I co-sponsor this schedule with EPE witness Borden. The information that I sponsor on this schedule is the expense by month for the Test Year.

The H Schedules (Engineering Information)

Q. WHICH H SCHEDULES DO YOU SPONSOR?

A. I co-sponsor schedules H-1 (Summary of Test Year Production O&M Expenses), H-1.1 (Nuclear Company-Wide O&M Expenses Summary), H-1.1a (Nuclear Plant O&M Summary), H-1.1a.1 (Nuclear Unit O&M Summary) and H-3 (Summary of Actual Production O&M Expenses Incurred).

Q. PLEASE DESCRIBE SCHEDULES H-1 THROUGH H-1.1A1.

A. Schedule H-1 summarizes the nuclear and fossil fuel expenses by FERC account, for each month of the Test Year, and by fuel type for all generating plants or units. Schedules H-1.1 through H-1.1a1 provide a summary of Test Year expense for nuclear production O&M on a company-wide basis, by plant and by unit, respectively. I co-sponsor this schedule with EPE witnesses Hawkins and Tom Horton. The information I sponsor on this schedule is the Test Year amounts and footnote (A).

Q. WHAT DOES SCHEDULE H-3, SUMMARY OF ACTUAL PRODUCTION O&M EXPENSES INCURRED), ADDRESS?

A. Schedule H-3 provides a summary of the actual production O&M expenses per year for the five years preceding the Test Year. I co-sponsor this schedule with EPE witnesses J Kyle Olson, Hawkins and Horton. The information I sponsor on this schedule is the Test Year amounts.

Financial Statements (Schedule J)

Q. WHAT IS SCHEDULE J, FINANCIAL STATEMENTS?

A. Schedule J contains financial statement information for the Company.

- Schedule J, pages 2 through 7, provides EPE's Balance Sheet and Retained Earnings at December 31, 2020 and 2019, as well as its Income Statement, Statement of Comprehensive Income and Statement of Cash Flows for the Test Year and twelve month period immediately preceding the Test Year prepared on a FERC regulatory accounting basis. The Company has also provided EPE's financial statements in accordance with GAAP (e.g., Balance Sheet, Income Statement, Statement of Comprehensive Operations and Statement of Cash Flows) on pages 8 to 12. The Income Statement, Statement of Comprehensive Operations and Statement of Cash Flows cover the Test Year and twelve months immediately preceding the Test Year. Attachment A to Schedule J provides the Company's revised 2020 FERC Form 1 filing and Attachment B provides the financial statements and footnotes of the Company on a GAAP basis as of December 31, 2020.

- Schedule J-1 (Reconciliation – Total Company to Total Electric) reconciles the balance sheet and income statement presented on a Total Company basis in Schedule J with the same information presented on a Total Electric basis.

Financial Information (G & T Cooperatives) (Schedule R)

Q. WHAT INFORMATION IS REQUIRED TO BE PRESENTED IN THE R SCHEDULES?

A. The R schedules address generation and transmission cooperatives. These schedules are not applicable to EPE.

Test Year Review (Schedule S)

Q. IS EPE PROVIDING INFORMATION RESPONSIVE TO THE S SCHEDULES?

A. As explained in Section IX, above, in accordance with the Commission's Order waiving the Schedule S filing requirements in this case, the Company has met the conditions upon which the waiver was granted.

XI. Conclusion

Q. PLEASE STATE YOUR CONCLUSIONS.

A. The Company's overall, combined compensation and benefit costs are reasonable and necessary. The total amount of compensation and benefits is market-driven, consistent with other similarly situated businesses, and administered in a cost-effective manner. Likewise, the Company's administrative and general expenses are necessary for the Company to support its operations. The Company works to ensure that administrative expenses are reasonable by negotiating lower costs and using competitive bidding. Moreover, the Company endeavors to only use services necessary to operate its business.

The Company's calculation of excess ADIT, including the excess ADIT resulting from the TCJA, and its recommendation to return the excess ADIT to customers are reasonable and consistent with IRC normalization requirements.

The Company is in compliance with certain commitments (addressed in my testimony above) included in the resolution of and final order in Docket No. 49849, *Joint Report and Application of El Paso Electric Company, Sun Jupiter Holdings LLC, and IIF US Holdings 2 LP for Regulatory Approvals Under PURA §§ 14.101, 39.262, and 39.915.*

The Company's proposal to recover costs associated with the COVID-19 pandemic is consistent with the relevant Commission orders under Project No. 50664. Moreover, the FERC Account reclassification of administrative and general expenses relating to the third-party billings represents a shift from A&G into O&M accounts and does not represent an increase in costs incurred during the Test Year ended December 31, 2020.

The Company's financial statements are consistent with GAAP and FERC accounting requirements. Further, the Company is in compliance with the conditions established in the Commission order granting a waiver of the Schedule S filing requirements in this rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED AND CO-SPONSORED BY CYNTHIA S. PRIETO

Schedule	Description	Sponsorship
A	Overall Cost of Service	Co-Sponsor
A-2	Cost of Service Detail by Account	Co-Sponsor
A-4	Detail TYE Trial Balance	Sponsor
A-5	Unadjusted O&M	Sponsor
	Rate Base and Return	
B-1	Total Company	Co-Sponsor
B-2	Accumulated Provision Balances	Sponsor
B-2.1	Accumulated Provision Policies	Sponsor
	Short Term Assets and Inventories	
E-1	Monthly Balances of Short Term Assets	Sponsor
E-1.1	Detail of Short Term Assets	Sponsor
E-1.3	Short Term Assets Policies	Sponsor
E-2.3	Fossil Fuel Inventories	Co-Sponsor
E-2.4	Fossil Fuel Inventory Levels	Co-Sponsor
E-2.5	Fossil Fuel Inventory Values	Co-Sponsor
E-3.1	Fuel Oil Burns	Co-Sponsor
E-5	Prepayments and Materials and Supplies	Sponsor
E-6	Customer Deposits	Sponsor
F	**Description of Company**	**Sponsor**
	Accounting Information	
G-1	Payroll Information	Sponsor
G-1.1	Regular and Overtime Payroll	Sponsor
G-1.2	Regular Payroll by Category	Sponsor
G-1.3	Payroll Capitalized vs. Expensed	Sponsor
G-1.4	Payroll by Company	Sponsor
G-1.5	Number of Employees	Sponsor
G-1.6	Payments Other Than Standard Pay	Sponsor
G-2	General Employee Benefit Information	Sponsor
G-2.1	Pension Expense	Sponsor
G-2.2	Postretirement Benefits Other Than Pension	Sponsor
G-2.3	Administration Fees	Sponsor
G-3	Bad Debt Expense	Sponsor
G-4	Summary of Advertising, Contributions, & Dues	Co-Sponsor
G-4.1	Summary of Advertising Expense	Sponsor
G-4.1a	Summary of Informational/Instructional Advertising	Sponsor
G-4.1b	Summary of Advertising to Promote & Retain Usage	Sponsor
G-4.1c	Summary of General Advertising Expense	Sponsor

SCHEDULES SPONSORED AND CO-SPONSORED BY CYNTHIA S. PRIETO

Schedule	Description	Sponsorship
G-4.1d	Capitalized Advertising	Sponsor
G-4.2	Summary of Contribution & Donation Expense	Sponsor
G-4.2a	Summary of Educational Contributions & Donations	Sponsor
G-4.2b	Summary of Community Service Contributions & Donations	Sponsor
G-4.2c	Summary of Economic Development Contributions & Donations	Sponsor
G-4.3	Summary of Membership Dues Expense	Sponsor
G-4.3a	Summary of Industry Organization Dues	Sponsor
G-4.3b	Summary of Business/Economic Dues	Sponsor
G-4.3c	Summary of Professional Dues	Sponsor
G-4.3d	Summary of Social, Recreational, Fraternal or Religious Expenses	Sponsor
G-4.3e	Summary of Political Organizations Expense	Sponsor
G-5	Summary of Exclusions from Test Year Expense	Sponsor
G-5.1	Analysis of Legislative Advocacy	Co-Sponsor
G-5.1a	Payments to Registered Lobbyists	Co-Sponsor
G-5.1b	Payments for Monitoring Legislation	Co-Sponsor
G-5.2	Summary of Penalties and Fines	Sponsor
G-6	Summary of Test Year Affiliate Transactions	Sponsor
G-6.1	Summary of Test Year Expense by Affiliate	Sponsor
G-6.2	Summary of Adjustments to Test Year Expense by Affiliate	Sponsor
G-7.9	Amortization of Protected and Unprotected Excess Deferred Taxes	Sponsor
G-7.9a	Analysis of Excess Deferred Taxes by Timing Difference	Sponsor
G-7.9b	Reconciliation of Excess	Sponsor
G-7.9c	Analysis of Reserve Accounting for Excess Deferred Taxes	Sponsor
G-7.13	List of Fit Testimony	Co-Sponsor
G-8	Outside Services Employed – FERC 900 Series Expenses	Sponsor
G-10	Factoring Expense	Sponsor
G-12	Below the Line Expenses	Co-Sponsor
G-15	Monthly O&M Expense	Co-Sponsor
	Engineering Information	
H-1	Summary of Test Year Production O&M Expenses	Co-Sponsor
H-1.1	Nuclear Company-Wide O&M Expenses Summary	Co-Sponsor
H-1.1a	Nuclear Plant O&M Summary	Co-Sponsor
H-1.1a1	Nuclear Unit O&M Summary	Co-Sponsor
H-3	Summary of Actual Production O&M Expensed Incurred	Co-Sponsor
J	**Financial Statements**	Sponsor
J-1	Reconciliation – Total Company to Total Electric	Sponsor
R	**Financial Information (G&T Cooperatives) – N/A**	Sponsor
S	**Test Year Review**	Sponsor

EL PASO ELECTRIC COMPANY
EXCESS ACCUMULATED DEFERRED INCOME TAX
ARAM ILLUSTRATION
SPONSOR. CYNTHIA S. PRIETO

		(a)	(b)	(a x b = c)	(a / 10 = d)	(c - d = e)	(f)	(g)	(e x g = h)	(f x g = i)	(j)	(e x j = k)	(l)
Line No.	Year	Asset Cost (A)	5-year MACRS Tax Depreciation Rate (B)	Tax Depreciation	Book Depreciation 10 yrs. S/L (C)	Annual Temporary Difference	Cummulative Temporary Difference	Tax Rate	Annual ADIT	Cumulative ADIT Balance	Average Excess ADIT Rate (E)	Annual Excess ADIT Amortization under ARAM	Exess ADIT Cumulative Balance under ARAM
1	2016	$ 1,000,000	20 00%	$ 200,000	$ 100,000	$ 100,000	$ 100,000	35.00%	$ 35,000	$ 35,000			
2	2017		32.00%	320,000	100,000	220,000	320,000	35.00%	77,000	112,000			
2a.	**Remeasurement under TCJA at December 31, 2017 (D)**						**320,000**	**21.00%**		**67,200**			**44,800**
3	2018		19.20%	192,000	100,000	92,000	412,000	21.00%	19,320	86,520		-	44,800
4	2019		11.52%	115,200	100,000	15,200	427,200	21 00%	3,192	89,712		-	44,800
5	2020		11.52%	115,200	100,000	15,200	442,400	21.00%	3,192	92,904		-	44,800
6	2021		5.76%	57,600	100,000	(42,400)	400,000	21 00%	(8,904)	84,000	10 1266%	(4,294)	40,506
7	2022			-	100,000	(100,000)	300,000	21 00%	(21,000)	63,000	10 1266%	(10,127)	30,380
8	2023			-	100,000	(100,000)	200,000	21.00%	(21,000)	42,000	10 1266%	(10,127)	20,253
9	2024			-	100,000	(100,000)	100,000	21.00%	(21,000)	21,000	10.1266%	(10,127)	10,127
10	2025			-	100,000	(100,000)	-	21 00%	(21,000)	-	10 1266%	(10,127)	-
	Total			$ 1,000,000	$ 1,000,000	$ -			$ 44,800	$ -		$ (44,800)	

NOTES:

(A) $1,000,000 fixed asset placed in service on January 1, 2016

(B) Tax Depreciation using MACRS, five-year life, half-year convention

(C) Book Depreciation using straight-line method, 10-year life, no half-year convention

(D) At the end of 2017, when the tax rate changes, the ADIT is remeasured at 21%. The remeasurement reclassifies a portion of the ADIT as Excess ADIT (line 2a) The remeasured ADIT reverses normally (i e the book-tax difference times the current statutory rate) while the Excess ADIT reverses following ARAM.

(E) Average Rate (Column k) computed when the book-tax difference reverses (Column e-Year 2021). Computation is based on dividing the Excess ADIT balance at the time of reversal ($44,800 in Column l) by the cumulative book-tax differences at the beginning of the year ($442,400 - the total originating differences in Column f).

DOCKET NO. ________

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

AFFIDAVIT OF MARK L. LAVALLE, CPA, PARTNER KPMG LLP

Before me, the undersigned authority, personally appeared Mark L. LaValle, CPA (licensed in Texas), Partner KPMG LLP, who, being by me duly sworn, stated under oath as follows:

1. My name is Mark L. LaValle, CPA. I am of sound mind and capable of making this affidavit. The facts stated herein are correct and based on my personal knowledge.

2. I am an audit partner of KPMG LLP ("KPMG").

3. KPMG was engaged by El Paso Electric Company ("EPE") to conduct the audits of EPE's financial statements for the calendar years ending December 31, 2020, and December 31, 2019 which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of operations, comprehensive operations, changes in common stock equity, and cash flows for the years then ended, and the related notes to the financial statements ("GAAP Financial Statements"). I was the audit partner for these audits.

4. Our Independent Auditors' Report on the GAAP Financial Statements (the "GAAP Report") explained that our responsibility was to express an opinion on the GAAP Financial Statements based on our audits; that we conducted our audits in accordance with auditing standards generally accepted in the United States of America; and that those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

5. Further, our GAAP Report explained that an audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements; that the procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error; and that in making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we expressed no such opinion.

6. Our GAAP Report explained further that an audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. Our GAAP Report stated that we believe, and

we do believe, that the audit evidence we obtained is sufficient and appropriate to provide a basis for our audit opinion.

7. As stated in the GAAP Report, it is our opinion that the GAAP Financial Statements of EPE present fairly, in all material respects, the financial position of EPE as of December 31, 2020 and 2019, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

8. KPMG has not performed any audit procedures over EPE subsequent to March 30, 2021. However, I am not aware of any facts that would cause KPMG to change the opinion that it issued in the GAAP Report on March 30, 2021.

9. KPMG was also engaged by EPE to audit its Federal Energy Regulatory Commission Form No. 1 for the year ended December 31, 2020, which comprise the comparative balance sheet as of December 31, 2020 and 2019, and the related statements of income, retained earnings, and cash flows for the years then ended, included on pages 110 through 123 of the Federal Energy Regulatory Commission Form No. 1, and the related notes to the financial statements ("FERC Financial Statements"). I was the audit partner for these audits.

10. Our Independent Auditors' Report on the FERC Financial Statements (the "FERC Report") explained that our responsibility was to express an opinion on the FERC Financial Statements based on our audits; that we conducted our audits in accordance with auditing standards generally accepted in the United States of America; and that those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

11. The FERC Report also explained that an audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements, that the procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error; and that in making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we expressed no such opinion.

12. Moreover, our FERC Report explained that an audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. Our FERC Report stated that we believe, and we do believe, that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

13. Note 1 of the FERC Financial Statements describes the basis of accounting for those statements. As described in Note 1 to the FERC Financial Statements, the FERC

Financial Statements are prepared by EPE in conformity with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than U.S. generally accepted accounting principles, to meet the requirements of the Federal Energy Regulatory Commission. Our opinion was not modified with respect to this matter.

14. As stated in the FERC Report, it is our opinion that the FERC Financial Statements of EPE present fairly, in all material respects, the financial position of EPE as of December 31, 2020 and 2019, and the result of its operations and cash flows for the years then ended in accordance with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

15. KPMG has not performed any audit procedures over EPE subsequent to March 30, 2021. However, I am not aware of any facts that would cause KPMG to change the opinion that it issued in the FERC Report on March 30, 2021

Affiant states nothing further.

Mark L. LaValle

SWORN TO AND SUBSCRIBED before me on this 17th day of May 2021.

Notary Public, State of Texas

NOTARY PUBLIC STATE OF TEXAS
SCOTT SHIPLEY
Notary ID #128976394
My Commission Expires
May 19, 2024

DOCKET NO. ______

APPLICATION OF EL PASO	§	PUBLIC UTILITY COMMISSION
ELECTRIC COMPANY TO CHANGE	§	OF TEXAS
RATES	§	

DIRECT TESTIMONY

OF

LISA D. BUDTKE

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Lisa D. Budtke is Director of Treasury Services and Investor Relations for El Paso Electric Company ("EPE" or "Company"). Her responsibilities include treasury, financial systems, budgeting, financial forecasting, and investor relations functions of EPE.

Mrs. Budtke discusses EPE's capital expansion plan, capital structure, cost of capital, financing plans, and the need to maintain EPE's credit ratings. Mrs. Budtke also presents the test period adjustments for revolving credit facility commitment fees and Board of Directors compensation.

TABLE OF CONTENTS

EXHIBIT

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa D. Budtke. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company") in the position of Director of Treasury Services and Investor Relations.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I hold a Bachelor of Accountancy from New Mexico State University and a Master of Business Administration from the University of Phoenix. I was hired by EPE as Assistant Treasurer in April 2010. After the Vice President, Treasurer position was eliminated in September 2014, I assumed full responsibility for the Treasury Department. In December 2015, my title was changed to Director of Treasury Services and Investor Relations.

Prior to my employment with the Company, I worked for Petro Stopping Centers, L.P. and an affiliated company in various financial and leadership capacities. My last position at Petro Stopping Centers, L.P. was Treasurer, Assistant Secretary, and Director of Finance, where I oversaw the areas of credit, accounts payable, audit services, treasury, tax, fixed assets, and financial planning. I also worked for several other local companies in El Paso, including Columbia Healthcare and Verde Realty.

Q. WHAT ARE YOUR PRINCIPAL RESPONSIBILITIES WITH EPE?

A. I have executive responsibility for the treasury, financial systems, budgeting, financial forecasting, and investor relations functions at EPE. I also have oversight of trust investments and administration.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY REGULATORY AGENCY?

A. Yes. I have filed testimony before the Public Utility Commission of Texas ("Commission") and the New Mexico Public Regulation Commission ("NMPRC"). I have also testified before the NMPRC.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Direct Testimony is to present and address the capital needed for EPE to fund its anticipated construction program. In addition, I discuss the capital required to satisfy the Company's obligation to serve while meeting the increasing demands placed on the system by the continued growth in EPE's service territory. I address the requested capital structure, cost of debt, and the weighted average cost of capital, which reflects the Company's requested return on equity ("ROE"). EPE's expert witness, Jennifer E. Nelson, supports the requested ROE. I also discuss the Company's credit ratings and the need to maintain investment grade credit ratings to prevent EPE and its customers from having to pay increased borrowing costs. Further, my testimony discusses the need to include the Company's revolving credit facility ("RCF") commitment fees in EPE's revenue requirements and the reasonableness of Board of Directors fees.

Q. WHAT SCHEDULES DO YOU SPONSOR?

A. The schedules I sponsor and co-sponsor are listed in Exhibit LDB-1.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. Capital Requirements and Financing Plan

Q. IS EPE PLANNING TO MAKE SIGNIFICANT CAPITAL EXPENDITURES IN THE NEXT FIVE YEARS?

A. Yes, as Table LDB-1 below shows, EPE is currently projecting to spend approximately \$1.6 billion over the next five years. As can be seen in Table LDB-1, cash construction expenditures are anticipated to be in excess of \$300 million each year through year 2025.

Table LDB-1

Cash Capital Expenditures ($ in millions) Calendar Year Basis				
Forecasted Expenditures				
2021	2022	2023	2024	2025
$340	$354	$312	$309	$322

(The amounts shown in this table do not include AFUDC)

The anticipated cash capital expenditures for years 2021 through 2025 include approximately $113 million for the construction of a 228-megawatt(s) ("MW") combustion turbine generating unit at the Company's Newman Power Station with an anticipated operational date of 2023. The Company is currently undergoing an analysis of future generating requirements and has included the initial estimates for 370 MW of future generation additions totaling approximately $111 million over this period of time. EPE's peak load continues to grow as does the need for additional generating resources. In July 2020, EPE set a new record peak of 2,173 MW, which was 9.5% higher than the previous peak established in 2019. In addition, EPE expects to make significant capital investments in transmission and distribution plant to upgrade and replace aging equipment, expand its system to meet customer growth, and for additional infrastructure to add and improve customer service options through advanced metering. Palo Verde Generating Station ("PVGS") also requires capital investments to sustain its operations. These investments will help EPE meet its obligation to serve, which includes satisfying growing customer demand and replacing old, less efficient generating assets with more efficient, cleaner generation, among other things.

Q. ARE THE PROJECTED CAPITAL EXPENDITURES FOR THE YEARS 2021 THROUGH 2025 MORE THAN WHAT WAS INCLUDED IN EPE'S FIVE-YEAR CAPITAL EXPENDITURE REGULATORY COMMITMENT IN THE APPROVAL OF ITS PURCHASE BY SUN JUPITER HOLDINGS LLC IN DOCKET NO. 49849?

A. Yes, EPE's projected capital expenditures for the years 2021 through 2025 are more than the amounts included in EPE's minimum capital expenditure regulatory commitment for the five-year period beginning January 1, 2021 in Docket No. 49849[1].

Q. WHAT IS THE MINIMAL CAPITAL EXPENDITURE REGULATORY COMMITMENT YOU ARE REFERENCING AND IS EPE IN COMPLIANCE?

A. EPE committed to make minimum capital expenditures in an amount equal to EPE's preceding five-year budget (as reported in EPE's 2018 SEC Form 10-K) for the five-year period beginning January 1, 2021, subject to specified adjustments. Because this commitment begins January 1, 2021, it is not yet time to evaluate this commitment. Currently, EPE expects to meet and to exceed its capital commitment. Our current five-year budget (2021 Budget) exceeds the commitment by approximately 14%, subject to revision.

Q. WHAT ARE THE EXPECTED SOURCES OF CAPITAL FOR EPE TO MEET ITS CONSTRUCTION NEEDS OVER THE NEXT SEVERAL YEARS?

A. EPE uses its RCF as a bridge loan to finance utility operations and ongoing utility construction projects necessary to provide service to its customers. From time to time, such short-term debt is repaid through the issuance of long-term debt in order to maintain appropriate levels of liquidity and the Company's long-term capital structure.

The Company's sources of permanent capital include long-term debt issuances in the capital markets and equity infusions from EPE's parent, Sun Jupiter Holdings LLC ("Sun Jupiter" or "Parent"),[2] to finance its construction requirements. The Company's exact percentage mix of equity and long-term debt may periodically vary in the short run due primarily to the timing of long-term debt issuances and equity infusions. All things being equal, equity ratios decrease as debt is issued or dividends are distributed. On the other hand, equity ratios increase as debt matures and is not refinanced or equity infusions are received.

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[1] *Joint Report and Application of El Paso Electric Company, Sun Jupiter Holdings LLC, and IIF US Holding 2 LP for Regulatory Approvals under PURA §§ 14.101, 39.262, and 39.915*, Docket No. 49849, Findings of Fact 58(e) (Jan. 28, 2020).

[2] Sun Jupiter Holdings LLC is an indirect, wholly owned subsidiary of IIF US Holding 2 LP ("IIF").

Q. DID EPE HAVE ANY SHORT-TERM BORROWINGS OUTSTANDING AT THE END OF THE TEST YEAR?

A. Yes. EPE maintains a RCF for working capital and general corporate purposes, and for bridge financing nuclear fuel through the Rio Grande Resources Trust II ("RGRT").

EPE had a total of $192.3 million of short-term borrowings outstanding at the end of the Test Year, December 31, 2020. Of this amount, $121.0 million was for working capital or general corporate purposes, including the financing of a portion of its $214.1 million year-end construction work in progress balance. In addition, EPE had $71.3 million of outstanding borrowings made by the RGRT for nuclear fuel at the end of the Test Year. None of the assets funded by the RCF are in the Company's rate base request in this case because the RCF is used to fund fuel and construction work in progress.

Q. HAS EPE AMENDED ITS RCF SINCE THE 2017 RATE CASE?

A. Yes. On September 13, 2018, EPE amended and restated its RCF to include the availability of $350 million and an initial term of September 13, 2023. In late March 2020, the Company exercised (i) its option to increase the size of its $350 million RCF by $50 million to a total of $400 million and (ii) its option to extend the maturity date by one year to September 13, 2024. EPE has an additional option to extend the facility by one additional year to September 2025, subject to approval by the lenders and upon the satisfaction of certain conditions.

