DOCKET NO. ______

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

DIRECT TESTIMONY

OF

SEAN M. IHORN

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Sean M. Ihorn, Director of Tax for El Paso Electric Company (the "Company" or "EPE"), presents the tax schedules and amounts included in the cost of service and deferred tax amounts considered in the determination of rate base for the Company for the historical Test Year. In his testimony, he specifically discusses:

- Federal and State Income Taxes included in Cost of Service
- Tax Schedules provided in the Rate Filing Package ("RFP")
- Taxes Other Than Income

Federal and state income tax expense included in EPE's cost of service has been calculated using the "return" method for the historical Test Year, as required by the Instructions and Schedules to the RFP. This return method calculation reflects a "stand-alone" approach that includes in cost of service only federal and state income taxes that result from the provision of utility service to customers. Mr. Ihorn demonstrates that it is neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendition of utility service to customers.

Use of the return method also satisfies the provisions of PURA § 36.060. In the Company's filing, requested tax expense is based solely on the income and expenses used in determining the Company's revenue requirement and rate base. The Company's stand-alone method ensures that customers benefit from the tax deductions that are generated by the expenses included in cost of service. This approach is reasonable and fair for all parties.

Mr. Ihorn demonstrates that the federal and state income tax schedules that are part of the Company's filing are in compliance with the prescribed RFP and are in accordance with the rules of the Public Utility Commission of Texas ("PUCT"). Adjustments made to tax expense, cost of service, and to rate base are both reasonable and appropriate.

Mr. Ihorn also explains that the treatment of state deferred income taxes is consistent with the Final Order in PUCT Docket No. 44941, which EPE agreed to continue to abide by as part of the settlement approved in the Final Order in PUCT Docket No. 46831.

In his discussion of "taxes other than income," Mr. Ihorn discusses the Test Year property tax amount and demonstrates that the remaining "revenue-related taxes," (e.g., local franchise fees, sales, use and gross receipts taxes and other miscellaneous taxes plus state regulatory assessments) are reasonable and necessary.

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I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sean M. Ihorn. My business address is 100 North Stanton Street, El Paso, Texas 79901.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Director of Tax.

Q. DESCRIBE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science in Cellular and Molecular Biology from the University of Michigan and a Master of Accountancy, with a concentration in tax, from The University of Texas at El Paso. I am a Certified Public Accountant in Texas. I began my career with KPMG, LLP's federal tax practice in January 2003. My experience also includes work at Petro Stopping Centers, L.P., where I was a manager overseeing Sarbanes Oxley and tax compliance activities and at Hunt Administrative Services, LLC, where I was as a manager overseeing state and local tax compliance and planning. In addition, I have worked in the tax practices of two El Paso CPA firms where I assisted in supervising tax department staff. I also served as the Chief Financial Officer at SWK Partners, LLC, where I had overall responsibility for all financial and accounting functions. I am a part-time lecturer in the Master of Accountancy program at The University of Texas at El Paso where I teach courses in corporate and partnership taxation. I joined EPE in July of 2017, managing accounting special projects. I was promoted to Director of Plant, Revenue and Technical Accounting in September of 2019 and then to my current position in December of 2020.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for preparing the federal and state income tax returns and maintaining tax accounting data for the Company. This includes the preparation of tax accounting and related tax data used in regulatory filings. I am also responsible for oversight of the payroll department and Plant Accounting.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony addresses a number of topics. First, I support the Company's federal and state income tax amounts found in the G-7 schedules of the Rate Filing Package ("RFP") and included in EPE's requested cost of service and rate base. My testimony will also address the calculation of income tax expense on a stand-alone basis and explains that the Company began normalizing state income tax expense in accordance with the settlement agreement approved by the Commission in the Company's 2015 rate case, PUCT Docket No. 44941, which EPE continued to abide by as part of the settlement approved in the Final Order in the Company's last Texas base rate case, PUCT Docket No. 46831. I also sponsor EPE's taxes other than income, referenced on the G-9 schedules.

Q. WHY ARE YOU THE APPROPRIATE PERSON TO SPONSOR THESE TOPICS?

A. In my role as Director of Tax, I have detailed knowledge regarding the income tax accounts used to determine income tax expense as well as the amounts included in current income taxes payable, unamortized investment tax credits, accumulated deferred income taxes, and taxes other than income paid by the Company.

Q. WHAT TEST YEAR IS THE COMPANY USING IN THIS FILING?

A. This filing uses the 12 months ended December 31, 2020, as the Test Year.

Q. WHAT RFP SCHEDULES DO YOU SPONSOR OR CO-SPONSOR IN THIS PROCEEDING?

A. Exhibit SMI-1 indicates the schedules that I am sponsoring or co-sponsoring with other witnesses.

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

A. Yes, they were.

Q. ON WHAT BASIS WERE THE REFERENCED SCHEDULES PREPARED?

A. The schedules were prepared using the books and records of the Company, and they are accurate summaries of the business records upon which they are based.

III. Background of Income Tax Accounting and Ratemaking

Q. CAN YOU PLEASE DESCRIBE THE ACCOUNTING FOR INCOME TAXES REQUIRED UNDER GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. Accounting for income taxes under GAAP is contained in the Accounting Standards Codification ("ASC") in section ASC 740 (formerly SFAS No. 109, Accounting for Income Taxes ("SFAS 109")). There are several components to the calculation: currently payable income taxes, deferred income taxes, and investment tax credits.

Q. WHAT IS THE FIRST COMPONENT, CURRENTLY PAYABLE INCOME TAXES?

A. Currently payable income tax expense represents the estimated amount of current year income taxes payable based on current year taxable income. Taxable income for the year is determined in accordance with the Internal Revenue Code ("IRC"). For purposes of preparing an income tax return each year, the IRC contains procedures for determining if and when an item is taxable or deductible.

Q. WHAT IS THE SECOND COMPONENT, DEFERRED INCOME TAXES?

A. The IRC rules for determining what is taxable or deductible may differ from what is reportable as revenue or expense under GAAP. For instance, certain expenses recorded on the financial statements under GAAP in one year may be deductible on the tax return in a different period. There are also instances where the amounts shown as deductions on the tax return in one year are not reflected on the financial statements until a later year. As a result, at the end of each reporting period, there will likely be accumulated differences of reported assets and liabilities resulting from different book and tax return treatment of revenues and expenses. These differences are referred to as temporary differences.

Q. CAN YOU FURTHER EXPLAIN WHAT IS MEANT BY THE TERM "TEMPORARY DIFFERENCES" AND PROVIDE AN EXAMPLE?

A. Yes. One common temporary difference is depreciation. For book purposes, GAAP requires that the asset be depreciated over its estimated useful life in a systematic and rational manner. As a result, straight-line depreciation over the useful life of assets is used for book purposes. For income tax purposes, the asset may be depreciated using an accelerated depreciation method that is generally shorter than the estimated useful life. Initially, tax depreciation will exceed book depreciation. In the later years, the reverse will be true because given the same capitalized asset cost, over the life of the asset total depreciation will be the same.

Q. WHAT IS THE ACCOUNTING FOR TEMPORARY DIFFERENCES UNDER ASC 740?

A. Under GAAP, because the financial statements reflect accrual and not cash basis accounting, deferred income taxes are recorded on temporary differences. As a result, income tax expense under GAAP includes both a currently payable component (as previously described, based on the tax return) as well as a deferred income tax component (based on temporary differences). Such deferred income taxes reflect the liability or asset for income taxes payable or receivable in the future stemming from transactions recorded in the financial statements currently. The balance sheet liability or asset for future taxes is referred to as Accumulated Deferred Income Tax ("ADIT").[1] In other words, to the extent that accelerated tax depreciation is claimed on the income tax return in an amount that exceeds book depreciation reported on the financial statements, a liability for future taxes results. This future tax liability is due to the fact that greater depreciation claimed in early years will "use up" the tax basis of assets and result in higher taxes in the future.

Under ASC 740, a calculation of required ADIT is performed at the end of each reporting period. The required ADIT is measured by multiplying the temporary differences by the currently applicable income tax rates. Comparing the ADIT at the current balance sheet date to the ADIT at the previous balance sheet date results in "deferred income tax expense." For regulated entities, such as EPE, the process of recording deferred income

[1] The use of the acronym ADIT refers to deferred taxes recorded for both federal and state income tax.

taxes on temporary differences is referred to as "normalization", "deferred tax accounting", or "comprehensive interperiod income tax allocation".

Q. DOES CLAIMING DEDUCTIONS FOR INCOME TAX PURPOSES IN EXCESS OF EXPENSES RECORDED FOR BOOK PURPOSES PROVIDE INCENTIVES TO THE COMPANY THAT BENEFIT CUSTOMERS?

A. Yes. By claiming tax deductions for such things as accelerated depreciation, the Company reduces its current income tax payments. But, with respect to temporary differences, tax payments will be higher in the future when the temporary differences reverse. As a result, ADIT balances are "interest free loans" from the U.S. Treasury. This was the objective Congress intended when it included accelerated depreciation provisions in the IRC. Congress believed that allowing companies to increase their tax depreciation deductions (and thereby reduce current income tax payments) would lower the financing costs of their investment in capital assets and thus companies would be incented to make such expenditures. For accounting purposes, using up the tax basis of capital assets is both a cost to be recognized in the financial statements when claimed (i.e., deferred tax expense) and a liability for future taxes due when the turnaround occurs and book depreciation exceeds tax depreciation (i.e., ADIT).

Q. ARE ALL BOOK/TAX DIFFERENCES "TEMPORARY DIFFERENCES" AND SIMPLY A MATTER OF WHEN THE ITEM IS INCLUDED ON THE TAX RETURN VERSUS WHEN THE ITEM IS SHOWN ON THE FINANCIAL STATEMENTS?

A. No. Most differences between their treatment on the books and income tax return are simply temporary and over time, the same amount will be included on the financial statements and tax returns. However, certain items of revenue and expense are, over time, treated differently for financial reporting purposes than for income tax purposes. These are referred to as permanent differences.

Deferred income taxes are not required on permanent differences. In the period reported, current income taxes will be adjusted to reflect the increased deduction or non-deductibility of these costs and there will be no deferred income taxes since these amounts will either never be included in the financial statements or deducted on the tax return thereby permanently decreasing or increasing current tax expense.

Q. IS THE DISTINCTION BETWEEN PERMANENT AND TEMPORARY DIFFERENCES IMPORTANT IN THE INCOME TAX CALCULATION?

A. Yes. Permanent differences need to be separately identified and included in the income tax calculation because they do not require deferred income tax accounting and permanently increase or decrease total income tax expense that needs to be recovered in revenue requirements in a rate case.

Q. IS THERE ANOTHER COMPONENT OF THE INCOME TAX CALCULATION?

A. Yes. In addition to current and deferred income taxes, a third element of the tax computation is the Investment Tax Credit ("ITC").

Q. CAN YOU PLEASE SUMMARIZE WHAT THE ITC IS AND HOW IT IS TREATED FOR ACCOUNTING/RATEMAKING PURPOSES?

A. The ITC, which has gone in and out of existence over the years, lowers income tax expense permanently if certain qualifying investments are made. It is intended as an incentive for companies to invest in qualifying assets. To make sure that its objectives are met for regulated utilities, the IRC prescribes methods of sharing the benefit between customers and shareholders.

The ITC is a direct reduction of income taxes payable in a given year. Unlike accelerated depreciation and other book-tax differences that will eventually reverse or turn around, the ITC is comparable to a rebate. The ITC provides an incentive to capital investment by granting a tax credit (a direct, dollar-for-dollar offset to current taxes payable) based on a percentage applied to investment in tangible personal property (most generation, transmission, and distribution assets).

The accounting for the ITC is contained in ASC 740, codifying the accounting for ITC previously contained in Accounting Principles Board Opinions 2 and 4, *Accounting for the Investment Credit*. Most utilities, like EPE, account for the ITC by reducing current income taxes payable in the year the credit is earned for the full amount of the credit but recognize an equal and offsetting amount of deferred tax expense. The amount of the credit is then amortized to reduce income tax expense over the book life of the property giving rise to the ITC.

In 1972, for ratemaking purposes, the IRS required utilities to elect how they intended to share the ITC between customers and shareholders. Most utilities, including EPE, elected to share the ITC as described in the preceding paragraph by including the annual amortization to income tax expense as a reduction to income tax expense. In accordance with this election, the unamortized ITC basis is not deducted from rate base. Reduced income tax expense benefits customers when it is included in rates.

IV. Normalization Requirements

Q. WHAT IS THE FEDERAL ENERGY REGULATORY COMMISSION'S ("FERC") POSITION ON DEFERRED INCOME TAXES?

A. The FERC Uniform System of Accounts embraces normalization of deferred income taxes by requiring comprehensive interperiod income tax allocation for all book-tax timing (temporary) differences. FERC Order Nos. 144 and 144A provide guidance in this area. This has been the FERC methodology since the early 1980s.

Q. IS NORMALIZATION ACCOUNTING REQUIRED FOR A UTILITY TO REFLECT CERTAIN DEDUCTIONS AND CREDITS ON ITS FEDERAL TAX RETURN?

A. Yes. The IRC requires that regulated utilities must use the normalization method and not the flow-through method to calculate the tax expense related to depreciation-related temporary differences (IRC section 168), Contributions In Aid of Construction (IRS Notice 87-82), investment tax credits, excess deferred taxes, and net operating loss ("NOLs") carryforwards created by accelerated depreciation in order to avoid certain penalties.

