/25	Evergy Kansas Central and Evergy Kansas South, Inc.	25-EKCE-294-RTS	Capital Structure
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed CIRA capital tracking mechanism
Michigan Public Service Commission				
DTE Electric Company	04/25	DTE Electric Company	U-21860	Cost of Capital
Montana Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
NorthWestern Corporation	08/22	NorthWestern Corporation	2022-7-78 (elect.) 2022-7-78 (gas)	Alternative Ratemaking Proposals
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	DE 21-030	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
North Carolina Utilities Commission				
Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	04/21	Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	G-5, Sub 632	Cost of Capital
Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	03/24	Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	E-22, Sub 694	Cost of Capital
Public Service Company of North Carolina	04/25	Public Service Company of North Carolina	G-5, Sub 686	Cost of Capital
Public Utilities Commission of Ohio				
The East Ohio Gas Company d/b/a Dominion Energy Ohio	11/23	The East Ohio Gas Company d/b/a Dominion Energy Ohio	23-0894-GA-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
Public Utility Commission of Oregon				
Northwest Natural Gas Company dba NW Natural	12/23	Northwest Natural Gas Company dba NW Natural	UG 490	Cost of Capital
Northwest Natural Gas Company dba NW Natural	12/24	Northwest Natural Gas Company dba NW Natural	UG 520	Cost of Capital
Public Utilities Commission of South Carolina				
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Dominion Energy South Carolina	03/24	Dominion Energy South Carolina	2024-34-E	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Public Utilities Commission of Texas				
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
El Paso Electric Company	06/21	El Paso Electric Company	52195	Cost of Capital
Wind Energy Transmission Texas, LLC dba WETT	12/24	Wind Energy Transmission Texas, LLC dba WETT	57299	Cost of Capital
El Paso Electric Company	01/25	El Paso Electric Company	57568	Cost of Capital
Utah Public Service Commission				
Enbridge Gas Utah	05/25	Enbridge Gas Utah	25-057-06	Cost of Capital
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital
Virginia State Corporation Commission				
Virginia Electric & Power Company (Dominion Energy Virginia)	03/25	Virginia Electric & Power Company (Dominion Energy Virginia)	PUR-2025-00058	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc.	04/25	Hope Gas, Inc.	25-0417-G-42T	Cost of Capital
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital
Washington Utilities & Transportation Commission				
Northwest Natural Gas Company d/b/a NW Natural	08/25	Northwest Natural Gas Company d/b/a NW Natural	UG-250610	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] S&P Capital IQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$2.03	$61.22	3.32%	3.42%	6.60%	6.64%	6.00%	6.41%	9.42%	9.84%	10.07%
Ameren Corporation	AEE	$2.84	$96.16	2.95%	3.05%	7.00%	7.00%	6.50%	6.83%	9.55%	9.89%	10.06%
American Electric Power Company, Inc.	AEP	$3.72	$102.48	3.63%	3.75%	6.40%	6.90%	6.50%	6.60%	10.15%	10.35%	10.65%
Avista Corporation	AVA	$1.96	$37.97	5.16%	5.31%	6.10%	5.50%	5.50%	5.70%	10.80%	11.01%	11.42%
CenterPoint Energy, Inc.	CNP	$0.88	$36.75	2.39%	2.48%	7.80%	7.99%	6.50%	7.43%	8.97%	9.91%	10.48%
CMS Energy Corporation	CMS	$2.17	$69.90	3.10%	3.21%	7.80%	7.00%	5.50%	6.77%	8.69%	9.98%	11.03%
Consolidated Edison, Inc.	ED	$3.40	$102.33	3.32%	3.42%	5.60%	6.20%	6.00%	5.93%	9.02%	9.35%	9.63%
Dominion Energy, Inc.	D	$2.67	$55.83	4.78%	4.96%	Exclude	9.20%	6.00%	7.60%	10.93%	12.56%	14.20%
DTE Energy Company	DTE	$4.36	$134.55	3.24%	3.34%	7.60%	7.15%	4.50%	6.42%	7.81%	9.76%	10.96%
Duke Energy Corporation	DUK	$4.18	$116.25	3.60%	3.71%	6.30%	6.40%	6.00%	6.23%	9.70%	9.94%	10.11%
Entergy Corporation	ETR	$2.40	$82.36	2.91%	3.02%	9.50%	8.88%	3.00%	7.13%	5.96%	10.14%	12.55%
Eversource Energy	ES	$3.01	$64.19	4.69%	4.82%	5.70%	5.50%	5.50%	5.57%	10.32%	10.39%	10.52%
Exelon Corporation	EXC	$1.60	$43.22	3.70%	3.82%	6.40%	6.13%	NMF	6.27%	9.95%	10.08%	10.22%
FirstEnergy Corporation	FE	$1.78	$40.92	4.35%	4.48%	6.40%	7.00%	4.50%	5.97%	8.95%	10.45%	11.50%
Evergy, Inc.	EVRG	$2.67	$67.00	3.99%	4.11%	5.70%	5.71%	7.50%	6.30%	9.80%	10.41%	11.63%
IDACORP, Inc.	IDA	$3.44	$115.46	2.98%	3.09%	8.10%	8.70%	6.00%	7.60%	9.07%	10.69%	11.81%
NextEra Energy, Inc.	NEE	$2.27	$71.26	3.18%	3.31%	7.70%	7.57%	8.50%	7.92%	10.88%	11.23%	11.81%
NorthWestern Energy Group, Inc.	NWE	$2.64	$53.15	4.97%	5.11%	6.90%	6.00%	4.50%	5.80%	9.58%	10.91%	12.04%
OGE Energy Corporation	OGE	$1.69	$44.17	3.81%	3.94%	6.30%	6.50%	6.50%	6.43%	10.23%	10.37%	10.44%
Pinnacle West Capital Corporation	PNW	$3.58	$90.03	3.98%	4.06%	2.10%	5.70%	5.00%	4.27%	6.12%	8.33%	9.79%
Portland General Electric Company	POR	$2.10	$41.37	5.08%	5.20%	3.30%	4.50%	6.50%	4.77%	8.46%	9.96%	11.74%
Public Service Enterprise Group Inc.	PEG	$2.52	$80.81	3.12%	3.22%	7.00%	6.10%	7.00%	6.70%	9.31%	9.92%	10.23%
Southern Company	SO	$2.96	$89.56	3.30%	3.41%	6.50%	6.57%	6.50%	6.52%	9.91%	9.94%	9.98%
Xcel Energy Inc.	XEL	$2.28	$68.78	3.31%	3.44%	7.50%	7.75%	7.00%	7.42%	10.43%	10.85%	11.19%
Proxy Group Mean				3.70%	3.82%	6.53%	6.77%	5.96%	6.44%	9.33%	10.26%	11.00%
Proxy Group Median				3.46%	3.57%	6.50%	6.61%	6.00%	6.43%	9.56%	10.11%	10.81%
Average of Mean and Median				3.58%	3.70%	6.52%	6.69%	5.98%	6.43%	9.45%	10.19%	10.90%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks; Growth rate for Dominion Energy is excluded as an outlier
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] S&P Capital IQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$2.03	$61.85	3.28%	3.39%	6.60%	6.64%	6.00%	6.41%	9.38%	9.80%	10.03%
Ameren Corporation	AEE	$2.84	$97.74	2.91%	3.01%	7.00%	7.00%	6.50%	6.83%	9.50%	9.84%	10.01%
American Electric Power Company, Inc.	AEP	$3.72	$104.46	3.56%	3.68%	6.40%	6.90%	6.50%	6.60%	10.08%	10.28%	10.58%
Avista Corporation	AVA	$1.96	$39.48	4.96%	5.11%	6.10%	5.50%	5.50%	5.70%	10.60%	10.81%	11.22%
CenterPoint Energy, Inc.	CNP	$0.88	$36.37	2.42%	2.51%	7.80%	7.99%	6.50%	7.43%	9.00%	9.94%	10.50%
CMS Energy Corporation	CMS	$2.17	$71.76	3.02%	3.13%	7.80%	7.00%	5.50%	6.77%	8.61%	9.89%	10.94%
Consolidated Edison, Inc.	ED	$3.40	$105.34	3.23%	3.32%	5.60%	6.20%	6.00%	5.93%	8.92%	9.26%	9.53%
Dominion Energy, Inc.	D	$2.67	$54.94	4.86%	5.04%	Exclude	9.20%	6.00%	7.60%	11.01%	12.64%	14.28%
DTE Energy Company	DTE	$4.36	$134.29	3.25%	3.35%	7.60%	7.15%	4.50%	6.42%	7.82%	9.77%	10.97%
Duke Energy Corporation	DUK	$4.18	$117.90	3.55%	3.66%	6.30%	6.40%	6.00%	6.23%	9.65%	9.89%	10.06%
Entergy Corporation	ETR	$2.40	$83.12	2.89%	2.99%	9.50%	8.88%	3.00%	7.13%	5.93%	10.12%	12.52%
Eversource Energy	ES	$3.01	$61.54	4.89%	5.03%	5.70%	5.50%	5.50%	5.57%	10.53%	10.59%	10.73%
Exelon Corporation	EXC	$1.60	$44.32	3.61%	3.72%	6.40%	6.13%	NMF	6.27%	9.85%	9.99%	10.13%
FirstEnergy Corporation	FE	$1.78	$40.81	4.36%	4.49%	6.40%	7.00%	4.50%	5.97%	8.96%	10.46%	11.51%
Evergy, Inc.	EVRG	$2.67	$67.28	3.97%	4.09%	5.70%	5.71%	7.50%	6.30%	9.78%	10.39%	11.62%
IDACORP, Inc.	IDA	$3.44	$115.58	2.98%	3.09%	8.10%	8.70%	6.00%	7.60%	9.07%	10.69%	11.81%
NextEra Energy, Inc.	NEE	$2.27	$70.01	3.24%	3.36%	7.70%	7.57%	8.50%	7.92%	10.93%	11.29%	11.87%
NorthWestern Energy Group, Inc.	NWE	$2.64	$55.35	4.77%	4.91%	6.90%	6.00%	4.50%	5.80%	9.38%	10.71%	11.83%
OGE Energy Corporation	OGE	$1.69	$44.55	3.78%	3.90%	6.30%	6.50%	6.50%	6.43%	10.20%	10.34%	10.41%
Pinnacle West Capital Corporation	PNW	$3.58	$91.82	3.90%	3.98%	2.10%	5.70%	5.00%	4.27%	6.04%	8.25%	9.71%
Portland General Electric Company	POR	$2.10	$42.65	4.92%	5.04%	3.30%	4.50%	6.50%	4.77%	8.30%	9.81%	11.58%
Public Service Enterprise Group Inc.	PEG	$2.52	$80.96	3.11%	3.22%	7.00%	6.10%	7.00%	6.70%	9.31%	9.92%	10.22%
Southern Company	SO	$2.96	$89.78	3.30%	3.40%	6.50%	6.57%	6.50%	6.52%	9.90%	9.93%	9.98%
Xcel Energy Inc.	XEL	$2.28	$69.44	3.28%	3.41%	7.50%	7.75%	7.00%	7.42%	10.40%	10.82%	11.16%
Proxy Group Mean				3.67%	3.78%	6.53%	6.77%	5.96%	6.44%	9.30%	10.23%	10.97%
Proxy Group Median				3.42%	3.53%	6.50%	6.61%	6.00%	6.43%	9.44%	10.05%	10.84%
Average of Mean and Median				3.54%	3.66%	6.52%	6.69%	5.98%	6.43%	9.37%	10.14%	10.90%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks; Growth rate for Dominion Energy is excluded as an outlier
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] S&P Capital IQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$2.03	$60.95	3.33%	3.44%	6.60%	6.64%	6.00%	6.41%	9.43%	9.85%	10.08%
Ameren Corporation	AEE	$2.84	$94.46	3.01%	3.11%	7.00%	7.00%	6.50%	6.83%	9.60%	9.94%	10.11%
American Electric Power Company, Inc.	AEP	$3.72	$100.67	3.70%	3.82%	6.40%	6.90%	6.50%	6.60%	10.21%	10.42%	10.72%
Avista Corporation	AVA	$1.96	$38.33	5.11%	5.26%	6.10%	5.50%	5.50%	5.70%	10.75%	10.96%	11.37%
CenterPoint Energy, Inc.	CNP	$0.88	$33.89	2.60%	2.69%	7.80%	7.99%	6.50%	7.43%	9.18%	10.12%	10.69%
CMS Energy Corporation	CMS	$2.17	$69.92	3.10%	3.21%	7.80%	7.00%	5.50%	6.77%	8.69%	9.98%	11.02%
Consolidated Edison, Inc.	ED	$3.40	$100.73	3.38%	3.48%	5.60%	6.20%	6.00%	5.93%	9.07%	9.41%	9.68%
Dominion Energy, Inc.	D	$2.67	$55.56	4.81%	4.99%	Exclude	9.20%	6.00%	7.60%	10.95%	12.59%	14.23%
DTE Energy Company	DTE	$4.36	$128.47	3.39%	3.50%	7.60%	7.15%	4.50%	6.42%	7.97%	9.92%	11.12%
Duke Energy Corporation	DUK	$4.18	$115.12	3.63%	3.74%	6.30%	6.40%	6.00%	6.23%	9.74%	9.98%	10.15%
Entergy Corporation	ETR	$2.40	$79.36	3.02%	3.13%	9.50%	8.88%	3.00%	7.13%	6.07%	10.26%	12.67%
Eversource Energy	ES	$3.01	$61.09	4.93%	5.06%	5.70%	5.50%	5.50%	5.57%	10.56%	10.63%	10.77%
Exelon Corporation	EXC	$1.60	$41.72	3.84%	3.96%	6.40%	6.13%	NMF	6.27%	10.09%	10.22%	10.36%
FirstEnergy Corporation	FE	$1.78	$40.90	4.35%	4.48%	6.40%	7.00%	4.50%	5.97%	8.95%	10.45%	11.50%
Evergy, Inc.	EVRG	$2.67	$64.93	4.11%	4.24%	5.70%	5.71%	7.50%	6.30%	9.93%	10.54%	11.77%
IDACORP, Inc.	IDA	$3.44	$112.95	3.05%	3.16%	8.10%	8.70%	6.00%	7.60%	9.14%	10.76%	11.88%
NextEra Energy, Inc.	NEE	$2.27	$72.29	3.13%	3.26%	7.70%	7.57%	8.50%	7.92%	10.83%	11.18%	11.77%
NorthWestern Energy Group, Inc.	NWE	$2.64	$54.63	4.83%	4.97%	6.90%	6.00%	4.50%	5.80%	9.44%	10.77%	11.90%
OGE Energy Corporation	OGE	$1.69	$43.24	3.90%	4.02%	6.30%	6.50%	6.50%	6.43%	10.32%	10.46%	10.52%
Pinnacle West Capital Corporation	PNW	$3.58	$89.88	3.98%	4.07%	2.10%	5.70%	5.00%	4.27%	6.12%	8.33%	9.80%
Portland General Electric Company	POR	$2.10	$43.73	4.80%	4.92%	3.30%	4.50%	6.50%	4.77%	8.18%	9.68%	11.46%
Public Service Enterprise Group Inc.	PEG	$2.52	$84.02	3.00%	3.10%	7.00%	6.10%	7.00%	6.70%	9.19%	9.80%	10.10%
Southern Company	SO	$2.96	$87.98	3.36%	3.47%	6.50%	6.57%	6.50%	6.52%	9.97%	10.00%	10.05%
Xcel Energy Inc.	XEL	$2.28	$68.29	3.34%	3.46%	7.50%	7.75%	7.00%	7.42%	10.46%	10.88%	11.22%
Proxy Group Mean				3.74%	3.86%	6.53%	6.77%	5.96%	6.44%	9.37%	10.30%	11.04%
Proxy Group Median				3.51%	3.62%	6.50%	6.61%	6.00%	6.43%	9.52%	10.24%	10.90%
Average of Mean and Median				3.62%	3.74%	6.52%	6.69%	5.98%	6.43%	9.45%	10.27%	10.97%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks; Growth rate for Dominion Energy is excluded as an outlier
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] S&P Capital IQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Alliant Energy Corporation	LNT	$0.48	$0.48	$0.51	$0.51	$0.51	$0.51	$0.54	$0.54	$61.22	6.60%	6.64%	6.00%	6.41%	9.54%	9.97%	10.21%
Ameren Corporation	AEE	$0.67	$0.67	$0.71	$0.71	$0.72	$0.72	$0.76	$0.76	$96.16	7.00%	7.00%	6.50%	6.83%	9.66%	10.01%	10.18%
American Electric Power Company, Inc.	AEP	$0.88	$0.93	$0.93	$0.93	$0.94	$0.99	$0.99	$0.99	$102.48	6.40%	6.90%	6.50%	6.60%	10.35%	10.56%	10.87%
Avista Corporation	AVA	$0.48	$0.48	$0.49	$0.49	$0.50	$0.50	$0.52	$0.52	$37.97	6.10%	5.50%	5.50%	5.70%	11.08%	11.29%	11.72%
CenterPoint Energy, Inc.	CNP	$0.20	$0.21	$0.22	$0.22	$0.21	$0.23	$0.24	$0.24	$36.75	7.80%	7.99%	6.50%	7.43%	9.04%	10.00%	10.58%
CMS Energy Corporation	CMS	$0.52	$0.52	$0.54	$0.54	$0.55	$0.55	$0.58	$0.58	$69.90	7.80%	7.00%	5.50%	6.77%	8.79%	10.12%	11.19%
Consolidated Edison, Inc.	ED	$0.83	$0.83	$0.85	$0.85	$0.88	$0.88	$0.90	$0.90	$102.33	5.60%	6.20%	6.00%	5.93%	9.18%	9.53%	9.81%
Dominion Energy, Inc.	D	$0.67	$0.67	$0.67	$0.67	$0.72	$0.72	$0.72	$0.72	$55.83	Exclude	9.20%	6.00%	7.60%	11.28%	12.99%	14.70%
DTE Energy Company	DTE	$1.09	$1.09	$1.09	$1.09	$1.16	$1.16	$1.16	$1.16	$134.55	7.60%	7.15%	4.50%	6.42%	7.99%	9.99%	11.23%
Duke Energy Corporation	DUK	$1.05	$1.05	$1.05	$1.05	$1.11	$1.11	$1.11	$1.11	$116.25	6.30%	6.40%	6.00%	6.23%	9.95%	10.20%	10.37%
Entergy Corporation	ETR	$0.57	$0.60	$0.60	$0.60	$0.61	$0.64	$0.64	$0.64	$82.36	9.50%	8.88%	3.00%	7.13%	6.02%	10.32%	12.79%
Eversource Energy	ES	$0.72	$0.72	$0.75	$0.75	$0.75	$0.75	$0.79	$0.79	$64.19	5.70%	5.50%	5.50%	5.57%	10.51%	10.58%	10.72%
Exelon Corporation	EXC	$0.38	$0.38	$0.40	$0.40	$0.40	$0.40	$0.43	$0.43	$43.22	6.40%	6.13%	NMF	6.27%	10.10%	10.24%	10.38%
FirstEnergy Corporation	FE	$0.43	$0.43	$0.43	$0.45	$0.45	$0.45	$0.45	$0.47	$40.92	6.40%	7.00%	4.50%	5.97%	9.04%	10.59%	11.69%
Evergy, Inc.	EVRG	$0.64	$0.67	$0.67	$0.67	$0.68	$0.71	$0.71	$0.71	$67.00	5.70%	5.71%	7.50%	6.30%	10.03%	10.66%	11.93%
IDACORP, Inc.	IDA	$0.83	$0.86	$0.86	$0.86	$0.89	$0.93	$0.93	$0.93	$115.46	8.10%	8.70%	6.00%	7.60%	9.24%	10.90%	12.05%
NextEra Energy, Inc.	NEE	$0.52	$0.52	$0.57	$0.57	$0.56	$0.56	$0.61	$0.61	$71.26	7.70%	7.57%	8.50%	7.92%	10.97%	11.33%	11.93%
NorthWestern Energy Group, Inc.	NWE	$0.65	$0.65	$0.66	$0.66	$0.69	$0.69	$0.70	$0.70	$53.15	6.90%	6.00%	4.50%	5.80%	9.84%	11.23%	12.41%
OGE Energy Corporation	OGE	$0.42	$0.42	$0.42	$0.42	$0.45	$0.45	$0.45	$0.45	$44.17	6.30%	6.50%	6.50%	6.43%	10.51%	10.65%	10.72%
Pinnacle West Capital Corporation	PNW	$0.90	$0.90	$0.90	$0.90	$0.93	$0.93	$0.93	$0.93	$90.03	2.10%	5.70%	5.00%	4.27%	6.25%	8.54%	10.06%
Portland General Electric Company	POR	$0.50	$0.50	$0.50	$0.53	$0.52	$0.52	$0.52	$0.55	$41.37	3.30%	4.50%	6.50%	4.77%	8.51%	10.08%	11.94%
Public Service Enterprise Group Inc.	PEG	$0.60	$0.60	$0.63	$0.63	$0.64	$0.64	$0.67	$0.67	$80.81	7.00%	6.10%	7.00%	6.70%	9.44%	10.07%	10.38%
Southern Company	SO	$0.72	$0.72	$0.72	$0.74	$0.77	$0.77	$0.77	$0.79	$89.56	6.50%	6.57%	6.50%	6.52%	10.08%	10.10%	10.15%
Xcel Energy Inc.	XEL	$0.55	$0.55	$0.57	$0.57	$0.59	$0.59	$0.61	$0.61	$68.78	7.50%	7.75%	7.00%	7.42%	10.61%	11.05%	11.40%
Proxy Group Mean											6.53%	6.77%	5.96%	6.44%	9.50%	10.46%	11.23%
Proxy Group Median											6.50%	6.61%	6.00%	6.43%	9.75%	10.28%	11.03%
Average of Mean and Median															9.63%	10.37%	11.13%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	$0.48	$0.48	$0.51	$0.51	$0.51	$0.51	$0.54	$0.54	$61.85	6.60%	6.64%	6.00%	6.41%	9.50%	9.93%	10.17%
Ameren Corporation	AEE	$0.67	$0.67	$0.71	$0.71	$0.72	$0.72	$0.76	$0.76	$97.74	7.00%	7.00%	6.50%	6.83%	9.61%	9.96%	10.13%
American Electric Power Company, Inc.	AEP	$0.88	$0.93	$0.93	$0.93	$0.94	$0.99	$0.99	$0.99	$104.46	6.40%	6.90%	6.50%	6.60%	10.28%	10.49%	10.80%
Avista Corporation	AVA	$0.48	$0.48	$0.49	$0.49	$0.50	$0.50	$0.52	$0.52	$39.48	6.10%	5.50%	5.50%	5.70%	10.86%	11.07%	11.50%
CenterPoint Energy, Inc.	CNP	$0.20	$0.21	$0.22	$0.22	$0.21	$0.23	$0.24	$0.24	$36.37	7.80%	7.99%	6.50%	7.43%	9.07%	10.03%	10.61%
CMS Energy Corporation	CMS	$0.52	$0.52	$0.54	$0.54	$0.55	$0.55	$0.58	$0.58	$71.76	7.80%	7.00%	5.50%	6.77%	8.71%	10.03%	11.10%
Consolidated Edison, Inc.	ED	$0.83	$0.83	$0.85	$0.85	$0.88	$0.88	$0.90	$0.90	$105.34	5.60%	6.20%	6.00%	5.93%	9.08%	9.43%	9.71%
Dominion Energy, Inc.	D	$0.67	$0.67	$0.67	$0.67	$0.72	$0.72	$0.72	$0.72	$54.94	Exclude	9.20%	6.00%	7.60%	11.37%	13.08%	14.79%
DTE Energy Company	DTE	$1.09	$1.09	$1.09	$1.09	$1.16	$1.16	$1.16	$1.16	$134.29	7.60%	7.15%	4.50%	6.42%	7.99%	10.00%	11.24%
Duke Energy Corporation	DUK	$1.05	$1.05	$1.05	$1.05	$1.11	$1.11	$1.11	$1.11	$117.90	6.30%	6.40%	6.00%	6.23%	9.89%	10.14%	10.32%
Entergy Corporation	ETR	$0.57	$0.60	$0.60	$0.60	$0.61	$0.64	$0.64	$0.64	$83.12	9.50%	8.88%	3.00%	7.13%	5.99%	10.29%	12.76%
Eversource Energy	ES	$0.72	$0.72	$0.75	$0.75	$0.75	$0.75	$0.79	$0.79	$61.54	5.70%	5.50%	5.50%	5.57%	10.73%	10.80%	10.94%
Exelon Corporation	EXC	$0.38	$0.38	$0.40	$0.40	$0.40	$0.40	$0.43	$0.43	$44.32	6.40%	6.13%	NMF	6.27%	10.00%	10.14%	10.28%
FirstEnergy Corporation	FE	$0.43	$0.43	$0.43	$0.45	$0.45	$0.45	$0.45	$0.47	$40.81	6.40%	7.00%	4.50%	5.97%	9.05%	10.61%	11.70%
Evergy, Inc.	EVRG	$0.64	$0.67	$0.67	$0.67	$0.68	$0.71	$0.71	$0.71	$67.28	5.70%	5.71%	7.50%	6.30%	10.01%	10.64%	11.91%
IDACORP, Inc.	IDA	$0.83	$0.86	$0.86	$0.86	$0.89	$0.93	$0.93	$0.93	$115.58	8.10%	8.70%	6.00%	7.60%	9.23%	10.90%	12.05%
NextEra Energy, Inc.	NEE	$0.52	$0.52	$0.57	$0.57	$0.56	$0.56	$0.61	$0.61	$70.01	7.70%	7.57%	8.50%	7.92%	11.03%	11.39%	11.99%
NorthWestern Energy Group, Inc.	NWE	$0.65	$0.65	$0.66	$0.66	$0.69	$0.69	$0.70	$0.70	$55.35	6.90%	6.00%	4.50%	5.80%	9.62%	11.01%	12.18%
OGE Energy Corporation	OGE	$0.42	$0.42	$0.42	$0.42	$0.45	$0.45	$0.45	$0.45	$44.55	6.30%	6.50%	6.50%	6.43%	10.48%	10.62%	10.69%
Pinnacle West Capital Corporation	PNW	$0.90	$0.90	$0.90	$0.90	$0.93	$0.93	$0.93	$0.93	$91.82	2.10%	5.70%	5.00%	4.27%	6.17%	8.46%	9.97%
Portland General Electric Company	POR	$0.50	$0.50	$0.50	$0.53	$0.52	$0.52	$0.52	$0.55	$42.65	3.30%	4.50%	6.50%	4.77%	8.35%	9.92%	11.77%
Public Service Enterprise Group Inc.	PEG	$0.60	$0.60	$0.63	$0.63	$0.64	$0.64	$0.67	$0.67	$80.96	7.00%	6.10%	7.00%	6.70%	9.43%	10.06%	10.37%
Southern Company	SO	$0.72	$0.72	$0.72	$0.74	$0.77	$0.77	$0.77	$0.79	$89.78	6.50%	6.57%	6.50%	6.52%	10.07%	10.09%	10.14%
Xcel Energy Inc.	XEL	$0.55	$0.55	$0.57	$0.57	$0.59	$0.59	$0.61	$0.61	$69.44	7.50%	7.75%	7.00%	7.42%	10.58%	11.01%	11.36%
Proxy Group Mean											6.53%	6.77%	5.96%	6.44%	9.46%	10.42%	11.19%
Proxy Group Median											6.50%	6.61%	6.00%	6.43%	9.62%	10.22%	11.02%
Average of Mean and Median															9.54%	10.32%	11.10%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] S&P Capital IQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Alliant Energy Corporation	LNT	$0.48	$0.48	$0.51	$0.51	$0.51	$0.51	$0.54	$0.54	$60.95	6.60%	6.64%	6.00%	6.41%	9.55%	9.99%	10.22%
Ameren Corporation	AEE	$0.67	$0.67	$0.71	$0.71	$0.72	$0.72	$0.76	$0.76	$94.46	7.00%	7.00%	6.50%	6.83%	9.72%	10.07%	10.24%
American Electric Power Company, Inc.	AEP	$0.88	$0.93	$0.93	$0.93	$0.94	$0.99	$0.99	$0.99	$100.67	6.40%	6.90%	6.50%	6.60%	10.43%	10.63%	10.95%
Avista Corporation	AVA	$0.48	$0.48	$0.49	$0.49	$0.50	$0.50	$0.52	$0.52	$38.33	6.10%	5.50%	5.50%	5.70%	11.02%	11.24%	11.67%
CenterPoint Energy, Inc.	CNP	$0.20	$0.21	$0.22	$0.22	$0.21	$0.23	$0.24	$0.24	$33.89	7.80%	7.99%	6.50%	7.43%	9.26%	10.22%	10.80%
CMS Energy Corporation	CMS	$0.52	$0.52	$0.54	$0.54	$0.55	$0.55	$0.58	$0.58	$69.92	7.80%	7.00%	5.50%	6.77%	8.79%	10.11%	11.19%
Consolidated Edison, Inc.	ED	$0.83	$0.83	$0.85	$0.85	$0.88	$0.88	$0.90	$0.90	$100.73	5.60%	6.20%	6.00%	5.93%	9.24%	9.59%	9.87%
Dominion Energy, Inc.	D	$0.67	$0.67	$0.67	$0.67	$0.72	$0.72	$0.72	$0.72	$55.56	Exclude	9.20%	6.00%	7.60%	11.30%	13.02%	14.73%
DTE Energy Company	DTE	$1.09	$1.09	$1.09	$1.09	$1.16	$1.16	$1.16	$1.16	$128.47	7.60%	7.15%	4.50%	6.42%	8.15%	10.16%	11.40%
Duke Energy Corporation	DUK	$1.05	$1.05	$1.05	$1.05	$1.11	$1.11	$1.11	$1.11	$115.12	6.30%	6.40%	6.00%	6.23%	9.99%	10.24%	10.41%
Entergy Corporation	ETR	$0.57	$0.60	$0.60	$0.60	$0.61	$0.64	$0.64	$0.64	$79.36	9.50%	8.88%	3.00%	7.13%	6.14%	10.44%	12.91%
Eversource Energy	ES	$0.72	$0.72	$0.75	$0.75	$0.75	$0.75	$0.79	$0.79	$61.09	5.70%	5.50%	5.50%	5.57%	10.77%	10.84%	10.98%
Exelon Corporation	EXC	$0.38	$0.38	$0.40	$0.40	$0.40	$0.40	$0.43	$0.43	$41.72	6.40%	6.13%	NMF	6.27%	10.25%	10.39%	10.53%
FirstEnergy Corporation	FE	$0.43	$0.43	$0.43	$0.45	$0.45	$0.45	$0.45	$0.47	$40.90	6.40%	7.00%	4.50%	5.97%	9.04%	10.59%	11.69%
Evergy, Inc.	EVRG	$0.64	$0.67	$0.67	$0.67	$0.68	$0.71	$0.71	$0.71	$64.93	5.70%	5.71%	7.50%	6.30%	10.17%	10.80%	12.07%
IDACORP, Inc.	IDA	$0.83	$0.86	$0.86	$0.86	$0.89	$0.93	$0.93	$0.93	$112.95	8.10%	8.70%	6.00%	7.60%	9.31%	10.98%	12.13%
NextEra Energy, Inc.	NEE	$0.52	$0.52	$0.57	$0.57	$0.56	$0.56	$0.61	$0.61	$72.29	7.70%	7.57%	8.50%	7.92%	10.92%	11.28%	11.88%
NorthWestern Energy Group, Inc.	NWE	$0.65	$0.65	$0.66	$0.66	$0.69	$0.69	$0.70	$0.70	$54.63	6.90%	6.00%	4.50%	5.80%	9.69%	11.08%	12.26%
OGE Energy Corporation	OGE	$0.42	$0.42	$0.42	$0.42	$0.45	$0.45	$0.45	$0.45	$43.24	6.30%	6.50%	6.50%	6.43%	10.60%	10.74%	10.82%
Pinnacle West Capital Corporation	PNW	$0.90	$0.90	$0.90	$0.90	$0.93	$0.93	$0.93	$0.93	$89.88	2.10%	5.70%	5.00%	4.27%	6.26%	8.55%	10.07%
Portland General Electric Company	POR	$0.50	$0.50	$0.50	$0.53	$0.52	$0.52	$0.52	$0.55	$43.73	3.30%	4.50%	6.50%	4.77%	8.23%	9.79%	11.64%
Public Service Enterprise Group Inc.	PEG	$0.60	$0.60	$0.63	$0.63	$0.64	$0.64	$0.67	$0.67	$84.02	7.00%	6.10%	7.00%	6.70%	9.31%	9.94%	10.25%
Southern Company	SO	$0.72	$0.72	$0.72	$0.74	$0.77	$0.77	$0.77	$0.79	$87.98	6.50%	6.57%	6.50%	6.52%	10.14%	10.17%	10.21%
Xcel Energy Inc.	XEL	$0.55	$0.55	$0.57	$0.57	$0.59	$0.59	$0.61	$0.61	$68.29	7.50%	7.75%	7.00%	7.42%	10.64%	11.07%	11.42%
Proxy Group Mean											6.53%	6.77%	5.96%	6.44%	9.54%	10.50%	11.26%
Proxy Group Median											6.50%	6.61%	6.00%	6.43%	9.71%	10.41%	11.09%
Average of Mean and Median															9.62%	10.46%	11.18%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Expected Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.28%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	13.44%
[3] Market Cap. Weighted Estimated Required Market Return	14.81%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line DCF-based expected market return provided in Confidential WP-9
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Expected Market Return
Market DCF Based Method - Bloomberg EPS Growth