Q. DOES THE COST OF LONG-TERM DEBT IN THIS RATE FILING INCLUDE RIO GRANDE RESOURCES TRUST DEBT?

A. No. EPE has excluded the financial obligations of the RGRT from the debt component of the capital structure. As discussed later in my testimony, nuclear fuel is financed through the RGRT and is not included in rate base and the costs of that fuel, including the financing costs, are recovered separately through EPE's fixed fuel factor.

Q. HAVE THERE BEEN ANY REFINANCINGS OR ISSUANCES OF LONG-TERM DEBT SINCE THE 2017 BASE RATE CASE (DOCKET NO. 46831)?

A. Yes. There have been three long-term debt transactions:

- On June 28, 2018, the RGRT completed the sale of $65 million aggregate principal amount of 4.07% Senior Guaranteed Notes due August 15, 2025. Although the RGRT debt does not impact the Company's cost of debt in this case, the Company does guarantee the payment of principal and interest on the RGRT Senior Guaranteed Notes;

- On June 28, 2018, EPE issued $125 million of 4.22% Senior Notes due August 15, 2028; and
- On May 22, 2019, EPE refinanced $63.5 million of 2009 Series A and $37.1 million of 2009 Series B 7.25% Maricopa County, Arizona Pollution Control Bonds ("PCBs") with a new interest rate of 3.60%. The 2009 Series A and the 2009 Series B PCBs mature on February 1, 2040 and April 1, 2040, respectively. The 2009 Series A and the 2009 Series B PCBs are subject to optional redemption at a redemption price of par on or after June 1, 2029.

Q. HAS ANY OF THE RGRT'S OR EPE'S LONG-TERM DEBT MATURED SINCE THE 2017 BASE RATE CASE?

A. Yes. On August 15, 2020, the RGRT's $45.0 million Series C 5.04% Senior Guaranteed Notes matured and were paid utilizing funds borrowed under the RCF. Although the notes were paid utilizing funds from the RCF, the RGRT debt and all RCF borrowings are excluded from the Company's cost of debt as described in more detail later in my testimony.

Q. HAS EPE RECEIVED ANY EQUITY INFUSIONS FROM ITS PARENT SINCE BEING ACQUIRED BY SUN JUPITER?

A. Yes. EPE received equity infusions from Sun Jupiter of $125 million and $105 million on September 24, 2020, and on March 26, 2021, respectively.

Q. DOES EPE HAVE A PLAN FOR FUTURE DEBT ISSUANCES OR EQUITY INFUSIONS?

A. Yes. EPE has several financings on the horizon to fund its obligation to serve:

- The Company anticipates guaranteeing the issuance of up to $45 million of debt by the RGRT in the second half of 2021. As previously mentioned, the RGRT's $45 million Series C 5.04% Senior Guaranteed Notes matured in August 2020 and were paid with borrowings from the Company's RCF. This new debt will be used to repay the RCF borrowings outstanding for nuclear fuel. Since the RGRT debt is excluded from rate base, it will not impact the Company's cost of debt in base rates.

- EPE's $59.2 million 4.50% 2012 Maricopa Series A PCBs, due 2042, are redeemable at par (i.e., stated or face value) in August 2022. EPE is not required to take action on these PCBs. However, depending on market conditions, EPE may seek to refinance the PCBs.
- The Company may also seek to replace the $150 million 3.30% Senior Notes, which mature in December 2022.
- EPE plans to continue to balance its capital structure and maintain its investment grade credit ratings through equity contributions when needed.

The need for additional future debt issuances and equity infusions is dependent upon a variety of factors; therefore, additional transactions not listed here may be necessary.

IV. Requested Capital Structure and Cost of Capital

Q. WHAT WAS THE COMPANY'S CAPITAL STRUCTURE AS OF DECEMBER 31, 2020, THE END OF THE TEST YEAR?

A. As of the December 31, 2020, Test Year, the Company's capital structure was comprised of 52.5% equity and 47.5% long-term debt. The Company has excluded the financial obligations of the RGRT from the debt component of the capital structure because nuclear fuel financed by the RGRT is excluded from rate base. The RGRT's only purpose is to finance nuclear fuel with 100% debt. Financing nuclear fuel with 100% debt rather than including nuclear fuel in rate base, which is effectively financed at the weighted average cost of capital, reduces costs to customers. The cost of nuclear fuel, along with the RGRT financing costs, is recovered through EPE's fuel factor.

Q. IS THE COMPANY REQUESTING A DIFFERENT CAPITAL STRUCTURE THAN ITS ACTUAL CAPITAL STRUCTURE AS OF DECEMBER 31, 2020, THE END OF THE TEST YEAR?

A. Yes, as noted above, the Company's actual capital structure at the end of the Test Year was 52.5% equity and 47.5% long-term debt. The Company is requesting a capital structure that is comprised of 51% equity and 49% long-term debt.

Q. WHY IS THE COMPANY REQUESTING A DIFFERENT CAPITAL STRUCTURE IN THIS CASE?

A. The Company is requesting a capital structure in this proceeding that is more reflective of its projected capital structure over the next few years. The Company is requesting an equity ratio that is lower than the amount of equity contained within its actual capital structure as of the Test Year end, but that is still credit supportive. The requested equity layer in this case will be more reflective of the resulting impacts of anticipated future debt issuances and dividend distributions to and equity infusions from Sun Jupiter. The Company expects to maintain a minimum 51% equity capitalization in the future as this is (i) the minimum level that will be required to maintain investment grade credit ratings and (ii) less than the 53.56% average equity ratio maintained by its peer group utilities, as explained in EPE expert witness Nelson's Direct Testimony. As a result, the requested capital structure is reasonable and results in lower costs to customers.

Q. DOES EPE REGULARLY REVIEW ITS COST OF DEBT?

A. Yes, EPE continues to review its debt and the capital markets to make sure costs are reduced when possible.

Q. WHAT IS THE COST OF LONG-TERM DEBT INCLUDED IN THIS RATE FILING?

A. The cost of long-term debt shown on Schedule K-3 as of the end of the Test Year was 5.576%. This reflects EPE's actual outstanding long-term debt as of December 31, 2020. The weighted cost of debt reflects the average yield to maturity for EPE's long-term debt required by the Commission's rate filing package. The resulting cost of long-term debt is less than the 5.922% cost of debt approved in the Company's 2017 Texas base rate case.

Q. HOW DO CUSTOMERS BENEFIT FROM THIS REDUCTION IN THE COST OF DEBT?

A. The reduction in EPE's cost of debt decreased the required return requested in this case by approximately $4.4 million on a total Company basis.

Q. WHY DID EPE'S COST OF LONG-TERM DEBT DECREASE SINCE THE COMPANY'S 2017 TEXAS BASE RATE CASE?

A. EPE has been able to lower its cost of long-term debt since the 2017 Texas base rate case due to several debt issuances that were accomplished at lower than historical costs. One of the primary issuances was for the refinancing of the Company's 2009 Series A and B PCBs. EPE refinanced the 2009 Series A and B notes when they became callable at par as mentioned earlier in my testimony. The refinancing dropped the interest rate on the $100.6 million of Series A and Series B PCBs from 7.25% to 3.60%, resulting in an annual interest savings of approximately $3.7 million.

Q. WHY ARE BORROWINGS UNDER THE RCF EXCLUDED FROM THE COST OF DEBT?

A. The RCF is excluded from the cost of debt because it is used to fund EPE's (1) nuclear fuel financing obligations in the most cost-effective and efficient manner and (2) construction work in progress, both of which are excluded from rate base.

Q. WHAT IS THE COST OF EQUITY INCLUDED IN THIS BASE RATE FILING?

A. As supported in the Direct Testimony of EPE's expert witness Nelson, the Company is requesting a 10.3% return on equity in this filing.

Q. WHAT IS THE COST OF CAPITAL (REQUESTED RATE OF RETURN) INCLUDED IN THIS BASE RATE FILING?

A. The Company's cost of capital (requested rate of return) is 7.985%. The calculation used to obtain the cost of capital is contained in Schedule K-1 and reflects the 10.3% return on equity recommended by EPE expert witness Nelson and the requested capital structure of 51% equity and 49% long-term debt.

Q. ARE THE COMPANY'S REQUESTED CAPITAL STRUCTURE AND COST OF CAPITAL REASONABLE?

A. Yes. The requested capital structure will allow the Company to attract debt investors at reasonable costs and provide a reasonable return to its equity investor. In addition, the requested capital structure will allow the Company to obtain capital required to satisfy its obligation to serve and to fund its construction program at a reasonable price. This will also help support the Company's financial credit metrics, which will allow the Company to maintain its investment-grade credit ratings. The overall cost of capital, which includes both the cost of equity and the weighted cost of debt, is reasonable. EPE expert witness Nelson provides additional support for the reasonableness of EPE's capital structure and the cost of equity.

V. Rating Agencies and the Importance of Credit Ratings

Q. WHAT IS THE SIGNIFICANCE OF CREDIT RATINGS?

A. Credit ratings are a measure of the creditworthiness of the Company's debt. The Company's creditworthiness, as reflected in its credit ratings, will directly affect the Company's ability to attract capital and the resulting cost of that capital. Financial institutions and fixed-income and equity investors evaluate and utilize the Company's credit ratings to determine its access to capital and the acceptable rate of return on its invested capital. The lower the credit rating, the higher the associated cost of debt. Customers ultimately bear the costs of higher priced debt. Rating agencies, in the assignment of their credit ratings to the Company, evaluate the Company's ability to pay the interest on borrowings outstanding and ultimately the principal of the borrowings when due.

Q. WHO RATES THE COMPANY'S DEBT?

A. The Company's outstanding debt is currently rated by Moody's Investors Services, Inc. ("Moody's") and Fitch Ratings, Inc. ("Fitch") (together, the "credit rating agencies"). The determination of the assigned credit rating of the Company by the credit rating agencies is premised on several metrics that include, among other things, the evaluation of the amount of leverage the Company has and its cash flow metrics.

Q. WHAT ARE EPE'S CURRENT CREDIT RATINGS?

A. The credit ratings of EPE are outlined in Table LDB-2:

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Table LDB-2

	Moody's[3]	Fitch[4]
Credit Rating	Baa2	BBB
Outlook	Stable	Stable

Because these current credit ratings are investment grade, they allow the Company to access the capital markets at reasonable rates. However, the ratings are near the bottom of the range of investment grade credit ratings as shown in Table LDB-3:

Table LDB-3

	Moody's[5]	Fitch[6]
Investment Grade	Aaa	AAA
	Aa1	AA+
	Aa2	AA
	Aa3	AA-
	A1	A+
	A2	A
	A3	A-
	Baa1	BBB+
	Baa2	BBB
	Baa3	BBB-
Non-Investment Grade	Ba1	BB+
	Ba2	BB
	Ba3	BB-
	Caa1	CCC+
	Caa2	CCC
	Caa3	CCC-

Maintaining investment grade credit ratings is important because many institutional investors are not permitted to purchase non-investment grade securities (less than Baa3 for Moody's and BBB- for Fitch). Institutional investors include banks, insurance companies, pension funds, endowments, and mutual funds that invest money on behalf of individuals or other institutions. These investors are critically important to the market and to the

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[3] Moody's Investors Service, *Credit Opinion: El Paso Electric Company, Update to credit analysis,* September 21, 2020 at 1.
[4] Fitch Ratings, *Rating Report: El Paso Electric Company*, July 6, 2020 at 1.
[5] Moody's, https://www.moodys.com/ratings-process/Ratings-Definitions/002002 (last visited May 4, 2021).
[6] Fitch Ratings, https://www.fitchratings.com/criteria/corporate-finance (last visited May 4, 2021).

Company. Institutional investors own substantially all of EPE's outstanding bonds, and it is critical for EPE and its customers that institutional investors be allowed to own its debt instruments in order to maximize access to capital at reasonable rates. In times of capital restrictions, companies with less than investment grade ratings may not have access to capital at any cost.

Q. WHAT FACTORS DO THE CREDIT RATING AGENCIES CONSIDER IN ORDER TO ESTABLISH CREDIT RATINGS?

A. The rating agencies base credit ratings upon a number of factors. One of the primary factors is their assessment of a company's ability to pay interest and principal on its outstanding debt when they are due. The credit rating agencies' analyses include the amount of debt in a company's capital structure; specific credit metrics, or coverage ratios, that indicate the ability of a company to pay interest and principal on outstanding debt when they are due; and a company's liquidity (i.e., the ability to obtain cash when needed). In establishing the credit ratings of a regulated utility, credit rating agencies also consider the regulatory structure in which a company operates and whether regulatory commissions authorize rates that support a utility's credit ratings.

In conducting their analyses, the credit rating agencies make various adjustments to the debt component of a company's balance sheet, resulting in changes in the percentage of debt and equity in the capital structure for credit rating purposes. As discussed earlier, EPE finances its nuclear fuel through the RGRT. The debt of the RGRT does not appear in EPE's capital structure used to finance rate base because it is recovered through fuel clauses in both New Mexico and Texas for regulatory purposes. However, for purposes of evaluating credit quality, the credit rating agencies consider the RGRT debt as EPE debt as it is guaranteed by EPE. Additionally, the rating agencies will also include all outstanding short-term borrowings on the RCF in their calculation of the Company's total debt even though those borrowings are excluded from the Company's regulatory capital structure. As a result, it is important that EPE maintain adequate equity in its capital structure and adequate coverage ratios to support investment grade credit ratings.

Q. HAVE THE CREDIT RATING AGENCIES ISSUED RECENT REPORTS

IDENTIFYING POTENTIAL NEGATIVE IMPACTS TO THE COMPANY'S CASH FLOWS?

A. Yes, in a recent report on EPE's credit ratings, Moody's identified the 2017 Tax Cut and Jobs Act ("TCJA") as putting negative pressure on the Company's cash flows and credit ratings. More specifically, on July 1, 2019, Moody's issued a press release stating the Company was placed on review for downgrade prompted by a projected weakening in the Company's financial metrics and credit profile due to debt-funded capital expenditures, negative cash flow effects from tax reform, along with the uncertainty of the credit implications of the acquisition of EPE by IIF.[7] Then on September 17, 2019, Moody's downgraded the Company to Baa2 with a stable outlook from Baa1 with a rating under review. The downgrade by Moody's was due to a combination of high, partly debt-funded capital expenditures and cash flow pressure from tax reform. The downgrade also considered the then-pending acquisition of the Company, which supported the stable rating outlook due to the transaction being funded primarily with equity.[8]

Q. HOW HAS THE TCJA NEGATIVELY IMPACTED CASH FLOWS AND CREDIT RATINGS?

A. Among the tax changes discussed by Company witness Cynthia S. Prieto, the TCJA amended Section 168(k) of the Internal Revenue Code to eliminate the availability of bonus depreciation for costs incurred on public utility property after December 31, 2017. This has lowered the amount of accelerated depreciation that EPE can deduct on its income tax return each year. Prior to the TCJA's enactment, EPE recovered the deferred income taxes for the additional depreciation deducted on its tax return in excess of book depreciation from customers and used the cash flow for capital construction expenditures and working capital. Without the availability of bonus depreciation, the Company will no longer have the associated amount of Accumulated Deferred Income Taxes ("ADIT") as a source of cost-free capital. A secondary impact of this change is that, without the deduction for bonus depreciation, EPE will have more current taxable income than it had before the TCJA. As

[7] Moody's Investors Service, *Rating Action: Moody's places El Paso Electric on review for downgrade,* Jul. 1, 2019 at 1.

[8] Moody's Investors Service, *Rating Action: Moody's downgrades El Paso Electric to Baa2, outlook stable,* Sep. 17, 2019 at 2.

a result, while overall tax expense paid by customers has decreased, EPE will pay more current (i.e., cash) taxes to the federal government. EPE utilized its net operating loss carryforwards ("NOL carryforwards") in its 2018 and 2019 tax returns to reduce cash tax payments. However, the reduction in tax deductions caused by the discontinuation of bonus depreciation resulted in the utilization of EPE's NOL carryforwards approximately one year earlier than previously anticipated. This early use of the NOL carryforwards resulted in higher income tax payments beginning in 2020, the tax years starting after the Company fully utilized its NOL and tax credit carryforwards.

Q. IS THERE ANOTHER IMPACT OF THE TCJA ON CASH FLOWS IN THE FUTURE?

A. Yes. When EPE was able to take advantage of bonus depreciation and other accelerated tax deductions in the past, it deferred income taxes at the 35% corporate income tax rate in effect at the time they were deferred. However, EPE will now pay these taxes in the future at the 21% income tax rate rather than at the prior 35% income tax rate. Under GAAP, EPE reduced its balance of ADIT to reflect the new 21% corporate income tax rate and the amount of taxes that will be paid in the future. This reduction in ADIT is often referred to as "excess" deferred income taxes. As required by the Commission's Final Order in Docket No. 46831, EPE recorded a regulatory liability for excess deferred income taxes at December 31, 2017, and is now, in its rate case subsequent to 2017, seeking to determine the amortization of that regulatory liability. Since EPE collected deferred income taxes from customers, it will seek to refund the regulatory liability for excess deferred income taxes collected from customers over an appropriate period of time. EPE witness Prieto discusses the refund of excess deferred income taxes in her testimony. While customers will see a significant benefit from the refund of the regulatory liability, the refund, in connection with the loss of bonus depreciation, will result in a reduction in cash flows for the Company.

Q. HAVE THE CREDIT RATING AGENCIES IDENTIFIED OTHER FACTORS THAT MAY NEGATIVELY IMPACT THE COMPANY'S CREDIT RATINGS?

A. Yes, the latest credit opinions on EPE issued by the rating agencies contain factors that may result in credit rating downgrades. In the Moody's credit opinion published on

September 21, 2020, Moody's indicated that if EPE's cash coverage ratio (Cash Flow Operations pre-working capital/Debt) declines below 15% on a sustained basis and if a contentious political or regulatory environment emerges in Texas or New Mexico, it could result in a downgrade in credit ratings.[9] Additionally, in the credit opinion issued by Fitch on July 6, 2020, Fitch similarly concluded that if EPE was subjected to materially unfavorable regulatory developments or if its coverage ratio (Funds from Operations leverage) exceeded 5.3x on a sustained basis, it could result in a downgrade in credit ratings.[10]

Q. HOW WILL THE ACQUISITION OF THE COMPANY IMPACT EPE'S CASH FLOWS?

A. The acquisition by Sun Jupiter will have a positive impact on EPE's cash flows from financing activities. As indicated above, rather than seeking equity in the capital markets, Sun Jupiter has and will continue to provide EPE with needed equity, which provides the Company more security in executing its business plan for the benefit of its customers. The acquisition allows EPE to obtain equity capital from its long-term financial partner when needed and without the significant cost or risks of raising equity in the public markets.

Q. WILL EQUITY INFUSIONS HELP SUPPORT THE COMPANY'S CREDIT RATINGS?

A. Yes. As a result of the transaction, EPE will seek additional capital in the form of equity infusions from Sun Jupiter as needed, which can be accessed more efficiently and economically with less risk. EPE received equity infusions from Sun Jupiter in September 2020 and March 2021 of $125 million and $105 million, respectively, and anticipates additional contributions in the future. In this case, the Company is requesting a capital structure with 49% long-term debt and 51% equity, which is lower than the Test Year-End and peer average equity ratios. This requested equity ratio is necessary to help maintain the Company's current investment-grade credit metrics. The Company's equity ratio is anticipated to be maintained through the Company's long-term debt issuances, and dividend distributions to and equity contributions from Sun Jupiter. Approval of the

[9] *Supra* note 3 at p.2.
[10] *Supra* note 4 at p.4.

Company's requested capital structure and return on common stock equity, in addition to adequate rate relief for the balance of EPE's Cost of Service, should allow the Company to maintain investment grade credit ratings in light of the ongoing impacts of the TCJA on cash flow.

VI. Miscellaneous Issues

A. Nuclear Fuel Financing and RCF Commitment Fees

Q. HOW IS NUCLEAR FUEL FINANCED AND COLLECTED?

A. EPE finances its nuclear fuel through a trust arrangement, the RGRT, whereby the costs of nuclear fuel including all of the related costs of refining, processing, and fabrication into fuel rods and carrying costs are included in eligible fuel costs on a monthly basis as power is generated and nuclear fuel is consumed. Schedule C-6.10 describes the RGRT and includes a description of the costs that arise through the operation of the trust and an explanation of how these costs are paid to the trustee and recovered from ratepayers.

EPE repays its fuel trust obligations with monthly fuel revenues. As discussed above, because the costs of nuclear fuel are collected through EPE's fuel factor and thus not included in non-fuel base rates, the liability and the costs related to the nuclear fuel trust are excluded from the debt component of EPE's capital structure and the calculation of the cost of long-term debt. Utilizing the RGRT and borrowing the funds to finance nuclear fuel purchases by the RGRT is less expensive than including the fuel in EPE's rate base because nuclear fuel is financed with 100% debt.

Q. PLEASE BRIEFLY DESCRIBE THE RGRT AND HOW IT IS FINANCED?

A. The RGRT is a Texas grantor trust whose obligations are guaranteed by the Company. The RGRT utilizes a combination of short- and long-term debt to finance the Company's portion of nuclear fuel for PVGS. EPE maintains a $400 million RCF for working capital and general corporate purposes and the financing of nuclear fuel through the RGRT. Financing for the RGRT is provided through senior notes and the RCF. Financing for nuclear fuel by the RGRT was $136.3 million at December 31, 2020, of which $71.3 million was borrowed under the RCF and $65 million was borrowed through senior notes that the RGRT issued in a private placement transaction in 2018. The RGRT issued the senior notes in 2018 to recognize the long-term nature of the RGRT nuclear fuel investments, to provide more liquidity under the RCF, and to reduce interest rate volatility.

Interest costs on borrowings to finance nuclear fuel are accumulated by the RGRT and charged to EPE as fuel is consumed and are recovered from customers through the fixed fuel factor.

Q. WHAT ADMINISTRATIVE COST DOES EPE INCUR TO MAINTAIN THE ABILITY TO BORROW UNDER THE COMPANY'S RCF?

A. Under the terms of EPE's RCF, each lender has committed to lend EPE or the RGRT up to an allocated amount of the RCF's current $400 million capacity. As compensation for this commitment to make funds available, EPE pays a fee of 0.175% (17.5 basis points) on a quarterly basis for the unused amount of the commitment. This fee is an administrative cost to ensure the availability of funds when needed and is based upon the unused portion of the RCF.

Q. WHY IS IT REASONABLE AND NECESSARY FOR EPE TO MAINTAIN AN UNUSED PORTION OF ITS RCF?

A. The RCF's purpose is to ensure that the Company has cash available on a short-term basis to maintain liquidity as well as to meet short-term funding requirements and in the event of an unexpected contingency. If internally generated funds are fully utilized and EPE does not have timely access to the capital markets, the RCF provides a source of liquidity for EPE. The commitment fees are incurred to ensure that EPE has an available source of liquidity (the RCF), if required. The significance of this liquidity for the financial health of the Company is demonstrated by the fact that the RCF is a key component of the rating agencies' review of liquidity in establishing the Company's credit ratings.

Q. HOW DOES THE ABILITY TO HAVE AVAILABLE, BUT UNISSUED, SHORT-TERM DEBT BENEFIT CUSTOMERS?

A. First, having available, but unissued, short-term debt is a critical component of the rating agencies' review of EPE's credit ratings. Without the unissued debt under the RCF, EPE's credit ratings would likely be downgraded, possibly to below investment grade. Second, without the ability to issue short-term debt offered by the RCF, EPE would need much higher balances of cash available both for unanticipated cash expenditures and to manage the daily fluctuations in receipts and payments. The higher cash balances would need to be reflected in working capital paid by customers. Third, available, but unissued, short-term debt provides available cash in the event of unanticipated cash expenditures or the inability to access the capital markets or both.

Q. DOES EPE USE THE RCF TO MEET UNEXPECTED FLUCTUATIONS IN EXPENDITURES OR RECEIPT OF CASH?

A. Yes. Unexpected cash funding requirements can arise for a number of reasons, including increases in fuel expenses, capital expenditures, timing of bill payments, and timing of long-term debt issuances and equity infusions. In addition, absent the RCF, EPE has no guarantee that funds will be available in the capital markets. In past years, EPE has seen sudden and substantial increases in natural gas prices that could not be recovered from customers on a timely basis. This resulted in the need for short-term funds from the RCF for the interim financing of fuel costs.

Q. HAVE THERE BEEN PERIODS OF TIME WHEN FUNDS WERE NOT AVAILABLE IN THE CAPITAL MARKETS?

A. Yes. During the credit crisis of 2007-2008, EPE experienced a period during which it did not have access to the capital markets for long-term debt at a reasonable cost. The RCF played a key role in ensuring that EPE had cash available for operating and construction activities during this period. When access was available, it was at significantly higher costs. Additionally, as a precautionary measure in response to the COVID-19 pandemic and economic turmoil, on March 13, 2020, EPE borrowed $50 million under its RCF to increase the Company's cash position and maintain financial flexibility. EPE repaid this borrowing in September 2020.