V. Federal Income Taxes

Q. HOW HAVE FEDERAL INCOME TAXES INCLUDED IN COST OF SERVICE BEEN CALCULATED?

A. Federal income taxes have been calculated using the return method for the Adjusted Test Year, as required by the Instructions and Schedules to the RFP.

Q. WHAT IS THE RETURN METHOD?

A. The calculation of federal income taxes provided on Schedule G-7.8 is commonly referred to as the return method because it calculates federal income taxes using after-tax return as the starting point. Under this method, equity return, or total return less interest, is adjusted for items for which there is no tax deduction to offset amounts recovered through revenues — such as book amortization of Allowance for Equity Funds Used During Construction, other flow-through differences, permanent differences, ITC amortization, and the amortization of excess ADIT. The return method calculates federal income tax expense in total, with no segregation between current and deferred federal income taxes. The return method tax calculation provided on Schedule G-7.8 reflects a stand-alone approach to calculating federal income taxes.

Q. WHAT IS THE BASIS FOR THE PERMANENT DIFFERENCES INCLUDED IN THE RETURN METHOD?

A. Permanent differences can arise when costs are reported as expenses in the financial statements but will never be deductible on the income tax return. In addition, permanent differences can also arise when deductions are allowed on the income tax return that will never be reported as expenses in the financial statements. An example of a permanent difference in EPE's tax calculation is the cost of meals and entertainment. The cost of meals and entertainment are reported as expenses in the financial statements but, under the IRC, are not completely deductible on the income tax return and are therefore a permanent difference which increases current tax expense.

Q. WHAT IS MEANT BY A STAND-ALONE APPROACH?

A. The stand-alone methodology calculates federal income taxes on utility revenues and expenses that are included in the utility's revenue requirement. This approach appropriately allocates federal income taxes between customers and shareholders using the benefits-burdens criteria outlined by FERC Opinion No. 173. Under this methodology, federal income tax expense relates to, and results from, the provision of utility service to customers. Additionally, the stand-alone federal income tax calculation includes an adjustment to synchronize interest. Synchronized interest represents the portion of return that is deductible for tax purposes and is calculated by multiplying the weighted cost of debt by rate base. Use of synchronized interest in the tax calculation effectively synchronizes the calculation of federal income tax expense with rate base and rate of return. Synchronized interest may be more or less than the actual interest deducted on the tax return.

Q. WHY IS THE STAND-ALONE APPROACH THE PROPER METHODOLOGY TO USE IN CALCULATING FEDERAL INCOME TAXES FOR RATEMAKING PURPOSES?

A. The stand-alone approach, required by section 36.060 of the Public Utility Regulatory Act ("PURA"), includes in cost of service only federal income taxes that result from the provision of utility service to customers. Federal income taxes requested by the Company are based on revenues and expenses included in the cost of service calculation. There are no additions to or reductions from tax expense resulting from revenues or expenses not included in the Company's request. It is neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendition of utility service to customers.

Said another way, income taxes have no independent existence of their own. They are based on revenues and expenses. Once the Commission decides on the appropriate revenues and expenses that are necessary for the provision of electric service, the related income taxes can be determined.

Q. WHAT IS THE AMOUNT OF FEDERAL INCOME TAX EXPENSE THE COMPANY IS REQUESTING TO BE INCLUDED IN RATES?

A. The Company is requesting the amount of federal income tax expense that is included in overall cost-of-service in Schedule A as calculated on Schedule G-7.8.

Q. HAS THE COMPANY COMPUTED FEDERAL INCOME TAXES IN ACCORDANCE WITH SECTIONS 36.059 AND 36.060 OF PURA?

A. Yes. PURA sections 36.059 and 36.060 address the treatment of certain tax benefits, including ITC and consolidated tax savings. PURA sections 36.059(b) and 36.060(c) specifically require a utility that retains ITC to deduct it from the rate base to which the credit applied, to the extent allowed by the IRC. The post-1970 portion of unamortized ITC is not included as a reduction of rate base because the Company is an Option 2 company for ITC purposes. Under IRC Section 46(f), an Option 2 election requires that the post-1970 ITC be returned to customers as a reduction of cost-of-service, rather than as a reduction of rate base.

Additionally, PURA section 36.060(b) requires that income taxes related to intercompany profits on affiliated purchases be applied to reduce the cost of the property or service purchased. As a result of its merger with Sun Jupiter Holdings, LLC ("Sun Jupiter"), the Company did have affiliates for the Test Year ended December 31, 2020 and anticipates participating in a consolidated tax return for 2020, but the Company has no intercompany profits on affiliated purchases for the Test Year. As a result, tax expense included in this filing has been calculated in accordance with PURA section 36.060(b).

Further, PURA section 36.060(a) requires that income tax expense included in cost of service reflect only expenses and investments included in cost of service and rate base. Accordingly, the Company has calculated its income tax expense on a stand-alone basis. As a result of the reduction in the federal income tax rate under the Tax Cuts and Jobs Act of 2017 ("TCJA"), the Company reduced the book balance of its ADIT to reflect the current tax rate and recorded the reduction (referred to as "excess ADIT") as a regulatory liability to customers. EPE has included the amortization of this excess ADIT in its calculation of income tax expense in cost of service and continued to deduct the balance of the regulatory liability from rate base. The Company's income tax amounts included in cost of service are consistent with this provision. Please refer to the direct testimony of EPE witness Cynthia S. Prieto for discussion of the amortization of excess deferred income taxes in this case.

Q. WILL THE REFUND FACTOR FROM DOCKET NO. 48124 BE EXTENDED FOR THE RATES ESTABLISHED IN THIS CASE?

A. No. As discussed in the direct testimony of Company witness Prieto, the refund factor will no longer be necessary. The refund factor from Docket No. 48124 accounted for the difference between income tax rates in effect at the date of the Company's last base rate case in Docket No. 46831 and lower income tax rates established by the TCJA. The lower rates established by the TCJA will be the basis for income tax expense in cost of service in this case.

VI. State Income Taxes

Q. WHAT IS THE AMOUNT OF STATE INCOME TAX EXPENSE THE COMPANY IS REQUESTING BE INCLUDED IN COST OF SERVICE?

A. The Company is requesting the amount of state income tax expense in cost of service reflected on Schedules G-7.6 and G-7.8.

Q. WHICH ACCOUNTING METHOD HAS EPE USED TO DETERMINE STATE INCOME TAX EXPENSE IN THIS CASE?

A. Consistent with the settlement agreement that was approved by the Commission Final Order in the Company's 2015 base rate case, PUCT Docket No. 44941, the Company has used the normalization method to determine the state income tax expense included in cost of service.

Q. WHAT DID THE SETTLEMENT IN PUCT DOCKET NO. 44941 PROVIDE WITH RESPECT TO STATE INCOME TAX EXPENSE?

A. Prior to PUCT Docket No. 44941, the Company used the flow through method to calculate state income tax expense. However, in PUCT Docket No. 44941, the Company requested to switch to the normalization method. The settlement approved in the case authorized the change in methodologies. Article I., section F. of the Settlement Agreement stated:

> Beginning January 1, 2016, EPE should begin normalizing state income tax expense. In other words, it should begin including both current and deferred state income tax expense in its revenue requirement (just as it does for federal income tax expense) instead of just the current portion of state income tax

> expense. On that date, it should also begin amortizing the test year-end balance of accumulated deferred state income tax expense that has not yet been included in cost of service over a 15-year period.

This provision was adopted in Findings of Fact Numbers 40 and 60 in the Final Order issued in PUCT Docket No. 44941.

Q. HAS THE COMPANY COMPLIED WITH THIS PROVISION?

A. Yes, it has.

Q. WHAT IS THE AMOUNT OF STATE INCOME TAX EXPENSE THE COMPANY IS REQUESTING BE INCLUDED IN ITS COST OF SERVICE?

A. State income tax expense is shown on pages 3 to 5 of Schedules G-7.6 and G-7.8. The annual amortization of excess accumulated deferred state income tax is calculated on Schedule G-7.9(a), line 76, column (c) and included in income tax expense on Schedule G-7.8, page 1, line 10, column (c). As fully discussed in the direct testimony of EPE witness Prieto, the Company is requesting amortization of excess accumulated deferred state income tax expense for reduced state income tax rates in Texas, New Mexico, and Arizona. As provided in the settlement agreement for PUCT Docket No. 44941, the Company will amortize the related balance of the excess accumulated deferred state income tax over a period of 15 years. The amount is calculated on Schedule G-7.9(a), line 77, column (c).

VII. Income Tax Schedules

Q. PLEASE DESCRIBE SCHEDULE G-7.1, RECONCILIATION OF TEST YEAR BOOK NET INCOME TO TAXABLE NET INCOME.

A. Schedule G-7.1 is the reconciliation of book net income to taxable net income on a total company basis for the Test Year and for the most recently filed federal income tax return. Since Schedule G-7.1 is a comparison to the most recently filed federal income tax return, amounts include both operating and nonoperating activities. Schedule G-7.1 contains explanations of all items in the reconciliation for both the Test Year and the tax return.

Q. PLEASE DESCRIBE SCHEDULE G-7.1(a), RECONCILIATION OF TIMING DIFFERENCES.

A. This schedule includes a listing of timing differences and other items that produce federal income tax for the Test Year at a tax rate different than the statutory 21% federal tax rate, with explanations describing each item.

Q. PLEASE DESCRIBE SCHEDULE G-7.2, PLANT ADJUSTMENTS.

A. This schedule provides the tax basis, tax in-service date, tax depreciation methods, and tax depreciation in the Test Year and projected for the two subsequent years, and the amount of Accumulated Deferred Federal Income Taxes ("ADFIT") as of the Test Year-end for any new generating unit requested (purchased or constructed since the Company's last rate case) and any requested plant adjustments to the Test Year. The Company has not added any new generating plant since filing its last base rate case and is not requesting any post-Test Year plant adjustments.

Q. PLEASE DESCRIBE SCHEDULE G-7.3, CONSOLIDATED TAXES.

A. This schedule is not applicable. This schedule provides descriptions of any tax effect on the filing utility because of its inclusion within a consolidated income tax return for the most recent tax year. EPE did not file as part of a consolidated group in its most recently filed tax return for the calendar year ended December 31, 2019.

Q. PLEASE DESCRIBE SCHEDULE G-7.3(a), CONSOLIDATION BENEFITS.

A. This schedule is not applicable. The Company did not file as part of a consolidated group on its most recently filed income tax return.

Q. PLEASE DESCRIBE SCHEDULE G-7.3(b), CONSOLIDATION/INTER-CORPORATE TAX ALLOCATION.

A. This schedule is not applicable to the Company. The Company did not file as part of a consolidated group on its most recently filed income tax return.

Q. WILL THE COMPANY BECOME A MEMBER OF A CONSOLIDATED GROUP AS A RESULT OF THE MERGER TRANSACTION WITH SUN JUPITER?

A. Yes. As a result of its merger with Sun Jupiter, the Company will be a part of two federal income tax returns for the 2020 income tax year. The first income tax return will be the final EPE stand-alone income tax return for the portion of the 2020 tax year up to the date of the consummation of the merger, July 28, 2020. The second income tax return will be a consolidated income tax return, from the date of the consummation of the merger with the Sun Jupiter consolidated tax group for the remainder of the 2020 tax year, which will be carried out subject to a formal tax sharing agreement. The final EPE stand-alone income tax return and the short period consolidated Sun Jupiter income tax return are not anticipated to be filed until October 2021. Exhibit SMI-2 provides a copy of the Tax Sharing Agreement with Sun Jupiter.

Q. PLEASE DESCRIBE SCHEDULE G-7.4, ADFIT.

A. This schedule shows the balance sheet amount of ADIT, which includes both federal and state, for each of the twelve months of the Test Year; at the end of the Test Year; and the additions and reductions during the Test Year as well as the requested adjustments to the balances. Each item that gives rise to ADIT is shown separately on this schedule.

Q. PLEASE DESCRIBE SCHEDULE G-7.4(a), ADFIT-DESCRIPTION OF TIMING DIFFERENCES.

A. This schedule includes a description of the nature and remaining life, where applicable, of each timing difference listed in Schedule G-7.4.

Q. PLEASE DESCRIBE SCHEDULE G-7.4(b), ADJUSTMENTS TO ADFIT.

A. This schedule shows the details of the adjustments to the balance sheet ADIT accounts. The reasons for these adjustments are included as well as the supporting calculations, if any.

Q. DOES THIS SCHEDULE REFLECT THE IMPACTS OF BONUS DEPRECIATION?

A. Yes. The Company has claimed bonus depreciation as permitted by the IRC. Depending on the year certain capital assets were placed in service, the additions were eligible for the 50% or 100% bonus depreciation deduction based on the applicable rate enacted for that year. This effectively means that, for income tax purposes—in addition to tax depreciation computed using the Modified Accelerated Cost Recovery System ("MACRS")—the Company claimed an additional 50% or 100% of the eligible tax basis as a tax depreciation deduction in the first year. As a result, EPE's Test Year end ADIT related to these book-tax depreciation temporary differences reflect the future tax liability associated with these accelerated deductions. Due to the requirements of the TCJA, the Company can no longer claim bonus depreciation.

Q. DID THE COMPANY REMOVE TEST YEAR END ADIT FOR AMOUNTS RELATED TO UNCERTAIN TAX POSITIONS REQUIRED TO BE IDENTIFIED AND ACCOUNTED FOR BY FINANCIAL ACCOUNTING STANDARDS BOARD INTERPRETATION 48 ("FIN 48")?