[4] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.27%
[5] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	14.70%
[6] Market Cap. Weighted Estimated Required Market Return	16.06%

Notes:
[4] Source: Bloomberg Professional
[5] Source: Bloomberg DCF-based expected market return provided in Confidential WP-10
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]

Summary of CAPM and ECAPM Results

	Current 30-Year Treasury Yield (4.92%)	**Projected 30-Year Treasury Yield (4.52%)**
CAPM Forward Market Return	12.05%	11.94%
ECAPM Forward Market Return	12.74%	12.66%
Average Forward Market Return CAPM	12.35%	
CAPM Historical Market Return	10.15%	10.04%
ECAPM Historical Market Return	10.65%	10.57%
Average Historical Market Return CAPM	10.35%	

Source: Exhibit JEN-5, pages 2-5

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return

Company	Ticker	[1] Current 30-Year Treasury Yield	[2] 5-Year Bloomberg Beta Coefficient	[3] 5-Year Value Line Beta Coefficient	[4] Average Beta Coefficient	[5] DCF Expected Market Return	[6] Market Risk Premium	[7] Traditional CAPM	[8] Empirical CAPM
Alliant Energy Corporation	LNT	4.92%	0.62	0.80	0.71	14.81%	9.89%	11.92%	12.65%
Ameren Corporation	AEE	4.92%	0.63	0.80	0.72	14.81%	9.89%	11.99%	12.70%
American Electric Power Company, Inc.	AEP	4.92%	0.55	0.70	0.63	14.81%	9.89%	11.11%	12.03%
Avista Corporation	AVA	4.92%	0.58	0.75	0.66	14.81%	9.89%	11.48%	12.31%
CenterPoint Energy, Inc.	CNP	4.92%	0.72	0.85	0.78	14.81%	9.89%	12.68%	13.21%
CMS Energy Corporation	CMS	4.92%	0.57	0.70	0.64	14.81%	9.89%	11.22%	12.12%
Consolidated Edison, Inc.	ED	4.92%	0.48	0.65	0.57	14.81%	9.89%	10.51%	11.59%
Dominion Energy, Inc.	D	4.92%	0.60	0.75	0.68	14.81%	9.89%	11.62%	12.42%
DTE Energy Company	DTE	4.92%	0.60	0.80	0.70	14.81%	9.89%	11.83%	12.58%
Duke Energy Corporation	DUK	4.92%	0.51	0.70	0.60	14.81%	9.89%	10.88%	11.86%
Entergy Corporation	ETR	4.92%	0.68	0.80	0.74	14.81%	9.89%	12.23%	12.87%
Eversource Energy	ES	4.92%	0.63	0.85	0.74	14.81%	9.89%	12.26%	12.90%
Exelon Corporation	EXC	4.92%	0.67	NMF	0.67	14.81%	9.89%	11.58%	12.39%
FirstEnergy Corporation	FE	4.92%	0.60	0.75	0.68	14.81%	9.89%	11.60%	12.40%
Evergy, Inc.	EVRG	4.92%	0.59	0.75	0.67	14.81%	9.89%	11.53%	12.35%
IDACORP, Inc.	IDA	4.92%	0.58	0.75	0.66	14.81%	9.89%	11.48%	12.32%
NextEra Energy, Inc.	NEE	4.92%	0.78	0.90	0.84	14.81%	9.89%	13.22%	13.62%
NorthWestern Energy Group, Inc.	NWE	4.92%	0.60	0.80	0.70	14.81%	9.89%	11.83%	12.58%
OGE Energy Corporation	OGE	4.92%	0.69	0.85	0.77	14.81%	9.89%	12.54%	13.10%
Pinnacle West Capital Corporation	PNW	4.92%	0.65	0.80	0.72	14.81%	9.89%	12.08%	12.76%
Portland General Electric Company	POR	4.92%	0.59	0.80	0.69	14.81%	9.89%	11.78%	12.54%
Public Service Enterprise Group Inc.	PEG	4.92%	0.71	0.90	0.80	14.81%	9.89%	12.86%	13.35%
Southern Company	SO	4.92%	0.59	0.75	0.67	14.81%	9.89%	11.53%	12.35%
Xcel Energy Inc.	XEL	4.92%	0.59	0.75	0.67	14.81%	9.89%	11.55%	12.37%
							Mean:	11.80%	12.56%
							Median:	11.70%	12.48%
							Average of the Mean and Median:	11.75%	12.52%

Company	Ticker	[9] Projected 30-Year Treasury Yield	[10] 5-Year Bloomberg Beta Coefficient	[11] 5-Year Value Line Beta Coefficient	[12] Average Beta Coefficient	[13] DCF Expected Market Return	[14] Market Risk Premium	[15] Traditional CAPM	[16] Empirical CAPM
Alliant Energy Corporation	LNT	4.52%	0.62	0.80	0.71	14.81%	10.30%	11.81%	12.56%
Ameren Corporation	AEE	4.52%	0.63	0.80	0.72	14.81%	10.30%	11.88%	12.61%
American Electric Power Company, Inc.	AEP	4.52%	0.55	0.70	0.63	14.81%	10.30%	10.96%	11.92%
Avista Corporation	AVA	4.52%	0.58	0.75	0.66	14.81%	10.30%	11.34%	12.21%
CenterPoint Energy, Inc.	CNP	4.52%	0.72	0.85	0.78	14.81%	10.30%	12.59%	13.15%
CMS Energy Corporation	CMS	4.52%	0.57	0.70	0.64	14.81%	10.30%	11.08%	12.01%
Consolidated Edison, Inc.	ED	4.52%	0.48	0.65	0.57	14.81%	10.30%	10.34%	11.46%
Dominion Energy, Inc.	D	4.52%	0.60	0.75	0.68	14.81%	10.30%	11.49%	12.32%
DTE Energy Company	DTE	4.52%	0.60	0.80	0.70	14.81%	10.30%	11.71%	12.49%
Duke Energy Corporation	DUK	4.52%	0.51	0.70	0.60	14.81%	10.30%	10.72%	11.75%
Entergy Corporation	ETR	4.52%	0.68	0.80	0.74	14.81%	10.30%	12.12%	12.79%
Eversource Energy	ES	4.52%	0.63	0.85	0.74	14.81%	10.30%	12.16%	12.82%
Exelon Corporation	EXC	4.52%	0.67	NMF	0.67	14.81%	10.30%	11.45%	12.29%
FirstEnergy Corporation	FE	4.52%	0.60	0.75	0.68	14.81%	10.30%	11.47%	12.31%
Evergy, Inc.	EVRG	4.52%	0.59	0.75	0.67	14.81%	10.30%	11.40%	12.25%
IDACORP, Inc.	IDA	4.52%	0.58	0.75	0.66	14.81%	10.30%	11.35%	12.22%
NextEra Energy, Inc.	NEE	4.52%	0.78	0.90	0.84	14.81%	10.30%	13.15%	13.57%
NorthWestern Energy Group, Inc.	NWE	4.52%	0.60	0.80	0.70	14.81%	10.30%	11.71%	12.49%
OGE Energy Corporation	OGE	4.52%	0.69	0.85	0.77	14.81%	10.30%	12.44%	13.04%
Pinnacle West Capital Corporation	PNW	4.52%	0.65	0.80	0.72	14.81%	10.30%	11.97%	12.68%
Portland General Electric Company	POR	4.52%	0.59	0.80	0.69	14.81%	10.30%	11.65%	12.44%
Public Service Enterprise Group Inc.	PEG	4.52%	0.71	0.90	0.80	14.81%	10.30%	12.78%	13.29%
Southern Company	SO	4.52%	0.59	0.75	0.67	14.81%	10.30%	11.40%	12.25%
Xcel Energy Inc.	XEL	4.52%	0.59	0.75	0.67	14.81%	10.30%	11.42%	12.27%
							Mean:	11.68%	12.47%
							Median:	11.57%	12.38%
							Average of the Mean and Median:	11.63%	12.42%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: JEN-4; Value Line DCF-based expected market return
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14, and Vol. 44, No. 7, July 2, 2025 at 2
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return

Company	Ticker	[1] Current 30-Year Treasury Yield	[2] Bloomberg Beta Coefficient - 10 Year	[3] DCF Expected Market Return	[4] Market Risk Premium	[5] Traditional CAPM	[6] Empirical CAPM
Alliant Energy Corporation	LNT	4.92%	0.75	14.81%	9.89%	12.31%	12.93%
Ameren Corporation	AEE	4.92%	0.72	14.81%	9.89%	12.04%	12.73%
American Electric Power Company, Inc.	AEP	4.92%	0.71	14.81%	9.89%	11.92%	12.64%
Avista Corporation	AVA	4.92%	0.71	14.81%	9.89%	11.91%	12.63%
CenterPoint Energy, Inc.	CNP	4.92%	0.93	14.81%	9.89%	14.12%	14.29%
CMS Energy Corporation	CMS	4.92%	0.70	14.81%	9.89%	11.82%	12.57%
Consolidated Edison, Inc.	ED	4.92%	0.59	14.81%	9.89%	10.73%	11.75%
Dominion Energy, Inc.	D	4.92%	0.68	14.81%	9.89%	11.60%	12.40%
DTE Energy Company	DTE	4.92%	0.78	14.81%	9.89%	12.61%	13.16%
Duke Energy Corporation	DUK	4.92%	0.68	14.81%	9.89%	11.62%	12.42%
Entergy Corporation	ETR	4.92%	0.83	14.81%	9.89%	13.09%	13.52%
Eversource Energy	ES	4.92%	0.77	14.81%	9.89%	12.49%	13.07%
Exelon Corporation	EXC	4.92%	0.80	14.81%	9.89%	12.85%	13.34%
FirstEnergy Corporation	FE	4.92%	0.75	14.81%	9.89%	12.36%	12.97%
Evergy, Inc.	EVRG	4.92%	0.75	14.81%	9.89%	12.33%	12.95%
IDACORP, Inc.	IDA	4.92%	0.74	14.81%	9.89%	12.23%	12.88%
NextEra Energy, Inc.	NEE	4.92%	0.79	14.81%	9.89%	12.70%	13.23%
NorthWestern Energy Group, Inc.	NWE	4.92%	0.82	14.81%	9.89%	13.00%	13.45%
OGE Energy Corporation	OGE	4.92%	0.87	14.81%	9.89%	13.53%	13.85%
Pinnacle West Capital Corporation	PNW	4.92%	0.78	14.81%	9.89%	12.65%	13.19%
Portland General Electric Company	POR	4.92%	0.74	14.81%	9.89%	12.23%	12.88%
Public Service Enterprise Group Inc.	PEG	4.92%	0.82	14.81%	9.89%	13.06%	13.50%
Southern Company	SO	4.92%	0.74	14.81%	9.89%	12.20%	12.85%
Xcel Energy Inc.	XEL	4.92%	0.70	14.81%	9.89%	11.89%	12.62%
					Mean:	12.39%	12.99%
					Median:	12.32%	12.94%
					Average of the Mean and Median:	12.35%	12.97%

Company	Ticker	[7] Projected 30-Year Treasury Yield	[8] Bloomberg Beta Coefficient - 10 Year	[9] DCF Expected Market Return	[10] Market Risk Premium	[11] Traditional CAPM	[12] Empirical CAPM
Alliant Energy Corporation	LNT	4.52%	0.75	14.81%	10.30%	12.21%	12.86%
Ameren Corporation	AEE	4.52%	0.72	14.81%	10.30%	11.92%	12.65%
American Electric Power Company, Inc.	AEP	4.52%	0.71	14.81%	10.30%	11.80%	12.56%
Avista Corporation	AVA	4.52%	0.71	14.81%	10.30%	11.79%	12.55%
CenterPoint Energy, Inc.	CNP	4.52%	0.93	14.81%	10.30%	14.09%	14.27%
CMS Energy Corporation	CMS	4.52%	0.70	14.81%	10.30%	11.70%	12.48%
Consolidated Edison, Inc.	ED	4.52%	0.59	14.81%	10.30%	10.56%	11.63%
Dominion Energy, Inc.	D	4.52%	0.68	14.81%	10.30%	11.47%	12.31%
DTE Energy Company	DTE	4.52%	0.78	14.81%	10.30%	12.52%	13.09%
Duke Energy Corporation	DUK	4.52%	0.68	14.81%	10.30%	11.49%	12.32%
Entergy Corporation	ETR	4.52%	0.83	14.81%	10.30%	13.02%	13.47%
Eversource Energy	ES	4.52%	0.77	14.81%	10.30%	12.40%	13.00%
Exelon Corporation	EXC	4.52%	0.80	14.81%	10.30%	12.77%	13.28%
FirstEnergy Corporation	FE	4.52%	0.75	14.81%	10.30%	12.26%	12.90%
Evergy, Inc.	EVRG	4.52%	0.75	14.81%	10.30%	12.23%	12.87%
IDACORP, Inc.	IDA	4.52%	0.74	14.81%	10.30%	12.13%	12.80%
NextEra Energy, Inc.	NEE	4.52%	0.79	14.81%	10.30%	12.61%	13.16%
NorthWestern Energy Group, Inc.	NWE	4.52%	0.82	14.81%	10.30%	12.93%	13.40%
OGE Energy Corporation	OGE	4.52%	0.87	14.81%	10.30%	13.48%	13.81%
Pinnacle West Capital Corporation	PNW	4.52%	0.78	14.81%	10.30%	12.56%	13.13%
Portland General Electric Company	POR	4.52%	0.74	14.81%	10.30%	12.13%	12.80%
Public Service Enterprise Group Inc.	PEG	4.52%	0.82	14.81%	10.30%	12.99%	13.45%
Southern Company	SO	4.52%	0.74	14.81%	10.30%	12.09%	12.77%
Xcel Energy Inc.	XEL	4.52%	0.70	14.81%	10.30%	11.77%	12.53%
					Mean:	12.29%	12.92%
					Median:	12.22%	12.87%
					Average of the Mean and Median:	12.25%	12.89%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: JEN-4; Value Line DCF-based expected market return
[4] Equals Col. [3] - Col. [1]
[5] Equals Col. [1] + (Col. [2] x Col. [4])
[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[7] Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14, and Vol. 44, No. 7, July 2, 2025 at 2
[8] See Note [2]
[9] See Note [3]
[10] Equals Col. [9] - Col. [7]
[11] Equals Col. [7] + (Col. [8] x Col. [10])
[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.92%	0.62	0.80	0.71	12.17%	7.25%	10.05%	10.58%
Ameren Corporation	AEE	4.92%	0.63	0.80	0.72	12.17%	7.25%	10.10%	10.62%
American Electric Power Company, Inc.	AEP	4.92%	0.55	0.70	0.63	12.17%	7.25%	9.45%	10.13%
Avista Corporation	AVA	4.92%	0.58	0.75	0.66	12.17%	7.25%	9.72%	10.34%
CenterPoint Energy, Inc.	CNP	4.92%	0.72	0.85	0.78	12.17%	7.25%	10.61%	11.00%
CMS Energy Corporation	CMS	4.92%	0.57	0.70	0.64	12.17%	7.25%	9.54%	10.20%
Consolidated Edison, Inc.	ED	4.92%	0.48	0.65	0.57	12.17%	7.25%	9.02%	9.81%
Dominion Energy, Inc.	D	4.92%	0.60	0.75	0.68	12.17%	7.25%	9.83%	10.41%
DTE Energy Company	DTE	4.92%	0.60	0.80	0.70	12.17%	7.25%	9.98%	10.53%
Duke Energy Corporation	DUK	4.92%	0.51	0.70	0.60	12.17%	7.25%	9.29%	10.01%
Entergy Corporation	ETR	4.92%	0.68	0.80	0.74	12.17%	7.25%	10.27%	10.75%
Eversource Energy	ES	4.92%	0.63	0.85	0.74	12.17%	7.25%	10.30%	10.77%
Exelon Corporation	EXC	4.92%	0.67	NMF	0.67	12.17%	7.25%	9.80%	10.39%
FirstEnergy Corporation	FE	4.92%	0.60	0.75	0.68	12.17%	7.25%	9.82%	10.41%
Evergy, Inc.	EVRG	4.92%	0.59	0.75	0.67	12.17%	7.25%	9.77%	10.37%
IDACORP, Inc.	IDA	4.92%	0.58	0.75	0.66	12.17%	7.25%	9.73%	10.34%
NextEra Energy, Inc.	NEE	4.92%	0.78	0.90	0.84	12.17%	7.25%	11.00%	11.29%
NorthWestern Energy Group, Inc.	NWE	4.92%	0.60	0.80	0.70	12.17%	7.25%	9.99%	10.53%
OGE Energy Corporation	OGE	4.92%	0.69	0.85	0.77	12.17%	7.25%	10.50%	10.92%
Pinnacle West Capital Corporation	PNW	4.92%	0.65	0.80	0.72	12.17%	7.25%	10.17%	10.67%
Portland General Electric Company	POR	4.92%	0.59	0.80	0.69	12.17%	7.25%	9.95%	10.50%
Public Service Enterprise Group Inc.	PEG	4.92%	0.71	0.90	0.80	12.17%	7.25%	10.74%	11.10%
Southern Company	SO	4.92%	0.59	0.75	0.67	12.17%	7.25%	9.77%	10.37%
Xcel Energy Inc.	XEL	4.92%	0.59	0.75	0.67	12.17%	7.25%	9.78%	10.38%
							Mean:	9.97%	10.52%
							Median:	9.89%	10.46%
							Average of the Mean and Median:	9.93%	10.49%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.52%	0.62	0.80	0.71	12.17%	7.65%	9.94%	10.50%
Ameren Corporation	AEE	4.52%	0.63	0.80	0.72	12.17%	7.65%	9.99%	10.53%
American Electric Power Company, Inc.	AEP	4.52%	0.55	0.70	0.63	12.17%	7.65%	9.30%	10.02%
Avista Corporation	AVA	4.52%	0.58	0.75	0.66	12.17%	7.65%	9.59%	10.23%
CenterPoint Energy, Inc.	CNP	4.52%	0.72	0.85	0.78	12.17%	7.65%	10.52%	10.93%
CMS Energy Corporation	CMS	4.52%	0.57	0.70	0.64	12.17%	7.65%	9.39%	10.09%
Consolidated Edison, Inc.	ED	4.52%	0.48	0.65	0.57	12.17%	7.65%	8.85%	9.68%
Dominion Energy, Inc.	D	4.52%	0.60	0.75	0.68	12.17%	7.65%	9.70%	10.32%
DTE Energy Company	DTE	4.52%	0.60	0.80	0.70	12.17%	7.65%	9.86%	10.44%
Duke Energy Corporation	DUK	4.52%	0.51	0.70	0.60	12.17%	7.65%	9.13%	9.89%
Entergy Corporation	ETR	4.52%	0.68	0.80	0.74	12.17%	7.65%	10.17%	10.67%
Eversource Energy	ES	4.52%	0.63	0.85	0.74	12.17%	7.65%	10.20%	10.69%
Exelon Corporation	EXC	4.52%	0.67	NMF	0.67	12.17%	7.65%	9.67%	10.29%
FirstEnergy Corporation	FE	4.52%	0.60	0.75	0.68	12.17%	7.65%	9.69%	10.31%
Evergy, Inc.	EVRG	4.52%	0.59	0.75	0.67	12.17%	7.65%	9.63%	10.27%
IDACORP, Inc.	IDA	4.52%	0.58	0.75	0.66	12.17%	7.65%	9.60%	10.24%
NextEra Energy, Inc.	NEE	4.52%	0.78	0.90	0.84	12.17%	7.65%	10.94%	11.24%
NorthWestern Energy Group, Inc.	NWE	4.52%	0.60	0.80	0.70	12.17%	7.65%	9.87%	10.44%
OGE Energy Corporation	OGE	4.52%	0.69	0.85	0.77	12.17%	7.65%	10.41%	10.85%
Pinnacle West Capital Corporation	PNW	4.52%	0.65	0.80	0.72	12.17%	7.65%	10.06%	10.59%
Portland General Electric Company	POR	4.52%	0.59	0.80	0.69	12.17%	7.65%	9.82%	10.41%
Public Service Enterprise Group Inc.	PEG	4.52%	0.71	0.90	0.80	12.17%	7.65%	10.66%	11.04%
Southern Company	SO	4.52%	0.59	0.75	0.67	12.17%	7.65%	9.63%	10.27%
Xcel Energy Inc.	XEL	4.52%	0.59	0.75	0.67	12.17%	7.65%	9.65%	10.28%
							Mean:	9.84%	10.43%
							Median:	9.76%	10.36%
							Average of the Mean and Median:	9.80%	10.39%