Q. WHAT AMOUNT OF RCF COMMITMENT FEES IS EPE PROPOSING FOR THE TEST YEAR PERIOD?

A. EPE is requesting $571,211 of non-RGRT commitment fees paid to the lenders. RGRT's share of commitment fees has been excluded from the requested amount. The calculation of the commitment fees is shown below:

Table LDB-4

RCF Balance	$ 400,000,000
Highest level of borrowing for nuclear fuel during the Test Year	73,594,000
Balance available for working capital	$ 326,406,000
Commitment Fee	0.00175
RCF Commitment Fees (excluding RGRT)	$ 571,211

Q. IS THIS ADMINISTRATIVE EXPENSE NECESSARY AND REASONABLE, AND SHOULD IT BE INCLUDED IN THE ADJUSTED TEST YEAR COST OF SERVICE?

A. Yes, having the ability to borrow up to $400 million on the RCF provides EPE with flexibility in funding capital expenditures and nuclear fuel, in timing debt issuances and repayments, and ensuring adequate liquidity for working capital and general corporate purposes. The cost of ensuring this flexibility is lower than borrowing long-term debt to meet future needs, which benefits customers. RCF commitment fees are an ordinary and necessary cost of business to ensure liquidity in all economic circumstances. The RCF commitment fee cost is necessary and reasonable.

B. Board of Directors Fees

Q. IS THE COMPANY SEEKING RECOVERY OF DIRECTORS FEES?

A. Yes, director fees are included in the requested cost of service. As a result of the acquisition of EPE by Sun Jupiter on July 29, 2020, and since EPE is no longer a public company, its new Board of Directors has a different and lower level of compensation than that of the Company's previous Board of Directors when EPE was a publicly traded company. EPE's current Board of Directors is comprised of ten Directors, but only seven Directors are compensated for their service. Therefore, the Company is seeking a level of Director compensation that reflects the actual compensation the Company will now be paying to its current Board of Directors. Each Director's compensation amount is dependent upon the number of board committees on which they serve and their respective role. For example, the Chairman and Vice-Chairman of the Board will receive a slightly higher level of compensation than the other directors. The adjusted Board of Directors fees, which reflects the compensation that the new Board of Directors will receive, are necessary and reasonable. EPE witness Borden discusses adjustments to the director fees in her testimony.

VII. Conclusion

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY L. BUDTKE

Schedule	Description	Sponsorship
C-6.8	ALLOCATION OF UNASSIGNED BALANCE	Co-Sponsor
C-6.10	NUCLEAR FUEL TRUST/LEASE	Sponsor
K-1	WEIGHTED AVERAGE COST OF CAPITAL	Sponsor
K-2	WEIGHTED AVERAGE COST OF PREFERRED STOCK	Sponsor
K-3	WEIGHTED AVERAGE COST OF DEBT	Sponsor
K-4	NOTES PAYABLE	Sponsor
K-5	SECURITY ISSUANCE RESTRICTIONS	Sponsor
K-6	FINANCIAL RATIOS	Sponsor
K-7	CAPITAL REQUIREMENTS AND ACQUISITION PLAN	Sponsor
K-8	HISTORICAL GROWTH IN EARNINGS, DIVIDENDS, AND BOOK VALUE	Sponsor
K-9	RATING AGENCY REPORTS	Sponsor
L	FINANCIAL INFORMATION (RIVER AUTHORITIES) - N/A	Sponsor

DOCKET NO. ______

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

LARRY J. HANCOCK

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Larry J. Hancock is Manager-Plant Accounting for El Paso Electric Company ("EPE" or "the Company"). Mr. Hancock is responsible for the accounting of the physical assets of the Company, including power generation, transmission and distribution facilities and general and intangible plant. He is also responsible for all utility plant in service, construction work in progress, and the Company's nuclear decommissioning accounting, including accounting for the asset retirement obligations and helping determine the funding requirements for the Palo Verde Nuclear Decommissioning Trust.

Mr. Hancock presents EPE's plant in service and accumulated depreciation in rate base, together with related adjustments. He also supports the Company's proposed depreciation expense.

Mr. Hancock identifies those capital additions that have already been included in rate base and those for which EPE seeks rate base treatment in this case. Specifically, EPE seeks to include in rate base capital additions from October 1, 2016 through the December 31, 2020 Test Year end. These capital additions are listed on his Exhibit LJH-2.

Mr. Hancock also explains how EPE wrote down the book value of its investment in the Palo Verde Generating Station to reflect the fresh-start values from EPE's 1996 emergence from bankruptcy. Customers benefit from this adjustment, which was approved in EPE's rate case in Docket No. 37690.

Mr. Hancock then addresses the schedules he sponsors, which include C Schedules (cost of plant) and D Schedules (depreciation and accumulated depreciation). That discussion is followed by an explanation of specific plant in service adjustments, accumulated depreciation adjustments, and depreciation expense adjustments.

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EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Larry J. Hancock. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Manager-Plant Accounting.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I received my bachelor's degree in Accounting from the University of Texas at El Paso in 1982. That same year, I began my career with EPE in the accounting department as a staff accountant. In 1989, I transferred to the Plant Accounting department and was promoted to Supervisor of Plant Accounting. I was promoted to my current position as Manager-Plant Accounting in 2012.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EPE?

A. As Manager-Plant Accounting, I am responsible for the accounting of the physical assets of the Company, including power generation, transmission and distribution facilities and general and intangible plant. I am also responsible for all utility plant in service, construction work in progress, and the Company's nuclear decommissioning accounting, including accounting for the asset retirement obligations and helping to determine the funding requirements for the Palo Verde Nuclear Decommissioning Trust.

Q. WHAT TRAINING AND EXPERIENCE DO YOU HAVE WITH DEPRECIATION RATES?

A. As part of my college education, I learned the theory and practice of depreciation. As part of my job responsibilities in Plant Accounting, I run the depreciation expense calculation in PowerPlant, the Company's Asset Management System. This involves reviewing the results and ensuring that the amounts and rates for all the depreciable plant accounts are accurate. In addition, when the situation arises, I will develop depreciation and amortization rates for certain items of plant that are not included in the depreciation studies, such as software projects and new generation assets (wind and solar plant).

I have also been heavily involved in the preparation and approval of all the Company's depreciation studies dating back to 1992. These studies are the foundation of the Company's requested depreciation expense in all the Company's rate filings since 1993 in both the Texas and New Mexico jurisdictions. While the studies are prepared by external consultants (Stone & Webster and Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming")), I have been responsible for providing all the utility plant and accumulated depreciation data used in determining the specific depreciation rate by FERC plant (300) account. In addition, I am responsible for analyzing the study results to ensure that the rates are rational and in accordance with regulatory standards.

I have also attended numerous electric utility conferences sponsored by the Edison Electric Institute and others that included presentations and discussions related specifically to utility depreciation.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY UTILITY REGULATORY BODIES?

A. Yes, I have presented testimony before the Public Utility Commission of Texas ("PUCT" or "Commission") and the New Mexico Public Regulation Commission.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present EPE's plant in service and accumulated depreciation and amortization in rate base, together with related adjustments. I also support the Company's proposed depreciation expense including the development of depreciation rates for transportation equipment. Additionally, I support the reasonableness of the Company's requested general and intangible plant additions, and I support the Company's decommissioning funding calculation.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In the next section of my testimony (Section III), I discuss the capital additions for which EPE seeks rate base treatment in this case. For convenience, I identify all these additions in my Exhibit LJH-2. The scope of additions includes those added to plant in service from October 1, 2016, through December 31, 2020, the end of the Test Year. I focus on the General and Intangible Plant additions in this testimony.

In Section IV, I discuss separately the single largest adjustment to EPE's plant in service, which is the write down of the original cost of EPE's investment in the Palo Verde Generating Station ("PVGS" or "Palo Verde") to reflect EPE's emergence from bankruptcy in 1996. This treatment was approved in EPE's 2009 rate case in Docket No. 37690 and followed in Docket Nos. 40094, 44941 and 46831.

In Section V, I discuss in sequence the various schedules I sponsor or co-sponsor. Where helpful, I discuss in detail the subject matter of each schedule. In connection with my discussion of the D Schedules, I present EPE's depreciation proposal in this case.

In Sections VI, VII, and VIII, I discuss each of the plant in service, accumulated depreciation, and depreciation expense adjustments, respectively.

In Section IX, I discuss the Company's calculation of its requested decommissioning funding.

Q. WHAT RATE CASE SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. I sponsor or co-sponsor the schedules listed on Exhibit LJH-1.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. Capital Additions

Q. THROUGH WHAT PERIOD HAVE EPE'S CAPITAL ADDITIONS ALREADY BEEN INCLUDED IN RATE BASE?

A. All EPE's capital additions through September 30, 2016, have been included in rate base. In addition, EPE has carried forward its plant in service through December 31, 2020, the end of the Test Year in this proceeding.

Q. WHAT IS THE AMOUNT OF TOTAL COMPANY ADDITIONS TO RATE BASE FROM OCTOBER 1, 2016, THROUGH DECEMBER 31, 2020?

A. Total company plant additions from October 1, 2016, through December 31, 2020, the Test Year end, were $953,333,144 as shown on Exhibit LJH-2. These investments have not yet been explicitly included in rate base. However, all distribution capital additions from October 1, 2016 through June 30, 2020, were presented in the Company's 2019 and 2020 DCRF filings. Additionally, all transmission capital additions from October 1, 2016, through September 30, 2018, were presented in the Company's 2019 TCRF filing. EPE seeks to include the Texas jurisdictional portion of these plant additions in Texas jurisdictional rate base, as discussed by EPE witness Adrian Hernandez.

Q. WHAT DOES EXHIBIT LJH-2 REPRESENT?

A. Exhibit LJH-2 includes a summary of all of the plant additions I discussed in my previous answer by capital project. This exhibit reflects the capital EPE has invested and added to plant in service through the December 31, 2020 Test Year end that is used and useful in serving its customers. Exhibit LJH-2 also indicates the EPE witness who is sponsoring the information under each function and will be discussing the items in their testimony. EPE witnesses David C. Hawkins and Todd Horton sponsor the information about nuclear production plant additions; EPE witness J Kyle Olson sponsors the information about steam and other production plant additions; EPE witness R. Clay Doyle sponsors the information about transmission and distribution plant additions, and I sponsor the information about general and intangible plant additions. I discuss the general and intangible plant additions below.

Q. WHAT DOES THE CREDIT BALANCE REFLECTED ON EXHIBIT LJH-2 FOR PROJECT GE180 REPRESENT?

A. The credit balance of $12,843,892 on the Montana Common (GE180) Project resulted from a reallocation of costs to Montana Units 1 and 2. The reallocation resulted from "unitizing" all of the Montana units in 2019. Unitization involves the final classification of the cost of a project into the appropriate generating unit, FERC account and retirement unit. During the unitization process, certain costs that had originally been charged to Montana Common work orders were determined to be related to Montana Units 1 and 2. Therefore, these costs were transferred to the appropriate work orders.

Q. WHAT DO THE CREDIT BALANCES SHOWN ON EXHIBIT LJH-2 FOR PROJECTS TL234 AND TL139 REPRESENT?

A. The $1,766,104 credit for the TXDOT Collector Lane Rebuild (TL234) project resulted from a reimbursement received from the Texas Department of Transportation (TXDOT) in October 2017. The two credits totaling $3,055,012 related to the Fort Bliss Industrial Complex (TL139) were the result of a reimbursement of cost incurred to construct a transmission substation at Fort Bliss. Both projects were completed prior to October 1, 2016; however, the costs were adjusted out of requested rate base in EPE's last rate case, Docket No. 46831, pending receipt of the reimbursements from TXDOT and Fort Bliss.

Q. IS THE COMPANY SEEKING TO INCLUDE IN RATE BASE THE TOTAL CAPITAL INVESTMENT IN PROJECT GN162, NEWMAN UNIT 5 STEAM GENERATOR?

A. Yes. However, as noted in footnote (a) of my Exhibit LJH-2, the capital costs of this project were offset by insurance proceeds received by the Company in the amount of $18,146,155 that were credited to Accumulated Provision for Depreciation in accordance with FERC guidelines. Therefore, the net total capital addition for Project GN162 that EPE seeks to include in rate base is $3,484,352.

A. General Plant Capital Additions

Q. WHAT ARE THE CAPITAL ADDITIONS INCLUDED IN GENERAL PLANT?

A. The Company is requesting general plant rate base capital additions of $68,655,076 on a total Company basis for projects placed in service between October 1, 2016, and December 31, 2020, the end of the Test Year in this case. As included in the Table LJH-1 below, the costs consist of the following projects:

TABLE LJH-1	
MAJOR PROJECT	TOTAL COMPANY COST
Transportation Equipment/Fleet Acquisitions	$15,965,131
Shared Services Facility Services Improvements Blanket	4,956,118
IT Hardware Blankets	9,340,694
Physical Security Improvements (CIP-014)	3,898,501
System Operations Building Expansion	3,647,861
Distribution General Plant Acquisitions	3,571,551
Fabens Distribution Center	2,516,192
Other Projects (less than $2.5 million)	24,759,028
TOTAL	$68,655,076

Q. FOR EASE OF PRESENTATION, HAVE YOU DISTINGUISHED BETWEEN MAJOR CAPITAL PROJECTS AND OTHER PROJECTS?

A. Yes. Major capital projects are those costing $2.5 million or more, and minor capital projects are those costing less than $2.5 million. Minor capital projects are identified as "Other Projects" from this point forward in my testimony.

Q. WHAT ARE THE MAJOR CAPITAL ADDITIONS RELATED TO GENERAL PLANT?

A. Major capital projects related to general plant include: (1) Transportation Equipment/Fleet Acquisitions, (2) Shared Services Facility Services Improvements Blanket, (3) Information Technology ("IT") Hardware Blankets, (4) Physical Security Improvements (CIP-014), (5) System Operations Building Expansion, (6) Distribution\General Plant Acquisitions, (7) Fabens Distribution Center, and (8) Other Projects.

Q. DOES EPE HAVE PROCESSES AND PROCEDURES IN PLACE TO ENSURE THAT COSTS ASSOCIATED WITH GENERAL PLANT CAPITAL PROJECTS ARE REASONABLE?

A. Yes. The Company uses an established process to ensure that general plant additions are acquired in the most efficient and cost-effective manner. While the cost of general plant is important, ensuring that the acquisitions meet the Company's needs is equally, or more, important. The process starts with defining the requirements for each addition/acquisition. Once the requirements are developed, the Company routinely uses competitive bidding processes to identify the vendors that best meet the Company's requirements in the most cost-effective manner. The Company's general plant acquisition process seeks to meet the Company's needs at the lowest cost over the life of the plant.

Q. HOW DOES EPE ENSURE THAT CAPITAL RESOURCES ARE APPROPRIATELY BUDGETED?

A. The Company has procedures in place for budget approval. Projects over $500,000 go through a specific budget approval process and are reviewed by the Capital Planning Committee. IT Projects, excluding software, over $50,000 are reviewed by the Technology Planning Committee and, if approved, those projects over $500,000 receive further review by the Capital Planning Committee.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE TRANSPORTATION EQUIPMENT/FLEET ACQUISITIONS PROJECT?

A. The Transportation Equipment/Fleet Acquisitions project consists primarily of costs for vehicles and other transportation equipment such as trailers. These vehicles and equipment are utilized throughout the Company's service territory and directly support the Company's effort to provide safe, secure, and reliable electric service to its customers. Purchase of new vehicles and transportation equipment is performed in accordance with the Company's purchasing policies and procedures.

Q. WHAT IS THE MAKE-UP OF EPE'S TRANSPORTATION FLEET?

A. The Company's vehicle fleet is made up of transportation and vocational vehicles and trailers/trailered equipment. Transportation vehicles include sedans, pickup trucks, and SUVs used during the normal course of performing Company business to transport employees and material to and from job sites. Vocational vehicles include heavy-duty work trucks, bucket trucks, boom trucks, cranes, elevators, digger derricks, and other similar vehicles used in the normal course of Company business to transport employees, material, and equipment to and from job sites and to perform work at job sites in a safe and cost-effective manner. Trailers and trailered equipment include pull trailers and motorized equipment such as wire pulling and tensioning equipment, backyard machines, portable transformers, and construction equipment. All vehicles, trailers, and trailered equipment are used to perform the work needed to construct, operate, and maintain the Company's electrical facilities and associated infrastructure and to support the Company's effort to provide safe, secure, and reliable service to its customers. Transportation equipment is purchased under a blanket work order and closed (added) to plant in service as the equipment is placed in service.

Q. IN WHAT FERC ACCOUNT IS TRANSPORTATION EQUIPMENT INCLUDED?

A. Vehicles and trailers are included in FERC Account 392, Transportation Equipment, while trailered equipment is included in FERC Account 396, Power Operated Equipment.

Q. WHAT IS THE TOTAL COST OF THE TRANSPORTATION EQUIPMENT/FLEET ACQUISITIONS PROJECT?

A. The cost of the Transportation Equipment/Fleet Acquisitions project added to plant in service was approximately $16 million.

Q. WHAT IS A "BLANKET" PROJECT?

A. Blanket projects are primarily used for routine annual acquisitions that relate to general and intangible plant. For internal tracking and management purposes, the Company organizes projects from a specific functional area or for a specific Company location into a blanket project. For example, the Shared Services Facility Services Improvements Blanket allows EPE to track and manage all capital improvements that occur on a regular basis at its various facilities throughout its service territory.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE SHARED SERVICES FACILITY SERVICES IMPROVEMENTS BLANKET?

A. The Shared Services Facility Services Improvements Blanket is made up of capital improvement projects completed primarily in the Stanton Tower. The Stanton Tower serves as EPE's corporate headquarters. It is an 18-story building constructed in 1979 and purchased by EPE in February 2008. The facility houses corporate functions such as accounting, finance, budgeting, legal, compliance, risk management, billing, revenue collections, information technology, customer service, and other corporate level departments, all of which are critical to the Company's provision of electric service to its customers. Over the last several years, EPE has completed multiple projects within the facility to address aging infrastructure, safety and security enhancement, obsolescence, and space utilization. As part of the Shared Services Facility Services Improvements Blanket, the Company renovated multiple areas and replaced equipment throughout the building (e.g., cooling towers, the fire alarm system, and elevators). EPE also completed various smaller capital improvement projects. These projects included office and cubicle buildouts, equipment replacements (e.g., HVAC, electrical, lighting, plumbing, etc.), and furniture purchases for new offices, cubicles, and conference rooms.

Q. WHAT IS THE TOTAL COST OF THE SHARED SERVICES FACILITY SERVICES IMPROVEMENTS BLANKET?

A. The cost of the Shared Services Facility Services Improvements Blanket added to plant in service was approximately $4.95 million.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE IT HARDWARE BLANKETS?

A. The IT Hardware Blankets, including both the IT Corporate Hardware Blanket and IT Operations Hardware Blanket, consist primarily of the costs of hardware for infrastructure purchases necessary to support work performed during the normal course of business. Hardware costs include amounts for servers, routers, switches, network storage, cyber security, and corporate telephone systems. These costs also include other items such as replacement and purchase of new personal computers (desktops and laptops), departmental printers, peripherals, and monitors. All these items are critical to the Company's provision of electric service to its customers.

Q. WHAT ARE THE TOTAL COSTS OF THE IT HARDWARE BLANKETS?

A. The cost of the IT Hardware Blankets added to plant in service was approximately

$9.3 million.

Q. WHAT NEW CAPITAL ADDITIONS ARE INCLUDED IN THE PHYSICAL SECURITY IMPROVEMENTS (CIP-014) PROJECT?

A. The Physical Security Improvements (CIP-014) project consists of costs necessary to improve physical security at various critical infrastructure locations throughout EPE's service territory. On November 20, 2014, the FERC issued Reliability Standard Critical Infrastructure Protection (CIP) 014-1 in response to a FERC order issued on March 7, 2014. The purpose of the standard was to enhance physical security measures for the most critical Bulk Power System facilities to protect against physical attacks. In response, systems were installed to deter, detect, delay, assess, communicate and respond to threats and vulnerabilities. Those systems included:

- Ballistic-rated glass guard house and high-security gate operator controller at System Operations;
- Access control and intrusion detection systems at System Operations and Newman and Luna Substations;
- Line detection and security lighting at Newman and Luna Substations;
- Ground based radar at Newman and Luna Substations;
- Gunshot detection at Newman and Luna Substations;
- Video surveillance systems at System Operations and Newman and Luna Substations; and
- Prefabricated concrete walls at Newman and Luna Substations.

Q. WHAT IS THE TOTAL COST OF THE CIP PHYSICAL SECURITY IMPROVEMENTS PROJECT?

A. The cost of the Physical Security Improvements (CIP-014) project added to plant in service was approximately $3.9 million.

Q. WHAT NEW CAPITAL ADDITIONS ARE INCLUDED IN THE SYSTEM OPERATIONS BUILDING EXPANSION PROJECT?

A. The System Operations Building Expansion project consists of the expansion and renovation of an existing EPE facility. The System Operations facility was originally constructed in 1990 and was expanded in 2002 to accommodate the Distribution Dispatch function. Currently, the facility houses the Company's System Operations, System Planning, Energy Management System Support, and System Dispatch functions. The facility also serves as a remote reporting location for the North American Electric Reliability Council ("NERC") compliance personnel.

The facility was renovated to meet current life safety, fire code, and Americans with Disabilities Act requirements. The renovation effort also included updating the existing lighting and mechanical systems throughout the building.

Q. WHAT IS THE TOTAL COST OF THE SYSTEM OPERATIONS BUILDING EXPANSION PROJECT?

A. The cost of the System Operations Building Expansion project added to plant in service was approximately $3.6 million.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE DISTRIBUTION GENERAL PLANT ACQUISITIONS PROJECT?

A. This project includes a variety of costs, including but not limited to, costs for tools, testing equipment, communication equipment, office furniture and equipment, power operated equipment, meter testing equipment, hand-held radios, hands-free communication devices, and other miscellaneous general plant items, all of which are necessary for the Company to provide electric service to its customers.

Q. WHAT FERC ACCOUNTS ARE THESE COSTS INCLUDED IN?

A. The costs are primarily included in the following FERC accounts:

391 OFFICE FURNITURE AND EQUIPMENT
394 TOOLS, SHOP AND GARAGE EQUIPMENT
395 LABORATORY EQUIPMENT
396 POWER OPERATED EQUIPMENT
397 COMMUNICATION EQUIPMENT.

Q. WHAT IS THE TOTAL COST OF THE DISTRIBUTION GENERAL PLANT ACQUISITIONS PROJECT?

A. The cost of the Distribution General Plant Acquisitions Project added to plant in service was approximately $3.5 million.

Q. HOW DOES THE COMPANY MANAGE COSTS ASSOCIATED WITH GENERAL PLANT CAPITAL IMPROVEMENT BLANKETS?

A. Projects are undertaken in accordance with the Company's purchasing policies and procedures. EPE uses a competitive bidding process, with the successful bidder identified as the vendor providing the best value option. In addition, options are evaluated from initial acquisition cost and ongoing maintenance perspectives, and, when feasible and appropriate, different technologies are considered.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE FABENS DISTRIBUTION CENTER PROJECT?

A. The Fabens Distribution Center project included improvements to the distribution pole yard and warehouse. The Fabens Pole Yard was expanded from approximately 0.8 acres to approximately two acres of land through the purchase and development of an adjacent parcel. The additional land was purchased to provide enough laydown area for storage of poles and material and for construction of a new warehouse. Along with the expansion and updates to the distribution pole yard, a 3,000 square foot warehouse was constructed to support distribution maintenance and construction activities and a 3,700 square foot canopy was constructed to store equipment, trucks, trailers, and an environmental containment area. The remainder of the pole yard improvements consist of pole racks, employee parking, a perimeter rock wall, wrought iron fencing and gates, asphalt paving, and an underground storm water retainage system.

Currently, distribution personnel assigned to the Fabens Pole Yard work out of a portable building, and the existing customer care facility needs major renovations. Expansion of this site will allow for future construction of a permanent building that will house distribution and customer care personnel and will allow the Company to vacate existing facilities. Provisions, such as utility stub outs, were made to accommodate the future construction of the permanent building, the design which will be completed by the end of the 2nd quarter 2021, with construction expected to begin in the 4th quarter 2021 and completed by the 3rd quarter of 2022.

Q. WHAT WAS THE TOTAL COST OF THE CAPITAL ADDITIONS FOR THE FABENS DISTRIBUTION CENTER PROJECT?

A. The total cost of the capital additions for the Fabens Distribution Center project added to plant in service was approximately $2.5 million.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE CATEGORY DESIGNATED AS "OTHER PROJECTS"?

A. Other Projects represent minor capital projects, including operational technology network buildouts at various EPE facilities, energy management systems hardware for System Operations, the general acquisition blanket for shared service personnel, miscellaneous IT communications equipment, and physical security systems at low impact sites. These projects represent routine capital expenditures made during the normal course of business that are necessary and reasonable for the continued provision of safe and reliable service.