A. No reductions were made to Test Year end ADIT in rate base for FIN 48 reserves.

Q. PLEASE DESCRIBE SCHEDULE G-7.4(c), ADFIT AND ITC – PLANT ADJUSTMENTS AND ALLOCATIONS.

A. This schedule provides the accumulated deferred income tax balances at Test Year end related to additions for new generating plant in service since the Company's last filing and any plant adjustments to the Test Year end requested by the Company and the supporting calculations. The Company has not added any new generating plant since filing its last base rate case and is not requesting any post-Test Year plant adjustments.

Q. PLEASE DESCRIBE SCHEDULE G-7.4(d), ADFIT-RATE CASE EXPENSE.

A. This schedule is not applicable. The Company did not have any ADIT associated with rate case expense reflected on the books at December 31, 2020.

Q. PLEASE DESCRIBE SCHEDULE G-7.5, ANALYSIS OF ITCS.

A. This schedule presents the analysis of the ITC adjustment for Deferred Investment Tax Credit ("DITC") to be included in cost of service. The Company's election under Section 46(f)(2) of the IRC does not permit amortization of ITC to reduce income tax expense in cost of service at a rate more rapidly than ratably — no faster than over the book life of the assets that generated the ITC. The stripped book depreciation rate requested is derived from the proposed depreciation rate calculations supported by EPE witness John Spanos. This rate represents the life or investment portion of the depreciation rate without regard to amounts for cost of removal or salvage. The stripped depreciation rate is multiplied by the ITC amortization base to calculate the annual amount of DITC amortization included in cost of service. The stripped depreciation rate is used in this computation to avoid a potential normalization violation that could result if the ITCs were amortized in cost of service at a rate more rapid than ratably. Workpaper G-7.5 shows the calculation of the Test Year ITC. For each class of assets generating the ITC, the Company applied the stripped depreciation rate to the ITC amortization base to arrive at the ITC amortization used to reduce income tax expense.

Q. PLEASE DESCRIBE SCHEDULE G-7.5(a), UTILIZED.

A. This schedule shows the ITC utilized (claimed on the income tax return) each year.

Q. PLEASE DESCRIBE SCHEDULE G-7.5(b), GENERATED BUT NOT UTILIZED.

A. This schedule presents the ITC generated but not utilized at the Test Year end December 31, 2020. This schedule is not applicable to the Company. All investment credits that were generated prior to December 31, 2020 have been utilized by EPE.

Q. PLEASE DESCRIBE SCHEDULE G-7.5(c), UTILIZED – STAND-ALONE BASIS.

A. This schedule is not applicable to the Company. All investment credits have been utilized by EPE on a stand-alone basis.

Q. PLEASE DESCRIBE SCHEDULE G-7.5(d), ITC ELECTION.

A. This schedule describes the tax elections made by EPE with regard to ITC.

Q. PLEASE DESCRIBE SCHEDULE G-7.5(e), FERC ACCOUNT 255 BALANCE.

A. This schedule shows the account balance for FERC Account No. 255 – Accumulated Deferred Investment Tax Credits as of December 31, 2020.

Q. PLEASE DESCRIBE SCHEDULE G-7.6, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT – TAX METHOD 2.

A. This schedule calculates federal and state income tax expense for the Test Year using Tax Method 2. This method of calculating federal and state income tax expense determines the current and deferred components of tax expense separately. The components of tax expense shown on this schedule include taxes currently payable, deferred taxes, and DITC amortization. The total income tax expense amount calculated by Tax Method 2 is equal to the amount of tax expense computed under the return method (see Schedule G-7.8).

Q. PLEASE DESCRIBE SCHEDULE G-7.6(a), ANALYSIS OF DEFERRED FIT.

A. This schedule is an analysis of each deferred tax item that makes up the federal deferred tax expense in Schedule G-7.6.

Q. PLEASE DESCRIBE SCHEDULE G-7.7, ANALYSIS OF ADDITIONAL DEPRECIATION REQUESTED.

A. This schedule provides the detailed support for the requested adjustment to return for additional depreciation. This schedule summarizes the major components related to flow-through book depreciation for which there is no tax benefit. Workpaper G-7.7 provides the detailed calculations for this schedule.

Q. PLEASE DESCRIBE SCHEDULE G-7.8, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT – TAX METHOD 1.

A. This schedule calculates federal and state income tax expense for the Test Year using Tax Method 1, the return method. The income tax expense calculated by Tax Method 1 is equal to the amount of tax expense computed by Tax Method 2 (see Schedule G-7.6).

Q. PLEASE DESCRIBE SCHEDULE G-7.9, AMORTIZATION OF PROTECTED AND UNPROTECTED EXCESS DEFERRED TAXES.

A. This schedule summarizes the amortization of protected and unprotected excess deferred federal income tax and the amortization methodology utilized.

Q. DO YOU SPONSOR THE G-7.9 SCHEDULES?

A. No. The schedules related to G-7.9 are sponsored by Company witness Prieto as part of her direct testimony.

Q. PLEASE DESCRIBE SCHEDULE G-7.10, EFFECTS OF ACCOUNTING ORDER DEFERRALS.

A. This schedule is not applicable. The Company does not have any ADIT or federal income tax as of December 31, 2020, related to accounting order deferrals.

Q. PLEASE DESCRIBE SCHEDULE G-7.11, EFFECTS OF POST-TEST YEAR ADJUSTMENT.

A. This schedule is not applicable. The Company's request does not include post-Test Year adjustments to plant.

Q. PLEASE DESCRIBE SCHEDULE G-7.12, EFFECTS OF RATE MODERATION PLAN.

A. The Company does not have an existing rate moderation plan and is not requesting a rate moderation plan.

Q. PLEASE DESCRIBE SCHEDULE G-7.12(a), TREATMENT OF FIT AND ADFIT IN RATE MODERATION PLAN.

A. The Company does not have an existing rate moderation plan and all federal income tax and ADIT from previous rate moderation plans have been fully amortized.

Q. PLEASE DESCRIBE SCHEDULE G-7.13, LIST OF FIT TESTIMONY.

A. This schedule lists all witnesses that are filing testimony in this case that support the Company's federal income tax and ADIT requests. The most recent tax return filed (for the calendar year ended December 31, 2019) is included as part of the confidential workpapers for this schedule.

Q. PLEASE DESCRIBE SCHEDULE G-7.13(a), HISTORY OF TAX NORMALIZATION.

A. This schedule details the history of tax normalization for the Company and also provides details of the first year for each timing difference and the first year normalized.

Q. PLEASE DESCRIBE SCHEDULE G-7.13(b), TAX ELECTIONS.

A. Tax elections made by the Company since the Test Year end reflected in the last base rate filing, Docket No. 46831, are detailed in this schedule.

Q. PLEASE DESCRIBE THE CHANGES IN ACCOUNTING FOR DEFERRED TAXES SHOWN ON SCHEDULE G-7.13(c).

A. There have been no changes in accounting for federal deferred income taxes. As previously discussed, the Company has included deferred state income taxes in cost of service and is recovering the prior accumulated state ADIT using a South Georgia methodology over a 15-year period.

Q. PLEASE DESCRIBE SCHEDULE G-7.13(d), IRS AUDIT STATUS.

A. This schedule explains the Company's current federal income tax audit status. For the period up through the consummation of the merger (including the 2019 tax year), the Company participated in the IRS Compliance Assurance Process ("CAP") Program. As described in this Schedule, the CAP Program is a method of resolving tax issues between the taxpayer and the IRS through open and transparent interactions and communications to resolve issues prior to the filing of tax returns. Upon consummation of the merger, EPE is a party to the Sun Jupiter consolidated tax group and will no longer participate in the CAP Program.

Q. SCHEDULE G-7.13(e) RELATES TO PRIVATE LETTER RULINGS SINCE THE LAST RATE FILING. HAVE THERE BEEN ANY PRIVATE LETTER RULINGS

RECEIVED SINCE THE LAST RATE FILING THAT AFFECT THE FEDERAL INCOME TAX OF THE COMPANY?

A. There have been no private letter rulings received by the Company since the last rate filing.

Q. PLEASE DESCRIBE SCHEDULE G-7.13(f), METHOD OF ACCOUNTING FOR ADFIT RELATED TO NOL CARRYFORWARD.

A. This schedule describes the method of accounting for the Company's NOL Carryforwards and the balances included in ADIT at the Test Year end December 31, 2020.

VIII. Taxes Other Than Income

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I first discuss the Company's property taxes. I then discuss the remaining taxes other than income that the Company incurs.

A. Property Taxes

Q. WHAT WAS THE TOTAL AMOUNT OF PROPERTY TAXES DURING THE TEST YEAR?

A. The total amount of property taxes for the Company in the Test Year is shown on Schedule G-9, column (f), lines 1 to 3.

Q WHAT IS THE NET REQUESTED RECOVERY AMOUNT FOR THE COMPANY'S PROPERTY TAXES?

A. The total amount of requested property taxes can be found on Schedule G-9, column (h), lines 1 to 3.

Q. HOW ARE THE PROPERTY TAXES FOR THE COMPANY DETERMINED?

A. The property taxes charged to the Company are the amounts imposed by taxing authorities to which the Company is subject. Property taxes are capitalized to construction work in process for assets currently under construction based on an assessed value or are expensed for assets in electric plant in service.

Q. PLEASE DESCRIBE THE VARIOUS TAXING AUTHORITIES THAT LEVY PROPERTY TAXES AGAINST THE COMPANY'S PROPERTY.

A. The Company is subject to property taxation by many different taxing jurisdictions. These taxing jurisdictions include, but are not limited to, counties, cities, independent school districts, fire districts, and industrial districts. Also, various taxing jurisdictions overlap, and, for example, a single piece of utility property may be the basis for property tax levied by as many as six or more jurisdictions.

Q. HOW ARE THE PROPERTY TAX AMOUNTS IMPOSED BY THE TAXING JURISDICTIONS DETERMINED?

A. Property tax is typically assessed against the appraised or taxable value of the Company's property located within the jurisdiction of a taxing authority. Generally, the property tax appraisal process is a two-step process for a regulated utility. The first step is to establish a market value for all of the utility's property, collectively. This is referred to as a "unit" valuation. The second step is to allocate that market value of the unit to the taxing jurisdictions in which the utility owns taxable property.

Once the taxable value for a tax jurisdiction is determined and final, the jurisdiction calculates and sends a bill to the taxpayer. The billed amount is determined by multiplying the jurisdiction's tax rate by the taxable value of EPE's property in that jurisdiction.

Q. PLEASE DESCRIBE SCHEDULE G-9.1, AD VALOREM TAXES AND PLANT BALANCES.

A. This schedule shows the amount of ad valorem taxes assessed, penalties paid, and discounts taken for the three calendar years shown on Schedule G-9, as well as the net plant balances at the beginning of each of those years.

Q. HAS THE COMPANY MADE ANY PRO FORMA ADJUSTMENTS TO ITS TEST YEAR PROPERTY TAX AMOUNT?

A. Yes. The Company has made pro forma adjustments to its Test Year property tax amounts to reflect an effective rate of tax assessed on adjusted net plant in service balances at December 31, 2020. The adjustment is included in Workpaper A-3, Adjustment No. 15.

B. Revenue-Related Taxes

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I sponsor the Company's revenue-related taxes. By "revenue-related taxes", I mean the Company's directly incurred local franchise fees; sales, use and gross receipts taxes; and other miscellaneous taxes plus state regulatory assessments.

Q. WHAT WAS THE TOTAL AMOUNT OF REVENUE-RELATED TAXES DURING THE TEST YEAR?

A. The total amount of revenue-related taxes for the Company in the Test Year is shown on Schedule G-9, column (f), lines 9, 10, and 12 to 16.

Q WHAT IS THE NET REQUESTED RECOVERY AMOUNT FOR THE COMPANY'S REVENUE-RELATED TAXES?

A. The total amount of requested revenue-related taxes can be found on Schedule G-9, column (h), lines 9, 10, and 12 to 16.

Q. HAS THE COMPANY MADE ANY PRO FORMA ADJUSTMENTS TO ITS TEST-YEAR REVENUE-RELATED TAXES?

A. Yes. Adjustments were made to revenue-related taxes where necessary to reflect adjustments to the underlying amounts in cost of service. The adjustments were calculated based on an effective tax rate determined by dividing the applicable taxes expensed by taxable Company revenues. These effective tax rates were adjusted for the effective uncollectible expenses rate and then applied to requested revenues to determine the amount of taxes included in the requested cost of service. These adjustments are reflected on Schedule G-9 and are calculated in Workpaper A-3, Adjustment No. 17. It was determined that the adjustment factor used to calculate the revenue related taxes associated with the revenue deficiency did not include the effect of the Covid-19 adjustment made to uncollectible accounts receivable. This resulted in a $5,858 overstatement in the Company's requested revenue requirement. Please see the testimony of Company witness

Jennifer I. Borden for discussion of these amounts, which are reflected in Adjustment 17 as a Covid-19 Rate Adjustment.

C. Payroll Taxes

Q. WHAT WAS THE TOTAL AMOUNT OF PAYROLL TAXES DURING THE TEST YEAR?

A. The total amount of payroll taxes for the Company in the Test Year is shown on Schedule G-9, column (f), lines 4 to 8.