[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Kroll Cost of Capital Navigator
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14, and Vol. 44, No. 7, July 2, 2025 at 2
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return

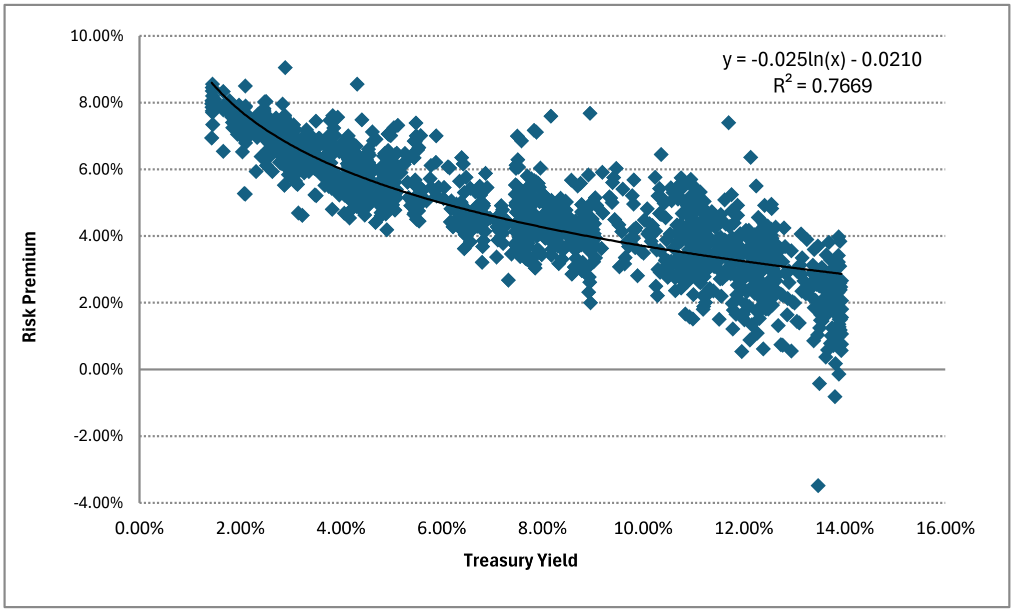
		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.92%	0.75	12.17%	7.25%	10.33%	10.79%
Ameren Corporation	AEE	4.92%	0.72	12.17%	7.25%	10.14%	10.64%
American Electric Power Company, Inc.	AEP	4.92%	0.71	12.17%	7.25%	10.05%	10.58%
Avista Corporation	AVA	4.92%	0.71	12.17%	7.25%	10.04%	10.57%
CenterPoint Energy, Inc.	CNP	4.92%	0.93	12.17%	7.25%	11.66%	11.79%
CMS Energy Corporation	CMS	4.92%	0.70	12.17%	7.25%	9.97%	10.52%
Consolidated Edison, Inc.	ED	4.92%	0.59	12.17%	7.25%	9.18%	9.93%
Dominion Energy, Inc.	D	4.92%	0.68	12.17%	7.25%	9.82%	10.41%
DTE Energy Company	DTE	4.92%	0.78	12.17%	7.25%	10.55%	10.96%
Duke Energy Corporation	DUK	4.92%	0.68	12.17%	7.25%	9.83%	10.42%
Entergy Corporation	ETR	4.92%	0.83	12.17%	7.25%	10.91%	11.22%
Eversource Energy	ES	4.92%	0.77	12.17%	7.25%	10.47%	10.90%
Exelon Corporation	EXC	4.92%	0.80	12.17%	7.25%	10.73%	11.09%
FirstEnergy Corporation	FE	4.92%	0.75	12.17%	7.25%	10.37%	10.82%
Evergy, Inc.	EVRG	4.92%	0.75	12.17%	7.25%	10.35%	10.80%
IDACORP, Inc.	IDA	4.92%	0.74	12.17%	7.25%	10.28%	10.75%
NextEra Energy, Inc.	NEE	4.92%	0.79	12.17%	7.25%	10.62%	11.01%
NorthWestern Energy Group, Inc.	NWE	4.92%	0.82	12.17%	7.25%	10.84%	11.17%
OGE Energy Corporation	OGE	4.92%	0.87	12.17%	7.25%	11.23%	11.47%
Pinnacle West Capital Corporation	PNW	4.92%	0.78	12.17%	7.25%	10.59%	10.98%
Portland General Electric Company	POR	4.92%	0.74	12.17%	7.25%	10.28%	10.75%
Public Service Enterprise Group Inc.	PEG	4.92%	0.82	12.17%	7.25%	10.89%	11.21%
Southern Company	SO	4.92%	0.74	12.17%	7.25%	10.26%	10.73%
Xcel Energy Inc.	XEL	4.92%	0.70	12.17%	7.25%	10.03%	10.56%
					Mean:	10.39%	10.84%
					Median:	10.34%	10.80%
					Average of the Mean and Median:	10.37%	10.82%

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.52%	0.75	12.17%	7.65%	10.23%	10.72%
Ameren Corporation	AEE	4.52%	0.72	12.17%	7.65%	10.02%	10.56%
American Electric Power Company, Inc.	AEP	4.52%	0.71	12.17%	7.65%	9.93%	10.49%
Avista Corporation	AVA	4.52%	0.71	12.17%	7.65%	9.92%	10.49%
CenterPoint Energy, Inc.	CNP	4.52%	0.93	12.17%	7.65%	11.63%	11.77%
CMS Energy Corporation	CMS	4.52%	0.70	12.17%	7.65%	9.85%	10.43%
Consolidated Edison, Inc.	ED	4.52%	0.59	12.17%	7.65%	9.01%	9.80%
Dominion Energy, Inc.	D	4.52%	0.68	12.17%	7.65%	9.69%	10.31%
DTE Energy Company	DTE	4.52%	0.78	12.17%	7.65%	10.46%	10.89%
Duke Energy Corporation	DUK	4.52%	0.68	12.17%	7.65%	9.70%	10.32%
Entergy Corporation	ETR	4.52%	0.83	12.17%	7.65%	10.84%	11.17%
Eversource Energy	ES	4.52%	0.77	12.17%	7.65%	10.38%	10.83%
Exelon Corporation	EXC	4.52%	0.80	12.17%	7.65%	10.65%	11.03%
FirstEnergy Corporation	FE	4.52%	0.75	12.17%	7.65%	10.27%	10.75%
Evergy, Inc.	EVRG	4.52%	0.75	12.17%	7.65%	10.25%	10.73%
IDACORP, Inc.	IDA	4.52%	0.74	12.17%	7.65%	10.18%	10.67%
NextEra Energy, Inc.	NEE	4.52%	0.79	12.17%	7.65%	10.53%	10.94%
NorthWestern Energy Group, Inc.	NWE	4.52%	0.82	12.17%	7.65%	10.77%	11.12%
OGE Energy Corporation	OGE	4.52%	0.87	12.17%	7.65%	11.18%	11.43%
Pinnacle West Capital Corporation	PNW	4.52%	0.78	12.17%	7.65%	10.50%	10.92%
Portland General Electric Company	POR	4.52%	0.74	12.17%	7.65%	10.18%	10.67%
Public Service Enterprise Group Inc.	PEG	4.52%	0.82	12.17%	7.65%	10.82%	11.15%
Southern Company	SO	4.52%	0.74	12.17%	7.65%	10.15%	10.66%
Xcel Energy Inc.	XEL	4.52%	0.70	12.17%	7.65%	9.91%	10.48%
					Mean:	10.29%	10.76%
					Median:	10.24%	10.72%
					Average of the Mean and Median:	10.27%	10.74%

[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Kroll Cost of Capital Navigator
[4] Equals Col. [3] - Col. [1]
[5] Equals Col. [1] + (Col. [2] x Col. [4])
[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[7] Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14, and Vol. 44, No. 7, July 2, 2025 at 2
[8] See Note [2]
[9] See Note [3]
[10] Equals Col. [9] - Col. [7]
[11] Equals Col. [7] + (Col. [8] x Col. [10])
[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Bond Yield Plus Risk Premium