Q. WHAT IS THE TOTAL COST OF OTHER PROJECTS?

A. The total cost of Other Projects added to plant in service was approximately $24.8 million.

Q. WHAT IS THE TOTAL COST FOR GENERAL PLANT ADDITIONS THE COMPANY IS SEEKING IN RATE BASE?

A. EPE is requesting $68,655,076 in rate base for general plant capital additions as listed in Table LJH-1 above.

Q. ARE THE COSTS OF THE CAPITAL ADDITIONS TO GENERAL PLANT NECESSARY, REASONABLE AND PRUDENT?

A. Yes. Transportation Equipment/Fleet Acquisition costs were incurred for the purchase of new and replacement vehicles, as well as equipment required to provide safe and reliable service to customers and to address changes in operational requirements. Vehicle and equipment options were evaluated from a best-value perspective, and when applicable, different technologies were considered. In addition, the development of specifications for vehicles and equipment was performed through interdepartmental collaboration to ensure work requirements were effectively met.

The Shared Services Facility Services Improvement Blanket project, the System Operations Building Expansion project, and the Fabens Distribution Center project were incurred to upgrade and renovate aging infrastructure and equipment and to address safety, security, and maintenance issues related to the Company's facilities.

The IT Hardware Blankets project costs were incurred to replace equipment that the Company no longer uses, to address changes in operational requirements, and to allow EPE to leverage improvements in technology for the benefit of the Company's customers.

The Physical Security Improvements (CIP-014) project was necessary to improve physical security at various critical infrastructure locations throughout EPE's service territory

The Distribution General Plant Acquisitions project costs were incurred in the normal course of business to purchase materials, tools, and equipment required for the Company's ongoing maintenance and construction of its distribution lines, which are necessary for the provision of safe and reliable service to EPE's customers.

Lastly, minor capital project costs included in Other Projects represent routine capital expenditures made during the normal course of business that are necessary for the provision of safe and reliable service.

Q. HOW DID THE COMPANY ENSURE THAT THE COSTS INCURRED FOR THESE PROJECTS WERE REASONABLE?

A. Projects are undertaken in accordance with the Company's purchasing policies and procedures. This may include use of a competitive bidding process, with the successful bidder identified as the vendor providing the best value option. In addition, options are evaluated from both initial acquisition cost and ongoing maintenance perspectives and, when feasible and appropriate, different technologies are considered. As a result, all these costs are reasonable, necessary and prudent.

B. Intangible Plant Capital Additions

Q. WHAT ARE THE CAPITAL ADDITIONS INCLUDED IN INTANGIBLE PLANT?

A. Intangible plant capital additions are charged to FERC Account 303, Miscellaneous Intangible Plant. Intangible plant is primarily composed of the cost of purchasing and developing computer software systems. The Company uses computer software systems to support the operation and management of every area of the Company, including billing and accounts receivable, meter reading, general ledger, plant accounting, accounts payable, outage management, work management, generation maintenance management, system operations, and other systems. Often, development of computer software includes the purchase of computer hardware to support the systems (computer hardware is included in the general plant additions previously discussed).

Q. WHAT AMOUNT OF RATE BASE ADDITIONS IS THE COMPANY SEEKING FOR INTANGIBLE PLANT?

A. The Company is requesting Intangible Plant rate base capital additions of $46,227,602, on a total Company basis, for projects placed in service between October 1, 2016, and December 31, 2020, the end of the Test Year in this case.

Q. WHAT ARE SOME OF THE SIGNIFICANT INTANGIBLE PLANT ADDITIONS SINCE APRIL 2015?

A. As shown on Exhibit LJH-2, there are five intangible projects greater than $2.5 million included in the Company's requested rate base. Table LJH-2 identifies those projects and their costs, along with the cumulative cost of the intangible projects costing less than $2.5 million.

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TABLE LJH-2	
MAJOR PROJECT	TOTAL COMPANY COST
EMS Replacement Software	$12,707,391
Work Management System (A.R.M.) for Transmission, Substation and Relay	4,567,438
Customer Care & Billing (CC&B) 2.4 Upgrade Software	3,649,039
Regulatory Management Suite Software	2,761,190
IT Operations Blanket Software	2,654,418
Other Projects (less than $2.5 million)	19,888,126
TOTAL	$46,227,602

Q. WHICH COMPANY WITNESSES DESCRIBE THE PURPOSE AND USE OF THE ENERGY MANAGEMENT SYSTEM ("EMS") REPLACEMENT SOFTWARE AND THE ARM WORK MANAGEMENT SYSTEM PROJECT IN TESTIMONY?

A. The direct testimony of EPE witness Hawkins supports the Company's investment in the EMS Replacement Software, while the support for the ARM Work Management System can be found in the direct testimony of EPE witness Doyle.

Q. WHAT ARE THE TOTAL COSTS OF THE EMS REPLACEMENT SOFTWARE AND THE ARM WORK MANAGEMENT SYSTEM PROJECTS?

A. The total cost of the EMS Replacement Software and the ARM Work Management System projects closed to plant in service was approximately $12.7 million and $4.6 million, respectively.

Q. CAN YOU DESCRIBE THE PURPOSE AND USE OF THE CUSTOMER CARE & BILLING ("CC&B") 2.4 UPGRADE SOFTWARE PROJECT?

A. The Company was required to upgrade its CC&B software to version 2.4 for continued vendor product support. The major software improvements from the 2.4 upgrade included (1) implementation of a new customer web self-service application; (2) significant reductions in the nightly batch processing time for billings, loading meter reads, and collections (from approximately 12 hours to four hours), which gives EPE time to correct batch processing errors and ensure bills are sent to the bill print vendor for timely processing; and (3) elimination of late penalty assessments on final bills for commercial accounts. The systematic solution to eliminate late penalty assessments replaced a more time-consuming and expensive manual process.

Q. WHAT IS THE TOTAL COST OF THE CC&B 2.4 UPGRADE PROJECT?

A. The cost of the CC&B 2.4 Upgrade Software project completed and closed to plant was approximately $3.6 million.

Q. CAN YOU DESCRIBE THE PURPOSE AND USE OF THE REGULATORY MANAGEMENT SUITE ("RMS") SOFTWARE?

A. The RMS software is a PowerPlan module used to manage data required for the Company's regulatory filings. The software program encompasses analytics of accounting, regulatory, and planning data (including the development of historic test year periods, jurisdictional cost of service, and class cost of service). The RMS software integrates with EPE's existing general ledger platform, allowing the Company to derive information from its books at a greater level of detail using a regulatory ledger. The regulatory ledger is presented using "Reg Accounts", which are subaccounts under the FERC account level that provide a more granular level of detail of cost captured in EPE's accounting system. Additionally, as a proprietary server-based application, the RMS software produces a working spreadsheet version of EPE's cost-of-service model (the collaboration engine) in Microsoft Excel format. This provides transparency to auditors, intervenors and regulators, while maintaining control of the model. It helps improve communications during the approval process, eliminate redundant models and reduce errors.

Q. WHAT IS THE TOTAL COST OF THE RMS SOFTWARE PROJECT?

A. The cost of the RMS Software project completed and closed to plant was approximately $2.8 million.

Q. WHAT CAPITAL ADDITIONS ARE INCLUDED IN THE IT SOFTWARE BLANKET?

A. The IT Software Blanket consists primarily of projects associated with software for infrastructure purchases needed to support work performed during the normal course of business. Costs include amounts for software and operating system licensing for servers, workstations, network devices, storage, cyber security, and corporate telephone systems. More specifically, these amounts include:

1. Microsoft Windows operating system licenses for servers, databases and workstations;
2. Red Hat Linux operating system licensing;
3. VmWare virtualization licensing for EPE's on-premise data centers;
4. Oracle software licensing for applications and systems using Oracle's platforms such as Customer Care and Billing and iExpense (expense reporting);
5. Network licensing associated with EPE's corporate network;
6. Software licensing associated with the Company's corporate telephone systems and call center;
7. Information security licensing for software, including the Company's configuration management, multifactor authentication, workstation encryption, and antivirus solutions;
8. Software licensing associated with EPE's enterprise storage; and
9. Software licensing associated with the Company's workstation asset management solution.

These costs also include any internal labor or external consulting work required to implement or deploy the software or systems.

Q. WHAT IS THE TOTAL COST OF THE IT SOFTWARE BLANKET?

A. The cost of the IT Software Blanket completed and closed to plant was approximately $2.7 million.

Q. WHAT INTANGIBLE PLANT CAPITAL ADDITIONS ARE INCLUDED IN THE CATEGORY DESIGNATED AS "OTHER PROJECTS?"

A. Other Projects represent intangible plant capital expenditures of less than $2.5 million, including upgrade costs for the Company's PowerPlan, Livelink, Outage Management and

ARM software, the Human Resource Information System (UltiPro) software, GIS Data Gathering software and costs for the PowerPlan Lease Accounting module. In addition, Other Projects include costs for minor systems development, software purchases, and minor system upgrades made during the normal course of business that are necessary and reasonable for the continued provision of safe and reliable service.

Q. DOES EPE HAVE PROCESSES AND PROCEDURES IN PLACE TO ENSURE THAT COSTS ASSOCIATED WITH INTANGIBLE PLANT CAPITAL PROJECTS ARE REASONABLE?

A. Yes. The Company uses an established systems development process to ensure that systems are developed in an efficient and cost-effective manner. While the cost of information systems is important, ensuring that the systems meet the Company's needs is equally, or more, important. The systems development process starts with defining the requirements for each system or software product. A key requirement of any system is that it interfaces with existing systems. Once the system requirements are developed, the Company uses competitive bidding processes to identify the product and developers that best meet the Company's requirements in the most cost-effective manner. Systems are analyzed not only based upon the development costs, but also on the cost of operating the system during its useful life. The Company's systems development process seeks to meet the Company's information needs at the lowest cost over the life of the system.

Q. DO INTANGIBLE PLANT PROJECTS GO THROUGH AN APPROVAL PROCESS?

A. Yes. Purchases of intangible plant go through a budget approval process each year. Budgets are reviewed in detail and ultimately approved by the Board of Directors. Purchases are then subject to a purchase authorization process before they are made. Systems development projects are not only subject to budget approval, but projects greater than $50,000 and less than $100,000 are reviewed and either approved or rejected by the Company's Technology Planning Committee ("TPC"). Project approval is based upon cost/benefit analysis, business requirements, and adherence to technology standards. The TPC also provides recommendations for approval or rejection of software projects with a total cost greater than $100,000 to the Company's Capital Planning Committee ("CPC").

The CPC is composed of executives or their representatives from all areas of the Company. The CPC reviews each project for business need. In addition, the CPC reviews proposed software purchases to ensure that they integrate with other systems and meet the Company's long-term systems development requirements. These processes I have described ensure that the Company undertakes only those projects it needs and that the costs are prudently incurred.

Q. ARE THE INTANGIBLE PLANT CAPITAL PROJECTS ON YOUR EXHIBIT LJH-2 PRUDENT AND USED AND USEFUL?

A. Yes, they are. The Company utilizes all its software projects to help provide reliable service to its customers.

IV. Write-Down of the Original Cost of Palo Verde to Post-Bankruptcy Fresh-Start Values

Q. THE COMMISSION'S RATE FILING PACKAGE INSTRUCTIONS REQUIRE THE USE OF ORIGINAL COST. ARE THE ITEMS IN RATE BASE SCHEDULE B-1 AND THE RATE BASE EPE PROPOSES TO USE TO DETERMINE ITS REVENUE REQUIREMENTS BASED ON ORIGINAL COST?

A. Yes, they are, with the exception of the PVGS, the book value of which is based on the fresh-start values as determined upon EPE's emergence from bankruptcy in 1996 (post-bankruptcy fresh-start value), which is the method approved in Docket No. 37690 and used in every case since. I emphasize that EPE's customers benefit from this adjustment to Palo Verde's original cost because the adjustment reduces EPE's rate base compared to what it would be absent the adjustment.

Q. WERE SPECIFIC ACCOUNTING TREATMENTS RELATED TO THE POST-BANKRUPTCY FRESH-START VALUE OF PALO VERDE AGREED TO IN THE DOCKET NO. 37690 FINAL ORDER?

A. Yes. These are contained in Findings of Fact Nos. 16 and 45 of that final order. The accounting treatment approved in that docket was intended to ensure that "fresh-start" plant values would be used for both financial accounts/reports and EPE's regulatory books. At the time the Company emerged from bankruptcy, its regulatory books reflected the historical original cost less depreciation ("OCLD") of the Company's generation assets. However, the Company's financial reporting books and records, prepared in accordance with generally accepted accounting principles, reflected the effects of applying "fresh-start" accounting. The term "fresh start" means what it implies—the restatement of asset values in light of the emergence from bankruptcy.

When EPE emerged from bankruptcy in February 1996, it adopted fresh-start accounting in accordance with the requirements of the American Institute of Certified Public Accountants Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code (now Topic 852 under the Financial Accounting Standards Board's accounting standards codification).

Q. HOW WERE PLANT COSTS TREATED UNDER FRESH-START ACCOUNTING?

A. In applying fresh-start accounting, the Company first determined its reorganization value as a company. The Company then assigned this reorganization value to its various assets. Liabilities were stated in accordance with their "fair values" as of February 12, 1996, the date the Company's plan of bankruptcy reorganization became effective and the Company emerged from bankruptcy. As a result, the Company's generation assets were, on balance, written down for financial reporting purposes upon its emergence from bankruptcy to reflect reorganization values. Palo Verde was written down by approximately $737 million, from $1.299 billion to $562 million.

Q. DID EPE WRITE DOWN PALO VERDE ON ITS REGULATORY BOOKS TO REFLECT THE FRESH-START VALUES WHEN IT EMERGED FROM BANKRUPTCY?

A. No, it did not. EPE continued to use OCLD for its regulatory books as the basis for Palo Verde.

Q. WHAT SPECIFIC PALO VERDE GENERATION BALANCES RESULTED FROM THE FRESH-START VALUES?

A. The revalued basis of Palo Verde generation units as of February 11, 1996, on a total

Company basis were:

TABLE LJH-3

Plant	Revalued Basis $(000s)
Unit 1	$173,140
Unit 2	$215,285
Unit 3	$173,904

EPE received approval in Docket No. 22280 to credit accumulated depreciation and recognize a regulatory asset to record the net write-down for regulatory purposes. The Docket No. 22280 stipulation provided for EPE's non-nuclear units to be written up in value. The increase in value for these units was recorded in FERC Account 116, Utility Plant Adjustments. The Utility Plant Adjustments write-up in non-nuclear units has now been fully amortized on a Texas jurisdictional basis and is not reflected in rate base or cost of service in this filing. The net plant balances for Palo Verde as of the end of the Test Year were developed based upon the revalued basis in the table above.

Q. HOW WERE THE PALO VERDE NET PLANT BALANCES CALCULATED AS OF THE END OF THE TEST YEAR?

A. Per the treatment approved in Docket No. 37690, EPE's cost of service as filed and the requested base rates continue to reflect the revaluation and write-down of nuclear generation plant. Beginning with the fresh-start plant values as of February 11, 1996, additions and retirements were added or subtracted from the beginning balance to calculate a gross plant balance at December 31, 2020, for each unit. Accumulated depreciation was calculated in a similar fashion by adding calculated annual depreciation expense, subtracting retirements and cost of removal, and adding salvage to determine the ending balance as of December 31, 2020. Annual depreciation expense was developed by depreciating the revalued basis at February 11, 1996, and net additions each year over the remaining, extended life of the plant based upon the year of the addition. Exhibit LJH-3 shows the detail of the Palo Verde net plant balances.

Q. DO EPE'S CUSTOMERS BENEFIT FROM THE FRESH-START VALUATION YOU JUST DESCRIBED?

A. Yes. The fresh-start valuations reflect a substantial reduction in the rate base value of the Company's generating assets. As a result, rates charged to customers have been and will continue to be less than they would have been if the Company had reflected these assets at their OCLD values. The following table compares the net book value of Palo Verde and the value per kilowatt of generating capability for the fresh-start accounting to the net book value and the value per kilowatt of generating capability as if the original cost less depreciation was recognized.

TABLE LJH-4

Description	PV Amount
Net Plant Value – Fresh-Start Accounting (000)	$ 782,920
Cost per KW	$ 1,237
Net Plant Value – OCLD (000)	$ 986,209
Cost per KW	$ 1,558

In summary, current customers are receiving a $203 million (i.e., $986,209 - $782,920) reduction in rate base.

V. Schedules

A. Schedules B-1.2 through B-1.4

Q. WHAT ARE THE B SCHEDULES?

A. The B Schedules (which extend through Schedule B-2.1) contain requested rate base and return. I sponsor Schedules B-1.2 through B-1.4, which are related to percentage of plant in service, penalties and fines and post-test year adjustments.

B. Schedules C-1 through C-5 (Original Cost of Plant)

Q. WHAT ARE THE C SCHEDULES?

A. The C Schedules (which extend through Schedule C-6.10) contain original cost of plant and nuclear fuel information. I sponsor Schedules C-1 through C-5, which are related to plant in service and construction work in progress.

Q. WHAT DOES SCHEDULE C-1 (ORIGINAL COST OF UTILITY PLANT) ADDRESS?

A. This schedule reflects the amounts of utility plant classified by major FERC account as of the beginning of the Test Year. It then adds/subtracts the book additions, retirements, transfers, and adjustments to the per-book amounts to arrive at the requested amount of plant in service at the end of the Test Year. I explain all plant in service-related adjustments later in my testimony.

Q. WHAT DOES SCHEDULE C-2 (DETAIL OF ORIGINAL COST OF UTILITY PLANT) ADDRESS?

A. This schedule presents the detail by FERC Primary ("300") account of the amounts presented by major plant accounts in Schedule C-1. Schedule C-2 includes per-book adjustments to arrive at the requested amount of plant in service at the end of the Test Year.

Q. WHAT DOES SCHEDULE C-3 (MONTHLY DETAIL OF UTILITY PLANT IN SERVICE) ADDRESS?

A. Schedule C-3 includes the monthly book balance of plant by FERC Primary account for each month of the Test Year. As in Schedules C-1 and C-2, Schedule C-3 includes per-book adjustments to arrive at the requested amount of plant in service.

Q. WHAT DO THE TWO C-4 SCHEDULES ADDRESS?

A. Schedules C-4.1 and C-4.2 address construction work in progress ("CWIP").

Schedule C-4.1 (CWIP by functional group) provides information about CWIP by project and function with total expenditures amounting to $100,000 or more as of the end of the Test Year. This schedule also includes the project number, including description, amount expended, AFUDC, estimated completion date, and estimated total cost.

Schedule C-4.2 (CWIP allowed in rate base) describes the amount of CWIP requested and allowed in rate base for EPE's two most recent-base rate filings. No CWIP was included in rate base in EPE's two most recent base-rate filings: Docket No. 44941 (which was filed in 2015 and decided in 2016) and Docket No. 46831 (which was filed and decided in 2017).

The Company is not seeking to include any CWIP in rate base in this case.

Q. WHAT DOES SCHEDULE C-5 (ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC")) ADDRESS?

A. Schedule C-5 addresses AFUDC and construction overheads. This schedule states the methods, procedures, and calculations EPE follows in capitalizing AFUDC and other construction overheads. It also includes a list of the AFUDC rates for 2016 through 2020 and the amounts generated and transferred to plant in service in each of those years. In addition, it includes a list of the engineering and supervision as well as administrative and general overheads generated and transferred to plant in service for each of the last five years.

Q. DID THE SETTLEMENT IN EPE'S LAST RATE CASE, DOCKET NO. 46831, SPECIFY THE RETURN ON EQUITY RATE THAT EPE SHOULD USE FOR PURPOSES OF CALCULATING AFUDC?

A. Yes, it did. The settlement agreement in Article I.C., and the Commission's Final Order in Finding of Fact No. 30, specified that EPE should use a Return on Equity of 9.65% for purposes of calculating AFUDC. EPE has reflected this Return on Equity in its AFUDC rate calculation.

B. Schedules D-1 through D-8 (Depreciation)

Q. WHAT ARE THE D SCHEDULES?

A. The D Schedules (which extend through Schedule D-8) contain depreciation information, as described below.

Q. WHAT DOES SCHEDULE D PRESENT?

A. Schedule D is a narrative that includes descriptions of the computer programs, diskettes, schedules, file names, and other information associated with Schedules D-1, D-3, D-4, and D-7.

Q. WHAT DOES SCHEDULE D-1 (BY FUNCTIONAL GROUP AND/OR PRIMARY

ACCOUNT) ADDRESS?

A. Schedule D-1 shows accumulated provisions for depreciation detailed by functional group (e.g., steam production, transmission) at the beginning of the Test Year. It then adds/subtracts Test Year book accruals (depreciation expense), retirements, and adjustments (salvage, cost of removal, etc.) to the per-book amounts to arrive at the requested amount of accumulated depreciation at the end of the Test Year. I explain all accumulated depreciation related adjustments later in my testimony.

Q. WHAT DOES SCHEDULE D-2 (BOOKING METHODS) ADDRESS?

A. Schedule D-2 describes the methods and procedures followed in booking depreciation of plant, retirements, and abandonments. Since EPE has not had any abandonments, there is no methodology described for booking an abandonment.

Q. WHAT DOES SCHEDULE D-3 (PLANT HELD FOR FUTURE USE) SHOW?

A. Schedule D-3 lists plant held for future use recorded in FERC Account 105. This schedule is not applicable to EPE since it does not have any plant held for future use.

Q. WHAT DOES SCHEDULE D-4 (DEPRECIATION EXPENSE) ADDRESS?

A. Schedule D-4 shows EPE's plant depreciation expenses by functional group and primary account classification. Production plant is further subdivided by each generating unit. The three categories are:

1. Functional group,
2. Production plant generating unit, and
3. FERC primary account.

For each category, the following information is presented:

- Test Year end depreciable plant,
- Test Year end per-book (blended) depreciation rates,
- EPE's Test Year depreciation expense,
- EPE's requested depreciable plant,
- EPE's requested depreciation rates,
- EPE's requested depreciation expense, and

- Adjustments to the Test Year expense.

The depreciation rates requested by EPE in this filing are discussed below and in the direct testimony of EPE witness John J. Spanos.

Q. HAS EPE PREPARED A DEPRECIATION STUDY IN CONNECTION WITH THIS PROCEEDING?

A. Yes. EPE retained Gannett Fleming to prepare a depreciation study for EPE's plant in service amounts. The study incorporates updated plant and accumulated depreciation balances, along with any retirement and net salvage data for all plant as of December 31, 2019. The study is included in Schedule D-5 and is co-sponsored by EPE witness Spanos. Mr. Spanos describes and supports the results of the study in his direct testimony. The study results are utilized to calculate depreciation expense shown in Schedule D-4.

Q. HOW ARE THE PROPOSED NEW DEPRECIATION RATES REFLECTED IN EPE'S REQUESTED DEPRECIATION EXPENSE?

A. Schedule D-4 includes adjusted Test Year-end depreciable plant. EPE has applied the proposed rates from the study to these amounts to arrive at its requested depreciation expense. The Test Year per-book expense amount is subtracted from the resulting expense.

Q. WHAT INPUT DID EPE HAVE IN THE DETERMINATION OF THE RATES PRESENTED IN EPE WITNESS SPANOS' DEPRECIATION STUDY?

A. EPE provided EPE witness Spanos all the per-book "raw" data used in the determination of the current rates. This includes all additions to the depreciable plant accounts, accumulated depreciation balances by primary account at the end of the study year (December 31, 2019), and retirement/cost of removal/salvage data by vintage year, along with any other data requests made by Mr. Spanos.

Q. ARE THERE ANY RATES INCLUDED IN THE 2020 GANNETT FLEMING DEPRECIATION STUDY THAT WERE NOT USED IN THE PREPARATION OF SCHEDULE D-4?

A. Yes, there are rates in the study related to Rio Grande Unit 6; however, the Company is not requesting any costs for Rio Grande Unit 6 in this filing.

Q. WHAT DOES SCHEDULE D-7 (SUMMARY OF BOOK SALVAGE) SHOW?

A. Schedule D-7 summarizes the Test Year cost of removal, salvage, and retirement amounts for each functional group.

Q. WHAT DOES SCHEDULE D-8 (SERVICE LIFE) INCLUDE?

A. Schedule D-8 includes the average service life of each asset by FERC account, sorted by functional use. It also includes the Iowa Curves used to determine the average service lives.

VI. Plant in Service Adjustments

Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE PER-BOOK PLANT IN SERVICE AMOUNTS IN THIS FILING?

A. Yes, the Company has adjusted plant in service for the following items in this filing:

- Palo Verde Revaluation;
- Copper Gas Turbine;
- Capitalized Incentive Compensation ("CIC");
- Horizon Substation Land; and
- Rio Grande Unit 6

Q. WHAT RATE CASE SCHEDULE SHOWS THE ADJUSTMENTS TO PLANT IN SERVICE?

A. The workpapers to Schedule B-1, Adjustment No. 1, reflects the Company's adjustments to plant in service in rate base. EPE witness Jennifer I. Borden presents the workpapers to Schedule B-1. I explain and support each item in Adjustment No. 1.