Q. WHAT IS THE NET REQUESTED RECOVERY AMOUNT FOR THE COMPANY'S PAYROLL TAXES?

A. The total amount of requested payroll taxes can be found on Schedule G-9, column (h), lines 4 to 8.

Q. HAS THE COMPANY MADE ANY PRO FORMA ADJUSTMENTS TO ITS TEST YEAR PAYROLL TAXES?

A. Yes. Payroll taxes were calculated based on rates and maximum wage base limits effective in 2021 and have been adjusted to reflect requested salary and wage levels as discussed in the testimony of EPE witness Cynthia S. Prieto. These adjustments are reflected on Schedule G-9 and are calculated in Workpaper A-3, Adjustment No. 16. Adjustment No. 16 is sponsored by EPE witness Prieto.

Q. ARE THESE EXPENSES NECESSARY AND REASONABLE?

A. Yes. All of the above-described taxes are necessary because they are required by law in order to allow the Company to operate in its applicable jurisdictions. The amounts are reasonable because the taxes are imposed by law and calculated in accordance with applicable law and reflect the requested rate base and cost of service in this filing.

IX. Conclusion

Q. PLEASE STATE YOUR CONCLUSIONS.

A. The Company's per books and Test Year federal and state income tax amounts found in the G-7 schedules and included in the Company's requested cost of service and rate base are reasonable and necessary and calculated in accordance with PURA and the Commission's rules. The Company's income tax calculation includes amortization of the deficiency in state ADIT using a 15-year amortization as approved in the Final Order for PUCT Docket No. 44941. Additionally, the amounts of the Company's taxes other than income found in the G-9 schedules and included in the Company's requested cost of service are also reasonable and necessary and calculated in accordance with applicable law.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY S. IHORN

Schedule	Description	Sponsorship
G-7.1	RECONCILIATION OF TY BOOK NET INCOME TO TAXABLE NET INCOME	Sponsor
G-7.1a	RECONCILIATION OF TIMING DIFFERENCES	Sponsor
G-7.2	PLANT ADJUSTMENTS	Sponsor
G-7.3	CONSOLIDATED TAXES	Sponsor
G-7.3a	CONSOLIDATION BENEFITS	Sponsor
G-7.3b	CONSOLIDATION / INTER-CORPORATE TAX ALLOCATION	Sponsor
G-7.4	ADFIT	Sponsor
G-7.4a	ADFIT - DESCRIPTION OF TIMING DIFFERENCES	Sponsor
G-7.4b	ADJUSTMENTS TO ADFIT	Sponsor
G-7.4c	ADFIT AND ITC - PLANT ADJUSTMENTS & ALLOCATIONS	Sponsor
G-7.4d	ADFIT - RATE CASE EXPENSE	Sponsor
G-7.5	ANALYSIS OF INVESTMENT TAX CREDITS	Sponsor
G-7.5a	UTILIZED	Sponsor
G-7.5b	GENERATED BUT NOT UTILIZED	Sponsor
G-7.5c	UTILIZED - STAND ALONE BASIS	Sponsor
G-7.5d	INVESTMENT TAX CREDIT ELECTION	Sponsor
G-7.5e	FERC ACCOUNT 255 BALANCE	Sponsor
G-7.6	ANALYSIS OF TYE FIT & REQUESTED FIT - TAX METHOD 2	Sponsor
G-7.6a	ANALYSIS OF DEFERRED FIT	Sponsor
G-7.7	ANALYSIS OF ADDITIONAL DEPRECIATION REQUESTED	Sponsor
G-7.8	ANALYSIS OF TYE FIT & REQUESTED FIT - TAX METHOD 1	Sponsor
G-7.10	EFFECTS OF ACCOUNTING ORDER DEFERRALS	Sponsor
G-7.11	EFFECTS OF POST TEST YEAR ADJUSTMENT	Sponsor

SCHEDULES SPONSORED BY S. IHORN

G-7.12	EFFECTS OF RATE MODERATION PLAN	Sponsor
G-7.12a	TREATMENT OF FIT AND ADFIT IN RATE MODERATION PLAN	Sponsor
G-7.13	LIST OF FIT TESTIMONY	Co-Sponsor
G-7.13a	HISTORY OF TAX NORMALIZATION	Sponsor
G-7.13b	TAX ELECTIONS	Sponsor
G-7.13c	CHANGES IN ACCOUNTING FOR DEFERRED FIT	Sponsor
G-7.13d	IRS AUDIT STATUS	Sponsor
G-7.13e	PRIVATE LETTER RULINGS	Sponsor
G-7.13f	METHOD OF ACCOUNTING FOR ADFIT RELATED TO NOL CARRYFORWARD	Sponsor
G-9	TAXES OTHER THAN INCOME TAXES	Sponsor
G-9.1	AD VALOREM TAXES & PLANT BALANCES	Sponsor

TAX SHARING AGREEMENT

This Tax Sharing Agreement (this "Agreement"), dated effective as of July 29, 2020, is made and entered into as of July 29, 2020, by and among Sun Jupiter Topco LLC, a Delaware Limited Liability Company ("Parent"), Sun Jupiter Parent LLC, a Delaware Limited Liability Company, Sun Jupiter Holdings LLC, a Delaware Limited Liability Company and El Paso Electric Company, a Texas Corporation (each party, a "Sun Jupiter Affiliate" and collectively, the "Sun Jupiter Affiliates").

RECITALS

WHEREAS, all of the Sun Jupiter Affiliates are members of an affiliated group of corporations within the meaning of section 1504(a) of the Internal Revenue Code of 1986, as amended (the "Code"), of which Parent is the common parent (the "Sun Jupiter Group");

WHEREAS, some or all of the Sun Jupiter Affiliates may be included in a group of entities headed by Parent or another Sun Jupiter Affiliate that is entitled to file Tax Returns (as defined below) with respect to state or local Taxes (as defined below) on a consolidated, combined, or unitary basis (a "State Group"); and

WHEREAS, the Sun Jupiter Affiliates desire to set forth their agreement regarding the allocation of Taxes and the rights and responsibilities of the Sun Jupiter Affiliates with respect to Tax Returns, Tax Contests (as defined below) and other related Tax matters.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual obligations and undertakings contained herein, the Sun Jupiter Affiliates agree as follows:

1. DEFINITIONS.

1.1 Previously Defined Terms. Each term defined in the first paragraph of this Agreement and the Recitals shall have the meaning specified above whenever used in this Agreement.

1.2 Other Definitions. When used in this Agreement, the following terms shall have the following respective definitions:

"Combined Tax Return" shall have the meaning specified in Section 3.2 of this Agreement.

"Consolidated Tax Return" shall have the meaning specified in Section 3.1 of this Agreement.

"Deconsolidation Event" shall mean any event or transaction that causes one or more Sun Jupiter Affiliates to no longer be eligible to file a Consolidated Tax Return or a Combined Tax Return.

"Estimated Payment Date" shall mean each of the due dates prescribed in section 6655(c) of the Code.

"Estimated Tax Sharing Amount" shall have the meaning specified in Section 4.4(a) of this Agreement.

"Federal Income Tax Liability" shall mean, for each taxable period, the Tax liability imposed under Subtitle A of the Code (including the Taxes imposed by section 11 of the Code), and any interest, additions to Tax or penalties applicable or related thereto.

"Final Determination" shall mean the final resolution of any Tax for a taxable period that, under applicable law, is not subject to further appeal, review or modification through proceedings or otherwise.

"Independent Tax Return" shall have the meaning specified in Sections 3.3 and 3.4 of this Agreement.

"Item" shall mean any item of income, gain, deduction, Loss or credit received, earned, paid or incurred by a Sun Jupiter Affiliate.

"Loss" shall mean the excess for a taxable period of a Sun Jupiter Affiliate's deductions for federal or state income Tax purposes over its income for such purposes computed in the manner used to compute its Separate Return Tax Liability (or its State or Local Tax Sharing Amount in the applicable state or local taxing jurisdiction).

"Payment Account" shall have the meaning specified in Section 8 of this Agreement.

"Payment Sections" shall have the meaning specified in Section 8 of this Agreement.

"Pre-Deconsolidation Period" shall mean any taxable period beginning on or before the date of a Deconsolidation Event.

"Separate Return Tax Liability" shall mean, for each taxable period, a Sun Jupiter Consolidated Member's allocable share of the Federal Income Tax Liability of the Sun Jupiter Group determined in accordance with the methodology set forth in sections 1.1552-1(a)(1) and 1.1502-33(d)(3) of the Treasury regulations.

"State Group Head" shall mean Parent or any other Sun Jupiter Affiliate that is the parent of a State Group.

"State or Local Tax Sharing Amount" shall have the meaning specified in Section 5.2 of this Agreement.

"Sun Jupiter Combined Member" shall mean, with respect to any State Group, a Sun Jupiter Affiliate that is included in such State Group and is not a disregarded entity with respect to such State Group.

"Sun Jupiter Consolidated Member" shall mean a Sun Jupiter Affiliate that is a member (within the meaning of section 1.1502-1(b) of the Treasury regulations) of the Sun Jupiter Group.

"Tax" shall mean any federal, state or local tax, impost, rate, charge, fee, duty, levy, or other assessment or charge of any kind whatsoever, together with any related interest, penalties or other additions to tax, imposed by a taxing authority.

"Tax Asset" shall mean any Item that has accrued for Tax purposes, but has not been realized during the taxable period in which it has accrued, and that could reduce a Tax in another taxable period, including a net operating loss, net capital loss, investment tax credit, foreign tax credit, charitable deduction or any other Tax credits.

"Tax Contest" shall have the meaning specified in Section 4.6 of this Agreement.

"Tax Return" shall mean any return, report, certificate, election, form or similar statement or document (including, any related or supporting information or schedule attached thereto and any information return, amended Tax Return, claim for refund or declaration of estimated Tax) supplied to, or filed with, or required to be supplied to, or filed with, a taxing authority in connection with the determination, assessment or collection of any Tax or the administration of any laws, regulations or administrative requirements relating to any Tax.

"Tax Sharing Amount" shall have the meaning specified in Section 4.1 of this Agreement.

2. AGENCY.

Each Sun Jupiter Affiliate hereby designates Parent as its sole and exclusive agent and attorney-in-fact in respect to all matters pertaining to (a) the payment of such Taxes as are imposed in the United States of America and calculated on a consolidated, combined or unitary basis, and (b) compliance with all laws applicable to such Taxes, and hereby authorizes Parent to take on its behalf such action (including execution of documents) as Parent in its sole discretion, may deem appropriate in any and all matters (including audits and other proceedings) relating to any Tax Return described in Sections 3.1 or 3.2 of this Agreement.

3. TAX RETURN PREPARATION.

3.1 Consolidated Federal Tax Returns. Parent shall have exclusive control over all matters relating to the preparation and filing of any consolidated federal income Tax Return of the Sun Jupiter Group (a "Consolidated Tax Return").

3.2 Consolidated, Combined or Unitary State or Local Tax Returns. Parent shall have exclusive control over all matters relating to the preparation and filing of any state or local Tax Return filed on a consolidated, combined, or unitary basis (including, without limitation, any Tax based in whole or in part by net income or gross income or any franchise, gross receipt, net capital or other similar Taxes) with respect to any State Group (a "Combined Tax Return").

3.3 Separately Filed State or Local Income Tax Returns. The applicable Sun Jupiter Affiliate shall have exclusive control over all matters relating to the preparation and filing of any of its state or local income Tax Returns other than any Combined Tax Returns (together with Tax Returns described in Section 3.4 of this Agreement, an "Independent Tax Return").

3.4 Non-Income State or Local Tax Returns. The applicable Sun Jupiter Affiliate shall have exclusive control over all matters relating to the preparation and filing of any of its non-income state or local Tax Returns (together with Tax Returns described in Section 3.3 of this Agreement, an "Independent Tax Return") .

4. ALLOCATION, PAYMENT AND REFUND OF FEDERAL INCOME TAXES.

4.1 Allocation of Federal Income Taxes. For each taxable period, each Sun Jupiter Consolidated Member shall be liable for and pay to Parent (or to such other person as is directed by Parent), at the times and in the manner set forth in Section 4.4 of this Agreement, cash in an amount equal to such Sun Jupiter Consolidated Member's Separate Return Tax Liability (the "Tax Sharing Amount") in order to reimburse Parent for such Sun Jupiter Consolidated Member's allocable share of the Federal Income Tax Liability of the Sun Jupiter Group.

4.2 Payment of the Consolidated Return Tax Liability. Parent shall pay, on behalf of itself and each Sun Jupiter Consolidated Member, to the Internal Revenue Service the Federal Income Tax Liability of the Sun Jupiter Group in the manner specified by the Code and the Treasury regulations promulgated thereunder.

4.3 Use of Items by the Sun Jupiter Group. For the avoidance of doubt, Parent shall pay any Sun Jupiter Consolidated Member for any Item that reduces the Federal Income Tax Liability of the Sun Jupiter Group.

4.4 Payment of Tax Sharing Amounts.

(a) Tax Sharing Installment Payments. Not later than fifteen (15) days prior to an Estimated Payment Date with respect to any taxable period, each Sun Jupiter Consolidated Member shall provide to Parent a reasonable estimate of the related installments of its Federal Income Tax Liability computed as if such Sun Jupiter Consolidated Member files a separate federal income Tax Return (computed in accordance with any estimated payment method under section 6655 of the Code chosen by Parent) and the basis for such estimate, setting forth the proposed treatment for United States federal income Tax purposes of all Items taken into account in determining such estimate. Parent shall review such estimate, and notify each Sun Jupiter Consolidated Member of any changes to such estimate not later than six (6) days prior to the applicable Estimated Payment Date (such estimate of the related installments, as adjusted by Parent, shall constitute the "Estimated Installment of the Separate Return Tax Liability"). Not later than five (5) days prior to the Estimated Payment Date, each Sun Jupiter Consolidated Member shall pay to Parent (or to such other person as is directed by Parent) the Estimated Installment of the Separate Return Tax Liability (the "Estimated Tax Sharing Amount").