[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
-2.10%	-2.52%			
Current 30-Year Treasury		4.92%	5.49%	10.41%
Projected 30-Year Treasury		4.52%	5.71%	10.22%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, Vol. 44, No. 6, June 02, 2025 at 14, and Vol. 44, No. 7, July 01, 2025 at 2
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Capital IQ
[7] Source: S&P Capital IQ
[8] Source: Bloomberg Professional, equals 202-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.39%	5.61%
1/14/1980	15.17%	9.41%	5.76%
1/17/1980	13.93%	9.43%	4.50%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.64%	3.36%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.96%	3.54%
3/26/1980	14.16%	10.09%	4.07%
3/27/1980	14.24%	10.11%	4.13%
3/28/1980	14.50%	10.13%	4.37%
4/10/1980	12.75%	10.25%	2.50%
4/13/1980	13.85%	10.27%	3.58%
4/15/1980	15.50%	10.29%	5.21%
4/21/1980	13.90%	10.33%	3.57%
4/21/1980	13.25%	10.33%	2.92%
4/23/1980	16.80%	10.36%	6.44%
4/29/1980	15.50%	10.40%	5.10%
5/6/1980	13.70%	10.44%	3.26%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.45%	3.30%
5/9/1980	14.35%	10.46%	3.89%
5/13/1980	13.60%	10.47%	3.13%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.50%	3.25%
5/27/1980	14.60%	10.53%	4.07%
5/27/1980	13.62%	10.53%	3.09%
5/29/1980	16.00%	10.55%	5.45%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.56%	5.07%
6/9/1980	15.90%	10.59%	5.31%
6/10/1980	13.78%	10.59%	3.19%
6/12/1980	14.25%	10.60%	3.65%
6/19/1980	13.40%	10.61%	2.79%
6/30/1980	13.00%	10.64%	2.36%
6/30/1980	13.40%	10.64%	2.76%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.67%	4.33%
7/15/1980	15.80%	10.69%	5.11%
7/18/1980	13.80%	10.70%	3.10%
7/22/1980	14.10%	10.71%	3.39%
7/24/1980	15.00%	10.72%	4.28%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/8/1980	14.00%	10.77%	3.23%
8/8/1980	13.50%	10.77%	2.73%
8/8/1980	15.45%	10.77%	4.68%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.83%	1.67%
9/15/1980	15.80%	10.87%	4.93%
9/15/1980	13.93%	10.87%	3.06%
9/15/1980	13.50%	10.87%	2.63%
9/24/1980	12.50%	10.92%	1.58%
9/24/1980	15.00%	10.92%	4.08%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.20%	10.96%	3.24%
9/30/1980	14.10%	10.96%	3.14%
10/1/1980	13.90%	10.96%	2.94%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	13.25%	11.00%	2.25%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	14.25%	11.10%	3.15%
10/31/1980	13.75%	11.10%	2.65%
11/4/1980	15.00%	11.11%	3.89%
11/5/1980	14.00%	11.12%	2.88%
11/5/1980	13.75%	11.12%	2.63%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	15.10%	11.23%	3.87%
12/8/1980	14.15%	11.23%	2.92%
12/9/1980	15.35%	11.23%	4.12%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.24%	2.01%
12/18/1980	15.80%	11.24%	4.56%
12/19/1980	14.50%	11.24%	3.26%
12/19/1980	14.64%	11.24%	3.40%
12/22/1980	13.45%	11.24%	2.21%
12/22/1980	15.00%	11.24%	3.76%
12/30/1980	14.50%	11.22%	3.28%
12/30/1980	14.95%	11.22%	3.73%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/26/1981	15.25%	11.21%	4.04%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.24%	4.51%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.51%	1.51%
3/18/1981	16.19%	11.54%	4.65%
3/19/1981	13.75%	11.55%	2.20%
3/23/1981	14.30%	11.57%	2.73%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.67%	2.86%
4/3/1981	19.10%	11.70%	7.40%
4/8/1981	15.00%	11.75%	3.25%
4/8/1981	15.30%	11.75%	3.55%
4/8/1981	17.00%	11.75%	5.25%
4/8/1981	16.50%	11.75%	4.75%
4/9/1981	13.75%	11.77%	1.98%
4/12/1981	13.57%	11.79%	1.78%
4/14/1981	15.30%	11.82%	3.48%
4/15/1981	13.50%	11.84%	1.66%
4/16/1981	14.10%	11.86%	2.24%
4/20/1981	16.80%	11.88%	4.92%
4/20/1981	14.00%	11.88%	2.12%
4/23/1981	16.00%	11.92%	4.08%
4/27/1981	13.61%	11.96%	1.65%
4/27/1981	12.50%	11.96%	0.54%
4/29/1981	13.65%	11.99%	1.66%
4/30/1981	13.50%	12.01%	1.49%
5/4/1981	16.22%	12.04%	4.18%
5/5/1981	14.40%	12.06%	2.34%
5/7/1981	16.25%	12.10%	4.15%
5/7/1981	16.27%	12.10%	4.17%
5/8/1981	13.00%	12.12%	0.88%
5/8/1981	16.00%	12.12%	3.88%
5/12/1981	13.50%	12.15%	1.35%
5/15/1981	15.75%	12.21%	3.54%
5/18/1981	14.88%	12.22%	2.66%
5/20/1981	16.00%	12.25%	3.75%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.29%	2.61%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.33%	3.17%
6/1/1981	16.50%	12.34%	4.16%
6/3/1981	14.67%	12.36%	2.31%
6/5/1981	13.00%	12.38%	0.62%
6/10/1981	16.75%	12.41%	4.34%
6/17/1981	14.40%	12.45%	1.95%
6/18/1981	16.33%	12.46%	3.87%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.55%	2.95%
7/1/1981	17.50%	12.55%	4.95%
7/10/1981	16.00%	12.61%	3.39%
7/14/1981	16.90%	12.63%	4.27%
7/15/1981	16.00%	12.64%	3.36%
7/17/1981	15.00%	12.66%	2.34%
7/20/1981	15.00%	12.67%	2.33%
7/21/1981	14.00%	12.68%	1.32%
7/28/1981	13.48%	12.73%	0.75%
7/31/1981	13.50%	12.77%	0.73%
7/31/1981	16.00%	12.77%	3.23%
7/31/1981	15.00%	12.77%	2.23%
8/5/1981	15.71%	12.82%	2.89%
8/10/1981	14.50%	12.86%	1.64%
8/11/1981	15.00%	12.87%	2.13%
8/20/1981	16.50%	12.94%	3.56%
8/20/1981	13.50%	12.94%	0.56%
8/24/1981	15.00%	12.96%	2.04%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.10%	1.40%
9/11/1981	16.00%	13.11%	2.89%
9/16/1981	16.00%	13.14%	2.86%
9/17/1981	16.50%	13.15%	3.35%
9/23/1981	15.85%	13.19%	2.66%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.32%	2.43%
10/15/1981	16.25%	13.36%	2.89%
10/16/1981	16.50%	13.37%	3.13%
10/16/1981	15.50%	13.37%	2.13%
10/19/1981	14.25%	13.38%	0.87%
10/20/1981	15.25%	13.40%	1.85%
10/20/1981	17.00%	13.40%	3.60%
10/23/1981	16.00%	13.44%	2.56%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	16.50%	13.50%	3.00%
10/29/1981	14.75%	13.50%	1.25%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.55%	1.62%
11/24/1981	15.50%	13.60%	1.90%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	15.25%	13.60%	1.65%
11/25/1981	15.35%	13.60%	1.75%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.00%	13.61%	2.39%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.62%	2.63%
12/14/1981	14.00%	13.62%	0.38%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	16.00%	13.66%	2.34%
12/30/1981	16.25%	13.66%	2.59%
12/30/1981	14.25%	13.66%	0.59%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.74%	2.01%
1/15/1982	15.00%	13.75%	1.25%
1/15/1982	16.50%	13.75%	2.75%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.81%	1.69%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.83%	2.61%
2/8/1982	15.50%	13.85%	1.65%
2/11/1982	16.00%	13.87%	2.13%
2/11/1982	16.20%	13.87%	2.33%
2/17/1982	15.00%	13.88%	1.12%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.88%	1.22%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.90%	3.10%
4/1/1982	16.50%	13.91%	2.59%
4/1/1982	14.70%	13.91%	0.79%
4/2/1982	15.50%	13.91%	1.59%
4/4/1982	15.50%	13.91%	1.59%
4/7/1982	16.40%	13.92%	2.48%
4/12/1982	14.50%	13.93%	0.57%
4/22/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	15.50%	13.94%	1.56%
4/30/1982	14.70%	13.94%	0.76%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.91%	0.78%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/20/1982	15.00%	13.91%	1.09%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.87%	2.13%
6/23/1982	16.17%	13.87%	2.30%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.85%	2.15%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	17.00%	13.78%	3.22%
7/22/1982	14.50%	13.78%	0.72%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.69%	3.81%
8/18/1982	17.07%	13.64%	3.43%
8/20/1982	15.73%	13.61%	2.12%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.49%	1.76%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.25%	2.50%
10/22/1982	17.15%	13.25%	3.90%
10/29/1982	15.54%	13.17%	2.37%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.12%	3.13%
11/5/1982	16.20%	13.10%	3.10%
11/9/1982	16.00%	13.06%	2.94%
11/23/1982	15.85%	12.89%	2.96%
11/23/1982	15.50%	12.89%	2.61%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/30/1982	16.50%	12.82%	3.68%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.74%	2.26%
12/6/1982	16.35%	12.74%	3.61%
12/10/1982	15.50%	12.67%	2.83%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	16.40%	12.63%	3.77%
12/14/1982	15.30%	12.63%	2.67%
12/20/1982	16.00%	12.58%	3.42%
12/21/1982	15.85%	12.56%	3.29%
12/21/1982	14.75%	12.56%	2.19%
12/22/1982	16.75%	12.55%	4.20%
12/22/1982	16.58%	12.55%	4.03%
12/22/1982	16.25%	12.55%	3.70%
12/29/1982	14.90%	12.49%	2.41%
12/29/1982	16.25%	12.49%	3.76%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.41%	4.92%
1/11/1983	15.90%	12.35%	3.55%
1/12/1983	15.50%	12.34%	3.16%
1/12/1983	14.63%	12.34%	2.29%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.23%	2.77%
1/24/1983	14.50%	12.21%	2.29%
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.20%	3.65%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.14%	6.36%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.99%	3.51%
2/22/1983	15.50%	11.98%	3.52%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%
3/2/1983	15.25%	11.90%	3.35%
3/9/1983	15.20%	11.83%	3.37%
3/15/1983	13.00%	11.78%	1.22%
3/18/1983	15.25%	11.74%	3.51%
3/23/1983	15.40%	11.70%	3.70%
3/24/1983	15.00%	11.68%	3.32%
3/29/1983	15.50%	11.64%	3.86%
3/30/1983	16.71%	11.62%	5.09%
3/31/1983	15.00%	11.61%	3.39%
4/3/1983	15.20%	11.61%	3.59%
4/7/1983	15.50%	11.54%	3.96%
4/10/1983	14.81%	11.52%	3.29%
4/18/1983	14.50%	11.41%	3.09%
4/19/1983	16.00%	11.39%	4.61%
4/29/1983	16.00%	11.26%	4.74%
5/1/1983	14.50%	11.26%	3.24%
5/9/1983	15.50%	11.16%	4.34%
5/11/1983	16.46%	11.13%	5.33%
5/12/1983	14.14%	11.12%	3.02%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/18/1983	15.00%	11.06%	3.94%
5/23/1983	14.90%	11.02%	3.88%
5/23/1983	15.50%	11.02%	4.48%
5/25/1983	15.50%	11.00%	4.50%
5/27/1983	15.00%	10.97%	4.03%
5/31/1983	15.50%	10.96%	4.54%
5/31/1983	14.00%	10.96%	3.04%
6/2/1983	14.50%	10.94%	3.56%
6/17/1983	15.03%	10.85%	4.18%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.76%	2.44%
7/19/1983	15.10%	10.75%	4.35%
7/19/1983	15.00%	10.75%	4.25%
7/25/1983	16.25%	10.74%	5.51%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.50%	10.75%	5.75%
8/3/1983	16.34%	10.75%	5.59%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	16.40%	10.80%	5.60%
8/22/1983	15.50%	10.80%	4.70%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.94%	4.56%
9/30/1983	16.15%	10.95%	5.20%
9/30/1983	15.25%	10.95%	4.30%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.98%	4.54%
10/17/1983	15.50%	10.99%	4.51%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.00%	5.50%
10/19/1983	16.25%	11.00%	5.25%
10/26/1983	15.00%	11.03%	3.97%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.19%	4.37%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.21%	4.79%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/20/1983	14.69%	11.21%	3.48%
12/20/1983	16.25%	11.21%	5.04%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.26%	3.49%
1/10/1984	15.90%	11.29%	4.61%
1/12/1984	15.60%	11.30%	4.30%
1/18/1984	13.75%	11.32%	2.43%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.36%	4.74%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	14.75%	11.40%	3.35%
2/6/1984	13.75%	11.40%	2.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.45%	3.55%
2/20/1984	15.00%	11.45%	3.55%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.50%	3.00%
3/2/1984	14.25%	11.53%	2.72%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.66%	3.84%
3/26/1984	14.71%	11.67%	3.04%
4/1/1984	15.50%	11.70%	3.80%
4/5/1984	14.74%	11.74%	3.00%
4/10/1984	15.72%	11.76%	3.96%
4/16/1984	15.00%	11.80%	3.20%
4/17/1984	16.20%	11.80%	4.40%
4/24/1984	14.64%	11.84%	2.80%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.25%	3.00%
7/2/1984	13.35%	12.26%	1.09%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
7/13/1984	16.25%	12.33%	3.92%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.35%	3.15%
7/18/1984	15.30%	12.35%	2.95%
7/19/1984	14.30%	12.36%	1.94%
7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.42%	3.58%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.48%	1.82%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.50%	3.80%
8/31/1984	15.55%	12.52%	3.03%
9/6/1984	16.00%	12.53%	3.47%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/10/1984	14.75%	12.54%	2.21%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.55%	4.83%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	16.25%	12.57%	3.68%
9/28/1984	15.00%	12.57%	2.43%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.58%	3.02%
10/22/1984	15.00%	12.58%	2.42%
10/26/1984	16.40%	12.58%	3.82%
10/31/1984	16.25%	12.58%	3.67%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.58%	3.17%
11/20/1984	15.25%	12.57%	2.68%
11/20/1984	15.92%	12.57%	3.35%
11/23/1984	15.00%	12.57%	2.43%
11/28/1984	16.15%	12.56%	3.59%
12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.52%	3.48%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.36%	2.11%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.29%	4.56%
3/14/1985	15.50%	12.26%	3.24%
3/15/1985	15.62%	12.26%	3.36%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/8/1985	15.50%	12.12%	3.38%
4/15/1985	15.70%	12.07%	3.63%
4/21/1985	14.00%	12.03%	1.97%
4/25/1985	15.50%	12.00%	3.50%
4/29/1985	15.00%	11.98%	3.02%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.90%	3.72%
5/10/1985	16.50%	11.88%	4.62%
5/29/1985	14.61%	11.74%	2.87%
5/31/1985	16.00%	11.72%	4.28%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.40%	3.10%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.09%	3.81%
9/23/1985	15.00%	11.07%	3.93%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.75%	11.04%	3.71%
10/2/1985	14.00%	11.04%	2.96%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.85%	10.96%	4.89%
10/24/1985	15.82%	10.96%	4.86%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.95%	5.70%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.70%	4.30%
12/20/1985	15.00%	10.68%	4.32%
12/20/1985	14.50%	10.68%	3.82%
12/20/1985	14.50%	10.68%	3.82%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.36%	4.64%
2/5/1986	15.00%	10.33%	4.67%
2/5/1986	15.75%	10.33%	5.42%
2/10/1986	13.30%	10.30%	3.00%
2/11/1986	12.50%	10.28%	2.22%
2/14/1986	14.40%	10.25%	4.15%
2/18/1986	16.00%	10.24%	5.76%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.16%	3.84%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.01%	3.49%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/13/1986	13.40%	9.71%	3.69%
4/22/1986	15.00%	9.59%	5.41%
5/16/1986	14.50%	9.33%	5.17%
5/16/1986	14.50%	9.33%	5.17%
5/29/1986	13.90%	9.20%	4.70%
5/30/1986	15.10%	9.19%	5.91%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.08%	4.92%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.88%	4.12%
7/10/1986	14.34%	8.76%	5.58%
7/11/1986	12.75%	8.74%	4.01%
7/14/1986	12.60%	8.72%	3.88%
7/17/1986	12.40%	8.67%	3.73%
7/25/1986	14.25%	8.58%	5.67%
8/6/1986	13.50%	8.45%	5.05%
8/14/1986	13.50%	8.36%	5.14%
9/16/1986	12.75%	8.07%	4.68%
9/19/1986	13.25%	8.04%	5.21%
10/1/1986	14.00%	7.96%	6.04%
10/3/1986	13.40%	7.94%	5.46%
10/31/1986	13.50%	7.78%	5.72%
11/5/1986	13.00%	7.76%	5.24%
12/3/1986	12.90%	7.59%	5.31%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.53%	6.07%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.47%	5.53%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.94%	5.04%
8/26/1987	12.63%	8.05%	4.58%
8/26/1987	12.75%	8.05%	4.70%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.13%	4.87%
9/30/1987	13.00%	8.30%	4.70%
9/30/1987	12.75%	8.30%	4.45%
10/2/1987	11.50%	8.33%	3.17%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.54%	4.46%
11/19/1987	13.00%	8.63%	4.37%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.72%	8.78%	4.94%
12/16/1987	13.50%	8.78%	4.72%
12/17/1987	11.75%	8.78%	2.97%
12/18/1987	13.50%	8.79%	4.71%
12/21/1987	12.01%	8.80%	3.21%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.93%	4.87%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.95%	4.25%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.95%	2.01%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	9.00%	3.75%
7/20/1988	13.40%	8.97%	4.43%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.01%	3.99%
12/20/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.03%	4.37%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/2/1989	13.20%	9.01%	4.19%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.92%	4.33%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.32%	4.58%
12/27/1989	13.00%	8.30%	4.70%
12/27/1989	12.50%	8.30%	4.20%
1/10/1990	12.80%	8.25%	4.55%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.18%	3.92%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.31%	4.89%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.35%	8.34%	4.01%
7/6/1990	12.10%	8.34%	3.76%
8/10/1990	12.55%	8.40%	4.15%
8/16/1990	13.21%	8.42%	4.79%
8/22/1990	13.10%	8.44%	4.66%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.66%	4.34%
10/25/1990	12.30%	8.67%	3.63%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/4/1991	12.50%	8.61%	3.89%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.42%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.52%	4.48%