A. Palo Verde Revaluation

Q. PLEASE DISCUSS THE ADJUSTMENT TO PALO VERDE.

A. Palo Verde has been restated to reflect the values as shown in Exhibit LJH-3 as required and explained in Section IV of my direct testimony.

B. Copper Gas Turbine

Q. PLEASE DISCUSS THE COPPER GAS TURBINE ADJUSTMENT.

A. The book cost of the Copper power plant gas turbine investment was removed as required in Finding of Fact No. 35 in the Final Order in Docket No. 44941.

C. Capitalized Incentive Compensation

Q. PLEASE DISCUSS THE ADJUSTMENT TO REMOVE THE CAPITALIZED INCENTIVE COMPENSATION ("CIC") RELATED TO FINANCIAL METRICS.

A. Incentive compensation based upon financial metrics capitalized to plant in service was excluded from requested rate base in this filing.

Q. WHY DID EPE MAKE THIS ADJUSTMENT?

A. Utilities in Texas have been required to remove capitalized financial-based CIC from requested rate base in their filings. As a result, EPE has made an adjustment to its requested plant in service to remove CIC based upon financial metrics from costs capitalized to plant.

Q. WHAT PERIODS WERE INCLUDED IN THE ADJUSTED AMOUNTS?

A. The adjustment includes incentive compensation that has been capitalized since June 2009, which was the first month after the end of the Test Year in Docket No. 37690.

D. Horizon Substation Land

Q. PLEASE DISCUSS THE HORIZON LAND SUBSTATION ADJUSTMENT.

A. EPE purchased land in November 2019 to be used for the expansion of the Horizon substation. However, the work order charged for the acquisition costs was inadvertently closed to plant in service. Therefore, it was necessary to remove these costs from rate base since the land is not used and useful in serving Texas customers.

E. Rio Grande Unit 6

Q. PLEASE DISCUSS THE RIO GRANDE UNIT 6 ADJUSTMENT.

A. EPE placed Rio Grande Unit 6 in inactive reserve status in November 2015. Although

Rio Grande Unit 6 is fully depreciated, it has not yet been retired from service and gross plant costs remain in the respective FERC (300) accounts. This adjustment removes the gross plant costs for Rio Grande Unit 6 from the Company's requested plant in service.

VII. Accumulated Depreciation Adjustments

Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE PER-BOOK ACCUMULATED DEPRECIATION AMOUNTS IN THIS FILING?

A. Yes, the Company has adjusted accumulated depreciation for the following items in this filing:

- Palo Verde Revaluation;
- Copper Gas Turbine;
- CIC;
- FERC Audit; and
- Rio Grande Unit 6

Q. WHAT RATE-CASE SCHEDULE SHOWS THE ADJUSTMENTS TO REQUESTED ACCUMULATED DEPRECIATION?

A. The workpapers to Schedule B-1, Adjustment No. 2, reflects the Company's adjustments to the requested accumulated depreciation included in rate base. EPE witness Borden presents the workpapers to Schedule B-1. I explain and support each item in Adjustment No. 2.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO ACCUMULATED DEPRECIATION.

A. The adjustments to accumulated depreciation relate to the adjustments made to plant in service as previously discussed.

A. Palo Verde Revaluation

Q. PLEASE DISCUSS THE ADJUSTMENT RELATED TO PALO VERDE ACCUMULATED DEPRECIATION.

A. In the Palo Verde revaluation discussed earlier, EPE adjusted accumulated depreciation to conform to the calculation of the Palo Verde revalued amounts and their depreciable lives as shown in Exhibit LJH-3, as approved in Docket No. 37690.

B. Copper Gas Turbine

Q. PLEASE DISCUSS THE COPPER GAS TURBINE ADJUSTMENT.

A. Since EPE removed the book cost of the Copper power plant gas turbine investment, it is also necessary to remove the related accumulated depreciation.

C. Capitalized Incentive Compensation

Q. PLEASE DISCUSS THE ADJUSTMENT TO REMOVE THE ACCUMULATED DEPRECIATION RELATED TO THE FINANCIAL-BASED CIC.

A. Since the financial-based CIC was excluded from requested rate base in this filing, it is also necessary to remove the related accumulated depreciation.

Q. HOW DID EPE CALCULATE THE ADJUSTMENT FOR ACCUMULATED DEPRECIATION ON THE FINANCIAL-BASED CIC?

A. The Company first determined the amounts capitalized for the financial-based CIC by year since June 2009. Next, EPE calculated the annual depreciation expense using the functional composite rates in effect each year, related to the plant amounts which received CIC. The resulting accumulated depreciation was then used as the basis for the adjustment related to CIC.

D. FERC Audit

Q. PLEASE EXPLAIN THE FERC AUDIT ADJUSTMENT RELATED TO ACCUMULATED DEPRECIATION?

A. Consistent with past rate cases, the Company has removed $5.6 million from accumulated depreciation related to plant depreciation in the FERC jurisdiction. This amount is the result of an adjustment arising from an audit conducted by the FERC in the 1980s and is specific to the FERC jurisdiction. Consequently, it is removed from rate base since it is not applicable to the Texas retail jurisdiction.

E. Rio Grande Unit 6

Q. PLEASE DISCUSS THE RIO GRANDE UNIT 6 ADJUSTMENT.

A. Since EPE removed the book cost of Rio Grande Unit 6 from plant in service, it is also necessary to remove the related accumulated depreciation.

VIII. Depreciation Expense Adjustments

Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE PER-BOOK DEPRECIATION EXPENSE IN THIS FILING?

A. Yes, the Company has adjusted the per-book depreciation expense for the following items:

- Palo Verde Revaluation,
- Annualized Depreciation on plant additions during the Test Year,
- New Depreciation Rates,
- Copper Gas Turbine,
- CIC,
- Other Adjustments to Depreciable Plant, and
- Adjustments to Intangible Plant Amortization.

Q. WHAT RATE-CASE SCHEDULE SHOWS THE ADJUSTMENTS TO THE REQUESTED DEPRECIATION EXPENSE?

A. Schedule A-3, Adjustment No. 14, reflects the Company's adjustments to the requested depreciation expense included in thc requested cost of service. EPE witness Borden presents Schedule A-3. I explain and support each item in Adjustment No. 14.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO DEPRECIATION EXPENSE AND HOW THEY ARE CATEGORIZED IN THIS FILING.

A. The adjustments to depreciation expense can be categorized in one of the following groups:

- Related to the adjustments made to plant in service as previously discussed;
- Related to new plant added since October 1, 2016 through the Test Year end;
- Related to the proposed new plant depreciation rates resulting from the 2019 Gannett Fleming Depreciation Study supported by EPE witness Spanos; or
- Adjustments to Test Year End depreciable/amortizable plant.

A. Palo Verde Revaluation

Q. PLEASE DISCUSS THE ADJUSTMENT RELATED TO THE REVALUED PALO VERDE PLANT IN SERVICE.

A. The per-book depreciation expense has been adjusted to reflect the revaluation of Palo Verde, as discussed above. Depreciation expense was calculated on the revalued plant amounts using the remaining operating lives of each Palo Verde unit by vintage year as shown in Exhibit LJH-3, as approved in Docket No. 37690.

B. Plant Additions

Q. PLEASE DISCUSS THE ADJUSTMENT TO DEPRECIATION EXPENSE FOR PLANT ADDED TO PLANT IN SERVICE DURING THE TEST YEAR.

A. EPE has included an adjustment to the Test Year depreciation expense to annualize depreciation expense for utility plant added during the Test Year.

Q. WHY WAS IT NECESSARY TO ANNUALIZE DEPRECIATION ON UTILITY PLANT ADDED TO PLANT IN SERVICE DURING THE TEST YEAR?

A. The Test Year end depreciable plant balances include amounts closed to plant in service throughout the Test Year. Since additions to plant in service were added well into or at the end of the Test Year, there was only a fraction or minimal depreciation expense included in the twelve months ended December 31, 2020. It is therefore appropriate to annualize the depreciation expense related to these additions to include depreciation expense that reflects a complete Test Year amount.

Q. HOW IS THE ANNUALIZED DEPRECIATION EXPENSE CALCULATED?

A. The depreciation rates presented in the depreciation study prepared by EPE witness Spanos and included in Schedule D-5 are applied to the Test Year end depreciable plant balances (which include these additions) to arrive at an annual amount of depreciation expense. The resulting expense is the amount being requested in this case and can be seen on Schedule D-4.

C. New Depreciation Rates

Q. EXPLAIN THE ADJUSTMENT TO DEPRECIATION EXPENSE FOR THE PROPOSED NEW DEPRECIATION RATES YOU IDENTIFIED ABOVE.

A. The Test Year end per-book depreciation expense reflects expense amounts that were calculated based on the rates resulting from the depreciation study prepared by Gannett Fleming and supported by EPE witness Spanos.

Q. HOW ARE THE PROPOSED NEW DEPRECIATION RATES FOR THESE ITEMS REFLECTED IN EPE'S REQUESTED DEPRECIATION EXPENSE?

A. As previously discussed, Schedule D-4 includes adjusted Test Year-end depreciable plant. EPE applied the proposed new depreciation rates from the depreciation study to the adjusted Test Year end depreciable plant accounts to arrive at its requested depreciation expense. The per-book amount is subtracted from the resulting expense to arrive at the adjustment to depreciation expense included in our request.

D. Copper Gas Turbine

Q. PLEASE DISCUSS THE COPPER GAS TURBINE ADJUSTMENT.

A. Since the Company removed the book cost of the Copper power plant gas turbine investment, it is also necessary to remove the related depreciation expense from the requested depreciation expense amount in this filing.

E. Capitalized Incentive Compensation

Q. PLEASE DISCUSS THE ADJUSTMENT TO REMOVE THE DEPRECIATION EXPENSE RELATED TO THE FINANCIAL-BASED CIC.

A. Since the financial-based CIC was excluded from requested plant in service in this filing, it is also necessary to remove the related depreciation expense from the Company's requested depreciation expense amount.

Q. HOW DID EPE CALCULATE THE ADJUSTMENT FOR DEPRECIATION ON THE FINANCIAL-BASED CIC?

A. As discussed in Section VII above, EPE calculated the annual depreciation expense using the functional composite rates in effect each year related to the plant amounts which received financial-based CIC. The resulting depreciation expense for the twelve months ending December 31, 2020, was then removed from EPE's requested depreciation expense in this filing.

F. Other Adjustments to Depreciable Plant

Q. WHAT OTHER ADJUSTMENTS HAVE YOU MADE TO TEST YEAR DEPRECIATION EXPENSE IN THIS FILING?

A. Certain Test Year end depreciable plant balances (primarily transportation equipment) include amounts related to individual assets that are fully depreciated. EPE removes the fully depreciated assets from the adjusted Test Year end depreciable plant balance when calculating its requested depreciation expense.

G. Adjustments to Intangible Plant Amortization

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE INTANGIBLE PLANT AMORTIZATION EXPENSE IN THIS FILING?

A. There were several miscellaneous software projects that closed to plant in service throughout the Test Year. Since these additions to plant in service were added during the Test Year, it is appropriate to annualize the amortization expense related to these additions to include expense that reflects a complete rate year. Conversely, those projects that will be fully amortized within the year following the Test Year were removed from the Company's requested amortization expense.

IX. Palo Verde Nuclear Decommissioning Funding

Q. HOW ARE DECOMMISSIONING COSTS ESTIMATED?

A. TLG Services, Inc. ("TLG"), the firm selected by the PVGS owners to provide decommissioning and engineering services, routinely prepares a decommissioning cost estimate for the PVGS owners. The most recent decommissioning cost estimate used in this rate filing was prepared in 2019 (the "2019 Decommissioning Study") and was adopted by the PVGS owners. That study is presented and supported by EPE witness Rodrick A. Knight and is attached to his direct testimony as Exhibit RAK-2. As explained in EPE witness Knight's direct testimony, the owners have typically updated the decommissioning estimate every three years.

The Commission has included the Texas jurisdictional portion of the annual decommissioning funding amount in the cost of service in prior rate cases. My testimony addresses the need for additional decommissioning funding for PVGS Units 1, 2 and 3.

Q. DOES EPE HAVE AN OBLIGATION TO PAY FOR COSTS OF DECOMMISSIONING?

A. Yes. Federal regulations require holders of nuclear licenses to pay for the costs of decommissioning. Pursuant to the PVGS-Participation Agreement governing the obligations of the PVNGS owners, EPE must fund its share (15.8 percent) of these costs in advance through annual deposits to an irrevocable decommissioning trust fund for each PVGS unit, with each fund held by an independent trustee. EPE has established both qualified and non-qualified trust funds for each unit. Qualified trust funds receive tax deductions and lower tax rates than the non-qualified funds.

Q. HAS THE COMMISSION PREVIOUSLY AUTHORIZED DECOMMISSIONING COST RECOVERY IN EPE'S RATES?

A. Yes. Beginning in 1987, the Company began reflecting decommissioning amounts in rates subject to adjustment in future rate cases for changes in decommissioning costs and other assumptions. In Docket No. 46831, the Company was authorized to contribute $2.1 million annually on a Texas jurisdictional basis to fund decommissioning.

Q. DOES THE COMPANY TAKE INTO ACCOUNT THE EFFECTS OF THE EXTENDED PLANT LIFE RESULTING FROM THE LICENSE EXTENSIONS GRANTED BY THE NUCLEAR REGULATORY COMMISSION (NRC) IN APRIL 2011?

A. Yes. On April 21, 2011, the NRC approved the PVGS license renewal application, which extended the operating license of all three Palo Verde units for 20 years beyond the original 40-year licenses. The renewed licenses for PVGS Units 1, 2, and 3 now expire in 2045, 2046, and 2047, respectively. The Commission has previously recognized and adopted these dates. The effects of the license extension for the PVGS have been included in the funding methodology used to calculate the need for additional funding of the decommissioning trust funds based upon the 2019 Decommissioning Cost Study.

Q. WHAT IS THE BASIS FOR THE COSTS OF DECOMMISSIONING PVGS UNITS 1, 2 AND 3 REQUESTED IN THIS RATE CASE?

A. The basis for EPE's decommissioning funding begins with the 2019 Decommissioning Study.

Q. HOW ARE THE COST ELEMENTS OF THE DECOMMISSIONING STUDY DERIVED?

A. As explained by Company witness Knight, the decommissioning cost estimates are based on the cost, in 2019 dollars, to decommission PVGS Units 1, 2, and 3 regardless of the year they are expected to occur. The 2019 Decommissioning Study provides annual expenditures over the expected duration of the decommissioning program in 2019 dollars, without accounting for cost escalations that would occur in the projected future periods during which any given decommissioning activity is undertaken. Thus, the cost estimates are prepared reflecting 2019 information and technologies but without attempting to estimate inflationary impacts on decommissioning components over the remaining plant life.

Q. DOES EPE CALCULATE THE ESTIMATED INFLATION FOR THESE COSTS IN ORDER TO ACCURATELY ESTIMATE THE YEARLY COSTS THAT MUST BE SET ASIDE FOR DECOMMISSIONING?

A. Yes. EPE applied an estimated escalation to the 2019 costs to more accurately estimate the yearly costs that must be set aside for decommissioning. EPE used an escalation methodology based on the historical escalation rate since 2007, which represents the year of the last decommissioning study performed prior to the extension of the PVGS operating licenses. EPE is using the decommissioning costs estimated in the 2007 study as a basis for calculating the compound annual growth rate of costs since that time. The 2007 decommissioning study estimated costs to be $2,053,412,000, and the 2019 Decommissioning Study estimated decommissioning costs to be $2,957,588,000. This results in a compound annual growth rate of 3.09 percent. EPE believes that cost increases during this 12-year period represents the recent changes in regulatory requirements and industry experiences. This approach in calculating a compound growth rate also serves to minimize the impact of fluctuations in estimates that may occur between studies by, effectively normalizing a total of four inter-study period changes occurring between each of the last five studies performed.

It should be noted that this methodology reflects more than just an assumption for inflation. Other changes, including new regulatory requirements and changes in the scope of decommissioning, are also inherently reflected in this rate.

Q. DOES EPE INCORPORATE PAST COLLECTION OF DECOMMISSIONING COSTS FOR PVGS UNITS 1, 2 AND 3 IN THIS CASE?

A. Yes. EPE has been collecting decommissioning costs in rates since 1987, and, therefore, incorporates past collection of decommissioning costs by deriving a beginning balance of all costs contributed thus far. This beginning balance was derived by calculating the collections from Texas customers from the point at which rates first reflected decommissioning expenses for each PVGS unit through December 31, 2020. Actual fund earnings through December 31, 2020 were allocated to Texas customers based on cumulative jurisdictional contributions.

Because EPE's decommissioning cost study represents total Company expenditures, it is necessary to "gross-up" the Texas jurisdictional accumulation (collections and earnings), to a total Company representation using a Commission-approved demand allocator. The various Commission cases approving collections for decommissioning costs also established related demand allocators that are used for this purpose.

Q. PLEASE SUMMARIZE EPE'S PROPOSAL FOR DECOMMISSIONING FUNDING IN THIS CASE.

A. In workpapers to my testimony, I developed a breakeven earnings rate required to fully fund the decommissioning trusts needed to fund decommissioning costs. The breakeven earnings rate is less than EPE's projected earnings rate on its current decommissioning trust fund investments. As a result, EPE is requesting that its funding contributions be reduced to zero in this proceeding because the current funds and the expected earnings on those funds are sufficient to meet all funding obligations at this time. However, this level of funding is requested for this case only and is subject to review and adjustment in future proceedings.

X. Conclusion

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED AND CO-SPONSOSRED BY LARRY J. HANCOCK

	Description	Sponsorship
B-1.2	PERCENTAGE OF PLANT IN SERVICE	Sponsor
B-1.3	PENALTIES OR FINES	Sponsor
B-1.4	POST TEST YEAR ADJUSTMENT	Sponsor
C-1	ORIGINAL COST OF UTILITY PLANT	Sponsor
C-2	DETAIL OF ORIGINAL COST OF UTILITY PLANT	Sponsor
C-3	MONTHLY DETAIL OF UTILITY PLANT IN SERVICE	Sponsor
C-4.1	CWIP BY FUNCTIONAL GROUP	Sponsor
C-4.2	CWIP ALLOWED IN RATE BASE	Sponsor
C-5	AFUDC OR IDC	Sponsor
D-1	ACCUMULATED DEPRECIATION BY FUNCTIONAL GROUP AND/OR PRIMARY ACCOUNT	Sponsor
D-2	BOOKING METHODS	Sponsor
D-3	PLANT HELD FOR FUTURE USE	Sponsor
D-4	DEPRECIATION EXPENSE	Sponsor
D-5	DEPRECIATION RATE STUDY	Co-Sponsor
D-7	SUMMARY OF BOOK SALVAGE	Sponsor
D-8	SERVICE LIFE	Co-Sponsor
H-5.1	CAPITAL COSTS METHODOLOGY	Sponsor
H.5.2a	NUCLEAR CAPITAL COSTS PROJECTS	Co-Sponsor
H-5.2b	FOSSIL CAPITAL COSTS PROJECTS	Co-Sponsor
H 5.3a	NUCLEAR CAPITAL EXPENDITURES (HISTORICAL, PRESENT, PROJECTED)	Co-Sponsor
M-1	DECOMMISSIONING INFORMATION	Sponsor
M-2	DECOMMISSIONING FUNDING PLAN	Sponsor

RATE BASE ADDITIONS
FOR THE PERIOD OCTOBER 1, 2016 THROUGH DECEMBER 31, 2020

PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS		Sponsor
Production				
Nuclear Production				
GP009	PALO VERDE CAPITAL IMPROVEMENTS	$ 182,228,800		T. HORTON
	Nuclear Production Total	182,228,800		
Steam Production				
GN162	NEWMAN UNIT 5 STEAM GENERATOR	21,630,507	(a)	K. OLSON
GN166	NEWMAN LAKE LINER REPLACEMENT AND UPGRADE	13,135,000		K. OLSON
GN003	NEWMAN CAPITAL IMPROVEMENT BLANKET	12,574,070		K. OLSON
GN191	NEWMAN UNIT 4/GT1 HOT GAS PATH IMPROVEMENTS	9,771,008		K. OLSON
GN210	NEWMAN UNIT 4 GT1 & GT2 IMPROVEMENTS	7,000,184		K. OLSON
GN161	NEWMAN UNIT 5 STEAM TURBINE UPGRADES	4,728,243		K. OLSON
GR014	RIO GRANDE CAPITAL IMPROVEMENT BLANKET	4,629,888		K. OLSON
GN156	NEWMAN GAS METERING UPGRADE	3,682,107		K. OLSON
GN174	NEWMAN UNIT 3 DISTRIBUTIVE CONTROL SYSTEM UPGRADE	3,333,248		K. OLSON
GN160	NEWMAN UNIT 4 STEAM GENERATOR ROTOR REPLACEMENT	2,972,091		K. OLSON
GN198	NEWMAN UNIT 5 HRSG BYPASS VALVE REPLACEMENT	2,774,647		K. OLSON
GR133	RIO GRANDE UNIT 8 CONTROLS UPGRADE (2017 OUTAGE)	2,645,152		K OLSON
GR180	RIO GRANDE UNIT 7 GENERATOR IMPROVEMENTS	2,138,333		K. OLSON
GN192	NEWMAN UNIT 4 GT2 HOT GAS PATH CAPITAL IMPROVEMENTS	1,752,589		K. OLSON
GN199	NEWMAN UNIT 5 HRSG BYPASS VALVE REPLACEMENT	1,750,953		K. OLSON
GN007	NEWMAN FACILITIES SERVICES IMPROVEMENTS BLANKET	1,641,983		K OLSON
GR131	RIO GRANDE UNIT 8 LOW PRESSURE TURBINE BLADES REPLACEMENT	1,361,920		K OLSON
GN163	NEWMAN UNIT 4 - SPARE GT PARTS	1,138,693		K. OLSON
GN144	NEWMAN UNIT 2 ECONOMIZER TUBE REPLACEMENT	1,113,060		K. OLSON
GN190	NEWMAN UNIT 4 GT2 COMBUSTER IMPROVEMENTS	1,101,785		K. OLSON
GN143	NEWMAN UNIT 1 ECONOMIZER TUBE REPLACEMENT	1,071,316		K. OLSON
GR007	RIO GRANDE FACILITIES SERVICES IMPROVEMENTS BLANKET	1,066,047		K. OLSON
GN177	NEWMAN UNIT 5 GT3 CONTROLS AND AVR UPGRADE	1,009,604		K. OLSON
GN178	NEWMAN UNIT 5 GT4 GT CONTROLS AND AVR UPGRADE	945,827		K. OLSON
GN158	NEWMAN UNIT 2-BOILER-SECONDARY SUPERHEATER REPLACEMENT	871,869		K OLSON
GN124	NEWMAN UNIT 4 GT2 NEW ECONOMIZER / HEADER REPLACEMENT	865,623		K. OLSON
GN128	NEWMAN UNIT 4 GT2 - NEW LOW PRESSURE SECTION	850,946		K. OLSON
GN187	NEWMAN UNIT 5 INSTRUMENT AIR COMPRESSOR REPLACEMENT	812,131		K. OLSON
GN189	NEWMAN UNIT 4/GT1 COMBUSTOR INSP CAPITAL	811,704		K. OLSON
GN211	NEWMAN UNIT 5/GT3 & GT4 CAP GE 7EAS REPLACEMENT PARTS	720,910		K. OLSON
GR144	RIO GRANDE UNIT 8 BOILER BURNER VALVES UPGRADE	720,781		K. OLSON
GN203	NEWMAN UNIT 3 COOLNG TOWER STRUCTURE IMPROVEMENTS	566,648		K. OLSON
GN146	NEWMAN UNIT 5 ST NEW VACUUM PUMP SYSTEM	566,237		K. OLSON
GR135	RIO GRANDE POWER PLANT - WELDING SHOP	550,406		K. OLSON
GN164	COLD REHEAT LINE AND VACUUM BREAKER VALVE	538,266		K. OLSON
GN168	NEWMAN UNIT 1 VOLTAGE REGULATOR REPLACEMENT	535,439		K. OLSON
GR177	RIO GRANDE DCS CIP CYBER IMPRVMNTS	470,534		K. OLSON
GN167	NEWMAN - MAIN OFFICE EXPANSION	449,426		K. OLSON
GN139	NEWMAN UNIT 5 GT3 WET COMPRESSION UPGRADE	435,066		K. OLSON
GR126	RIO GRANDE UNIT 8 BOILER TUBE REPLACEMENT	418,705		K. OLSON
GR165	RIO GRANDE WELL WATER PIPING REPLACEMENT	414,141		K. OLSON
GN232	NEWMAN DCS CIP CYBER IMPRVMTS	379,941		K. OLSON
GR170	RIO GRANDE EMPLOYEE ACCESS IMPROVEMENTS	367,722		K. OLSON
GN140	NEWMAN UNIT 5 GT4 WET COMPRESSION UPGRADE	344,369		K. OLSON
GN151	NEWMAN UNIT 4 GT2 CAPITAL SPARE PARTS	328,332		K. OLSON
GR141	RIO GRANDE - #3 WELL RELOCATION	305,788		K. OLSON
GR175	RIO GRANDE UNIT 8 4160V SWITCHGEAR BREAKER UPGRADE	294,560		K. OLSON
GR130	RIO GRANDE - #4 WELL RELOCATION	290,577		K. OLSON
GR176	RIO GRANDE UNIT 8 FEED WATER REGULATORS UPGRADE	280,768		K. OLSON
GN217	NEWMAN UNIT 2 AUTO VOLTAGE REGULATOR UPGRADE	272,169		K. OLSON
GR134	RIO GRANDE POWER PLANT - RESTROOM -MAINTENANCE SHOP	264,388		K. OLSON
GN219	NEWMAN UNIT 3 UNINTERRUPTIBLE SUPPLY UPGRADE	258,936		K. OLSON
GN222	NEWMAN UNIT 2 UNINTERUPTIBLE POWER UPGRADE	255,156		K. OLSON
GN218	NEWMAN UNIT 3 AUTO VOLTAGE REGULATOR UPGRADE	239,116		K. OLSON
GN238	NEWMAN UNIT 2 LP TURBINE PACKING REPLACEMENT	224,659		K. OLSON
GN181	NEWMAN UNIT 1 COOLING TOWER SOFT STARTS REPLACEMENTS	218,885		K. OLSON
GN172	NEWMAN UNIT 1 BENCH BOARD TO DCS UPGRADE	217,912		K. OLSON