(b) Tax Sharing True-Up Payments. As soon as reasonably practicable after the Consolidated Tax Return for a taxable period is filed, Parent shall deliver to each Sun Jupiter Consolidated Member the information reasonably necessary for such Sun Jupiter Consolidated Member to calculate its Tax Sharing Amount for such taxable period. Within fifteen (15) days after delivery of such information, each Sun Jupiter Consolidated Member shall deliver to Parent a schedule reflecting such Sun Jupiter Consolidated Member's Tax Sharing Amount for such taxable period. Parent shall review such estimate, and shall notify each Sun Jupiter Affiliate of any changes to the schedule as soon as reasonably practicable. Within five (5) days after Parent notifies an Sun Jupiter Consolidated Member of its acceptance of or any changes to the schedule, Parent shall pay to such Sun Jupiter Consolidated Member, or such Sun Jupiter Consolidated Member shall pay to Parent (or to such other person as is directed by Parent), as appropriate, an amount equal to the difference between (i) the sum of the Estimated Tax Sharing Amounts paid by such Sun Jupiter Consolidated Member for such taxable period and (ii) the Tax Sharing Amount set forth with respect to such Sun Jupiter Consolidated Member on the schedule (as adjusted by Parent), together with any interest or penalties assessed on account of such difference by any taxing authority.

4.5 Redetermination of Tax Sharing Amount. If, pursuant to a Final Determination, the treatment of any Item in determining the Sun Jupiter Group's Federal Income Tax Liability for a taxable period is different than that used to calculate any of the Sun Jupiter Consolidated Member's Tax Sharing Amount in respect of such taxable period (including a Final Determination to the effect that a Sun Jupiter Affiliate previously considered an Sun Jupiter Consolidated Member is not an Sun Jupiter Consolidated Member or vice versa), then the amount of any such Tax Sharing Amount (and any Tax Sharing Amounts with respect to prior open years) shall be redetermined by treating such Item in the manner finally determined by Parent, reasonably and in good faith, to be appropriate. The difference between the Tax Sharing Amounts of an Sun Jupiter Consolidated Member and the amounts thereof as redetermined shall be paid within thirty (30) days following such Final Determination by Parent to such Sun Jupiter Consolidated Member, or paid by such Sun Jupiter Consolidated Member to Parent (or to such other person as is directed by Parent), as appropriate, together with interest. Interest shall be computed under section 6621(a)(1) of the Code if the Tax Sharing Amounts are greater than the redetermined amounts, and under section 6621(a)(2) of the Code if the redetermined amounts are greater than the Tax Sharing Amounts. In addition to interest, any such payments shall include penalties which are fairly attributable to the redetermination with respect to such Item.

4.6 Contest. In the event of an audit or administrative or judicial proceeding involving an asserted liability for Taxes (a "Tax Contest") of the Sun Jupiter Group, Parent shall have the sole right to decide whether to contest such Tax Contest, and shall have full control over such Tax Contest. To the extent that a Tax Contest involves an Item attributable to a particular Sun Jupiter Consolidated Member, such member will reimburse Parent for all third-party out-of-pocket expenses associated with such Tax Contest that are attributable to such Item.

4.7 Refunds and Credits. Each Sun Jupiter Consolidated Member shall be entitled to all refunds and credits resulting from an Item attributable to such Sun Jupiter Consolidated Member in determining such member's Tax Sharing Amount. Upon receipt of any refund resulting from an Item attributable to a Sun Jupiter Consolidated Member, Parent shall pay over such refund to the applicable Sun Jupiter Consolidated Member.

5. ALLOCATION, PAYMENT AND REFUND OF STATE AND LOCAL TAXES.

5.1 Elections. Parent, in its sole discretion, may elect to have any State Group file a Combined Tax Return.

5.2 Allocation of State or Local Tax. For each state or local jurisdiction in which a State Group files a Combined Tax Return, each Sun Jupiter Combined Member included in such Combined Tax Return shall be liable for and pay to the applicable State Group Head (or to such other person as is directed by Parent), at the times and in the manner set forth in Section 5.5 of this Agreement, cash in an amount equal to such Sun Jupiter Combined Member's allocable share of the Tax liability of such State Group (the "State or Local Tax Sharing Amount") in order to reimburse such State Group Head for such Sun Jupiter Combined Member's allocable share of the Tax liability of such State Group. For purposes of this Section 5.2, each Sun Jupiter Combined Member's allocable share of the Tax liability of such State Group shall be determined in a manner consistent with the principles set forth in Section 4.1 of this Agreement, subject to any comparable provisions of applicable state or local tax law, if any. Any Tax liability not allocated pursuant to the preceding sentence shall be allocated to each Sun Jupiter Combined Member in a manner as if such Tax liability is separately incurred by such Member.

5.3 Payment of State or Local Tax. As directed by Parent, for each state or local Tax jurisdiction in which a State Group files a Combined Tax Return, the relevant State Group Head shall pay, on behalf of itself and each Sun Jupiter Combined Member included in such State Group, the annual Tax liability of the State Group to the state or local taxing authority in accordance with the laws of the state or local jurisdiction.

5.4 Use of Items by the State Group. For the avoidance of doubt, the State Group Head shall pay any Sun Jupiter Combined Member for any Item that reduces the State Group's Tax liability with respect to its Combined Tax Return.

5.5 Computation and Time of Payment. All payments required under Section 5.2 of this Agreement shall be determined and made in a manner consistent with the principles set forth in Section 4.4 of this Agreement; provided, however, that the timing with respect to each installment of a State or Local Tax Sharing Amount shall be determined by applying the rules specified in Section 4.4(a) of this Agreement to the applicable provisions of the relevant state or local tax law.

5.6 Redetermination. If, pursuant to a Final Determination, the treatment of any Item in determining a State Group's tax liability for a taxable period is different than that used under Section 5.2 of this Agreement to calculate the State or Local Tax Sharing Amounts in respect of such taxable period, such State or Local Tax Sharing Amounts (and any State or Local Tax Sharing Amounts with respect to prior open years) shall be redetermined by Parent, and the Sun Jupiter Affiliates shall make such payments as are necessary to comply with the redetermined amount, in a manner consistent with the principles set forth in Section 4.5 of this Agreement.

5.7 Contest. In the event of any Tax Contest involving a State Group, Parent shall have the sole right to decide whether to contest such Tax Contest, and shall have full control over such Tax Contest. To the extent that a Tax Contest involves an Item attributable to a particular Sun Jupiter Combined Member, such member will reimburse Parent for all third-party out-of-pocket expenses associated with such Tax Contest that are attributable to such Item.

5.8 Refunds and Credits. Each Sun Jupiter Combined Member shall be entitled to all refunds and credits resulting from an Item attributable to such Sun Jupiter Consolidated Member in determining its State or Local Tax Sharing Amount. Upon receipt of any refund resulting from an Item attributable to a Sun Jupiter Combined Member, Parent shall pay over such refund to the applicable Sun Jupiter Combined Member.

6. PAYMENT AND REFUND OF INDEPENDENT TAX RETURNS

6.1 Tax Liability and Payment. Any Sun Jupiter Affiliate required to file an Independent Tax Return shall pay on its own behalf any Tax liability with respect to such Independent Tax Return to the appropriate taxing authority in accordance with the relevant law.

6.2 Contests. In the event of any Tax Contest involving a Sun Jupiter Affiliate with respect to its Independent Tax Returns, such Sun Jupiter Affiliate shall have the sole right to decide whether to contest such Tax Contest, and shall have full control over such Tax Contest.

6.3 Refunds. Each Sun Jupiter Affiliate shall be entitled to all refunds and credits with respect to its Independent Tax Returns.

7. DECONSOLIDATION EVENTS.

7.1 Tax Allocations. Although no Sun Jupiter Affiliate has any plan or intent to effectuate any transaction that would constitute a Deconsolidation Event, the Sun Jupiter Affiliates have set forth how certain Tax matters with respect to a Deconsolidation Event would be handled in the event that, as a result of changed circumstances, a transaction that constitutes a Deconsolidation Event occurs at some future time.

7.2 Allocation of Tax Items. In the case of a Deconsolidation Event, all Tax computations for (1) any Pre-Deconsolidation Periods ending on and including the date of the Deconsolidation Event and (2) the immediately following taxable period of applicable Sun Jupiter Affiliate(s), shall be made pursuant to the principles of section 1.1502-76(b) of the Treasury Regulations or of a corresponding provision under the laws of other applicable jurisdictions, determined by Parent. Parent shall be entitled to make any election allowable under section 1502 of the Code and any Treasury regulations promulgated thereunder in respect of the Deconsolidation Event, including, without limitation, any election pursuant to section 1.1502-36 of the Treasury regulations, and any corresponding provisions under the laws of other applicable jurisdictions, determined by Parent.

7.3 Allocation of Tax Assets. In the case of a Deconsolidation Event, the applicable Sun Jupiter Affiliate and the remaining members of the Sun Jupiter Group shall cooperate in determining the allocation of any Tax Assets among each of the Sun Jupiter Affiliates. All Sun Jupiter Affiliates agree that in the absence of controlling legal authority or unless otherwise provided under this Agreement, Tax Assets shall be allocated to the legal entity that is required under Section 4 and Section 5 of this Agreement to bear the liability for the Tax associated with such Tax Asset, or in the case where no party is required hereunder to bear such liability, the party that incurred the cost or burden associated with the creation of such Tax Asset.

8. RESTRICTION ON PAYMENTS.

If an Sun Jupiter Affiliate is prohibited from making a payment as required by Section 4 or Section 5 of this Agreement by law or contractual obligation, and such prohibition is so acknowledged by Parent, then no such payment will be made under such Sections (collectively, the "Payment Sections"). Parent shall, however, keep an account reflecting the net balance of payments that would have been made had payments been made under the Payment Sections (the "Payment Account"). For purposes of keeping such account, interest shall be computed under section 6621(a)(1) of the Code if money is owed to Parent and under section 6621(a)(2) of the Code if money is owed to an Sun Jupiter Affiliate. If a prohibition referenced in the first sentence of this Section 8 is eliminated, then the affected Sun Jupiter Affiliate shall notify Parent in a timely manner, and within ten (10) days of such notification the amount reflected in the Payment Account shall be paid to Parent or the Sun Jupiter Affiliate, as appropriate.

9. CHANGE IN LAW.

If, after the date this Agreement is executed and delivered, as a result of an amendment to the Code, the promulgation of proposed, temporary or final regulations, the issuance of a ruling by the Internal Revenue Service, the decision of any court, or a change in any comparable applicable state or local Tax law, Parent believes that it is necessary or helpful to amend the provisions of this Agreement in order to preserve the rights and benefits contemplated herein, each of the Sun Jupiter Affiliates agrees to negotiate in good faith all such amendments and modifications as shall be necessary or appropriate in order to preserve as nearly as possible for the Sun Jupiter Affiliates the rights and benefits contemplated herein. Notwithstanding the preceding sentence, in the event of an amendment to section 6655(c) of the Code (or a comparable provision under state or local Tax law), this Agreement shall be amended so that the timing and amounts of Tax Sharing Amounts and/or State or Local Tax Sharing Amounts shall be revised to conform to such amendment.

10. COOPERATION.

Each Sun Jupiter Affiliate shall: (i) furnish Parent or the applicable State Group Head in a timely manner such information and documents as Parent or the applicable State Group Head may request for purposes of (A) preparing any Tax Return for which Parent or the applicable State Group head has filing responsibility under this Agreement, (B) evaluating, contesting, or defending any Tax Contest, and (C) making any determination or computation necessary or appropriate under this Agreement; (ii) make its employees available to provide explanations of documents and other materials and such other information as Parent or the applicable State Group Head may reasonably request in connection with the foregoing; (iii) cooperate in any Tax Contest of a Consolidated Tax Return or Combined Tax Return; (iv) retain and provide on demand books, records, documentation, or other information relating to any Tax Return until ninety (90) days after the expiration of the applicable statute of limitations (giving effect to any extension, waiver, or mitigation thereof); and (v) take such other actions as Parent or the applicable State Group Head may reasonably deem appropriate in connection therewith.

11. GENERAL PROVISIONS.

11.1 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware.

11.2 Notices. All notices or other communications required or permitted hereunder shall be in writing and shall be deemed given or delivered when delivered personally or when sent by registered or certified mail in accordance with the names and addresses shown on Schedule A, or in accordance with such name and address as a Sun Jupiter Affiliate may indicate by a notice delivered to the other Sun Jupiter Affiliates.

11.3 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of all the Sun Jupiter Affiliates and their respective successors and assigns. Nothing herein, expressed or implied, is intended or may be construed to confer upon any person other than the Sun Jupiter Affiliates and their successors and assigns any right, remedy or claim under or by reason of this Agreement.

11.4 Duration. Unless terminated earlier by agreement of all Sun Jupiter Affiliates, this Agreement shall remain in force and effect for all taxable periods for which any Sun Jupiter Group files Consolidated Tax Returns or any State Group files Combined Tax Returns. Notwithstanding any termination of this Agreement, the provisions hereof shall remain in effect (and each Sun Jupiter Affiliate shall continue to have all of the rights and obligations hereunder) with respect to any taxable period (or portion thereof) preceding the date of such termination.