3/8/1991	12.30%	8.52%	3.78%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	12.50%	8.18%	4.32%
11/26/1991	11.60%	8.18%	3.42%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.06%	4.59%
1/31/1992	12.00%	8.05%	3.95%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.99%	3.44%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.94%	3.56%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.90%	3.60%
5/12/1992	12.46%	7.89%	4.57%
5/12/1992	11.87%	7.89%	3.98%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	13.50%	7.84%	5.66%
7/13/1992	11.90%	7.84%	4.06%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.61%	4.19%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.45%	3.62%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.36%	4.89%
2/25/1994	12.00%	6.36%	5.64%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.53%	4.47%
6/27/1994	11.40%	6.64%	4.76%
8/5/1994	12.75%	6.87%	5.88%
10/31/1994	10.00%	7.32%	2.68%
11/9/1994	10.85%	7.38%	3.47%
11/9/1994	10.85%	7.38%	3.47%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.46%	4.14%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.70%	7.54%	4.16%
12/8/1994	11.50%	7.54%	3.96%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.57%	3.93%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.68%	3.32%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.21%	4.09%
9/27/1995	11.50%	7.13%	4.37%
9/27/1995	11.75%	7.13%	4.62%
9/27/1995	11.30%	7.13%	4.17%
9/29/1995	11.00%	7.12%	3.88%
11/9/1995	12.36%	6.90%	5.46%
11/9/1995	11.38%	6.90%	4.48%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.75%	4.65%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.67%	5.33%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.44%	4.81%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.44%	4.81%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.70%	4.30%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.80%	4.20%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.61%	4.39%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.40%	6.35%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.23%	4.27%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.55%	6.65%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.39%	4.91%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.51%	5.24%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.89%	5.21%
1/7/2000	11.50%	6.04%	5.46%
1/7/2000	11.50%	6.04%	5.46%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.19%	5.06%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.47%	5.53%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.99%	7.01%
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.93%	4.92%
12/17/2003	10.70%	4.93%	5.77%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.98%	5.77%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.08%	5.17%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.06%	5.44%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.06%	5.91%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.77%	5.98%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.65%	6.85%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.62%	5.51%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.55%	5.74%
12/21/2005	10.40%	4.55%	5.85%
12/22/2005	11.15%	4.54%	6.61%
12/22/2005	11.00%	4.54%	6.46%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.82%	5.38%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.89%	5.65%
9/14/2006	10.00%	4.90%	5.10%
10/6/2006	9.67%	4.92%	4.75%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.50%	4.95%	5.55%
12/1/2006	10.25%	4.95%	5.30%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	11.25%	4.95%	6.30%
12/21/2006	10.90%	4.95%	5.95%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.87%	4.88%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.81%	5.39%
5/22/2007	10.50%	4.81%	5.69%
5/23/2007	10.70%	4.81%	5.89%
5/25/2007	9.67%	4.81%	4.86%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.85%	5.35%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.82%	5.93%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.69%	4.41%
4/22/2008	10.25%	4.61%	5.64%
4/24/2008	10.10%	4.60%	5.50%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.57%	6.43%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	11.04%	4.54%	6.50%
6/27/2008	10.50%	4.54%	5.96%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.40%	5.85%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.97%	6.53%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.86%	7.24%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.75%	6.50%
5/28/2009	10.50%	3.75%	6.75%
6/22/2009	10.00%	3.77%	6.23%
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/21/2009	10.25%	3.81%	6.44%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.05%	6.83%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.09%	6.61%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.15%	6.60%
11/30/2009	10.35%	4.16%	6.19%
12/3/2009	10.50%	4.17%	6.33%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	11.00%	4.21%	6.79%
12/16/2009	10.90%	4.21%	6.69%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.27%	6.53%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.42%	5.58%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.46%	5.84%
5/12/2010	10.30%	4.46%	5.84%
5/28/2010	10.20%	4.44%	5.76%
5/28/2010	10.10%	4.44%	5.66%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	10.50%	4.43%	6.07%
6/28/2010	9.67%	4.43%	5.24%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.70%	4.43%	6.27%
7/15/2010	10.53%	4.43%	6.10%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.16%	5.70%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.15%	6.15%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.13%	6.17%
1/13/2011	10.30%	4.13%	6.17%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.23%	6.17%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.31%	4.89%
6/17/2011	9.95%	4.31%	5.64%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.38%	4.82%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.37%	5.63%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.88%	7.02%
11/30/2011	10.90%	3.88%	7.02%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.77%	6.43%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.75%	6.44%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/15/2012	10.20%	3.48%	6.72%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.42%	6.98%
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.19%	6.81%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.15%	6.85%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/19/2012	9.80%	2.94%	6.86%
9/26/2012	9.50%	2.94%	6.56%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.88%	2.90%	6.98%
11/29/2012	9.75%	2.90%	6.85%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	10.50%	2.88%	7.62%
12/13/2012	9.50%	2.88%	6.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.88%	6.83%
12/19/2012	10.25%	2.88%	7.37%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.45%	2.87%	7.58%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	9.50%	2.87%	6.63%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
2/13/2013	10.20%	2.85%	7.35%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.25%	3.26%	6.99%
9/11/2013	10.20%	3.26%	6.94%
9/24/2013	10.20%	3.30%	6.90%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.47%	6.73%
12/9/2013	8.72%	3.48%	5.24%
12/9/2013	9.75%	3.48%	6.27%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.50%	6.00%
12/17/2013	10.95%	3.50%	7.45%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.72%	5.68%
3/26/2014	9.96%	3.72%	6.24%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/14/2014	10.20%	3.36%	6.84%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.27%	6.56%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.96%	6.54%
3/26/2015	9.72%	2.96%	6.76%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.30%	2.88%	7.42%
11/19/2015	10.00%	2.88%	7.12%
12/3/2015	10.00%	2.89%	7.11%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.90%	6.70%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.92%	6.58%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.79%	6.21%
6/15/2016	9.00%	2.79%	6.21%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.62%	7.13%
9/1/2016	9.50%	2.60%	6.90%
9/8/2016	10.00%	2.58%	7.42%
9/28/2016	9.58%	2.54%	7.04%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.37%	2.54%	6.83%
12/19/2016	9.00%	2.54%	6.46%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.56%	6.94%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.71%	7.54%
4/12/2017	9.40%	2.73%	6.67%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.94%	6.56%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.93%	6.87%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.88%	5.52%
12/6/2017	8.40%	2.88%	5.52%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.65%	2.87%	6.78%
12/14/2017	9.60%	2.87%	6.73%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.86%	6.72%
12/21/2017	9.10%	2.86%	6.24%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10.00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	9.25%	2.89%	6.36%
4/18/2018	10.00%	2.89%	7.11%
4/26/2018	9.50%	2.90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2.96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2.97%	6.93%
6/28/2018	9.35%	2.97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%
8/24/2018	9.28%	3.00%	6.28%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	9.77%	3.04%	6.73%
9/26/2018	10.00%	3.04%	6.96%
9/27/2018	9.30%	3.05%	6.25%
10/4/2018	9.85%	3.06%	6.79%
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5.55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9.84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10.00%	3.13%	6.87%
2/27/2019	9.75%	3.12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3.12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9.73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3.11%	6.89%
5/8/2019	9.50%	3.10%	6.40%
5/14/2019	8.75%	3.10%	5.65%
5/16/2019	9.50%	3.09%	6.41%
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9.60%	2.90%	6.70%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.79%	7.21%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/7/2019	9.35%	2.58%	6.77%
11/29/2019	9.50%	2.53%	6.97%
12/4/2019	8.91%	2.51%	6.40%
12/4/2019	9.75%	2.51%	7.24%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	10.50%	2.48%	8.02%
12/17/2019	9.70%	2.48%	7.22%
12/19/2019	10.25%	2.47%	7.78%
12/19/2019	10.20%	2.47%	7.73%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.45%	2.47%	6.98%
12/20/2019	9.65%	2.47%	7.18%
12/24/2019	9.70%	2.46%	7.24%
1/8/2020	10.02%	2.43%	7.59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9.50%	2.40%	7.10%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.35%	7.65%
2/11/2020	9.30%	2.34%	6.96%
2/14/2020	9.40%	2.33%	7.07%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.30%	7.45%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.18%	7.22%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.03%	7.22%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.85%	7.40%
7/8/2020	9.40%	1.83%	7.57%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.77%	7.73%
8/27/2020	10.00%	1.66%	8.34%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	8.20%	1.66%	6.54%
10/22/2020	9.50%	1.50%	8.00%
10/28/2020	9.60%	1.49%	8.11%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.20%	1.44%	7.76%
11/24/2020	9.80%	1.44%	8.36%
12/9/2020	8.38%	1.43%	6.95%
12/9/2020	8.38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%
12/16/2020	9.50%	1.44%	8.06%
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8.06%
12/22/2020	9.15%	1.45%	7.70%
12/23/2020	10.00%	1.45%	8.55%
12/30/2020	9.65%	1.45%	8.20%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.67%	7.93%
4/16/2021	9.60%	1.73%	7.87%
5/4/2021	9.85%	1.79%	8.06%
5/18/2021	9.50%	1.84%	7.66%
6/4/2021	9.28%	1.90%	7.38%
6/23/2021	9.00%	1.94%	7.06%
6/28/2021	9.55%	1.95%	7.60%
6/30/2021	9.43%	1.96%	7.47%
6/30/2021	9.43%	1.96%	7.47%
7/14/2021	9.60%	1.99%	7.61%
7/21/2021	9.50%	2.00%	7.50%
8/5/2021	9.60%	2.01%	7.59%
8/18/2021	9.50%	2.03%	7.47%
8/31/2021	8.57%	2.04%	6.53%
9/1/2021	9.40%	2.04%	7.36%
9/27/2021	9.40%	2.07%	7.33%
10/21/2021	9.95%	2.10%	7.85%
10/26/2021	10.60%	2.10%	8.50%
10/28/2021	9.35%	2.10%	7.25%
11/2/2021	8.90%	2.10%	6.80%
11/4/2021	9.48%	2.11%	7.37%
11/17/2021	9.70%	2.11%	7.59%
11/18/2021	9.00%	2.11%	6.89%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/18/2021	9.25%	2.11%	7.14%
11/18/2021	9.35%	2.11%	7.24%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.11%	7.69%
12/1/2021	7.36%	2.10%	5.26%
12/7/2021	9.65%	2.09%	7.56%
12/13/2021	7.36%	2.08%	5.28%
12/15/2021	9.60%	2.08%	7.52%
12/22/2021	9.90%	2.07%	7.83%
12/28/2021	9.40%	2.05%	7.35%
1/20/2022	9.00%	2.03%	6.97%
2/16/2022	9.35%	2.02%	7.33%
2/23/2022	9.70%	2.02%	7.68%
3/16/2022	9.30%	2.02%	7.28%
4/14/2022	9.20%	2.07%	7.13%
4/25/2022	9.50%	2.11%	7.39%
5/12/2022	9.20%	2.18%	7.02%
5/23/2022	9.50%	2.22%	7.28%
8/31/2022	8.57%	2.64%	5.93%
9/8/2022	9.50%	2.68%	6.82%
9/15/2022	9.35%	2.73%	6.62%
10/4/2022	10.10%	2.84%	7.26%
10/4/2022	10.80%	2.84%	7.96%
10/25/2022	9.50%	2.99%	6.51%
11/3/2022	10.25%	3.06%	7.19%
11/3/2022	10.20%	3.06%	7.14%
11/3/2022	10.30%	3.06%	7.24%
11/17/2022	7.85%	3.16%	4.69%
11/18/2022	9.90%	3.16%	6.74%
11/30/2022	9.80%	3.22%	6.58%
12/1/2022	7.85%	3.23%	4.62%
12/14/2022	9.60%	3.29%	6.31%
12/14/2022	9.50%	3.29%	6.21%
12/14/2022	10.00%	3.29%	6.71%
12/15/2022	10.00%	3.29%	6.71%
12/15/2022	9.95%	3.29%	6.66%
12/15/2022	10.05%	3.29%	6.76%
12/16/2022	9.50%	3.30%	6.20%
12/20/2022	10.50%	3.31%	7.19%
12/22/2022	9.40%	3.32%	6.08%
12/22/2022	9.80%	3.32%	6.48%
12/27/2022	9.56%	3.35%	6.21%
12/29/2022	9.30%	3.36%	5.94%
12/29/2022	9.80%	3.36%	6.44%
1/19/2023	9.90%	3.44%	6.46%
1/23/2023	9.65%	3.45%	6.20%
1/26/2023	9.75%	3.46%	6.29%
2/9/2023	9.60%	3.49%	6.11%
2/17/2023	9.50%	3.52%	5.98%
3/9/2023	9.70%	3.58%	6.12%
3/24/2023	9.90%	3.60%	6.30%
4/27/2023	10.00%	3.66%	6.34%
5/31/2023	9.35%	3.76%	5.59%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/1/2023	9.25%	3.76%	5.49%
6/6/2023	9.35%	3.77%	5.58%
6/6/2023	9.75%	3.77%	5.98%
7/20/2023	9.25%	3.82%	5.43%
8/2/2023	9.80%	3.81%	5.99%
8/3/2023	9.57%	3.81%	5.76%
8/18/2023	9.80%	3.82%	5.98%
8/23/2023	9.58%	3.82%	5.76%
8/25/2023	9.55%	3.83%	5.72%
8/25/2023	8.63%	3.83%	4.80%
8/31/2023	11.45%	3.84%	7.61%
8/31/2023	9.40%	3.84%	5.56%
9/6/2023	9.30%	3.85%	5.45%
9/21/2023	9.65%	3.89%	5.76%
10/12/2023	9.75%	3.97%	5.78%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.20%	3.97%	5.23%
10/18/2023	9.50%	3.99%	5.51%
10/19/2023	9.50%	4.00%	5.50%
10/25/2023	9.65%	4.03%	5.62%
11/3/2023	9.30%	4.07%	5.23%
11/3/2023	9.70%	4.07%	5.63%
11/9/2023	9.80%	4.09%	5.71%
11/9/2023	9.80%	4.09%	5.71%
11/17/2023	9.60%	4.12%	5.48%
11/28/2023	9.35%	4.15%	5.20%
12/1/2023	9.90%	4.16%	5.74%
12/7/2023	9.70%	4.16%	5.54%
12/14/2023	10.00%	4.17%	5.83%
12/14/2023	8.72%	4.17%	4.55%
12/14/2023	8.91%	4.17%	4.74%
12/14/2023	9.50%	4.17%	5.33%
12/15/2023	10.10%	4.17%	5.93%
12/18/2023	9.50%	4.17%	5.33%
12/22/2023	10.70%	4.18%	6.52%
12/22/2023	10.65%	4.18%	6.47%
12/22/2023	10.75%	4.18%	6.57%
12/26/2023	9.52%	4.18%	5.34%
12/28/2023	9.60%	4.19%	5.41%
1/3/2024	9.26%	4.19%	5.07%
1/19/2024	9.75%	4.23%	5.52%
1/30/2024	9.75%	4.25%	5.50%
2/14/2024	9.60%	4.28%	5.32%
2/28/2024	9.70%	4.31%	5.39%
3/1/2024	9.90%	4.31%	5.59%
3/5/2024	9.55%	4.32%	5.23%
3/26/2024	9.80%	4.35%	5.45%
4/17/2024	9.90%	4.40%	5.50%
4/18/2024	9.60%	4.41%	5.19%
5/8/2024	9.85%	4.46%	5.39%
6/10/2024	9.50%	4.49%	5.01%
6/20/2024	9.94%	4.50%	5.44%
6/28/2024	9.40%	4.50%	4.90%
7/2/2024	9.86%	4.50%	5.36%
7/18/2024	9.50%	4.48%	5.02%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/8/2024	9.94%	4.43%	5.51%
8/21/2024	10.30%	4.40%	5.90%
8/26/2024	9.97%	4.40%	5.57%
9/17/2024	9.87%	4.36%	5.51%
9/18/2024	9.74%	4.36%	5.38%
9/23/2024	9.50%	4.36%	5.14%
9/26/2024	9.86%	4.36%	5.50%
9/30/2024	9.35%	4.36%	4.99%
10/3/2024	9.76%	4.36%	5.40%
10/9/2024	9.60%	4.37%	5.23%
10/10/2024	9.86%	4.37%	5.49%
10/17/2024	10.28%	4.38%	5.90%
10/17/2024	10.23%	4.38%	5.85%
10/17/2024	10.33%	4.38%	5.95%
10/24/2024	9.78%	4.38%	5.40%
11/20/2024	9.75%	4.40%	5.35%
11/25/2024	9.50%	4.41%	5.09%
11/26/2024	9.50%	4.41%	5.09%
12/3/2024	10.50%	4.41%	6.09%
12/19/2024	9.50%	4.42%	5.08%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/20/2024	9.34%	4.42%	4.92%
12/20/2024	9.80%	4.42%	5.38%
12/30/2024	10.10%	4.43%	5.67%
1/14/2025	9.95%	4.45%	5.50%
1/15/2025	9.50%	4.45%	5.05%
1/15/2025	9.90%	4.45%	5.45%
1/16/2025	10.00%	4.46%	5.54%
1/23/2025	9.90%	4.46%	5.44%
1/29/2025	9.75%	4.46%	5.29%
2/3/2025	9.80%	4.46%	5.34%
3/4/2025	10.15%	4.46%	5.69%
3/12/2025	9.40%	4.46%	4.94%
3/13/2025	9.35%	4.46%	4.89%
3/13/2025	9.65%	4.46%	5.19%
3/20/2025	9.75%	4.47%	5.28%
3/21/2025	9.90%	4.47%	5.43%
3/25/2025	9.10%	4.47%	4.63%
4/25/2025	9.38%	4.50%	4.88%
5/15/2025	9.45%	4.53%	4.92%
6/26/2025	9.75%	4.57%	5.18%
		# of Cases:	1,824