RATE BASE ADDITIONS
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PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS	Sponsor
GN201	NEWMAN UNIT 5 HRSG SPARE BOILER FEED PUMP ROTATING ELEMENT	212,491	K. OLSON
GN176	NEWMAN UNIT 2 CONTROL VALVE OVERHAUL	203,006	K. OLSON
GN159	NEWMAN POWER PLANT - CONTROL ROOM #1 RENOVATION	198,063	K. OLSON
GN228	NEWMAN UNIT 2 GENERATOR PROTECT RELAY UPGRADE	194,183	K. OLSON
GR174	RIO GRANDE PLANT CRANE RAILING UPGRADE	191,870	K. OLSON
GR137	RIO GRANDE POWER PLANT - CONTROL ROOM	175,222	K. OLSON
GN202	NEWMAN UNIT 5 HRSG VARIABLE SPEED DRIVE-BOILER FEED PUMP	167,485	K. OLSON
GR157	RIO GRANDE UNIT 8 SPARE FORCED DRAFT FAN MOTOR	162,883	K. OLSON
GN209	NEWMAN UNIT 5/GT3 BOILER FEED PUMP UPGRADE	161,997	K. OLSON
GR159	RIO GRANDE UNIT 8 BOILER BURNER TUBE REPLACEMENT	160,801	K. OLSON
GN165	NEWMAN STG 5 - POLE CROSSOVER MODIFICATIONS	156,239	K. OLSON
GN150	PRETREATMENT UNIT FOR NEW REVERSE OSMOSIS AT NEWMAN	149,538	K. OLSON
GN173	NEWMAN UNIT 2 BENCH BOARD TO DCS UPGRADE	143,543	K. OLSON
GN263	NEWMAN UNIT 4 - GT1 GNRTR HYDGN COOLR REPLACEMENT	134,077	K. OLSON
GN221	NEWMAN UNIT 4 TRANSFORMER COOLING TOWER REPLACEMENT	132,725	K. OLSON
GN204	NEWMAN UNIT 3 SPARE BOILER FEEDER PUMP ROTATING ELEMENT	127,968	K. OLSON
GN264	NEWMAN UNIT 4 - GT2 GNRTR HYDGN COOLR REPLACEMENT	122,582	K. OLSON
GN184	NEWMAN UNIT 4 - GT2 INSTRUMENTATION UPGRADES	118,282	K. OLSON
GR030	GENERATION - RIO GRANDE -CAPITAL IMPROVEMENT BLANKET	110,122	K. OLSON
VARIOUS	LESS THAN $100,000	420,407	K. OLSON
	Steam Production Total	123,553,849	
Other Production			
GS109	HOLLOMAN AIR FORCE BASE SOLAR PLANT	12,599,068	K. OLSON
GM120	MONTANA ACQUISITION OF CRITICAL SPARE PARTS	7,629,822	K. OLSON
GS110	TEXAS COMMUNITY SOLAR PROJECT	7,162,847	K. OLSON
GE182	MONTANA UNIT 2	6,914,171	K. OLSON
GM115	MPS WAREHOUSE AND ACCESS ROAD	5,427,716	K. OLSON
GE181	MONTANA UNIT 1	5,054,372	K OLSON
GM002	MONTANA STATION CAPITAL IMPROVEMENTS BLANKET	4,172,503	K. OLSON
GM112	MONTANA STATION GAS BLENDING	2,718,325	K. OLSON
GM117	MONTANA UNIT 1 PARTIAL HOT SECTION COMBUSTOR REPLACEMENT	2,531,389	K. OLSON
GR146	RIO GRANDE UNIT 9 GAS TURBINE HOT SECTION REPLACEMENT	1,974,598	K. OLSON
GM119	MONTANA UNIT 1 SUPERCORE ENGINE	1,368,034	K. OLSON
GC106	COPPER CONTROL SYSTEM UPGRADE	1,251,750	K. OLSON
GM106	MONTANA PORTABLE REVERSE OSMOSIS ELECTRODEIONIZATION WATER TREATMENT	1,110,451	K. OLSON
GM125	MONTANA STATION-INSTALL KIT GAS COMPRESSOR "B"	1,016,470	K. OLSON
GR014	GENERATION -RIO GRANDE BLANKET	681,723	K. OLSON
GC003	GENERATION-COPPER BLANKET	565,728	K. OLSON
GE184	MONTANA UNIT 4 TRAILING CHARGES	559,724	K. OLSON
GC105	COPPER LUBE OIL COOLER REPLACEMENT	529,278	K. OLSON
GR116	RIO GRANDE UNIT 9 CRITICAL SPARE COMPONENTS	454,351	K. OLSON
GR158	RIO GRANDE UNIT 9 SCR CO CATALYST REPLACEMENT	372,461	K. OLSON
GC104	GENERATION COPPER - CAPITAL PARTS AND LABOR	323,068	K. OLSON
GR156	RIO GRANDE UNIT 9 HMI HARDWARE UPGRADE	315,791	K. OLSON
GE183	MONTANA UNIT 3 TRAILING CHARGES	309,827	K. OLSON
GM126	MONTANA LIGHTNING PROTECTION INSTALL	290,846	K. OLSON
GM113	MONTANA CATHOTIC PROTECT JOINT UNITS 1&2 AND JOINT UNITS 3&4	273,765	K. OLSON
GM133	MONTANA DCS CIP CYBER IMPRVMNTS	272,929	K. OLSON
GR149	RIO GRANDE UNIT 9 GUEL GAS PIPE REPLACEMENT	253,019	K OLSON
GM111	REMOVAL AND REPLACEMENT MPS 4 INTERMEDIATE POWER TURBINE	233,741	K. OLSON
GM110	MONTANA UNIT 2 SUPERCORE HPT BLADES REPLACEMENT	230,435	K. OLSON
GM121	MONTANA UNIT 1 HMI HARDWARE UPGRADE	226,031	K. OLSON
GM124	MONTANA UNIT 4 HMI HARDWARE UPGRADE	178,303	K OLSON
GM122	MONTANA UNIT 2 HMI HARDWARE UPGRADE	176,423	K. OLSON
GM123	MONTANA UNIT 3 HMI HARDWARE UPGRADE	176,101	K. OLSON
GM130	MONTANA UNIT 3 CO CATALYST GASKET UPGRADE	144,108	K. OLSON
GM104	MONTANA POWER PLANT - CATWALKS	113,907	K OLSON
GR140	RIO GRANDE UNIT 9 HPC STAGE 1 BLADE REPLACEMENT	110,021	K. OLSON
VARIOUS	LESS THAN $100,000	53,527	K. OLSON
GE180	MONTANA COMMON	(12,843,892)	K. OLSON
	Other Production Total	54,932,731	
Production Total		360,715,380	

RATE BASE ADDITIONS
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PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS	Sponsor
Distribution			
DT069	TEXAS COMMERCIAL CONSTRUCTION BLANKET	44,746,028	C. DOYLE
DT061	TEXAS RESIDENTIAL CONSTRUCTION BLANKET	35,426,072	C. DOYLE
DT062	TEXAS DISTRIBUTION BETTERMENT BLANKET	33,156,327	C. DOYLE
DT359	NUWAY NEW DISTRIBUTION SUBSTATION	16,471,140	C. DOYLE
DT065	TEXAS DISTRIBUTION DAMAGE BLANKET	16,323,388	C. DOYLE
DN061	NEW MEXICO RESIDENTIAL CONSTRUCTION BLANKET	12,653,541	C. DOYLE
DN069	NEW MEXICO COMMERCIAL CONSTRUCTION BLANKET	12,420,834	C. DOYLE
DT371	EXECUTIVE (CE-1) NEW SUBSTATION	12,347,653	C. DOYLE
DT229	SCOTSDALE TRANSFORMER & SWITCHGEAR REPLACEMENTS	9,942,725	C. DOYLE
DT220	SANTA FE SUBSTATION TRANSFORMER, SWITCHGEAR, AND EQUIPMENT UPGRADES	8,801,042	C. DOYLE
DT186	LEO SUBSTATION 115 KV CONVERSION & GETAWAY UPGRADE	8,528,067	C. DOYLE
DT068	TEXAS OVERHEAD SERVICE NEW/REPLACE BLANKET	8,505,501	C. DOYLE
MT004	TEXAS METERS BLANKET	8,226,133	C. DOYLE
DN062	NEW MEXICO DISTRIBUTION BETTERMENT	7,989,900	C. DOYLE
DT189	TEXAS AREA 4KV CONVERSIONS	4,860,348	C. DOYLE
MN004	NEW MEXICO METERS BLANKET	4,685,672	C. DOYLE
DT365	SPARKS T2 TRANSFORMER, SWITCHGEAR, AND VOLTAGE REGULATORS	4,366,530	C. DOYLE
DN196	JORNADA SUBSTATION (T2 50 MVA TRANSFORMER ADDITION)	4,217,263	C. DOYLE
DN068	NEW MEXICO OVERHEAD SERVICE NEW AND/OR REPLACEMENT BLANKET	4,115,469	C. DOYLE
DN065	NEW MEXICO DISTRIBUTION DAMAGE BLANKET	4,014,074	C. DOYLE
DT382	RIPLEY T2 TRANSFORMER, SWITCHGEAR, AND VOLTAGE REGULATOR ADDITIONS	3,897,918	C. DOYLE
DT379	PENDALE T2 TRANSFORMER, SWITCHGEAR, AND VOLTAGE REGULATOR ADDITIONS	3,718,450	C. DOYLE
DT063	TEXAS SUBSTATION BETTERMENT BLANKET	3,674,064	C. DOYLE
DT389	SUNSET NORTH AUTO TRANSFORMER REPLACEMENT	3,656,864	C. DOYLE
DT372	POLE REPLACEMENT & IMPROVEMENTS TEXAS	3,451,028	C. DOYLE
DT291	GLOBAL REACH T2 AND SWITCHGEAR	3,439,982	C. DOYLE
DT194	SUNSET 69KV-4KV TRANSFORMER, REGULATORS, AND FEEDER REPLACEMENTS	3,020,849	C. DOYLE
DT383	PELLICANO T2 TRANSFORMER ADDITION	2,996,995	C. DOYLE
DT184	RIO BOSQUE CAPACITOR BANK ADDITION	2,855,028	C. DOYLE
DT218	SUNSET 14KV SWITCHGEAR AND NETWORK FEEDER REPLACEMENTS	2,809,949	C. DOYLE
DN063	NEW MEXICO SUBSTATION BETTERMENT BLANKET	2,670,255	C. DOYLE
DN198	JORNADA FEEDERS	2,613,641	C. DOYLE
DT121	TEXAS CABLE REPLACEMENT PROGRAM BLANKET	2,426,528	C. DOYLE
DT064	TEXAS LIGHTING BLANKET	2,391,878	C. DOYLE
DT416	DISTRIBUTION DUAL VOLTAGE MOBILE TRANSFORMER	2,313,824	C. DOYLE
DN192	HATCH 21 REBUILD	2,256,739	C. DOYLE
DT439	SUNSET T4 SWITCHGEAR REPLACEMENT	1,927,740	C. DOYLE
DN100	HATCH LINE REBUILD	1,864,281	C. DOYLE
DT353	STREET CAR (TROLLEY) - CITY OF EL PASO	1,850,161	C. DOYLE
DT300	FARMER 69KV 7.5 MVAR CAPACITOR BANK	1,841,131	C. DOYLE
DT361	SUBSTATION CIRCUIT BREAKER UPGRADES MPS	1,742,713	C. DOYLE
DT417	MONTWOOD T1 TRANSFORMER UPGRADE TO 50 MVA	1,704,074	C. DOYLE
DT392	SOL & VISTA DISTRIBUTION SUBSTATION UPGRADES	1,685,670	C. DOYLE
DT404	MONTWOOD SUBSTATION LAND & PRE-FAB WALL	1,662,443	C. DOYLE
DT354	NETWORK SYSTEM UPGRADE BY EATON	1,633,841	C. DOYLE
DT288	TRANSMOUNTAIN (NW-3) GETAWAYS/FEEDER	1,613,192	C. DOYLE
DT368	RIPLEY GETAWAYS AND FEEDER ADDITIONS	1,568,587	C. DOYLE
DT430	FORT BLISS EMERGENCY TRANSFORMER REPLACEMENT	1,556,787	C. DOYLE
DT270	GLOBAL REACH SUB FEEDERS	1,445,673	C. DOYLE
DT350	NEW SPARKS-T2 FEEDERS	1,437,027	C. DOYLE
DT377	PENDALE GETAWAYS AND FEEDER ADDITIONS	1,431,289	C. DOYLE
DT402	TEXAS 4KV GROUNDING AND FENCING ADDITIONS	1,385,936	C. DOYLE
DN202	ANTHONY SUBSTATION T2 TRANSFORMER REPLACEMENT	1,305,736	C. DOYLE
DT314	TWO WAY DISTRIBUTION CAPACITOR COMMUNICATION	1,252,972	C. DOYLE
DT203	FABENS CAPBANK ADDITION	1,187,305	C. DOYLE
DT369	PELLICANO T2 FEEDERS	1,151,442	C. DOYLE
DT370	EXECUTIVE (CE-1) NEW FEEDERS	1,140,587	C. DOYLE
DT230	MESA-18 RECONDUCTOR	1,070,441	C. DOYLE
DN064	NEW MEXICO LIGHTING BLANKET	1,067,047	C. DOYLE
DT437	SUNSET PERIMETER EXPANSION AND STRUCTURAL IMPROVEMENTS	1,058,110	C. DOYLE
DT234	RE-CABLE DOWNTWN NETWORK FEEDERS	998,306	C. DOYLE

RATE BASE ADDITIONS
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PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS	Sponsor
DT317	SANTA FE FEEDER IMPROVEMENTS	971,956	C. DOYLE
DT418	PELLICANO TRANSFORMER T1 50MVA UPGRADE	967,124	C. DOYLE
DT415	MONTWOOD T3 EMERGENCY REPLACEMENT	933,891	C. DOYLE
DT444	AMERICAS TRANSFORMER REPLACEMENT	840,376	C. DOYLE
DT015	RELAY UPGRADES TEXAS DISTRIBUTION SUBSTATION BLANKET	797,123	C. DOYLE
DT422	SUNSET 69KV SUB UPGRADES	711,751	C DOYLE
DN178	TALAVERA SUBSTATION GETAWAYS AND FEEDERS	700,117	C. DOYLE
DT256	SCOTSDALE 13 8 KV FEEDER GETAWAYS REPLACEMENT	653,273	C. DOYLE
DN177	NEW MEXICO SUBSTATION 4KV CONVERSIONS	590,290	C. DOYLE
DN183	CHAPARRAL-15 FEEDER	585,611	C. DOYLE
DT407	ASCARATE PRE-FAB WALL	546,017	C. DOYLE
DN015	RELAY UPGRADES NEW MEXICO DISTRIBUTION SUBSTATIONS	541,512	C. DOYLE
DN212	ARROYO ITE CIRCUIT BREAKER REPLACEMENT	523,724	C. DOYLE
DT391	NEW TRIUMPH (FE1) SUBSTATION	472,691	C. DOYLE
DT282	LEO GETAWAYS	469,906	C. DOYLE
DN203	NEW MEXICO 4KV GROUNDING AND FENCING IMPROVEMENTS	451,010	C. DOYLE
DT257	DIAMOND HEAD SUBSTATION (SE-2)	442,333	C. DOYLE
DT007	DISTRIBUTION TEXAS FACILITY SERVICES BLANKET	416,577	C. DOYLE
DT446	RIO BOSQUE DISTRIBUTION FEEDER ADDITIONS	407,697	C DOYLE
DN080	DISTRIBUTION NEW MEXICO RIGHT OF WAY AND LAND ACQUISITION BLANKET	372,745	C. DOYLE
DN194	UPGRADE TWO WAY DIST CAPACITOR COMM-NM	346,728	C. DOYLE
DT174	COPPER AND LANE FEEDER IMPROVEMENTS	340,858	C. DOYLE
MT102	ERT METER INSTALLATION BLANKET	334,455	C DOYLE
DT401	MONTOYA CONTROL HOUSE EXPANSION	314,102	C. DOYLE
DT398	DYER SUBSTATION EXPANSION	303,188	C. DOYLE
DT443	QUITMAN MOUNTAIN DISTRIBUTION LINE UPGRADES	297,440	C DOYLE
DN193	POLE REPLACEMENTS & IMPROVEMENTS NEW MEXICO BLANKET	281,309	C DOYLE
DN215	NEW MEXICO EMERGENCY & UNPLANNED DISTRIBUTION SUBSTATION EQUIPMENT BLANKET	253,049	C. DOYLE
DN206	SALOPEK SUBSTATION CONTROL HOUSE EXPANSION	230,355	C. DOYLE
DT188	DISTRIBUTION SUBSTATION CIRCUIT BREAKER REPLACEMENTS TEXAS BLANKET	212,826	C. DOYLE
DT312	REBUILD ALAMO 21 FEEDER	200,153	C. DOYLE
DT295	DFR INSTALLATION	164,511	C. DOYLE
DT429	DYER T1 TRANSFORMER LTC REPLACEMENT	163,961	C. DOYLE
DN210	INTERCONNECTION 5 MW HOLLOMAN SOLAR	158,444	C. DOYLE
DT384	MONTWOOD SUBSTATION EQUIPMENT ADDITIONS	108,499	C. DOYLE
DT373	EPE SYSTEM OPERATIONS BACKUP FEEDER	101,313	C. DOYLE
Various	LESS THAN $100,000	335,109	C. DOYLE
Distribution Total		363,116,214	
Transmission			
TL249	ISLETA PUEBLO LAND RIGHTS RENEWAL	16,824,750	C. DOYLE
TL101	RIO GRANDE TO SUNSET AND SUNSET NORTH TRANSMISSION LINE UPGRADES	9,111,117	C. DOYLE
TL174	LANE - COPPER 16900 LINE REBUILD	7,239,999	C. DOYLE
TH162	ARROYO AUTOTRANSFORMER ADDITION	7,022,925	C. DOYLE
TP100	PALO VERDE TRANSMISSION BLANKET	4,890,475	C. DOYLE
TA100	LUNA TO SPRINGERVILLE RIGHT OF WAY ACQUISITIONS AND RENEWALS	4,853,912	C. DOYLE
TL231	MILAGRO - LEO 69KV TO 115KV UPGRADE	4,789,170	C. DOYLE
TL015	TRANSMISSION LINES IMPROVEMENTS AND UPGRADES	5,039,804	C. DOYLE
TL127	FARMER - FELIPE STRUCTURE REPLACEMENT	4,692,597	C. DOYLE
TL239	DURAZNO-ASCARATE 115KV TRANSMISSION LINE REBUILD	4,378,604	C. DOYLE
TH166	ARROYO-WEST MESA 345 KV LINE REPLACEMENTS/IMPROVEMENTS	4,125,494	C. DOYLE
TL247	TXDOT TRANSMISSION LINE MODIFICATIONS	4,057,641	C. DOYLE
TL181	MONTANA SUBSTATION AND TRANSMISSION LINES	3,544,863	C. DOYLE
TL293	FABENS TO FELIPE TRANSMISSION LINE UPGRADES	3,288,981	C. DOYLE
TL240	SUNSET NORTH-DURZNO 115KV LINE UPGRADES	3,055,978	C. DOYLE
TS123	CALIENTE AUTOTRANSFORMER AND CIRCUIT BREAKER REPLACEMENT	2,920,232	C. DOYLE
TL189	SOL TO VISTA 115kV TRANSMISSION LINE RECONDUCTOR AND REBUILD	2,596,460	C. DOYLE
TS063	TRANSMISSION SUBSTATION IMPROVEMENTS BLANKET	2,390,466	C. DOYLE
TH760	SOUTHWEST NEW MEXICO TRANSMISSION BLANKET - MIXED COSTS	2,291,248	C. DOYLE
TE100	EMERGENCY TRANSMISSION STRUCTURE REPLACEMENT	2,029,022	C. DOYLE
TL135	APOLLO-COX TRANSMISSION LINE REBUILD	1,451,173	C. DOYLE
TH360	SOUTHWEST NEW MEXICO TRANSMISSION BLANKET – SHARED	1,444,352	C. DOYLE
TS126	NEWMAN SUBSTATION T3 AND T4 REPLACEMENTS	1,418,975	C. DOYLE

RATE BASE ADDITIONS
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PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS	Sponsor
TL233	MONTOYA TO NUWAY TRANSMISSION LINE REROUTE	1,416,162	C. DOYLE
TL259	SUNSET-SANTA FE TRANSMISSION LINE UPGRADES	1,357,197	C. DOYLE
TH167	AMRAD TO EDDY RIGHT OF WAY ACQUISITION AND RENEWALS	1,208,067	C. DOYLE
TL236	EXECUTIVE TRANSMISSION LINE TAP	817,206	C DOYLE
TL275	DIABLO - LUNA BLM PERMIT RENEWAL	805,790	C. DOYLE
TS128	NEWMAN CONTROL HOUSE ADDITION	790,000	C. DOYLE
TL269	LUNA-DIABLO AND LUNA-AFTON GROUND WIRE ADDITIONS	730,092	C DOYLE
TS065	RELAY UPGRADES IN TRANSMISSION SUBSTATIONS	660,849	C. DOYLE
TS158	EDDY TIE T2 TRANSFORMER REPLACEMENT	640,301	C DOYLE
TL253	69KV WOOD POLE REPLACEMENTS ON GATEWAY	619,821	C DOYLE
TS127	HIDALGO SUBSTATION REACTOR REPLACEMENT	608,124	C. DOYLE
TL238	TRANSMISSION LINE MARKER BALL ADDITIONS	589,378	C. DOYLE
TS130	NEWMAN 115KV CIRCUIT BREAKER REPLACEMENTS	580,554	C. DOYLE
TT080	TRANSMISSION RIGHT OF WAY AND LAND ACQUISITION BLANKET	553,477	C. DOYLE
TS151	AMRAD STATIC VAR COMPENSATOR CONTROLLER REPLACEMENT	550,161	C. DOYLE
TA015	ARIZONA INTERCONNECTION PROJECT (AIP) TRANSMISSION IMPROVEMENTS BLANKET	546,851	C. DOYLE
TH350	EASTERN INTERCONNECTION PROJECT CAPITAL BLANKET	445,065	C. DOYLE