11.5 New Affiliates. If at any time any other entity becomes an affiliate of Parent or the applicable State Group Head, such entity may become a party to this Agreement by executing together with Parent or the applicable State Group Head an agreement in substantially the same form as set forth in Schedule B. Unless otherwise specified, such new entity shall have all rights and obligations of an Sun Jupiter Affiliate under this Agreement.

11.6 Affiliates. Each Sun Jupiter Affiliate shall cause to be performed, and hereby guarantees the performance of, all actions, agreements and obligations set forth herein to be performed by any of the Sun Jupiter Affiliates.

11.7 Authorization, Etc. Each of the Sun Jupiter Affiliates hereby represents and warrants that is has the power and authority to execute, deliver and perform this Agreement, that this Agreement has been duly authorized by all necessary corporate action on the part of such Sun Jupiter Affiliate, that this Agreement constitutes a legal, valid and binding obligation of such Sun Jupiter Affiliate and that the execution, delivery and performance of this Agreement by such Sun Jupiter Affiliate does not contravene or conflict with any provision of law or of its charter or bylaws or any agreement, instrument or order binding on such Sun Jupiter Affiliate.

11.8 Entire Agreement; Amendments. This Agreement contains the entire understanding of the Sun Jupiter Affiliates with respect to the subject matter hereof and supersedes all prior agreements, understandings and intentions between or among any of the Sun Jupiter Affiliates. The Sun Jupiter Affiliates may amend, modify or supplement this Agreement, but only by mutual agreement in writing.

11.9 Headings. The headings and subheadings used in this Agreement are used for convenience of reference only and are not to be considered in construing or interpreting this Agreement.

11.10 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

[Remainder of Page Intentionally Blank]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the dates accompanying their respective signatures, but effective as of the date first above written.

Sun Jupiter Topco LLC

By: ______________________
Name: Preston T. Scherer
Title: Authorized Signatory
Dated: July 29, 2020

Sun Jupiter Parent LLC

By: ______________________
Name: Preston T. Scherer
Title: Authorized Signatory
Dated: July 29, 2020

Sun Jupiter Holdings LLC

By: ______________________
Name: Preston T. Scherer
Title: Authorized Signatory
Dated: July 29, 2020

El Paso Electric Company

By: ______________________
Name: ______________________
Title: ______________________
Dated: ______________________

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the dates accompanying their respective signatures, but effective as of the date first above written.

Sun Jupiter Topco LLC

By: ______________________
Name: ______________________
Title: ______________________
Dated: ______________________

Sun Jupiter Parent LLC

By: ______________________
Name: ______________________
Title: ______________________
Dated: ______________________

Sun Jupiter Holdings LLC

By: ______________________
Name: ______________________
Title: ______________________
Dated: ______________________

El Paso Electric Company

By: Nathan T. Hirschi
Name: Nathan T. Hirschi
Title: Senior Vice President and Chief Financial Officer
Dated: July 29, 2020

Schedule A

Sun Jupiter Topco LLC (EIN: 84-2665086)
277 Park Avenue 35th Floor
New York, NY 10172

Sun Jupiter Parent LLC (EIN: 84-2641326)
277 Park Avenue 35th Floor
New York, NY 10172

Sun Jupiter Holdings LLC (EIN: 61-1933163)
277 Park Avenue 35th Floor
New York, NY 10172

El Paso Electric Company (EIN: 74-0607870)
P.O. Box 982, Loc 112
El Paso, TX 79960

Schedule B

WHEREAS, Sun Jupiter Topco LLC, a Delaware limited liability company ("Parent"), owns, directly or indirectly, all of the outstanding stock or interests in the undersigned;

WHEREAS, the undersigned is not a party to the Tax Sharing Agreement, made and entered into as of July 29, 2020, by and among Parent and each of the Sun Jupiter Affiliates (as defined therein) (the "Agreement"); and

WHEREAS, the undersigned and Parent desire to have their tax sharing and other tax-related arrangements governed by the Agreement.

NOW, THEREFORE, in consideration of mutual obligations and undertakings contained in the Agreement, the parties agree that tax sharing and other tax-related arrangements between and among the undersigned and the other Sun Jupiter Affiliates will be governed by the terms of the Agreement, and that the Agreement is hereby amended to include the name of the undersigned among the entities listed thereon.

IN WITNESS WHEREOF, the parties have executed this agreement on the dates accompanying their respective signatures, but effective as of ______________.

[NAME]	**Sun Jupiter Topco LLC**
By: ____________________	By: ____________________
Title: ____________________	Title: ____________________
Dated: ____________________	Dated: ____________________

DOCKET NO. _____

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

DIRECT TESTIMONY

OF

DAVID C. HAWKINS

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

David C. Hawkins is the Vice President–Strategy and Sustainability for El Paso Electric Company ("EPE" or "Company"). He oversees renewable and emerging technologies, information technology and information security, operations technology, resource planning, contracting for generation and transmission interconnections, sustainability, and EPE's stake in the Palo Verde Generating Station ("Palo Verde" or "PVGS").

Mr. Hawkins' testimony discusses EPE's system operations activities which require reliable operation of EPE's generation resources. He also discusses the value of capacity that should be imputed to two long-term renewable energy contracts in accordance with the settlement and order in EPE's most recent base rate case, Docket No. 46831. In addition, he describes the Energy Imbalance Market that EPE agreed to join in 2023 and how it will benefit EPE customers. Mr. Hawkins describes EPE's Transportation Electrification Plan for electric vehicles and how that plan will benefit EPE customers. He then discusses the upgrade of EPE's Energy Management System and the benefits to EPE customers. Last, he supports the reasonableness of the capital additions placed in service at Palo Verde from October 2016 through December 2020, together with the reasonableness of the Palo Verde's Test Year operations and maintenance expenses.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Hawkins. My business address is 100 North Stanton Street, El Paso, Texas 79901-1341.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company").

Q. WHAT IS YOUR CURRENT POSITION WITH EPE?

A. I am Vice President of Strategy and Sustainability.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS VICE PRESIDENT OF STRATEGY AND SUSTAINABILITY?

A. I oversee renewable and emerging technologies, information technology and information security, operations technology, resource planning, contracting for transmission and generation interconnections, sustainability, and El Paso Electric's stake in Palo Verde Generating Station ("Palo Verde" or "PVGS").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from New Mexico State University with a Bachelor of Science degree in Electrical Engineering in 1993 and a Master of Science degree in Electrical Engineering in 1994.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I was employed by West Texas Utilities Company in Abilene, Texas, as a Power Marketing Engineer until July 1996. In August 1996, I began working for Public Service Company of New Mexico("PNM") as a Power Marketing Analyst, where my job duties included analysis of the wholesale power market and economic evaluation of wholesale transactions.

In April 2002, I began working for EPE as a Pre-scheduler, where my duties included optimization of EPE's generation dispatch through wholesale power transactions, daily and monthly natural gas procurement estimates, and regulatory compliance. In

October 2004, I was promoted to Supervisor of Resource Management. Resource Management is responsible for daily and long-term wholesale power transactions, contract negotiation, scheduling and accounting, and running PROMOD cases for financial planning. In March 2006, the responsibility of fuels planning and procurement for EPE's generating units was incorporated into Resource Management. In November 2007, I was promoted to Manager of Long-Term Trading and Fuels. My responsibilities in this position included wholesale power transactions, fuel supply planning and procurement, and development of PROMOD for financial planning and regulatory filings. In February 2010, I was promoted to Director of Energy Trading, where my additional responsibilities included oversight of the Company's real-time marketing operation.

In October 2011, I was laterally moved to Power Generation as Director-Generation Operations, where I supervised EPE's local generating plant operations and maintenance. In April 2013, I was promoted to Vice President–Power Marketing & Fuels and Resource Delivery Planning, where I oversaw the long-term planning of new generation resources as well as those previously mentioned throughout my time serving as Director of Energy Trading. In June 2014, I was promoted to Vice President–System Operations, Resource Planning and Management, where I retained the job functions of my previous position and, in addition, oversaw the System Operations department, which is responsible for the reliable real-time operation of EPE's electric grid. In February 2018, my title became Vice President–Power Generation and System Planning and Dispatch, where in addition to my previous responsibilities, I assumed responsibility for EPE's Power Generation fleet and began overseeing the operations and maintenance, engineering, and projects for EPE's local generation fleet.

In February 2021, I was promoted to Vice President of Strategy and Sustainability.

Q. HAVE YOU EVER PROVIDED TESTIMONY IN A REGULATORY PROCEEDING?

A. Yes, I have filed 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. First, I present an overview of EPE's system operations activities required for EPE to meet its load serving responsibilities. Second, I present EPE's proposal regarding the value of capacity that should be imputed to two long-term renewable energy contracts in accordance with the settlement and order in EPE's most recent base rate case in Docket No. 46831. Third, I describe the Western Energy Imbalance Market ("EIM") that EPE agreed to join in 2023 and how joining the EIM will benefit EPE customers. Fourth, I describe EPE's Transportation Electrification Plan for electric vehicles and how it will benefit EPE customers. Fifth, I discuss the capital addition of EPE's Energy Management System ("EMS") and its benefit to EPE customers. Finally, I support the reasonableness of the capital additions placed in service at the PVGS from October 2016 through December 2020, together with the reasonableness of the PVGS Test Year operations and maintenance ("O&M") expenses.

Q. WILL YOUR TESTIMONY ADDRESS A .RECONCILIATION OF FUEL AND PURCHASED POWER COSTS OR ANY ADJUSTMENTS TO THE COMPANY'S FUEL FACTOR?

A. No. EPE is not seeking to reconcile its fuel and purchased power costs nor is it seeking to change its fuel factor. That being said, I do sponsor many of the fuel schedules included in EPE's rate filing package. The costs contained in these schedules are taken from the Company's books and records and will be subject to review in a future fuel reconciliation filing.

Q. WHAT EXHIBITS AND SCHEDULES DO YOU SPONSOR?

A. The exhibits that I sponsor are identified in the Table of Contents of this testimony. The schedules that I sponsor or co-sponsor are identified in Exhibit DCH-1.

Q. WERE THE SCHEDULES AND EXHIBITS THAT YOU SPONSOR OR CO-SPONSOR PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

III. System Operations Overview

Q. PLEASE PROVIDE AN OVERVIEW OF EPE'S LOAD-SERVING RESPONSIBILITIES.

A. From an operational standpoint, EPE monitors its generation resources and transmission system to ensure that the system load and operating reserve obligations can be met on a real time basis. This means EPE's generation resources must provide dynamic response to system changes in load, frequency, and voltage. In addition, EPE must have sufficient resources to meet daily peak load and hourly load profile requirements as well as sufficient reserves in response to a generation resource or transmission contingency.

Q. DOES EPE SEEK TO MEET ITS LOAD-SERVING RESPONSIBILITIES AT THE LOWEST REASONABLE COST?

A. Yes. EPE forecasts its multi-year demand needs on an annual basis as demonstrated in its Loads and Resources document ("L&R"). The most recent L&R, dated July 2020, is shown in Exhibit DCH-2. EPE is developing its 2021 L&R; however, the July 2020 L&R was updated to reflect EPE's 2021 load forecast, including the significant increase in load compared to the July 2020 L&R, and is shown in Exhibit DCH-3. As part of that annual planning process, EPE evaluates its need for future generation capacity based on future load growth and planned generation retirements, as well as its obligation to reliably meet EPE's planning reserve margins. In order to meet identified future resource needs, EPE will conduct requests for proposals ("RFP") to identify the lowest reasonable cost resource portfolio to reliably serve its customers. In 2017, for example, EPE conducted an all-source RFP that resulted in the selection of a combination of solar, battery storage, and the Newman Unit 6 natural-gas turbine to meet forecasted load requirements in 2022 and 2023.

In addition to long-term planning, EPE seeks to optimize its system on a day-ahead and current-day basis to serve customer load at the lowest reasonable cost.

Q. DOES EPE UTILIZE DEMAND SIDE RESOURCE OPTIONS IN ITS PLANNING PROCESS TO REDUCE EPE'S NEED FOR NEW GENERATION RESOURCES?

A. Yes. As shown on line 1.9 of Exhibit DCH-2, EPE reduces the amount of capacity required to meet planning reserve targets by utilizing interruptible loads. Operationally, EPE utilizes the interruptible loads to contribute to the North American Electric Reliability

Corporation ("NERC") supply and demand balancing standards. Additional interruptible load capabilities would reduce or defer EPE's need for new generation resources to meet future planning reserve criteria, particularly given the projected increase in load as shown in Exhibit DCH-3. Please refer to the direct testimony of EPE witness James Schichtl for EPE's proposal for additional interruptible load.

Q. CAN YOU DESCRIBE THE ROLE OF EPE'S DAY-AHEAD PLANNING PROCESS IN THE DEVELOPMENT OF A UNIT COMMITMENT PLAN?

A. Yes. During the day-ahead planning process, a unit commitment plan is prepared weighing variables such as load forecasts, weather patterns, resource availability and cost, transmission availability and constraints, fuel delivery system constraints, operating reserve requirements, and power and natural gas prices at EPE's primary market hubs. The unit commitment study determines anticipated actions to be taken during the next day, including alternatives such as making fuel purchases, power purchases, and electricity sales in the spot market.