SIZE PREMIUM ANALYSIS

	($Mil)	
PPL Electric Common Equity	$6,800	[1]
Median Market to Book for Proxy Group	1.90	[2]
PPL Electric Implied Market Cap	$12,941	[3]

		[4]	[5]
Company Name	Ticker	Market Cap ($Mil)	Market to Book Ratio
Alliant Energy Corporation	LNT	$15,726	2.22
Ameren Corporation	AEE	$25,989	2.13
American Electric Power Company, Inc.	AEP	$54,744	2.00
Avista Corporation	AVA	$3,059	1.15
CenterPoint Energy, Inc.	CNP	$23,988	2.19
CMS Energy Corporation	CMS	$20,909	2.58
Consolidated Edison, Inc.	ED	$36,871	1.55
Dominion Energy, Inc.	D	$47,610	1.81
DTE Energy Company	DTE	$27,921	2.34
Duke Energy Corporation	DUK	$90,355	1.82
Entergy Corporation	ETR	$35,478	2.34
Eversource Energy	ES	$23,583	1.54
Exelon Corporation	EXC	$43,631	1.58
FirstEnergy Corporation	FE	$23,619	1.88
Evergy, Inc.	EVRG	$15,415	1.55
IDACORP, Inc.	IDA	$6,237	1.86
NextEra Energy, Inc.	NEE	$146,703	2.95
NorthWestern Energy Group, Inc.	NWE	$3,262	1.13
OGE Energy Corporation	OGE	$8,894	1.93
Pinnacle West Capital Corporation	PNW	$10,749	1.60
Portland General Electric Company	POR	$4,531	1.18
Public Service Enterprise Group Inc.	PEG	$40,326	2.46
Southern Company	SO	$98,435	2.91
Xcel Energy Inc.	XEL	$39,670	2.00
MEDIAN		$24,988	1.90
PPL as a Percentage of Median		52%	
MEAN		$35,321	1.95
PPL as a Percentage of Mean		37%	

Market Capitalization ($Mil) [6]			
Decile	Low End Market Capitalization	High End Market Capitalization	Size Premium
1	$ 47,157	$ 3,522,211	-0.01%
2	$ 20,191	$ 46,949	0.33%
3	$ 9,938	$ 20,178	0.49%
4	$ 6,197	$ 9,937	0.50%
5	$ 3,948	$ 6,181	0.74%
6	$ 2,482	$ 3,946	1.00%
7	$ 1,423	$ 2,465	1.19%
8	$ 731	$ 1,417	0.88%
9	$ 305	$ 730	1.73%
10	$ 1	$ 304	4.47%

Proxy Group Median	$ 24,988	0.33%
3rd Decile Size Premium	$ 12,941	0.49%
Difference from Proxy Group Median		0.16%

Notes:
[1] Source: PPL Electric Utilities Co. FERC Form 3-Q, June 30, 2025 pp. 110-111, Line 16 Total Proprietary Capital
[2] Equals Median of [5]
[3] Equals [1] * [2]
[4] Source: S&P Global Market Intelligence, 30-day average
[5] Source: S&P Global Market Intelligence, 30-day average
[6] Source: Kroll Cost of Capital Navigator, Size Premia Deciles as of December 31, 2024

FLOTATION COST ADJUSTMENT

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	Date	Shares Issued (000)	Offering Price	Under-writing Discount	Offering Expense (000)	Net Proceeds Per Share	Total Flotation Costs (000)	Gross Equity Issue Before Costs (000)	Net Proceeds (000)	Flotation Cost Percentage
Alliant Energy Corporation	11/14/2019	4,275	$ 52.63	$ 0.40	$ 500	$ 52.12	$ 2,189	$ 225,000	$ 222,811	0.97%
Alliant Energy Corporation	12/13/2018	8,359	$ 44.85	$ 0.52	$ 1,000	$ 44.21	$ 5,347	$ 374,900	$ 369,553	1.43%
Ameren Corporation	5/12/2025	5,550	$ 94.00	$ 2.12	$ 425	$ 91.81	$ 12,164	$ 521,739	$ 509,575	2.33%
Ameren Corporation	8/5/2019	7,549	$ 74.30	$ 0.12	$ 750	$ 74.08	$ 1,656	$ 560,906	$ 559,250	0.30%
American Electric Power Company, Inc.	4/1/2009	69,000	$ 24.50	$ 0.74	$ 400	$ 23.76	$ 51,115	$ 1,690,500	$ 1,639,385	3.02%
American Electric Power Company, Inc.	2/27/2003	56,000	$ 20.95	$ 0.63	$ 550	$ 20.31	$ 35,746	$ 1,173,200	$ 1,137,454	3.05%
Avista Corporation	12/12/2006	3,163	$ 25.05	$ 0.48	$ 300	$ 24.48	$ 1,818	$ 79,221	$ 77,403	2.29%
CenterPoint Energy, Inc.	5/27/2025	21,622	$ 37.00	$ 0.74	$ 700	$ 36.23	$ 16,700	$ 800,000	$ 783,300	2.09%
CenterPoint Energy, Inc.	8/7/2024	9,754	$ 25.63	$ 0.27	$ 400	$ 25.32	$ 3,034	$ 250,000	$ 246,966	1.21%
CMS Energy Corporation	3/30/2005	23,000	$ 12.25	$ 0.43	$ 325	$ 11.81	$ 10,187	$ 281,750	$ 271,563	3.62%
CMS Energy Corporation	10/7/2004	32,775	$ 9.10	$ 0.32	$ 325	$ 8.77	$ 10,764	$ 298,253	$ 287,489	3.61%
Consolidated Edison, Inc.	3/4/2025	6,300	$ 102.15	$ 1.93	$ 400	$ 100.16	$ 12,559	$ 643,545	$ 630,986	1.95%
Consolidated Edison, Inc.	12/3/2024	7,000	$ 97.53	$ 0.87	$ 450	$ 96.60	$ 6,540	$ 682,710	$ 676,170	0.96%
Dominion Energy, Inc.	3/27/2018	22,100	$ 67.33	$ 1.89	$ 350	$ 65.42	$ 42,212	$ 1,487,900	$ 1,445,688	2.84%
Dominion Energy, Inc.	4/4/2016	10,200	$ 74.16	$ 0.42	$ 200	$ 73.72	$ 4,484	$ 756,432	$ 751,948	0.59%
DTE Energy Company	10/30/2019	26,000	$ 50.00	$ 1.25	$ 2,100	$ 48.67	$ 34,600	$ 1,300,000	$ 1,265,400	2.66%
DTE Energy Company	10/30/2019	2,760	$ 126.00	$ 3.15	$ 300	$ 122.74	$ 8,994	$ 347,760	$ 338,766	2.59%
Duke Energy Corporation	3/2/2016	10,638	$ 72.00	$ 2.16	$ 400	$ 69.80	$ 23,377	$ 765,900	$ 742,523	3.05%
Entergy Corporation	3/17/2025	15,569	$ 83.50	$ 1.63	$ 850	$ 81.82	$ 26,200	$ 1,300,000	$ 1,273,800	2.02%
Entergy Corporation	6/6/2018	13,289	$ 75.25	$ 0.80	$ 650	$ 74.40	$ 11,281	$ 1,000,000	$ 988,719	1.13%
Evergy, Inc.	9/27/2016	60,490	$ 26.45	$ 0.79	$ 500	$ 25.65	$ 48,499	$ 1,599,961	$ 1,551,462	3.03%
Evergy, Inc.	9/24/2013	11,500	$ 14.00	$ 0.49	$ 500	$ 13.47	$ 6,135	$ 161,000	$ 154,865	3.81%
Eversource Energy	611/2020	6,000	$ 86.26	$ 1.35	$ 600	$ 84.81	$ 8,700	$ 517,560	$ 508,860	1.68%
Eversource Energy	5/30/2019	17,940	$ 72.50	$ 1.02	$ 615	$ 71.45	$ 18,914	$ 1,300,650	$ 1,281,736	1.45%
Exelon Corporation	8/4/2022	12,995	$ 43.32	$ 0.99	$ 900	$ 42.26	$ 13,765	$ 562,943	$ 549,178	2.45%
Exelon Corporation	6/10/2014	57,500	$ 35.00	$ 1.05	$ 600	$ 33.94	$ 60,975	$ 2,012,500	$ 1,951,525	3.03%
FirstEnergy Corp	9/12/2003	32,200	$ 30.00	$ 0.98	$ 423	$ 29.01	$ 31,818	$ 966,000	$ 934,182	3.29%
IDACORP, Inc.	5/8/2025	4,505	$ 111.00	$ 3.33	$ 350	$ 107.59	$ 15,350	$ 500,000	$ 484,650	3.07%
IDACORP, Inc.	11/7/2023	3,222	$ 92.80	$ 2.78	$ 275	$ 89.93	$ 9,232	$ 299,000	$ 289,768	3.09%
NorthWestern Energy Group	11/15/2021	6,986	$ 53.50	$ 1.61	$ 900	$ 51.77	$ 12,113	$ 373,750	$ 361,638	3.24%
NorthWestern Energy Group	11/4/2014	7,767	$ 51.50	$ 1.80	$ 1,000	$ 49.57	$ 15,000	$ 399,995	$ 384,996	3.75%
OGE Energy Corp.	8/21/2003	5,324	$ 21.60	$ 0.79	$ 325	$ 20.75	$ 4,531	$ 115,000	$ 110,469	3.94%
Public Service Enterprise Group Incorporated	9/30/2003	9,488	$ 41.75	$ 1.25	$ 350	$ 40.46	$ 12,233	$ 396,103	$ 383,870	3.09%
Public Service Enterprise Group Incorporated	11/11/2002	17,250	$ 26.55	$ 0.86	$ 350	$ 25.67	$ 15,235	$ 457,988	$ 442,753	3.33%
Pinnacle West Capital Corporation	2/28/2024	11,241	$ 66.50	$ 2.00	$ 550	$ 64.46	$ 22,975	$ 747,500	$ 724,525	3.07%
Pinnacle West Capital Corporation	4/8/2010	6,900	$ 38.00	$ 1.33	$ 190	$ 36.64	$ 9,367	$ 262,200	$ 252,833	3.57%
Portland General Electric Company	10/25/2022	11,615	$ 43.00	$ 1.24	$ 500	$ 41.72	$ 14,859	$ 499,445	$ 484,586	2.98%
Portland General Electric Company	6/11/2013	12,765	$ 29.50	$ 0.96	$ 600	$ 28.49	$ 12,839	$ 376,568	$ 363,728	3.41%
Southern Company	8/16/2016	32,500	$ 49.30	$ 1.66	$ 557	$ 47.62	$ 54,507	$ 1,602,250	$ 1,547,743	3.40%
Southern Company	5/5/2016	18,300	$ 48.60	$ 2.02	$ 395	$ 46.56	$ 37,361	$ 889,380	$ 852,019	4.20%
Xcel Energy Inc.	11/4/2024	21,069	$ 65.50	$ 1.06	$ 1,200	$ 64.38	$ 23,626	$ 1,380,000	$ 1,356,374	1.71%
Xcel Energy Inc.	10/30/2019	11,845	$ 63.32	$ 0.63	$ 650	$ 62.64	$ 8,112	$ 750,025	$ 741,913	1.08%
							$ 777,111	$ 30,709,533	$ 29,932,422	2.53%