RATE BASE ADDITIONS
FOR THE PERIOD OCTOBER 1, 2016 THROUGH DECEMBER 31, 2020

PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS	Sponsor
TS132	ORO GRANDE CIRCUIT BREAKER REPLACEMENTS	427,976	C. DOYLE
TH015	TRANSMISSION IMPROVEMENTS BLANKET (OLD)	410,135	C. DOYLE
TL246	SCOTSDALE TRANSMISSION LINE MODIFICATIONS	370,841	C. DOYLE
TS129	AMRAD CIRCUIT BREAKER 2968 REPLACEMENT	318,872	C. DOYLE
TL261	GREENLEE TO HIDALGO LINE IMPROVEMENTS	280,056	C. DOYLE
TT060	NERC COMPLIANCE ACTIVITY - TRANSMISSION	252,111	C. DOYLE
TS124	CALIENTE ACCESS ROAD PAVING	211,570	C. DOYLE
TS134	HIDALGO ITE CIRCUIT BREAKER 03882B REPLACEMENT	170,650	C. DOYLE
TS153	ARROYO P.I.R. CIRCUIT BREAKER REPLACEMENT	150,866	C DOYLE
TL137	DYER- LEO 115KV LINE ADJUSTMENTS	124,225	C. DOYLE
TL234	TXDOT COLLECTOR - LANE REBUILD	(1,766,104) (b)	C. DOYLE
TL139	FT. BLISS INDUSTRIAL COMPLEX	(2,898,959) (c)	C. DOYLE
VARIOUS	LESS THAN $100,000	189,299	C DOYLE
Transmission Total		114,618,871	
General			
SS005	TRANSPORTATION EQUIPMENT/FLEET ACQUISITIONS	15,965,131	L. HANCOCK
SF007	SHARED SERVICES FACILITY SERVICES IMPROVEMENTS BLANKET	4,956,118	L HANCOCK
ST040	IT OPERATIONS BLANKET HARDWARE	4,936,687	L. HANCOCK
SS040	INFORMATION TECHNOLOGY (IT) CORPORATE HARDWARE BLANKET	4,404,007	L. HANCOCK
SS189	PHYSICAL SECURITY IMPROVEMENTS (CIP-014)	3,898,501	L. HANCOCK
TS108	SYSTEM OPERATIONS BUILDING EXPANSION	3,647,861	L HANCOCK
DT030	DISTRIBUTION GENERAL PLANT ACQUISITIONS	3,571,551	L. HANCOCK
SF118	FABENS DISTRIBUTION CENTER	2,516,192	L. HANCOCK
SC050	OPERATIONAL TECHNOLOGY NETWORK CAPITAL BLANKET-HARDWARE	2,389,473	L. HANCOCK
TS109	ENERGY MGMT SYSTEM REPLACEMENT HARDWARE (SYSTEM OPERATIONS)	2,163,512	L HANCOCK
SS030	SHARED SERVICES GENERAL ACQUISITION BLANKET	1,666,152	L. HANCOCK
SC040	INFORMATION TECHNOLOGY COMMUNICATION BLANKET - HARDWARE	1,614,578	L. HANCOCK
SS070	PHYSICAL SECURITY SYSTEMS	1,272,722	L. HANCOCK
ST044	INFORMATION SECURITY BLANKET	995,929	L. HANCOCK
SS007	EASTSIDE DISTRIBUTION OPERATIONS CENTER FACILITY SERVICES BLANKET	985,106	L. HANCOCK
SS151	NEW EASTSIDE DISTRIBUTION OPERATIONS CENTER FACILITY	806,353	L. HANCOCK
SC145	COMMUNICATION RE-ENGINEERING	775,166	L HANCOCK
ST043	EMS SUPPORT BLANKET?	759,435	L. HANCOCK
ST103	EMS SHARED STORAGE	654,259	L. HANCOCK
SS190	SECURITY OPERATIONS CENTER	647,665	L. HANCOCK
SC146	VERIFICATION & INTEGRATIONS LAB BLNKT	636,230	L. HANCOCK
SS197	LAS CRUCES COMPRESS PERIPHERAL SECURITY	634,582	L. HANCOCK
SS157	STANTON BATHROOM RENOVATIONS	591,834	L HANCOCK
SF135	EASTSIDE DITRIBUTION OPERATIONS CENTER FLEET & WAREHOUSE IMPROVEMENTS	559,216	L. HANCOCK
SF119	SYSTEM OPERATIONS- ADDITIONAL BACK UP GENERATOR	531,906	L. HANCOCK
SS202	FLEET TELEMATICS	500,368	L. HANCOCK
TL184	MACHO SPRINGS INSTALL-FIBER OPTIC	490,265	L. HANCOCK
SF121	STANTON-SERVICE SINK CLOSET RENOVATIONS	472,891	L. HANCOCK
GM030	GENERATION - MONTANA POWER STATION BLANKET PROJECT	470,091	L. HANCOCK
SS191	CUSTOMER CARE & BILLING VERSION 2.4 UPGRADE SOFTWARE	391,996	L. HANCOCK
TT007	TRANSMISSION -FACILITY SERVICES BLANKET	347,828	L. HANCOCK
SC153	PROTECTION SIGNALING UPGRADES BLANKET	331,559	L. HANCOCK
SS262	STANTON AUDITORIUM IMPROVEMENTS	311,563	L. HANCOCK
SF115	MONTANA POWER STATION - ENVIRONMENTAL BUILDING	254,655	L. HANCOCK
SF109	EASTSIDE DISTRIBUTION OPERATIONS CENTER ENVIRONMENTAL BUILDING	244,305	L HANCOCK
GG012	GENERATION ENVIRONMENTAL BLANKET	237,128	L. HANCOCK
SF114	STANTON TOWER - CARPET REPLACEMENT	228,630	L. HANCOCK
DN007	DISTRIBUTION -NEW MEXICO -FACILITIES SERVICES BLANKET	202,803	L. HANCOCK
SC154	MICROWAVE RADIO UPGRADES-TRUEPOINT	201,131	L. HANCOCK
SS195	CYPHER LOCK SYSTEMS REPLACEMENT	196,292	L. HANCOCK
SC147	WAVELENGTH EXPANSION & NETWORK DESIGN	195,952	L. HANCOCK
SS208	OUTAGE MANAGEMENT SYSTEM SOFTWARE UPGRADE	192,444	L. HANCOCK
SS198	CIP V5 PHYSICAL SECURITY HARDWARE IMPROVEMENTS	172,226	L. HANCOCK
SC149	SYSTEM ONE GENERATION REFRESH/UPGRADE	169,833	L. HANCOCK
SS203	GIS VERSION 10.2 UPGRADE	160,173	L. HANCOCK

RATE BASE ADDITIONS
FOR THE PERIOD OCTOBER 1, 2016 THROUGH DECEMBER 31, 2020

PROJECT	PROJECT DESCRIPTION	ADJUSTED GROSS ADDITIONS		Sponsor
GN030	GENERATION -NEWMAN -BLANKET	154,463		L. HANCOCK
ST102	EMS ETERRA SOURCE UPGRADE	147,485		L. HANCOCK
SF136	LAS CRUCES WATER STREET PARKING LOT IMPROVEMENTS	133,224		L. HANCOCK
GR030	GENERATION -RIO GRANDE - BLANKET	133,200		L. HANCOCK
SS216	ITRON MVRS UPGRADE	126,289		L. HANCOCK
SF117	EASTSIDE DISTRIBUTION OPERATIONS CENTER WAREHOUSE EXPANSION	122,481		L. HANCOCK
TL139	FT. BLISS INDUSTRIAL COMPLEX	(156,053)	(c)	L. HANCOCK
VARIOUS	LESS THAN $100,000	641,688		L. HANCOCK
General Total		68,655,076		
Intangible				
TS109	ENERGY MGMT SYSTEM REPLACEMENT SOFTWARE (SYSTEM OPERATIONS)	12,707,391		L. HANCOCK
SS183	WORK MGMT SYSTEM (A.R.M) FOR TRANSMISSION, SUBSTATION AND RELAY	4,567,438		L. HANCOCK
SS191	CUSTOMER CARE & BILLING (CUSTOMER CARE & BILLING) 2.4 UPGRADE SOFTWARE	3,649,039		L. HANCOCK
SS192	REGULATORY MANAGEMENT SUITE SOFTWARE	2,761,190		L. HANCOCK
ST040	IT OPERATIONS BLANKET HARDWARE	2,654,418		L. HANCOCK
SS231	POWERPLAN SOFTWARE UPGRADE	1,882,168		L. HANCOCK
SS218	HUMAN RESOURCES INFORMATION SYSTEM (ULTIPRO) SOFTWARE	1,759,761		L. HANCOCK
SS040	INFORMATION TECHNOLOGY (IT) CORPORATE HARDWARE BLANKET	1,598,596		L. HANCOCK
SS105	LIVE LINK SYSTEM SOFTWARE UPGRADES BLANKET	1,239,111		L. HANCOCK
SS182	TRANSMISSION GIS DATA GATHERING SOFTWARE	1,214,541		L. HANCOCK
SS208	OUTAGE MANAGEMENT SYSTEM SOFTWARE UPGRADE	1,173,883		L. HANCOCK
ST044	INFORMATION SECURITY BLANKET	1,089,712		L. HANCOCK
SS204	ARM 2 UPGRADE SOFTWARE	1,085,469		L. HANCOCK
SS220	POWER PLANT LEASE ACCOUNTING MODULE	1,022,550		L. HANCOCK
ST041	BUSINESS APPLICATIONS BLANKET	837,635		L. HANCOCK
ST043	EMS SUPPORT BLANKET	820,382		L. HANCOCK
SS203	GIS VERSION 10.2 UPGRADE	751,459		L. HANCOCK
SS222	TIBCO UPGRADE	711,426		L. HANCOCK
SS112	CUSTOMER SERVICE SYSTEM UPGRADE BLNKT	428,498		L. HANCOCK
GG042	GENERATION SYSTEM UPGRADE BLANKET	426,352		L. HANCOCK
SS234	INSERVICE UPGRADE	352,499		L. HANCOCK
DT042	T&D SYSTEM UPGRADE BLANKET	242,730		L. HANCOCK
SS213	CREW CALLOUT SOFTWARE	212,211		L. HANCOCK
SS207	CUSTOMER CARE & BILLING SW ADAPTIVE WAREHOUSE TO DATA STAGE	207,063		L. HANCOCK
TT102	TRANSMISSION OUTAGE APPLICATION UPGRADE	200,461		L. HANCOCK
SS258	DISTR GEN INTERCONNECTION APPLICATION	187,972		L. HANCOCK
SC150	GENERATION OPEX SOFTWARE	186,328		L. HANCOCK
ST042	CORP TECH SYSTEM UPGRADE BLANKET	167,762		L. HANCOCK
SC146	VERIFICATION & INTEGRATION LAB BLANKET	166,064		L. HANCOCK
SC041	INFORMATION TECHNOLOGY COMMUNICATION BLANKET - HARDWARE	150,295		L. HANCOCK
SS201	COMMUNITY SOLAR PROJECT	144,152		L. HANCOCK
ST106	ENERGY MANAGEMENT SYSTM LOGRHYTHM REFRESH	115,288		L. HANCOCK
SS229	LAND MGMT RECORD DIGITIZATION	108,721		L. HANCOCK
SS223	TIDAL UPGRADE	108,514		L. HANCOCK
SS170	SYSTEM SIMULATION SOFTWARE	108,393		L. HANCOCK
SC050	OPERATIONAL TECHNOLOGY NETWORK CAPITAL BLANKET-SOFTWARE	107,204		L. HANCOCK
ST104	EMS - INTRUSION DETECTION SYSTEM	106,359		L. HANCOCK
SS243	CUSTOMER CARE & BILLING UPGRADE	101,368		L. HANCOCK
VARIOUS	LESS THAN $100,000	873,199		L. HANCOCK
Intangible Total		46,227,602		
Total Additions to Plant Since Last TX Rate Case (October 1, 2016 - December 31, 2020)		**$ 953,333,144**		

(a) The gross addition to plant in service was offset by insurance proceeds of $18,146,155 that were credited to Accumulated Provision for Depreciation (in accordance with FERC guidelines). As a result, the net addition to rate base is $3,484,352

(b) Includes $2,062,900 of reimbursements received from the Texas Department of Transportation (TXDOT) in October 2017. As a result, only $430,097 of net costs (non reimbursable) related to Project TL234 are included in rate base in this filing.

(c) Represents reimbursement of cost incurred to construct a transmission substation at Ft. Bliss.

El Paso Electric Company
Palo Verde Net Plant In Service
As of December 31, 2020

	Total Company		
	Gross Plant In Service	**Accumulated Provision for Depreciation**	**Net Plant In Service**
Unit 1	$ 389,330,841	$ (137,544,865)	$ 251,785,976
Unit 2	431,715,957	(160,701,818)	271,014,140
Unit 3	391,895,675	(131,776,201)	260,119,474
	$ 1,212,942,474	$ (430,022,884)	$ 782,919,589

	Texas (D-1: 81.161%)		
	Gross Plant In Service	**Accumulated Provision for Depreciation**	**Net Plant In Service**
Unit 1	$ 315,984,804	$ (111,632,788)	$ 204,352,016
Unit 2	350,384,988	(130,427,202)	219,957,786
Unit 3	318,066,449	(106,950,883)	211,115,566
	$ 984,436,241	$ (349,010,873)	$ 635,425,368

El Paso Electric Company
Palo Verde - Recalculated Gross Plant In Service
As of December 31, 2020

UNIT 1 Annual Details

As of:	Beginning Basis	Additions	Retirements	Net Addns	Gross Plant Balance
2/12/96 Revalued Basis	$ 173,140,000				$ 173,140,000
Dec 31, 1996		$ 1,402,653	$ (9,558)	$ 1,393,095	174,533,095
Dec 31, 1997		192,753	-	192,753	174,725,848
Dec 31, 1998		3,821,379	(1,703,333)	2,118,046	176,843,894
Dec 31, 1999		3,985,122	(77,910)	3,907,212	180,751,106
Dec 31, 2000		3,515,998	(1,656,748)	1,859,250	182,610,356
Dec 31, 2001		1,831,063	(631,736)	1,199,327	183,809,683
Dec 31, 2002		1,554,249	(114,668)	1,439,581	185,249,264
Dec 31, 2003		3,364,119	(318,900)	3,045,219	188,294,483
Dec 31, 2004		246,266	(759,170)	(512,904)	187,781,579
Dec 31, 2005		37,886,399	(4,845,589)	33,040,810	220,822,389
Dec 31, 2006		15,691,147	(2,713,937)	12,977,210	233,799,599
Dec 31, 2007		3,321,131	(683,150)	2,637,981	236,437,580
Dec 31, 2008		8,747,859	(388,507)	8,359,352	244,796,932
Dec 31, 2009		5,290,944	(1,453,357)	3,837,587	248,634,519
Dec 31, 2010		16,193,250	(1,751,888)	14,441,362	263,075,881
Dec 31, 2011		13,123,091	(1,013,005)	12,110,086	275,185,967
Dec 31, 2012		9,868,395	(740,950)	9,127,445	284,313,412
Dec 31, 2013		10,904,840	(1,401,113)	9,503,727	293,817,139
Dec 31, 2014		22,738,064	(284,260)	22,453,804	316,270,943
Dec 31, 2015		7,560,264	(1,076,917)	6,483,347	322,754,290
Dec 31, 2016		16,110,567	(3,024,078)	13,086,489	335,840,779
Dec 31, 2017		16,808,253	(903,597)	15,904,657	351,745,435
Dec 31, 2018		7,315,693	(1,326,947)	5,988,746	357,734,181
Dec 31, 2019		12,410,416	(1,472,490)	10,937,927	368,672,108
Dec 31, 2020		21,475,143	(816,410)	20,658,733	**$ 389,330,841**
		$ 245,359,059	$ (29,168,217)	$ 216,190,841	

UNIT 2 Annual Details

	Beginning Basis	Additions	Retirements	Net Addns	Gross Plant Balance
2/12/96 Revalued Basis	$ 215,285,000				$ 215,285,000
Dec 31, 1996		$ 2,184,331	$ (9,558)	$ 2,174,773	217,459,773
Dec 31, 1997		323,109	-	323,109	217,782,882
Dec 31, 1998		2,520,753	(1,963,046)	557,707	218,340,589
Dec 31, 1999		3,525,260	(2,161,421)	1,363,839	219,704,428
Dec 31, 2000		3,263,652	(1,525,374)	1,738,278	221,442,706
Dec 31, 2001		1,588,008	(181,700)	1,406,309	222,849,014
Dec 31, 2002		3,149,792	(631,804)	2,517,988	225,367,003
Dec 31, 2003		46,996,783	(3,404,528)	43,592,255	268,959,258
Dec 31, 2004		11,418,981	(3,055,177)	8,363,804	277,323,062
Dec 31, 2005		1,921,332	(281,665)	1,639,667	278,962,729
Dec 31, 2006		3,142,060	(403,297)	2,738,763	281,701,492
Dec 31, 2007		2,017,315	(775,300)	1,242,015	282,943,507
Dec 31, 2008		6,864,903	(798,438)	6,066,465	289,009,972
Dec 31, 2009		4,844,437	(518,255)	4,326,182	293,336,154
Dec 31, 2010		19,182,148	(3,409,013)	15,773,135	309,109,289
Dec 31, 2011		15,157,506	(1,780,689)	13,376,817	322,486,106
Dec 31, 2012		9,037,372	(371,461)	8,665,911	331,152,017
Dec 31, 2013		8,847,127	(2,126,659)	6,720,468	337,872,485
Dec 31, 2014		18,785,531	(2,436,117)	16,349,414	354,221,899
Dec 31, 2015		22,268,426	(657,421)	21,611,005	375,832,904
Dec 31, 2016		7,803,646	(1,855,112)	5,948,534	381,781,438
Dec 31, 2017		14,321,477	(971,770)	13,349,707	395,131,145
Dec 31, 2018		16,451,755	(1,688,043)	14,763,712	409,894,857
Dec 31, 2019		9,840,362	(1,417,380)	8,422,982	418,317,839
Dec 31, 2020		14,185,620	(787,502)	13,398,118	**$ 431,715,957**
		$ 249,641,688	$ (33,210,730)	$ 216,430,957	

El Paso Electric Company
Palo Verde - Recalculated Gross Plant In Service
As of December 31, 2020

		UNIT 3 Annual Details			
	Beginning Basis	**Additions**	**Retirements**	**Net Addns**	**Gross Plant Balance**
2/12/96 Revalued Basis	$ 173,904,000				$ 173,904,000
Dec 31, 1996		$ 2,785,565	$ (9,558)	$ 2,776,007	176,680,007
Dec 31, 1997		1,417,752	-	1,417,752	178,097,759
Dec 31, 1998		1,374,518	(1,268,778)	105,740	178,203,499
Dec 31, 1999		1,592,379	(84,293)	1,508,086	179,711,585
Dec 31, 2000		3,113,943	(1,580,066)	1,533,877	181,245,462
Dec 31, 2001		2,440,935	(438,877)	2,002,058	183,247,520
Dec 31, 2002		1,949,130	(104,085)	1,845,045	185,092,565
Dec 31, 2003		4,838,657	(481,461)	4,357,196	189,449,761
Dec 31, 2004		1,508,674	(398,899)	1,109,775	190,559,536
Dec 31, 2005		1,936,384	(1,255,935)	680,449	191,239,985
Dec 31, 2006		4,150,173	(345,139)	3,805,034	195,045,019
Dec 31, 2007		1,397,916	(193,599)	1,204,317	196,249,336
Dec 31, 2008		56,999,385	(7,502,223)	49,497,162	245,746,498
Dec 31, 2009		7,998,258	(1,197,560)	6,800,698	252,547,196
Dec 31, 2010		16,786,084	(1,495,222)	15,290,862	267,838,058
Dec 31, 2011		12,531,698	(1,009,527)	11,522,171	279,360,229
Dec 31, 2012		8,946,576	(1,054,898)	7,891,678	287,251,907
Dec 31, 2013		8,926,778	(1,165,255)	7,761,523	295,013,430
Dec 31, 2014		18,767,949	(595,845)	18,172,104	313,185,534
Dec 31, 2015		16,980,246	(1,297,394)	15,682,852	328,868,385
Dec 31, 2016		12,140,734	(166,721)	11,974,013	340,842,399
Dec 31, 2017		14,454,623	(1,354,917)	13,099,706	353,942,105
Dec 31, 2018		14,634,942	(1,531,682)	13,103,261	367,045,366
Dec 31, 2019		18,840,766	(566,011)	18,274,755	385,320,121
Dec 31, 2020		7,901,432	(1,325,878)	6,575,555	**$ 391,895,675**
		$ 244,415,498	$ (26,423,822)	$ 217,991,675	

		Annual Activity				
As of:	Beginning Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage	Ending Balance
Unit 1						
Sept 30 - Dec 31, 1996	$ -	$ (1,498,591)	$ 9,558	$ 34,537	$ (4,944)	$ (1,459,440)
1997	(1,459,440)	(6,021,825)	-	69,435	(1,777)	(7,413,607)
1998	(7,413,607)	(6,064,490)	1,703,333	47,194	(12,078)	(11,739,648)
1999	(11,739,648)	(6,178,852)	77,910	124,453	3,284	(17,712,853)
2000	(17,712,853)	(6,291,175)	1,656,748	51,772	(5,468)	(22,300,976)
2001	(22,300,976)	(6,353,346)	631,736	396,412	(4,292)	(27,630,466)
2002	(27,630,466)	(6,409,627)	114,668	9,796	(19,476)	(33,935,105)
2003	(33,935,105)	(6,510,132)	318,900	75,868	(6,844)	(40,057,313)
2004	(40,057,313)	(6,567,129)	759,170	50,236	(3,308)	(45,818,344)
2005	(45,818,344)	(7,380,937)	4,845,589	2,357,572	(4,386)	(46,000,506)
2006	(46,000,506)	(8,548,464)	2,713,937	253,908	(3,025)	(51,584,150)
2007	(51,584,150)	(8,963,246)	683,150	322,359	(5,468)	(59,547,355)
2008	(59,547,355)	(9,282,387)	388,507	80,282	(36,783)	(68,397,736)
2009	(68,397,736)	(9,648,176)	1,453,357	236,367	(2,577)	(76,358,765)
2010	(76,358,765)	(7,937,235)	1,751,888	579,962	(4,403)	(81,968,553)
2011	(81,968,553)	(6,009,386)	1,013,005	512,310	(6,054)	(86,458,678)
2012	(86,458,678)	(6,325,770)	740,950	99,590	(337,076)	(92,280,984)
2013	(92,280,984)	(6,612,560)	1,401,113	459,372	(356,323)	(97,389,382)
2014	(97,389,382)	(7,123,213)	284,260	492,332	-	(103,736,003)
2015	(103,736,003)	(6,557,399)	1,076,917	284,133	(451,514)	(109,383,865)
2016	(109,383,865)	(6,541,917)	3,024,078	1,375,652	(6,118)	(111,532,170)
2017	(111,532,170)	(7,050,270)	903,597	661,136	(43,345)	(117,061,052)
2018	(117,061,052)	(7,447,976)	1,326,947	467,184	(455,779)	(123,170,676)
2019	(123,170,676)	(7,767,198)	1,472,490	372,231	26,136	(129,067,017)
2020	(129,067,017)	(8,378,647)	816,410	774,815	(1,690,426)	**$ (137,544,865)**
		$ (173,469,948)	$ 29,168,217	$ 10,188,908	$ (3,432,043)	
Unit 2						
Sept 30 - Dec 31, 1996	$ -	$ (1,803,103)	$ 9,558	$ 654	$ (4,944)	$ (1,797,835)
1997	(1,797,835)	(7,254,230)	-	(46)	(1,777)	(9,053,888)
1998	(9,053,888)	(7,269,760)	1,963,046	90,742	(12,078)	(14,281,938)
1999	(14,281,938)	(7,304,975)	2,161,421	16,874	3,284	(19,405,334)
2000	(19,405,334)	(7,363,660)	1,525,374	32,504	(5,468)	(25,216,584)
2001	(25,216,584)	(7,425,215)	181,700	77,047	(4,292)	(32,387,344)
2002	(32,387,344)	(7,505,799)	631,804	412,380	(19,476)	(38,868,435)
2003	(38,868,435)	(8,505,915)	3,404,528	16,539	(6,844)	(43,960,127)
2004	(43,960,127)	(9,643,658)	3,055,177	2,179,878	(3,101)	(48,371,831)
2005	(48,371,831)	(9,872,785)	281,665	155,645	(4,386)	(57,811,692)
2006	(57,811,692)	(9,980,293)	403,297	62,900	(3,025)	(67,328,813)
2007	(67,328,813)	(10,081,447)	775,300	213,099	(5,468)	(76,427,329)
2008	(76,427,329)	(10,282,644)	798,438	162,064	(36,783)	(85,786,254)
2009	(85,786,254)	(10,578,398)	518,255	162,617	(2,577)	(95,686,357)
2010	(95,686,357)	(8,804,610)	3,409,013	713,451	(4,403)	(100,372,906)
2011	(100,372,906)	(6,781,720)	1,780,689	451,610	(6,054)	(104,928,381)
2012	(104,928,381)	(7,100,258)	371,461	319,622	(367,375)	(111,704,932)
2013	(111,704,932)	(7,329,523)	2,126,659	645,913	(651,635)	(116,913,517)
2014	(116,913,517)	(7,686,809)	2,436,117	882,572	(631,068)	(121,912,705)
2015	(121,912,705)	(7,153,158)	657,421	554,573	(7,391)	(127,861,259)
2016	(127,861,259)	(7,219,621)	1,855,112	363,238	(1,223,122)	(134,085,651)
2017	(134,085,651)	(7,548,461)	971,770	715,427	(83,156)	(140,030,071)
2018	(140,030,071)	(8,044,312)	1,688,043	388,401	(62,579)	(146,060,518)
2019	(146,060,518)	(8,468,128)	1,417,380	651,240	(60,631)	(152,520,657)
2020	(152,520,657)	(8,876,607)	787,502	854,718	(946,773)	**$ (160,701,818)**
		$ (199,885,089)	$ 33,210,730	$ 10,123,663	$ (4,151,122)	