Q. CAN YOU DESCRIBE HOW EPE'S CURRENT-DAY PLANNING AFFECTS SYSTEM DISPATCH?

A. Yes. The current-day planning process involves EPE's System Controllers, Preschedulers and Real-Time Marketers who coordinate the appropriate way to meet customers' needs over the course of the day. The main items that are considered include the forecasted customer load, the resources available to meet that load, projections about prices in the fuel and purchased power markets, and the relative costs of alternatives for serving load. The current-day planning process makes real-time adjustments to the previous day's unit commitment plan. These adjustments include refining the load projections and selling or purchasing energy as economic opportunities arise once reserves are met.

Q. WHAT ACTIONS ARE GENERALLY TAKEN AS A RESULT OF THE CURRENT-DAY PLANNING PROCESS?

A. The current-day planning process results in hour-by-hour and real-time decisions concerning the output level at which EPE's generating units should be operated and the extent to which EPE engages in wholesale power transactions. These decisions determine actions to be taken during the course of the day, including alternatives such as ramping local generating units up or down and making economically sound power purchases and sales in the spot market.

Q. HOW DOES EPE MEET ITS SUMMER PEAK LOAD OBLIGATIONS?

A. EPE relies on its generating units and purchased power, assisted by its transmission system, to meet load and operating reserve requirements during the summer period, which typically runs from May through September. Due to high summer load levels, which restrict EPE's ability to perform necessary planned maintenance, EPE seeks to complete maintenance of its generating units during the non-peak periods of the year to achieve generating unit availability throughout the summer period.

Q. DOES EPE HAVE IMPORTANT LOAD SERVING RESPONSIBILITIES OUTSIDE OF THE SUMMER PEAK PERIOD?

A. Yes. EPE is a summer peaking utility, so demand is much higher in the summer relative to other times of the year. However, the dynamic response of generation resources to system reliability needs remains a 24-hour, year-round obligation. As EPE witness J Kyle Olson describes in his direct testimony, EPE's generation resource portfolio is composed of base load, load following, and peaking units that provide system operational benefits during all seasons.

Q. HOW DO PEAKING GENERATION RESOURCES PROVIDE AN OPERATIONAL BENEFIT OUTSIDE OF THE SUMMER MONTHS?

A. The terms "peak" or "peak load" typically refer to the annual projected maximum hourly load usage. However, from an operational perspective, every day has an hour wherein the maximum energy usage occurs, which is the peak load of that day. Peaking resources can be used outside of the summer months to meet each day's peak load requirements, particularly in the winter months, as can be seen in the capacity factor characteristics in Schedule H-12.3a, which I co-sponsor with EPE witness Olson. Additionally, system contingencies including either unplanned generation or transmission outages can happen any time of year. Quick starting peaking units allow EPE to meet real-time contingencies during any season within the year.

Q. WHY DO EPE'S PEAKING RESOURCES PROVIDE A PARTICULAR BENEFIT IN THE WINTER MONTHS?

A. EPE's peaking resources benefit EPE's system in the winter months and are particularly useful during that season in managing the impact of solar resources, both large-scale and residential, on EPE's system. EPE's peak energy usage in the winter months typically occurs in the evening. As the sun goes down, EPE loses solar resource load serving contributions and then experiences an increase in customer energy usage, resulting in a relatively steep demand increase. Peaking resources serve not only to replace the contribution from solar generation, but also to meet the additional demand of a typical winter evening. In addition, in the pre-dawn morning hours prior to the solar resources' contribution, and as customer energy usage begins to climb, EPE utilizes peaking generation resources to meet increasing energy demand. As solar contribution increases as the sun rises, EPE is able to reduce its peaking generation, primarily from its General Electric LMS100 generation units (Rio Grande Unit 9 and Montana Units 1 through 4) that EPE witness Olson describes, due to their flexibility and dispatchability. Since these resources can be brought online in 10 minutes, they are particularly effective in supplementing EPE's intermittent solar resources. Although EPE relies on older steam-generating units operating at minimum output levels to provide system stability, even when the energy is not needed ("must-run generation"), this reliance on less efficient, older generation would be exacerbated in the absence of peaking resources.

IV. Imputed Capacity for Two Solar Purchased Power Agreements

Q. IS EPE REQUESTING TO INCLUDE PURCHASED POWER CAPACITY COSTS IN EPE'S COST OF SERVICE?

A. Yes. Consistent with the Final Order in Docket No. 46831, EPE seeks to include capacity costs associated with two renewable energy purchased power agreements ("PPAs") the Company uses to serve Texas customers: the Macho Springs 50-megawatt ("MW") solar agreement, which began commercial operation in May 2014, and the Newman 10-MW solar agreement, which began in December 2014. I present the imputed capacity costs associated with these contracts that were agreed to in Docket No. 46831, and EPE witness Jennifer I. Borden sponsors the adjustment to reflect the revised costs in the Company's cost of service.

Q. DO THESE SOLAR PPAs INCLUDE SPECIFIED CAPACITY CHARGES?

A. No. They do not. However, EPE's practice has been to account for these two solar PPAs in EPE's L&R, which is used to calculate EPE's planning reserve margin, thus demonstrating that the two solar PPAs have a capacity component.

Q. ARE THERE OTHER PPAs INCLUDED IN EPE'S CURRENT L&R WHICH CONTRIBUTE TO EPE'S PLANNING RESERVE MARGIN?

A. Yes. Although these other PPAs are similar to the Macho Springs and Newman solar PPAs—they are included in EPE's L&R, are for renewable resources, and are energy-only contracts—EPE is not seeking to impute associated capacity charges to include in its Texas jurisdictional cost of service. These other PPAs are entirely allocated to the New Mexico jurisdiction, as they were procured under the New Mexico Renewable Portfolio Standard ("RPS"). All of the costs for these contracts are recovered from New Mexico customers through the New Mexico RPS Cost Rider. To the extent that EPE enters into additional renewable PPAs to meet specific increases in the New Mexico RPS, those costs too shall be entirely recovered from New Mexico customers.

Q. DID THE SETTLEMENT AGREEMENT AND ORDER IN EPE'S LAST BASE RATE CASE IN DOCKET NO. 46831 SPECIFY HOW THE MACHO SPRINGS AND NEWMAN SOLAR PPAs WOULD BE TREATED FOR RATEMAKING PURPOSES?

A. Yes, they did. Article I.F of the Docket No. 46831 settlement agreement, titled "Imputed Capacity", specifies the rate treatment of these two PPAs as follows:

> The Signatories agree that the classification of costs incurred by EPE as either base rate capacity charges or fuel charges for the 50 MW Macho Springs solar PPA and the 10-MW Newman solar PPA shall be as follows for the term of these contracts: Effective beginning August 1, 2017, the imputed capacity charge for the 50 MW Macho Springs solar PPA shall be $2.35/kW per month, and the imputed capacity

> charge for the 10 MW Newman solar PPA shall be $2.33/kW per month. All remaining costs incurred under these two PPAs shall be classified as fuel expenses.

Finding of Fact 33 in the Commission's final order adopted this provision of the settlement agreement.

Q. DOES EPE'S PROPOSED RATE TREATMENT OF THE MACHO SPRINGS AND NEWMAN SOLAR PPAs COMPLY WITH THE DOCKET NO. 46831 AGREEMENT AND ORDER?

A. Yes, it does. Specifically, EPE has imputed capacity charges of $2.35 per kilowatt ("kW") per month to the Macho Springs PPA and $2.33 per kW per month to the Newman PPA. The resulting Test Year capacity charges have been included in EPE's cost of service.

V. EPE's Efforts To Reduce Fuel and Purchased Power Costs

Q. WHAT STEPS ARE EPE TAKING TO INCREASE THE EFFICIENCY OF ITS SYSTEM?

A. EPE seeks to operate its system in an economical manner by operating its most efficient units while maintaining reliability. In addition, EPE seeks to purchase power when it can be purchased at a lower cost than EPE can generate the power. EPE also seeks to sell power in the wholesale power market when it can earn a margin above the cost of the energy. Margins on off-system sales are credited to retail customers, thus lowering overall fuel costs. Going forward, EPE has signed an implementation agreement with the California Independent System Operator ("CAISO") for EPE to join the EIM in April 2023. Participation in the EIM will allow EPE to purchase and sell power in a broader market on an intra-hour basis, which should provide more efficiency savings to customers.

Additionally, with the expected increase of electric vehicles in EPE's service territory, EPE will seek to shift customers' charging patterns to non-peak periods, as I discuss later in my testimony.

Q. WHAT IS THE EIM AND HOW DOES IT WORK?

A. The EIM is a real-time, intra-hour energy-only market that seeks efficient dispatch of generation across the EIM footprint, which is most of the Western Interconnection, to serve real-time customer demand. The market optimizes regulation of customer load requirements and variable output from renewable resources by utilizing the most efficient regional generating resources, including renewables, made available for EIM dispatch. In doing so, the EIM facilitates greater integration of renewable resources and mitigates their curtailment by making these resources available for EIM entities to purchase. The EIM utilizes participants' available transmission capacity to re-dispatch at five-minute intervals across the EIM footprint.

Q. WHO ARE THE OTHER PARTICIPANTS IN THE EIM?

A. The majority of the Western Electricity Coordinating Council members have either joined or committed to join the EIM, which, on a regional basis, includes Nevada Energy, Arizona Public Service, Tucson Electric Power, and PNM.

Q. WHAT WILL BE THE BENEFITS OF EPE JOINING THE EIM?

A. Participation in the EIM will provide EPE access to intra-hour energy during unexpected contingencies. EPE's existing energy trading counterparts have committed to join or have already begun participating in the EIM. EPE has relied on its regional trading partners to mitigate generation costs or respond to unplanned system contingencies in the real-time energy market. Participating in the EIM mitigates the risk of diminished real-time supply options during emergency situations, as increased participation the EIM means there is and will continue to be less liquidity in the real-time and intra-hour bilateral trade market outside the EIM. The Company also expects a reduction in fuel and purchased power costs given the intra-hour re-dispatching. As an added benefit, joining the EIM will help optimize EPE's growing renewable generation portfolio by providing intra-hour load and resource balancing opportunities.

Q. WHAT IS EPE'S ESTIMATE OF THE NET BENEFITS THAT THE COMPANY EXPECTS ITS CUSTOMERS WILL REALIZE AS A RESULT OF JOINING THE EIM?

A. The Company contracted with Energy and Environmental Economics, Inc. ("E3") to perform a dispatch and market analysis to estimate fuel and purchased power costs. E3 performed similar analyses for many of the other entities that have joined or plan to join the EIM. Based on a conservative scenario, the E3 analysis showed approximately $13 million in net present value benefits to EPE customers due to EPE's EIM participation in the years 2023 through 2028. This economic benefit includes the initial and ongoing capital and O&M costs of EIM participation.

Q. WILL THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR OR EIM HAVE CONTROL OVER EPE TRANSMISSION FACILITIES?

A. No. The EIM only utilizes participants' unused and available transmission capacity that EPE has authorized as being available to the EIM. EPE will determine on an hourly basis its generation and transmission availability to participate in the EIM market.

Q. IS EPE SEEKING TO RECOVER THROUGH THE RATES TO BE SET IN THIS CASE THE CAPITAL COSTS AND O&M EXPENSES OF IMPLEMENTING ITS PLAN TO JOIN THE EIM?

A. No.

VI. Transportation Electrification Pilot Program

Q. WHAT IS EPE'S TRANSPORTATION ELECTRIFICATION PLAN?

A. The Company's Transportation Electrification Plan ("TEP") will be a portfolio of pilot programs to support expansion of transportation electrification in EPE's service territory. The portfolio will include rebate programs for residential and commercial customers intended to incentivize purchase and installation of smart charging infrastructure. Accompanied with this is a customer outreach program designed to (1) improve customer education and awareness of electric vehicles ("EVs") and transportation electrification benefits, (2) promote the rebate programs discussed below, and (3) assist customers with transition to electrification. As discussed in the direct testimony of EPE witnesses Schichtl and Manuel Carrasco, the TEP also includes an update to EPE's existing EV rate designed to incentivize off-peak charging.

These programs and updated rate are intended to mitigate barriers to EV adoption such as high upfront costs, lack of charging infrastructure, and unfamiliarity with the benefits from electricity as fuel for transportation. EPE expects the programs to provide information to evaluate the need for infrastructure updates and advanced load control programs as well as the effectiveness of the Company's EV rate. Market research conducted by EPE revealed that the rebate programs, combined with the customer outreach program and EV rate designed to incentivize off-peak charging, are reasonable first steps to expand transportation electrification over the next few years.

Q. HAS EPE FORECASTED EV'S IMPACT ON LOAD?

A. Yes. EPE estimates that EV owners can consume an estimated additional 3,767 kilowatt-hours ("kWh") per EV on an annual basis or approximately half (47%) of the annual average energy usage of a residential customer in EPE's service territory. EPE estimates that unmanaged EV load from residential customers can lead to an additional maximum non-coincident peak load of 85 MW by 2030 or an additional coincident peak load of 22 MW for the EPE service territory.

Q. WHY ARE ELECTRIC UTILITIES UNIQUELY POSITIONED TO SUPPORT EXPANSION OF TRANSPORTATION ELECTRIFICATION IN THEIR SERVICE TERRITORIES?

A. As utilities are responsible for the operation of the electric grid, they are best suited to proactively implement the plans required to ensure the electric grid will be able to accommodate the increased demand created by growing EV penetration. Additionally, as addressed by EPE witness Carrasco, effective management of increasing EV load may create downward pressure on electricity rates, which may benefit all customers. Utilities can also encourage increased EV adoption through customer education, outreach, and incentive programs that may help lower upfront cost of charging infrastructure, address charging infrastructure gaps, and improve customer awareness of transportation electrification benefits. This in turn further promotes equal access to electrified transportation, especially for low-income and underserved communities. Finally, transportation electrification has the potential to reduce vehicle-related emissions and improve air quality to benefit all customers.