Notes

[1] - [3] Source: S&P Capital IQ; Two most recent equity issuances of each company in the proxy group, excluding issuances without gross underwriting discount
[4] Source: Company Prospectus Supplements
[5] Equals Col. [8] / Col. [1]
[6] Equals (Col. [1] x Col. [3]) + Col. [4]
[7] Equals Col. [1] x Col. [2]
[8] Equals Col. [7] - Col. [6]
[9] Equals Col. [6] / Col. [7]

The flotation adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9748, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

FLOTATION COST ADJUSTMENT

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Div. Yield Adj. for Flotation Costs	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	DCF	Flotation Adjusted DCF
Alliant Energy Corporation	LNT	$2.03	$61.22	3.32%	3.42%	3.51%	6.60%	6.64%	6.00%	6.41%	9.84%	9.92%
Ameren Corporation	AEE	$2.84	$96.16	2.95%	3.05%	3.13%	7.00%	7.00%	6.50%	6.83%	9.89%	9.97%
American Electric Power Company, Inc.	AEP	$3.72	$102.48	3.63%	3.75%	3.85%	6.40%	6.90%	6.50%	6.60%	10.35%	10.45%
Avista Corporation	AVA	$1.96	$37.97	5.16%	5.31%	5.45%	6.10%	5.50%	5.50%	5.70%	11.01%	11.15%
CenterPoint Energy, Inc.	CNP	$0.88	$36.75	2.39%	2.48%	2.55%	7.80%	7.99%	6.50%	7.43%	9.91%	9.98%
CMS Energy Corporation	CMS	$2.17	$69.90	3.10%	3.21%	3.29%	7.80%	7.00%	5.50%	6.77%	9.98%	10.06%
Consolidated Edison, Inc.	ED	$3.40	$102.33	3.32%	3.42%	3.51%	5.60%	6.20%	6.00%	5.93%	9.35%	9.44%
Dominion Energy, Inc.	D	$2.67	$55.83	4.78%	4.96%	5.09%	N/A	9.20%	6.00%	7.60%	12.56%	12.69%
DTE Energy Company	DTE	$4.36	$134.55	3.24%	3.34%	3.43%	7.60%	7.15%	4.50%	6.42%	9.76%	9.85%
Duke Energy Corporation	DUK	$4.18	$116.25	3.60%	3.71%	3.80%	6.30%	6.40%	6.00%	6.23%	9.94%	10.04%
Entergy Corporation	ETR	$2.40	$82.36	2.91%	3.02%	3.10%	9.50%	8.88%	3.00%	7.13%	10.14%	10.22%
Eversource Energy	ES	$3.01	$64.19	4.69%	4.82%	4.94%	5.70%	5.50%	5.50%	5.57%	10.39%	10.51%
Exelon Corporation	EXC	$1.60	$43.22	3.70%	3.82%	3.92%	6.40%	6.13%	NMF	6.27%	10.08%	10.18%
FirstEnergy Corporation	FE	$1.78	$40.92	4.35%	4.48%	4.60%	6.40%	7.00%	4.50%	5.97%	10.45%	10.56%
Evergy, Inc.	EVRG	$2.67	$67.00	3.99%	4.11%	4.22%	5.70%	5.71%	7.50%	6.30%	10.41%	10.52%
IDACORP, Inc.	IDA	$3.44	$115.46	2.98%	3.09%	3.17%	8.10%	8.70%	6.00%	7.60%	10.69%	10.77%
NextEra Energy, Inc.	NEE	$2.27	$71.26	3.18%	3.31%	3.39%	7.70%	7.57%	8.50%	7.92%	11.23%	11.32%
NorthWestern Energy Group, Inc.	NWE	$2.64	$53.15	4.97%	5.11%	5.24%	6.90%	6.00%	4.50%	5.80%	10.91%	11.04%
OGE Energy Corporation	OGE	$1.69	$44.17	3.81%	3.94%	4.04%	6.30%	6.50%	6.50%	6.43%	10.37%	10.47%
Pinnacle West Capital Corporation	PNW	$3.58	$90.03	3.98%	4.06%	4.17%	2.10%	5.70%	5.00%	4.27%	8.33%	8.43%
Portland General Electric Company	POR	$2.10	$41.37	5.08%	5.20%	5.33%	3.30%	4.50%	6.50%	4.77%	9.96%	10.10%
Public Service Enterprise Group Inc.	PEG	$2.52	$80.81	3.12%	3.22%	3.31%	7.00%	6.10%	7.00%	6.70%	9.92%	10.01%
Southern Company	SO	$2.96	$89.56	3.30%	3.41%	3.50%	6.50%	6.57%	6.50%	6.52%	9.94%	10.03%
Xcel Energy Inc.	XEL	$2.28	$68.78	3.31%	3.44%	3.53%	7.50%	7.75%	7.00%	7.42%	10.85%	10.94%
MEAN											10.26%	10.36%
											[12]	0.10%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of June 30, 2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Zacks Earnings Growth
[7] Source: S&P Capital IQ
[8] Source: Value Line
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average of [11] − Average of [10]

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	Average
Alliant Energy Corporation	LNT	52.71%	52.10%	52.60%	52.47%
Ameren Corporation	AEE	53.52%	53.94%	53.66%	53.70%
American Electric Power Company, Inc.	AEP	48.58%	48.45%	48.56%	48.53%
Avista Corporation	AVA	50.45%	50.24%	51.06%	50.58%
CenterPoint Energy, Inc.	CNP	46.23%	46.20%	46.73%	46.39%
CMS Energy Corporation	CMS	48.71%	49.10%	49.78%	49.19%
Consolidated Edison, Inc.	ED	45.95%	47.50%	46.73%	46.73%
Dominion Energy, Inc.	D	53.40%	55.08%	52.25%	53.58%
DTE Energy Company	DTE	49.79%	49.72%	50.41%	49.97%
Duke Energy Corporation	DUK	53.08%	52.87%	53.04%	53.00%
Entergy Corporation	ETR	51.30%	51.96%	47.65%	50.30%
Eversource Energy	ES	56.69%	57.02%	56.45%	56.72%
Exelon Corporation	EXC	52.89%	53.27%	53.42%	53.19%
FirstEnergy Corporation	FE	58.94%	54.19%	55.52%	56.22%
Evergy, Inc.	EVRG	59.43%	58.84%	60.20%	59.49%
IDACORP, Inc.	IDA	49.95%	49.42%	54.37%	51.24%
NextEra Energy, Inc.	NEE	59.98%	58.67%	63.14%	60.60%
NorthWestern Energy Group, Inc.	NWE	50.08%	49.89%	50.34%	50.10%
OGE Energy Corporation	OGE	53.25%	53.53%	55.65%	54.14%
Pinnacle West Capital Corporation	PNW	52.22%	49.56%	50.25%	50.68%
Portland General Electric Company	POR	45.57%	45.37%	43.24%	44.73%
Public Service Enterprise Group Inc.	PEG	55.03%	55.40%	55.16%	55.20%
Southern Company	SO	55.54%	54.82%	54.58%	54.98%
Xcel Energy Inc.	XEL	54.24%	54.47%	54.84%	54.52%

Proxy Group					
MEAN		52.40%	52.15%	52.48%	52.34%
MEDIAN		52.80%	52.48%	52.82%	52.73%
LOW		45.57%	45.37%	43.24%	44.73%
HIGH		59.98%	58.84%	63.14%	60.60%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Interstate Power and Light Company	LNT	51.73%	49.74%	50.55%	50.67%
Wisconsin Power and Light Company	LNT	53.82%	54.77%	55.03%	54.54%
Ameren Illinois Company	AEE	55.36%	56.21%	55.63%	55.73%
Union Electric Company	AEE	51.92%	51.87%	51.88%	51.89%
AEP Texas Inc.	AEP	43.47%	45.69%	42.07%	43.74%
Appalachian Power Company	AEP	50.26%	48.44%	47.76%	48.82%
Indiana Michigan Power Company	AEP	50.18%	48.32%	49.29%	49.26%
Kentucky Power Company	AEP	44.93%	42.26%	43.82%	43.67%
Kingsport Power Company	AEP	52.99%	51.12%	53.89%	52.67%
Ohio Power Company	AEP	50.95%	51.30%	50.79%	51.01%
Public Service Company of Oklahoma	AEP	48.32%	51.75%	55.70%	51.92%
Southwestern Electric Power Company	AEP	51.55%	50.68%	52.54%	51.59%
Wheeling Power Company	AEP	44.66%	39.99%	49.14%	44.60%
Alaska Electric Light and Power Company	AVA	63.01%	62.52%	60.89%	62.14%
Avista Corporation	AVA	49.96%	49.74%	50.65%	50.12%
CenterPoint Energy Houston Electric, LLC	CNP	44.52%	44.46%	44.55%	44.51%
Southern Indiana Gas and Electric Company	CNP	55.93%	55.66%	56.48%	56.02%
Consumers Energy Company	CMS	48.71%	49.10%	49.78%	49.19%
Consolidated Edison Company of New York, Inc.	ED	45.86%	47.44%	46.75%	46.68%
Orange and Rockland Utilities, Inc.	ED	47.75%	48.57%	46.44%	47.59%
Dominion Energy South Carolina, Inc.	D	53.14%	52.63%	54.80%	53.52%
Virginia Electric and Power Company	D	53.46%	55.63%	51.62%	53.57%
DTE Electric Company	DTE	49.79%	49.72%	50.41%	49.97%
Duke Energy Carolinas, LLC	DUK	51.08%	52.00%	52.78%	51.95%
Duke Energy Florida, LLC	DUK	53.67%	51.31%	50.74%	51.91%
Duke Energy Indiana, LLC	DUK	53.41%	52.55%	52.06%	52.67%
Duke Energy Kentucky, Inc.	DUK	54.31%	61.54%	52.97%	56.27%
Duke Energy Ohio, Inc.	DUK	62.72%	64.39%	65.87%	64.32%
Duke Energy Progress, LLC	DUK	51.71%	50.72%	51.27%	51.23%
Entergy Arkansas, LLC	ETR	47.15%	45.08%	47.95%	46.73%
Entergy Louisiana, LLC	ETR	54.22%	55.45%	47.17%	52.28%
Entergy Mississippi, LLC	ETR	49.50%	49.32%	46.43%	48.42%
Entergy New Orleans, LLC	ETR	48.50%	54.37%	47.94%	50.27%
Entergy Texas, Inc.	ETR	49.74%	50.74%	49.99%	50.16%
NSTAR Electric Company	ES	57.43%	57.61%	56.13%	57.06%
Public Service Company of New Hampshire	ES	56.37%	56.16%	53.77%	55.43%
The Connecticut Light and Power Company	ES	56.06%	56.77%	57.70%	56.84%
Evergy Kansas Central, Inc.	EVRG	66.78%	65.11%	67.13%	66.34%
Evergy Metro, Inc.	EVRG	50.97%	52.00%	52.03%	51.67%
Evergy Missouri West, Inc.	EVRG	52.08%	56.02%	54.41%	54.17%
Westar Energy (KPL)	EVRG	57.12%	55.18%	58.03%	56.78%
Atlantic City Electric Company	EXC	50.02%	49.85%	50.08%	49.98%
Baltimore Gas and Electric Company	EXC	51.98%	54.21%	53.81%	53.33%
Commonwealth Edison Company	EXC	54.70%	54.95%	55.29%	54.98%
Delmarva Power & Light Company	EXC	50.28%	50.22%	50.33%	50.28%
PECO Energy Company	EXC	53.46%	53.10%	53.50%	53.35%
Potomac Electric Power Company	EXC	50.19%	50.10%	50.03%	50.11%
Jersey Central Power & Light Company	FE	67.97%	65.79%	64.86%	66.21%
FirstEnergy Pennsylvania Electric Company	FE	52.71%	N/A	N/A	52.71%
Metropolitan Edison Company	FE	N/A	49.86%	51.85%	50.86%
Monongahela Power Company	FE	53.58%	45.09%	49.23%	49.30%
Ohio Edison Company	FE	54.89%	57.90%	57.49%	56.76%
Pennsylvania Electric Company	FE	N/A	46.24%	50.97%	48.61%
Pennsylvania Power Company	FE	N/A	53.60%	49.28%	51.44%
The Cleveland Electric Illuminating Company	FE	67.19%	55.54%	55.10%	59.28%
The Potomac Edison Company	FE	51.72%	49.65%	53.39%	51.59%
The Toledo Edison Company	FE	55.44%	54.67%	57.09%	55.74%
West Penn Power Company	FE	N/A	50.03%	48.80%	49.41%
Idaho Power Company	IDA	49.95%	49.42%	54.37%	51.24%
Florida Power & Light Company	NEE	59.98%	58.67%	63.14%	60.60%
NorthWestern Corporation	NWE	50.08%	49.89%	50.34%	50.10%
Oklahoma Gas and Electric Company	OGE	53.25%	53.53%	55.65%	54.14%
Arizona Public Service Company	PNW	52.22%	49.56%	50.25%	50.68%
Portland General Electric Company	POR	45.57%	45.37%	43.24%	44.73%
Public Service Electric and Gas Company	PEG	55.03%	55.40%	55.16%	55.20%
Alabama Power Company	SO	53.88%	52.36%	52.22%	52.82%
Georgia Power Company	SO	56.53%	56.32%	56.05%	56.30%
Mississippi Power Company	SO	55.31%	55.01%	55.67%	55.33%
Northern States Power Company - Minnesota	XEL	53.37%	52.58%	52.79%	52.91%
Northern States Power Company - Wisconsin	XEL	53.23%	52.77%	53.45%	53.15%
Public Service Company of Colorado	XEL	55.21%	56.47%	57.18%	56.29%
Southwestern Public Service Company	XEL	54.17%	54.41%	54.30%	54.29%