		Annual Activity				
As of:	Beginning Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage	Ending Balance
Unit 3						
Sept 30 - Dec 31, 1996	$ -	$ (1,413,645)	$ 9,558	$ 17,724	$ (4,944)	$ (1,391,307)
1997	(1,391,307)	(5,722,984)	-	109	(1,777)	(7,115,959)
1998	(7,115,959)	(5,748,436)	1,268,778	88,404	(12,078)	(11,519,291)
1999	(11,519,291)	(5,777,189)	84,293	46,169	3,284	(17,162,734)
2000	(17,162,734)	(5,832,524)	1,580,066	29,850	(5,468)	(21,390,810)
2001	(21,390,810)	(5,899,430)	438,877	313,889	(4,292)	(26,541,766)
2002	(26,541,766)	(5,974,832)	104,085	87,216	(19,476)	(32,344,773)
2003	(32,344,773)	(6,102,508)	481,461	25,182	(6,844)	(37,947,482)
2004	(37,947,482)	(6,217,409)	398,899	12,046	(3,101)	(43,757,047)
2005	(43,757,047)	(6,256,999)	1,255,935	312,381	(4,386)	(48,450,116)
2006	(48,450,116)	(6,363,060)	345,139	94,853	(382,951)	(54,756,135)
2007	(54,756,135)	(6,483,764)	193,599	223,440	(5,468)	(60,828,328)
2008	(60,828,328)	(7,816,429)	7,502,223	3,344,634	(36,783)	(57,834,683)
2009	(57,834,683)	(9,307,894)	1,197,560	289,700	(2,577)	(65,657,894)
2010	(65,657,894)	(7,771,248)	1,495,222	693,043	(4,403)	(71,245,279)
2011	(71,245,279)	(5,928,777)	1,009,527	104,363	(6,054)	(76,066,220)
2012	(76,066,220)	(6,201,545)	1,054,898	556,754	(119,965)	(80,776,079)
2013	(80,776,079)	(6,428,424)	1,165,255	539,095	(758,037)	(86,258,189)
2014	(86,258,189)	(6,817,899)	595,845	46,161	-	(92,434,082)
2015	(92,434,082)	(6,455,058)	1,297,394	627,669	(452,293)	(97,416,370)
2016	(97,416,370)	(6,588,272)	166,721	865,333	(35,658)	(103,008,246)
2017	(103,008,246)	(6,993,583)	1,354,917	381,432	(21,552)	(108,287,031)
2018	(108,287,031)	(7,431,282)	1,531,682	949,883	(3,423,654)	(116,660,403)
2019	(116,660,403)	(7,973,581)	566,011	691,271	(37,462)	(123,414,163)
2020	(123,414,163)	(8,407,338)	1,325,878	663,298	(1,943,877)	**$ (131,776,201)**
		$ (161,914,110)	$ 26,423,822	$ 11,003,901	$ (7,289,816)	

Annualized Expense		
PV Unit 1	$	8,783,720
PV Unit 2		9,131,005
PV Unit 3		8,525,108
	$	26,439,833

UNIT 1 Annual Details

	Additions	Retirements	Net Additions	2014	Jan-Mar 2015	A/D	Apr-Dec 2015	2016	2017	2018	2019	2020	Annual Expense
Beginning Basis	173,140,000			3,533,469	883,367	98,876,222	1,841,251	2,455,001	2,455,001	2,455,001	2,455,001	2,455,001	2,455,001
1996	1,402,653	(9,558)	1,393,095	28,431	7,108	789,565	14,963	19,951	19,951	19,951	19,951	19,951	19,951
1997	192,753	-	192,753	4,016	1,004	108,568	2,087	2,783	2,783	2,783	2,783	2,783	2,783
1998	3,821,379	(1,703,333)	2,118,046	45,065	11,266	1,155,411	23,867	31,823	31,823	31,823	31,823	31,823	31,823
1999	3,985,122	(77,910)	3,907,212	84,939	21,235	2,056,508	45,885	61,180	61,180	61,180	61,180	61,180	61,180
2000	3,515,998	(1,656,748)	1,859,250	41,317	10,329	939,956	22,793	30,390	30,390	30,390	30,390	30,390	30,390
2001	1,831,063	(631,736)	1,199,327	27,257	6,814	579,219	15,374	20,499	20,499	20,499	20,499	20,499	20,499
2002	1,554,249	(114,668)	1,439,581	33,479	8,370	659,745	19,335	25,780	25,780	25,780	25,780	25,780	25,780
2003	3,364,119	(318,900)	3,045,219	72,505	18,126	1,313,332	42,939	57,252	57,252	57,252	57,252	57,252	57,252
2004	246,266	(759,170)	(512,904)	(12,510)	(3,128)	(205,967)	(7,610)	(10,147)	(10,147)	(10,147)	(10,147)	(10,147)	(10,147)
2005	37,886,399	(4,845,589)	33,040,810	826,020	206,505	12,183,800	517,116	689,488	689,488	689,488	689,488	689,488	689,488
2006	15,691,147	(2,713,937)	12,977,210	332,749	83,187	4,312,602	214,825	286,433	286,433	286,433	286,433	286,433	286,433
2007	3,321,131	(683,150)	2,637,981	69,421	17,355	769,414	46,328	61,771	61,771	61,771	61,771	61,771	61,771
2008	8,747,859	(388,507)	8,359,352	225,928	56,482	2,056,612	156,266	208,355	208,355	208,355	208,355	208,355	208,355
2009	5,290,944	(1,453,357)	3,837,587	106,600	26,650	746,200	76,646	102,195	102,195	102,195	102,195	102,195	102,195
2010	16,193,250	(1,751,888)	14,441,362	412,610	103,153	2,097,435	306,048	408,064	408,064	408,064	408,064	408,064	408,064
2011	13,123,091	(1,013,005)	12,110,086	356,179	89,045	1,335,672	267,134	356,179	356,179	356,179	356,179	356,179	356,179
2012	9,868,395	(740,950)	9,127,445	276,589	69,147	760,620	207,442	276,589	276,589	276,589	276,589	276,589	276,589
2013	10,904,840	(1,401,113)	9,503,727	296,991	74,248	519,735	222,743	296,991	296,991	296,991	296,991	296,991	296,991
2014	22,738,064	(284,260)	22,453,804	362,158	181,079	543,237	543,237	724,316	724,316	724,316	724,316	724,316	724,316
2015	7,560,264	(1,076,917)	6,483,347		27,014	27,014	80,372	215,219	215,219	215,219	215,219	215,219	215,219
2016	16,110,567	(3,024,078)	13,086,489					221,805	451,129	451,129	451,129	451,129	451,129
2017	16,808,253	(903,597)	15,904,657						279,029	567,849	567,849	567,849	567,849
2018	7,315,693	(1,326,947)	5,988,746							108,886	221,732	221,732	221,732
2019	12,410,416	(1,472,490)	10,937,927								206,376	412,752	412,752
2020	21,475,143	(816,410)	20,658,733									405,073	810,146
	245,359,059	(29,168,217)	216,190,841	7,123,213	1,898,357	131,624,898	4,659,042	6,541,917	7,050,270	7,447,976	7,767,198	8,378,647	8,783,720

Accumulated Dep @ 12/31/20 $ 173,469,948

UNIT 2 Annual Details

	Additions	Retirements	Net Additions	2014	Jan-Mar 2015	A/D	Apr-Dec 2015	2016	2017	2018	2019	2020	Annual Expense
Beginning Basis	215,285,000			4,305,700	1,076,425	119,124,371	2,320,255	3,093,673	3,093,673	3,093,673	3,093,673	3,093,673	3,093,673
1996	2,184,331	(9,558)	2,174,773	43,495	10,874	1,194,305	23,658	31,544	31,544	31,544	31,544	31,544	31,544
1997	323,109	-	323,109	6,594	1,649	176,168	3,545	4,727	4,727	4,727	4,727	4,727	4,727
1998	2,520,753	(1,963,046)	557,707	11,619	2,905	294,206	6,358	8,477	8,477	8,477	8,477	8,477	8,477
1999	3,525,260	(2,161,421)	1,363,839	29,018	7,255	693,478	16,175	21,567	21,567	21,567	21,567	21,567	21,567
2000	3,263,652	(1,525,374)	1,738,278	37,789	9,447	848,067	21,480	28,640	28,640	28,640	28,640	28,640	28,640
2001	1,588,008	(181,700)	1,406,309	31,251	7,813	654,710	18,135	24,180	24,180	24,180	24,180	24,180	24,180
2002	3,149,792	(631,804)	2,517,988	57,227	14,307	1,111,156	33,945	45,260	45,260	45,260	45,260	45,260	45,260
2003	46,996,783	(3,404,528)	43,592,255	1,013,773	253,443	18,082,627	615,521	820,694	820,694	820,694	820,694	820,694	820,694
2004	11,418,981	(3,055,177)	8,363,804	199,138	49,785	3,226,943	123,947	165,263	165,263	165,263	165,263	165,263	165,263
2005	1,921,332	(281,665)	1,639,667	39,992	9,998	580,358	25,560	34,080	34,080	34,080	34,080	34,080	34,080
2006	3,142,060	(403,297)	2,738,763	68,469	17,117	872,980	45,020	60,026	60,026	60,026	60,026	60,026	60,026
2007	2,017,315	(775,300)	1,242,015	31,847	7,962	347,381	21,587	28,782	28,782	28,782	28,782	28,782	28,782
2008	6,864,903	(798,438)	6,066,465	159,644	39,911	1,432,361	111,816	149,088	149,088	149,088	149,088	149,088	149,088
2009	4,844,437	(518,255)	4,326,182	116,924	29,231	809,871	84,845	113,127	113,127	113,127	113,127	113,127	113,127
2010	19,182,148	(3,409,013)	15,773,135	438,143	109,536	2,237,659	326,597	435,462	435,462	435,462	435,462	435,462	435,462
2011	15,157,506	(1,780,689)	13,376,817	382,195	95,549	1,433,231	288,186	384,248	384,248	384,248	384,248	384,248	384,248
2012	9,037,372	(371,461)	8,665,911	254,880	63,720	700,920	192,187	256,249	256,249	256,249	256,249	256,249	256,249
2013	8,847,127	(2,126,659)	6,720,468	203,651	50,913	356,389	153,559	204,745	204,745	204,745	204,745	204,745	204,745
2014	18,785,531	(2,436,117)	16,349,414	255,460	127,730	383,190	385,248	513,664	513,664	513,664	513,664	513,664	513,664
2015	22,268,426	(657,421)	21,611,005		87,141	87,141	262,828	698,071	698,071	698,071	698,071	698,071	698,071
2016	7,803,646	(1,855,112)	5,948,534					98,054	199,340	199,340	199,340	199,340	199,340
2017	14,321,477	(971,770)	13,349,707						227,554	462,866	462,866	462,866	462,866
2018	16,451,755	(1,688,043)	14,763,712							260,539	530,274	530,274	530,274
2019	9,840,362	(1,417,380)	8,422,982								154,081	308,162	308,162
2020	14,185,620	(787,502)	13,398,118									254,398	508,796
	249,641,688	(33,210,730)	216,430,957	7,686,809	2,072,708	154,647,511	5,080,450	7,219,621	7,548,461	8,044,312	8,468,128	8,876,607	9,131,005

Accumulated Dep @ 12/31/20 $ 199,885,089

UNIT 3 Annual Details

	Additions	Retirements	Net Additions	2014	Jan-Mar 2015	A/D	Apr-Dec 2015	2016	2017	2018	2019	2020	Annual Expense
Beginning Basis	173,904,000			3,409,882	852,471	93,331,772	1,849,854	2,466,472	2,466,472	2,466,472	2,466,472	2,466,472	2,466,472
1996	2,785,565	(9,558)	2 776,007	54,432	13,608	1,478,657	29,786	39,714	39,714	39,714	39,714	39,714	39,714
1997	1,417,752	-	1,417,752	28,355	7,089	749,040	15,353	20,471	20,471	20,471	20,471	20,471	20,471
1998	1,374,518	(1,268,778)	105,740	2,158	540	54,003	1,188	1,584	1,584	1,584	1,584	1,584	1,584
1999	1,592,379	(84,293)	1,508,086	31,418	7,855	741,696	17,596	23,461	23,461	23,461	23,461	23,461	23,461
2000	3,113,943	(1,580,066)	1,533,877	32,636	8,159	723,121	18,614	24,819	24,819	24,819	24,819	24,819	24,819
2001	2,440,935	(438,877)	2,002,058	43,523	10,881	899,752	25,308	33,744	33,744	33,744	33,744	33,744	33,744
2002	1,949,130	(104,085)	1,845,045	41,001	10,250	785,171	24,334	32,445	32,445	32,445	32,445	32,445	32,445
2003	4,838,657	(481,461)	4,357,196	99,027	24,757	1,741,228	60,060	80,080	80,080	80,080	80,080	80,080	80,080
2004	1,508,674	(398,899)	1,109,775	25,809	6,452	412,099	16,018	21,357	21,357	21,357	21,357	21,357	21,357
2005	1,936,384	(1,255,935)	680,449	16,201	4,050	231,605	10,305	13,740	13,740	13,740	13,740	13,740	13,740
2006	4,150,173	(345,139)	3,805,034	92,806	23,202	1,165,597	60,599	80,798	80,798	80,798	80,798	80,798	80,798
2007	1,397,916	(193,599)	1,204,317	30,108	7,527	323,661	20,219	26,959	26,959	26,959	26,959	26,959	26,959
2008	56,999,385	(7,502,223)	49,497,162	1,269,158	317,290	11,238,729	878,374	1,171,165	1,171,165	1,171,165	1,171,165	1,171,165	1,171,165
2009	7,998,258	(1,197,560)	6,800,698	178,966	44,742	1,227,905	127,946	170,594	170,594	170,594	170,594	170,594	170,594
2010	16,786,084	(1,495,222)	15,290,862	413,267	103,317	2,101,491	302,814	403,752	403,752	403,752	403,752	403,752	403,752
2011	12,531,698	(1,009,527)	11,522,171	320,060	80,015	1,200,225	236,981	315,975	315,975	315,975	315,975	315,975	315,975
2012	8,946,576	(1,054,898)	7,891,678	225,477	56,369	620,061	166,949	222,598	222,598	222,598	222,598	222,598	222,598
2013	8,926,778	(1,165,255)	7,761,523	228,280	57,070	399,490	169,025	225,366	225,366	225,366	225,366	225,366	225,366
2014	18,767,949	(595,845)	18,172,104	275,335	137,668	413,003	407,730	543,640	543,640	543,640	543,640	543,640	543,640
2015	16,980,246	(1,297,394)	15,682,852		61,261	61,261	181,438	481,958	481,958	481,958	481,958	481,958	481,958
2016	12,140,734	(166,721)	11,974,013			-	-	187,580	381,038	381,038	381,038	381,038	381,038
2017	14,454,623	(1,354,917)	13,099,706						211,853	430,558	430,558	430,558	430,558
2018	14,634,942	(1,531,682)	13,103,261							218,994	445,307	445,307	445,307
2019	18,840,766	(566,011)	18,274,755								315,986	631,973	631,973
2020	7,901,432	(1,325,878)	6,575,555									117,770	235,540
	244,415,498	(26,423,822)	217,991,675	6,817,899	1,834,570	119,899,565	4,620,488	6,588,272	6,993,583	7,431,282	7,973,581	8,407,338	8,525,108

Accumulated Dep @ 12/31/20 $ 161,914,110

DOCKET NO. _______

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

JENNIFER E. NELSON

OF

CONCENTRIC ENERGY ADVISORS, INC.

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Jennifer E. Nelson establishes that a Return on Equity rate of 10.30 percent is necessary for El Paso Electric Company ("EPE" or the "Company") to provide a reasonable return to its equity investors. Ms. Nelson's recommended 10.30 percent Return on Equity (sometimes referred to as the "ROE" or Cost of Equity) considers a variety of factors that affect the required return to equity investors.

Ms. Nelson presents multiple analytical techniques for the purposes of estimating the Company's ROE, including the constant growth and quarterly growth forms of the Discounted Cash Flow ("DCF") analysis, the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"), and a Bond Yield Plus Risk Premium analysis. In addition to the ROE estimation methods, Ms. Nelson considers the effect of certain business and financial risks on the Company's Cost of Equity. First, the regulatory environment in which a utility operates has direct consequences on the subject utility's financial integrity and ability to attract capital at reasonable terms to the benefit of customers. Ms. Nelson has also considered the Company's nuclear generation operations, and relatively small size. Lastly, Ms. Nelson considers several measures of capital market risk, including: (1) heightened volatility in the capital market; and (2) the steepening yield curve and expectations of increases in interest rates. Each of those measures provides information that is relevant to the implementation of models used to estimate the Cost of Equity, and in the interpretation of the model results.

Together with the exhibits attached to Ms. Nelson's testimony, this evidence demonstrates that a 10.30 percent Cost of Equity rate is reasonable, if not conservative, and should be adopted for EPE in order to provide the Company with an opportunity to generate earnings that maintain a reasonable return to its equity investors.

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SUBJECT **PAGE**

EXHIBITS

I. Introduction and Purpose

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors, Inc. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01742.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony (referred to throughout as my "Direct Testimony") before the Public Utility Commission of Texas ("Commission") on behalf of El Paso Electric Company ("EPE" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have worked in the energy industry for thirteen years, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and economic issues including rate case support (e.g., cost of capital and integrated resource planning) and policy and strategy issues (e.g., alternative ratemaking and natural gas distribution expansion). Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, where I worked on regulatory filings related to energy efficiency, renewable power contracts, smart grid and electric grid modernization, and retail choice. Prior to that, I was a petroleum economist for the State of Alaska, where my responsibilities included forecasting oil and natural gas tax revenue, as well as providing policy analysis and recommendations.

I hold a Bachelor's degree in Business Economics from Bentley College (now 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 Exhibit JEN-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE COMMISSION?

A. Yes, I have. I submitted testimony regarding the Cost of Capital on behalf of Sharyland Utilities, L.L.C. in Docket No. 51611. Additionally, I have previously filed testimony before regulatory commissions in Arkansas, Kentucky, Maine, New Hampshire, New Mexico, North Carolina, and West Virginia. 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. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present evidence and provide the Commission with a recommendation regarding EPE's ROE[1] and to assess the reasonableness of the Company's requested capital structure. My analyses and conclusions are supported by the data presented in Exhibits JEN-2 through JEN-8.

Q. WERE EXHIBITS JEN-2 THROUGH JEN-8 PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes.

II. Summary and Overview of Testimony

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY AND CAPITAL STRUCTURE FOR EPE?

A. My analyses indicate that the Company's Cost of Equity currently is in the range of 9.75 percent to 10.75 percent. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, and considering EPE's risk profile and the current volatile capital market environment, I conclude that an ROE of 10.30 percent is reasonable and appropriate. Further, I conclude that an overall capital structure consisting of 51.00 percent equity and 49.00 percent debt is reasonable and should be used for ratemaking purposes.

[1] Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE RECOMMENDATION.

A. The Cost of Equity, which is the return required by equity investors to assume the risks of ownership, is a market-based concept. Because it is not directly observable, the Cost of Equity must be estimated based on financial models that rely on market data. Since all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. As such, I relied on three widely accepted approaches to develop my ROE determination: (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 approach. The results of those analytical approaches are summarized in Table 1 below.

Table 1: Summary of Results[2]

Constant Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.67%	9.43%	10.01%
90-Day Average	8.68%	9.43%	10.01%
180-Day Average	8.67%	9.52%	10.07%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.76%	9.57%	10.17%
90-Day Average	8.74%	9.62%	10.17%
180-Day Average	8.71%	9.69%	10.23%

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[2] *See*, Exhibits JEN-2, JEN-3, JEN-5, JEN-6. DCF results are the average of the mean and median proxy group results.

CAPM (*Value Line*-derived)	**Current 30-Year Treasury Yield (2.31%)**	**Projected 30-Year Treasury Yield (2.88%)**
Proxy Group Average	12.71%	12.78%
Proxy Group Median	12.42%	12.51%
Empirical CAPM (*Value Line*-derived)	**Current 30-Year Treasury Yield (2.31%)**	**Projected 30-Year Treasury Yield (2.88%)**
Proxy Group Average	13.08%	13.14%
Proxy Group Median	12.87%	12.93%
Bond Yield Plus Risk Premium		
Current 30-Year Treasury Yield (2.31%)	9.81%	
Projected 30-Year Treasury Yield (2.88%)	9.81%	

In addition to the methods noted above, I considered: (1) the regulatory environment and the Company's need to access the capital necessary to execute its capital expenditure plan; (2) the Company's nuclear generation operations; and (3) the Company's small size. I also considered the current capital market and macroeconomic environment in which utilities such as EPE operate. Although those factors are relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Consequently, I did not make explicit adjustments to my ROE estimates in connection with those factors. Rather, I considered them in determining where the Company's Cost of Equity falls within the range of analytical results.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED RANGE FROM THE METHODS AND RESULTS SUMMARIZED ABOVE?

A. As noted earlier, the Cost of Equity is not directly observable and must be estimated based on both quantitative and qualitative information. As my Direct Testimony explains, no single model is more reliable than all others under all market conditions. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more, or less, relevant as market conditions change. Each model's results must be assessed in the context of current and expected capital market conditions, as well as relative to appropriate benchmarks. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity.[3] Because estimating the Cost of Equity is an approximation of investor behavior and cannot be precisely quantified, analysts and investors gather and evaluate relevant data from a wide variety of sources and rely on multiple analytical approaches. The use of various financial models provides different perspectives on investor return requirements, which enables a more robust and comprehensive assessment of the Cost of Equity.

Each model has its strengths and weaknesses, and it is important to recognize those differences when estimating the Cost of Equity. For example, the Constant Growth DCF model requires constant assumptions, inputs, and results in perpetuity, while Risk Premium-based methods provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity. Other Risk Premium approaches (e.g., the Bond Yield Plus Risk Premium approach) reflect the well-documented finding that the Cost of Equity does not move in lockstep with interest rates.

My recommendation therefore recognizes that estimating the Cost of Equity is not an entirely mathematical exercise. It relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that necessarily must be applied in determining the Cost of Equity for a particular company at a particular time. As such, I considered my analytical results in the context of Company-specific factors and current capital market conditions. The wide range of analytical results summarized in Table 1 above reflect the considerable uncertainty surrounding the scope and duration of the current economic and capital market associated with the COVID-19 pandemic. In developing my recommendation, I considered the quantitative results produced by each model and their comparability to returns available to other similarly-situated electric utilities, as well as each model's consistency with, and reflection of, the current capital market environment.

[3] *See, for example*, Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed., 2000, at 214.

As discussed below, the DCF model may not be producing reasonable results for the proxy group in the current market environment. Because Risk Premium-based methods more directly reflect increased risk associated with market volatility and uncertainty, I believe those results should be given more weight than the low and mean DCF results. Nonetheless, even if each of the analytical results shown in Table 1 are given equal weight – including the low and high estimates – the average is 10.44 percent. Although current market conditions suggest the investor-required ROE now falls toward the higher end of that range, I conclude an ROE of 10.30 percent, within a range of 9.75 percent to 10.75 percent, is conservative and reasonably reflects the market uncertainty reflected in the methods on which investors rely.

Q. WHY DO YOU BELIEVE THE CONSTANT GROWTH DCF MODEL MAY NOT CURRENTLY BE PRODUCING AN ACCURATE ESTIMATE OF EPE'S RETURN ON EQUITY?

A. As discussed below, the period over which my analyses were performed included market data that were inconsistent with that model's fundamental assumptions and produced results counterintuitive with current capital market conditions. Regardless of the method employed, however, an authorized ROE that is well below returns authorized for other utilities: (1) runs counter to the *Hope* and *Bluefield*[4] "comparable risk" standard, (2) would place the Company at a comparative disadvantage, and (3) makes it difficult for EPE to compete for capital at reasonable terms.

Q. WHAT IS THE BASIS OF YOUR VIEW THAT THE CONSTANT GROWTH DCF METHOD RECENTLY HAS PRODUCED UNREASONABLY LOW ROE ESTIMATES?

A. Since 2014, the model has produced results (i.e., mean results) consistently below authorized returns (*see* Chart 1, below). That data suggests state regulatory commissions have recognized the model's mean results are not necessarily reliable estimates of the Cost of Equity, and that other methods should be given meaningful weight in determining the ROE.

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[4] Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679, 692-93 (1923); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).