Operating Company					
MEAN		52.90%	52.49%	52.67%	52.63%
MEDIAN		52.85%	52.00%	52.22%	51.94%
LOW		43.47%	39.99%	42.07%	43.67%
HIGH		67.97%	65.79%	67.13%	66.34%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Evergy Kansas South was removed because it is financed with more than 80% common equity. Rockland Electric was removed because it is financed with 100% common equity.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	Average
Alliant Energy Corporation	LNT	47.29%	47.90%	47.40%	47.53%
Ameren Corporation	AEE	46.48%	46.06%	46.34%	46.30%
American Electric Power Company, Inc.	AEP	51.42%	51.55%	51.44%	51.47%
Avista Corporation	AVA	49.55%	49.76%	48.94%	49.42%
CenterPoint Energy, Inc.	CNP	53.77%	53.80%	53.27%	53.61%
CMS Energy Corporation	CMS	51.29%	50.90%	50.22%	50.81%
Consolidated Edison, Inc.	ED	54.05%	52.50%	53.27%	53.27%
Dominion Energy, Inc.	D	46.60%	44.92%	47.75%	46.42%
DTE Energy Company	DTE	50.21%	50.28%	49.59%	50.03%
Duke Energy Corporation	DUK	46.92%	47.13%	46.96%	47.00%
Entergy Corporation	ETR	48.70%	48.04%	52.35%	49.70%
Eversource Energy	ES	43.31%	42.98%	43.55%	43.28%
Exelon Corporation	EXC	47.11%	46.73%	46.58%	46.81%
FirstEnergy Corporation	FE	41.06%	45.81%	44.48%	43.78%
Evergy, Inc.	EVRG	40.57%	41.16%	39.80%	40.51%
IDACORP, Inc.	IDA	50.05%	50.58%	45.63%	48.76%
NextEra Energy, Inc.	NEE	40.02%	41.33%	36.86%	39.40%
NorthWestern Energy Group, Inc.	NWE	49.92%	50.11%	49.66%	49.90%
OGE Energy Corporation	OGE	46.75%	46.47%	44.35%	45.86%
Pinnacle West Capital Corporation	PNW	47.78%	50.44%	49.75%	49.32%
Portland General Electric Company	POR	54.43%	54.63%	56.76%	55.27%
Public Service Enterprise Group Inc.	PEG	44.97%	44.60%	44.84%	44.80%
Southern Company	SO	44.46%	45.18%	45.42%	45.02%
Xcel Energy Inc.	XEL	45.76%	45.53%	45.16%	45.48%

Proxy Group					
MEAN		47.60%	47.85%	47.52%	47.66%
MEDIAN		47.20%	47.52%	47.18%	47.27%
LOW		40.02%	41.16%	36.86%	39.40%
HIGH		54.43%	54.63%	56.76%	55.27%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Interstate Power and Light Company	LNT	48.27%	50.26%	49.45%	49.33%
Wisconsin Power and Light Company	LNT	46.18%	45.23%	44.97%	45.46%
Ameren Illinois Company	AEE	44.64%	43.79%	44.37%	44.27%
Union Electric Company	AEE	48.08%	48.13%	48.12%	48.11%
AEP Texas Inc.	AEP	56.53%	54.31%	57.93%	56.26%
Appalachian Power Company	AEP	49.74%	51.56%	52.24%	51.18%
Indiana Michigan Power Company	AEP	49.82%	51.68%	50.71%	50.74%
Kentucky Power Company	AEP	55.07%	57.74%	56.18%	56.33%
Kingsport Power Company	AEP	47.01%	48.88%	46.11%	47.33%
Ohio Power Company	AEP	49.05%	48.70%	49.21%	48.99%
Public Service Company of Oklahoma	AEP	51.68%	48.25%	44.30%	48.08%
Southwestern Electric Power Company	AEP	48.45%	49.32%	47.46%	48.41%
Wheeling Power Company	AEP	55.34%	60.01%	50.86%	55.40%
Alaska Electric Light and Power Company	AVA	36.99%	37.48%	39.11%	37.86%
Avista Corporation	AVA	50.04%	50.26%	49.35%	49.88%
CenterPoint Energy Houston Electric, LLC	CNP	55.48%	55.54%	55.45%	55.49%
Southern Indiana Gas and Electric Company	CNP	44.07%	44.34%	43.52%	43.98%
Consumers Energy Company	CMS	51.29%	50.90%	50.22%	50.81%
Consolidated Edison Company of New York, Inc.	ED	54.14%	52.56%	53.25%	53.32%
Orange and Rockland Utilities, Inc.	ED	52.25%	51.43%	53.56%	52.41%
Dominion Energy South Carolina, Inc.	D	46.86%	47.37%	45.20%	46.48%
Virginia Electric and Power Company	D	46.54%	44.37%	48.38%	46.43%
DTE Electric Company	DTE	50.21%	50.28%	49.59%	50.03%
Duke Energy Carolinas, LLC	DUK	48.92%	48.00%	47.22%	48.05%
Duke Energy Florida, LLC	DUK	46.33%	48.69%	49.26%	48.09%
Duke Energy Indiana, LLC	DUK	46.59%	47.45%	47.94%	47.33%
Duke Energy Kentucky, Inc.	DUK	45.69%	38.46%	47.03%	43.73%
Duke Energy Ohio, Inc.	DUK	37.28%	35.61%	34.13%	35.68%
Duke Energy Progress, LLC	DUK	48.29%	49.28%	48.73%	48.77%
Entergy Arkansas, LLC	ETR	52.85%	54.92%	52.05%	53.27%
Entergy Louisiana, LLC	ETR	45.78%	44.55%	52.83%	47.72%
Entergy Mississippi, LLC	ETR	50.50%	50.68%	53.57%	51.58%
Entergy New Orleans, LLC	ETR	51.50%	45.63%	52.06%	49.73%
Entergy Texas, Inc.	ETR	50.26%	49.26%	50.01%	49.84%
NSTAR Electric Company	ES	42.57%	42.39%	43.87%	42.94%
Public Service Company of New Hampshire	ES	43.63%	43.84%	46.23%	44.57%
The Connecticut Light and Power Company	ES	43.94%	43.23%	42.30%	43.16%
Evergy Kansas Central, Inc.	EVRG	33.22%	34.89%	32.87%	33.66%
Evergy Metro, Inc.	EVRG	49.03%	48.00%	47.97%	48.33%
Evergy Missouri West, Inc.	EVRG	47.92%	43.98%	45.59%	45.83%
Westar Energy (KPL)	EVRG	42.88%	44.82%	41.97%	43.22%
Atlantic City Electric Company	EXC	49.98%	50.15%	49.92%	50.02%
Baltimore Gas and Electric Company	EXC	48.02%	45.79%	46.19%	46.67%
Commonwealth Edison Company	EXC	45.30%	45.05%	44.71%	45.02%
Delmarva Power & Light Company	EXC	49.72%	49.78%	49.67%	49.72%
PECO Energy Company	EXC	46.54%	46.90%	46.50%	46.65%
Potomac Electric Power Company	EXC	49.81%	49.90%	49.97%	49.89%
Jersey Central Power & Light Company	FE	32.03%	34.21%	35.14%	33.79%
FirstEnergy Pennsylvania Electric Company	FE	47.29%	N/A	N/A	47.29%
Metropolitan Edison Company	FE	N/A	50.14%	48.15%	49.14%
Monongahela Power Company	FE	46.42%	54.91%	50.77%	50.70%
Ohio Edison Company	FE	45.11%	42.10%	42.51%	43.24%
Pennsylvania Electric Company	FE	N/A	53.76%	49.03%	51.39%
Pennsylvania Power Company	FE	N/A	46.40%	50.72%	48.56%
The Cleveland Electric Illuminating Company	FE	32.81%	44.46%	44.90%	40.72%
The Potomac Edison Company	FE	48.28%	50.35%	46.61%	48.41%
The Toledo Edison Company	FE	44.56%	45.33%	42.91%	44.26%
West Penn Power Company	FE	N/A	49.97%	51.20%	50.59%
Idaho Power Company	IDA	50.05%	50.58%	45.63%	48.76%
Florida Power & Light Company	NEE	40.02%	41.33%	36.86%	39.40%
NorthWestern Corporation	NWE	49.92%	50.11%	49.66%	49.90%
Oklahoma Gas and Electric Company	OGE	46.75%	46.47%	44.35%	45.86%
Arizona Public Service Company	PNW	47.78%	50.44%	49.75%	49.32%
Portland General Electric Company	POR	54.43%	54.63%	56.76%	55.27%
Public Service Electric and Gas Company	PEG	44.97%	44.60%	44.84%	44.80%
Alabama Power Company	SO	46.12%	47.64%	47.78%	47.18%
Georgia Power Company	SO	43.47%	43.68%	43.95%	43.70%
Mississippi Power Company	SO	44.69%	44.99%	44.33%	44.67%
Northern States Power Company - Minnesota	XEL	46.63%	47.42%	47.21%	47.09%
Northern States Power Company - Wisconsin	XEL	46.77%	47.23%	46.55%	46.85%
Public Service Company of Colorado	XEL	44.79%	43.53%	42.82%	43.71%
Southwestern Public Service Company	XEL	45.83%	45.59%	45.70%	45.71%

Operating Company				
MEAN	47.10%	47.51%	47.33%	47.37%
MEDIAN	47.15%	48.00%	47.78%	48.06%
LOW	48.27%	50.26%	49.45%	49.33%
HIGH	56.53%	60.01%	57.93%	56.33%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Evergy Kansas South was removed because it is financed with more than 80% common equity. Rockland Electric was removed because it is financed with 100% common equity.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3057164

PPL Electric Utilities Corporation

Statement No. 11

Direct Testimony of John J. Spanos

Topics: Depreciation Service Lives

Dated: September 30, 2025

Q. Please state your name and address.

A. My name is John J. Spanos. My business address is 300 Sterling Parkway, Mechanicsburg, Pennsylvania, 17050 (formerly 207 Senate Avenue, Camp Hill, Pennsylvania, 17011).

Q. With what firm are you associated?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. What is your position in the firm?

A. I am President.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Will you outline your experience in the field of depreciation?

A. I have over 39 years of depreciation experience which includes expert testimony in more than 500 cases before 47 regulatory commissions, including the Pennsylvania Public Utility Commission ("Commission"). These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have supervised over 900 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the utility plant of PPL Electric Utilities Corporation ("PPL Electric" or the "Company").

Q. Have you prepared exhibits presenting the results of your studies?

A. Yes. PPL Electric Exhibit JJS-1 presents the results of the depreciation study as of June 30, 2025. PPL Electric Exhibit JJS-2 presents the results of the depreciation study as of June 30, 2026. PPL Electric Exhibit JJS-3 presents the results of the depreciation study as of June 30, 2027. In addition, I am responsible for the responses to the following filing requirements pertaining to depreciation under Section 53.53(a)(1) of the Commission's regulations: V-A-2, V-A-3, V-B-1, V-B-2, V-C-1, V-D-1, V-D-2 and V-E-1 which present summaries of the study results as of the historic test year ("HTY") ending June 30, 2025, future test year ("FTY") ending June 30, 2026 and the fully projected future test year ("FPFTY") ending June 30, 2027.

Q. Please describe Exhibits JJS 1, JJS-2 and JJS-3.

A. PPL Electric Exhibit JJS-1, titled "2025 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of June 30, 2025," includes the results of the depreciation study as related to the original cost as of June 30, 2025. The report also includes the detailed depreciation calculations. PPL Electric Exhibit JJS-2, titled "2026 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of June 30, 2026," includes the results of the depreciation study as related to the estimated original cost as of June 30, 2026. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. PPL Electric Exhibit JJS-3, titled "2027 Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of June 30, 2027," includes the results of the depreciation study as related to the estimated original cost as of June 30, 2027.

Q. What was the purpose of your depreciation study?

A. The purpose of the depreciation studies was to estimate the annual depreciation accruals related to utility plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve as of June 30, 2025, June 30, 2026, and June 30, 2027.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent electric base rate proceeding.

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line, remaining life method of depreciation. For Accounts 391.20, 391.40, 393.00, 394.00, 394.20, 394.40, 394.60, 394.80, 395.00, 397.10, 397.20, 397.27, 397.30 and 398.00, the claim is based on the straight line, remaining life method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. All depreciable accounts utilize the methods and procedures based on the straight line remaining life method, using remaining lives consistent with the average service life procedure.

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. Their average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used in its most recent electric base rate proceeding?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve utilized by the Company in its last base rate proceeding and for its prior rate cases.

Q. How was the book reserve used in the calculation of annual depreciation?

A. The book reserve by account was allocated to vintages to determine original cost less accrued depreciation by vintage. The total annual accrual is the sum of the results of dividing the original costs less accrued depreciation by the vintage composite remaining lives.

Q. How was the book reserve as of June 30, 2026, estimated?

A. The book reserve as of June 30, 2026, by account, was projected by adding estimated accruals, salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve as of June 30, 2026. Annual accruals were estimated using the annual accrual rates calculated as of June 30, 2026. For most accounts, gross salvage and cost of removal were estimated by: (1) expressing actual gross salvage and cost of removal as a percent of retirements by account, for the most recent five-year period; and (2) applying those percents to the projected retirements by account. For the purpose of calculating the annual accruals, the projected book reserve by account was allocated to vintages based on calculated accrued depreciation as of June 30, 2026.

Q. Has a service life study of the Company's electric utility property been performed for this filing?

A. No, but the Company's most recent service life study was performed using data through 2021 because this Commission's regulations only require service life studies to be prepared every 5 years. That 2021 service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the electric utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as large service centers and office buildings within Account 390.20. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the electric plant through 2021. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its utility plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for electric utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for PPL Electric before the Commission.

Q. What approach did you use to estimate the lives of significant structures such as substation buildings, office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure, such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Commission.

Q. What are the bases for the probable retirement years that you have estimated for each structure?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar structures. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, analysis of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in PPL Electric Exhibit JJS-2?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages III-3 through III-5 of PPL Electric Exhibit JJS-2.

Q. Please outline the contents of PPL Electric Exhibit JJS-2.

A. PPL Electric Exhibit JJS-2 is presented in eight parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, and Part IV, Calculation of Annual and Accrued Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures.

Part V, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VI, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account. Part VIII, Experienced and Estimated Net Salvage, sets forth the recorded cost of removal and gross salvage for the period 2021 through June 30, 2025, and the estimated amounts for the six months ended December 31, 2025.

Table 1, pages V-4 through V-6, presents the estimated survivor curve, the original cost as of June 30, 2026, and the book reserve and calculated annual depreciation for each account or subaccount of Electric Plant. Table 2, pages V-7 and V-8, presents the bringforward to June 30, 2026, of the book depreciation reserve as of June 30, 2025. Table 3 on pages V-9 and V-10 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page V-11, presents the experienced and estimated net salvage by account during the five-year period, 2021 through 2025.

The section beginning on page VI-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VII-2 presents the depreciation calculations related to original cost. The tabulations on pages VII-7 through VII-148 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please outline the contents of PPL Electric Exhibit JJS-3.

A. PPL Electric Exhibit JJS-3 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of June 30, 2027. The descriptions and explanations presented in PPL Electric Exhibit JJS-2 are also applicable to the depreciation calculations presented in PPL Electric Exhibit JJS-3. The graphs and tables related to service life presented in PPL Electric Exhibit JJS-2 also support the service life estimates used in PPL Electric Exhibit JJS-3 inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of June 30, 2027, are organized and presented in the same manner as those as of June 30, 2026.

Q. Please outline the contents of PPL Electric Exhibit JJS-1.

A. PPL Electric Exhibit JJS-1 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of June 30, 2025. The descriptions and explanations presented in PPL Electric Exhibit JJS-2 are also applicable to the depreciation calculations presented in PPL Electric Exhibit JJS-1. The graphs and tables related to service life presented in PPL Electric Exhibit JJS-2 also support the service life estimates used in PPL Electric Exhibit JJS-1, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of June 30, 2025, are organized and presented in the same manner as those as of June 30, 2026.

Q. Please use an example to illustrate the manner in which the study is presented in PPL Electric Exhibit JJS-2.

A. I will use Account 364.40, Poles, Towers and Fixtures - Poles, as my example; inasmuch as it is one of the larger depreciable groups and represents approximately 9 percent of the original cost of depreciable utility plant as of June 30, 2026.

The retirement rate method was used to analyze the survivor characteristics of this group. The life table for the 1912-2021 experience band is presented on pages VI-69 through VI-71 of PPL Electric Exhibit JJS-2. The life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 55-R0.5, on page VI-68.

The calculation as of June 30, 2026, is presented on pages VII-65 through VII-67 of PPL Electric Exhibit JJS-2 and is based in part on the bringforward of the book reserve. The tabulation in PPL Electric Exhibit JJS-2 sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to the table on page V-5 in PPL Electric Exhibit JJS-2.

Q. Do you believe PPL Electric Exhibit JJS-2 reflects the appropriate survivor curves for PPL Electric to be adopted in this proceeding?

A. Yes, I do. The methods and procedures utilized in the development of survivor curves are consistent with past practices for PPL Electric and Pennsylvania ratemaking regulations. The service life study was completed as of December 31, 2021.

Q. Do you believe that the annual depreciation rates and the related depreciation expense claims should be adopted in this proceeding?

A. Yes, I do. The depreciation rates and expense claims are based on appropriate survivor curves, and the depreciation procedures are the same as those utilized by PPL Electric in past filings before this Commission.

Q. In what manner is net salvage incorporated in the depreciation calculations?

A. As stated on page I-5 of PPL Electric Exhibit JJS-2, no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation set forth on page I-5 of PPL Electric Exhibit JJS-1, page V-6 of PPL Electric Exhibit JJS-2 and on page I-5 of PPL Electric Exhibit JJS-3 should include an addition for the amortization of negative net salvage in accordance with the practice of this Commission. The amortization is based on experience during the period 2020 through 2024 for the calculation as of June 30, 2025, and on experience during the period 2021 through June 30, 2025, plus estimates for the last six months of 2025 for the calculation as of June 30, 2026.

The amortization for the June 30, 2027 calculation is based on experience during the period 2022 through June 30, 2025, plus estimates for the period July 2025 through December 2026. The amounts of the five-year amortizations are calculated in Table 2 on page I-6 of PPL Electric Exhibit JJS-1, in Table 4 on page V-8 of PPL Electric Exhibit JJS-2 and in Table 4 on page I-7 of PPL Electric Exhibit JJS-3.

Q. Are there new accounts or subaccounts established due to reclassification of assets related to FERC Order 898?

A. Yes. There are newly established subaccounts for Account 351.00, Account 363.00, 387.00 and Account 397.00. The assets in each of the accounts or subaccounts have depreciable lives or amortization periods consistent to what was established before the assets were reclassified to the new FERC Order 898 account numbering which went into effect in early 2025. These accounts are presented in Table 1 of each exhibit.

Q. Does this complete your direct testimony?

A. Yes, it does.