Q. HOW ARE THE TEP PROGRAMS EXPECTED TO IMPACT FUTURE EPE RESOURCE PLANNING?

A. The TEP pilot programs will be designed to encourage residential and commercial customers to purchase and install "networked" charging stations, also referred to as smart charging stations. Networked charging stations provide added capabilities to manage and shift the flexible EV charging load to off-peak hours, providing expected resource planning benefits that include:

- Mitigation of peak growth from EV charging,
- Reduction of renewable energy curtailment,
- Increased system operational flexibility, and
- Improved system efficiency and load factors.

Q. HOW IS THE PURCHASE AND INSTALLATION OF NETWORKED CHARGING STATIONS BY RESIDENTIAL AND COMMERCIAL CUSTOMERS EXPECTED TO IMPROVE THE EFFICIENCY OF EPE'S SYSTEM GENERATION RESOURCES?

A. Through networked charging stations and rate design, utilities can better manage when and how EV charging occurs, with a goal of shifting that usage from peak load hours to off-peak hours. This shift to off-peak hours increases the utilization of existing generation resources during off-peak hours, thus improving system load factors and efficiency and potentially delaying the need for new generation.

Q. IS THE PURCHASE AND INSTALLATION OF NETWORKED CHARGING STATIONS BY RESIDENTIAL AND COMMERCIAL CUSTOMERS EXPECTED TO IMPROVE ELECTRICAL SYSTEM OPERATIONAL FLEXIBILITY BENEFITING THE INTEGRATION OF VARIABLE RESOURCES?

A. Yes. Operational flexibility allows a power system to respond to variability in the system. Operational flexibility is especially important for the integration of renewable energy such as wind and solar that introduce intermittent variability to the system. The ability of the TEP programs to incentivize the deployment of networked charging infrastructure adds capability for shifting flexible EV load from peak to off-peak hours, thereby mitigating peak load growth and minimizing the need to add generation resources due to the added energy demands from EV charging. Additionally, shifting EV load to off-peak hours may also reduce steep power ramps caused by simultaneous EV charging and can mitigate the need for new fast ramping generation resources such as fossil-fuel peaking-type generation. Further, networked charging stations can help resolve the curtailment problem resulting from renewable generation production during low load hours by shifting the EV charging load to periods with excess renewable energy.

Q. IS THE PURCHASE AND INSTALLATION OF NETWORKED CHARGING STATIONS BY RESIDENTIAL AND COMMERCIAL CUSTOMERS EXPECTED TO IMPROVE SYSTEM GENERATION RESOURCE UTILIZATION DURING OFF-PEAK HOURS?

A. Yes. Smart charging infrastructure in combination with rate design facilitates the shift of flexible EV load to off-peak hours, improving system load factors by flattening the load profile and allowing for increased utilization of off-peak generation resources.

Q. WILL EPE'S TEP BE DESIGNED TO ADDRESS THE BARRIERS TO EV ADOPTION SUCH AS HIGH UPFRONT COSTS, LACK OF CHARGING INFRASTRUCTURE, AND LACK OF UNDERSTANDING OF ELECTRICITY AS FUEL FOR TRANSPORTATION?

A. Yes. EPE will be proposing residential programs to help its customers overcome barriers to EV adoption such as the upfront cost of networked charging station. These stations, when combined with advanced metering infrastructure, are expected to provide customers with necessary tools to manage EV usage, save money, and help EPE balance the grid. Data provided to EPE from a smart-meter-connected networked charger provides EPE real-time information on customer charging behavior, including customers' responsiveness to the proposed updated EV rate. This real-time data would allow EPE to (1) evaluate the grid impact of transportation electrification and (2) evaluate the need for infrastructure upgrades and load management programs.

Q. WHAT STEPS WILL EPE TAKE TO EDUCATE THE PUBLIC ABOUT EVS?

A. EPE created a website that includes a frequently asked question section but also provides information on the benefits of EVs, charging station types and locations, available incentives, and EPE's EV rate. EPE also engaged with local entities, such as El Paso Home Builders Association, El Paso Apartment Association, Greater El Paso Association of Realtors, Camino Real Regional Mobility Authority, University of Texas at El Paso and Housing Authority of the City of El Paso, to conduct informational sessions and presentations to help them understand EV technology, the infrastructure required, and how the transition to EVs is expected to happen. In addition, EPE will continue to participate and organize community outreach events or webinars with customers as well as civic and business leaders. Furthermore, EPE will continue working with external stakeholders on development of EV-friendly infrastructure.

Q. IS EPE PROPOSING CHANGES TO ITS EXISTING EV TARIFF IN THIS FILING?

A. Yes, it is. EPE witness Carrasco presents the proposed tariff changes in his testimony.

VII. Energy Management System

Q. ARE YOU SUPPORTING THE ENERGY MANAGEMENT SYSTEM ("EMS") CAPITAL ADDITION DISCUSSED IN EPE WITNESS LARRY HANCOCK'S DIRECT TESTIMONY?

A. Yes.

Q. CAN YOU GENERALLY DESCRIBE THE EMS?

A. The EMS acts as the central nervous system of EPE's bulk electric system due to its coordination of generation, transmission, and distribution assets in near real time. The e-terraplatform EMS is used by reliability coordinators such as the Electric Reliability Council of Texas, Florida Power & Light, British Columbia Hydro, and Southwest Power Pool, as well as by other utilities in the West such as AVISTA, BPA, and Idaho Power.

Q. WHAT IS THE COST OF THE EMS?

A. The total cost of the project was approximately $12.7 million. EPE selected the General Electric e-terraplatform EMS based on a request for proposals from various vendors.

Q. WHEN WAS THE EMS PLACED IN SERVICE?

A. The EMS was placed in service in March 2017.

Q. HOW IS THE EMS USED IN THE PROVISION OF ELECTRIC SERVICE TO EPE'S CUSTOMERS?

A. The EMS is necessary for the reliable operation of EPE's power grid and EPE's operation within the Western Interconnection. The EMS is designed to centrally monitor, analyze, optimize, simulate, and control EPE's generation, transmission, and distribution assets. The EMS allows for the coordination of electricity flows with EPE's neighboring utilities as well as generation control functions such as economic dispatch and automatic generation control, and it interfaces with system protection devices. The supervisory control and data acquisition components of the EMS include Data Acquisition, Data Processing, Inter-Control Center Communications Protocol, Supervisory Control, Real-time Calculations, Tagging, Alarming, and Load Shed and Restore. The network applications functions include Network Topology Processor, State Estimator, Dispatcher Power Flow, Contingency Analysis, and Dispatcher Training Simulator, which are all necessary for reliable system operation. EPE custom software includes Interchange Scheduling, Energy Accounting, Alarm Processing Monitor, Multiple Breaker Rotational Load Shed, and transfer capability applications such as Southern New Mexico Import Capability and El Paso Import Capability.

Q. WERE THE COSTS OF THE EMS NECESSARY AND REASONABLE?

A. Yes. EPE was notified that the vendor of EPE's previous EMS, which was installed in 2004, would be moving out of support and a new technology platform and hardware upgrade were required to maintain support. EPE followed a competitive procurement process and technical evaluation in selecting a new vendor, ensuring a fair market price for a replacement system. An appropriate analysis was conducted prior to bidder selection, resulting in a system that has added functionality, resiliency and redundancy. The costs associated with the new EMS were reasonable, necessary and prudent.

VIII. Palo Verde

Q. PLEASE DESCRIBE PVGS.

A. PVGS is a nuclear generating station, located on an approximately 4,000-acre site approximately 50 miles west of Phoenix, Arizona. The facility consists of three separate, virtually identical generating units and a variety of common support facilities. The net design electrical ratings of the facilities are 1,333 MW for Unit 1; 1,336 MW for Unit 2; and 1,334 MW for Unit 3. EPE's share of the total PVGS design capacity is 633 MW. PVGS also has a switchyard that operates at 500 kilovolts. EPE witness Todd Horton also provides a detailed description of PVGS in his direct testimony.

Q. PLEASE SUMMARIZE EPE'S COST OF SERVICE AND RATE BASE ADDITIONS REQUEST FOR PVGS.

A. EPE is requesting rate base capital additions of $182.2 million on a total Company basis for PVGS. EPE also is requesting $91.4 million in total unadjusted Company Test Year, non-fuel O&M for PVGS, along with the adjustments that I summarize below.

Q. ARE ANY ARIZONA PUBLIC SERVICE COMPANY ("APS") EMPLOYEES TESTIFYING ON EPE'S BEHALF IN THIS CASE?

A. Yes, EPE witness Horton is an employee of APS, which operates PVGS, and he discusses PVGS O&M and capital additions, from the plant wide perspective, from October 2016 through December 2020 in detail in his testimony.

Q. WHAT CONTROL DOES EPE HAVE OVER PVGS?

A. EPE is a minority, non-operating owner of PVGS. However, as a co-owner, EPE exercises its ownership and oversight rights provided to the Company by the PVGS operating agreement. The Company's oversight activities are discussed later in my testimony.

A. Overview of Palo Verde

Q. IS PVGS A RELIABLE AND ECONOMIC RESOURCE FOR THE COMPANY'S CUSTOMERS?

A. Yes, it is. PVGS has long been a source of base load power at low fuel prices for EPE's customers. PVGS diversifies EPE's portfolio of generation resources that provides long-term security to customers.

Q. HOW IS PVGS OWNED AND OPERATED?

A. The ownership of PVGS is divided among seven southwestern utilities ("Owners"): APS owns 29.10%, EPE owns 15.80%, Salt River Project Agricultural Improvement and Power District ("SRP") owns 17.49%, Southern California Edison Company owns 15.80%, PNM owns 10.20%, Southern California Public Power Authority owns 5.91%, and Los Angeles Department of Water and Power owns 5.70%. SRP has agreed to purchase a portion of PNM's ownership in PVGS Units 1 and 2 in the years 2023 and 2024, which will change the ownership percentages to approximately 20.39% (SRP) and 7.30% (PNM).

APS operates PVGS pursuant to a contract among the Owners, entitled the Arizona Nuclear Power Project Participation Agreement, which became effective August 23, 1973, and has been amended numerous times. The agreement calls for several Owner committees: Administrative Committee, Engineering & Operations ("E&O") Committee, Audit Committee, Fuel Committee, Switchyard Committee, and Termination Funding Committee. EPE employees are on the E&O, Termination Funding, Audit, Fuel, and Switchyard Committees, while I serve as an alternate on the E&O Committee. EPE also maintains an employee on-site.

B. PVGS Performance During the Test Year

Q. HAS PVGS OPERATED EFFICIENTLY?

A. Yes. For example, in 2019, PVGS achieved a record capacity factor of 92.6%. As a comparison, the Nuclear Energy Institute reported that the United States nuclear fleet averaged a 93.4% capacity factor in 2019. It should be noted that PVGS achieved this capacity factor while supporting a lengthy planned outage during which several large projects were implemented. PVGS is also currently subject to performance standards, and EPE receives penalties, rewards, or neither in fuel reconciliation cases depending on Palo Verde's level of performance as measured by achieved capacity factor.

APS and the Owners, through their oversight function, continue to work to improve performance at PVGS and will continue to incur costs related to the efforts to achieve excellent performance.

C. Palo Verde Capital Monitoring and Approval Process of Capital Costs

Q. HOW DOES EPE MONITOR PVGS CAPITAL ACTIVITIES AND COSTS?

A. EPE monitors Palo Verde capital activities and costs primarily through the PVGS E&O Committee's Capital Improvement Budget and Capital Project Approval Process ("Capital Budget Procedure"). EPE participated in the development of this procedure, which provides a process for all Owners to review, approve, and control PVGS capital improvement costs. The Owners must unanimously approve all capital improvements. A unanimous vote is likewise required for the capital budget each year. Once the budget is approved, APS can proceed with construction only on those projects for which E&O Committee approval has been received.

Q. WHAT IS EPE'S REVIEW PROCESS FOR THE PALO VERDE CAPITAL BUDGET?

A. EPE reviews the annual Palo Verde capital budget as part of the overall budget package, to ensure that budget items and levels match the requirements determined necessary for safe and efficient operation by the E&O Committee. EPE analyzes the line items for consistency with activities from prior years and with ongoing repair, replacement, and improvement efforts. EPE regularly attends and participates in plant meetings to better understand and evaluate capital budget needs.

EPE reviews budget submittals to ensure that projects are identified and accounted for in the correct budget (capital versus O&M), that they are in the correct budget category, and that carryover work from the current budget year is accurately represented. EPE also scrutinizes individual projects to ensure the projected total costs do not exceed the capital improvement work authorization variance limits contained in the Capital Budget Procedure. In addition, EPE reviews projected indirect PVGS capital improvement overhead costs and distributable costs and compares them to costs incurred in prior years. EPE also reviews capital project justifications.

Q. ARE THERE FURTHER REVIEWS OF THE CAPITAL BUDGET BY PROJECT?

A. Yes. Capital budget approval only indicates Owner concurrence to fund the capital project program at a certain level for a budget year. Projects are presented individually to the E&O Committee throughout the year using work authorization packages that include a business case and financial analysis for the proposed project. Non-regulatory projects above $500,000 must be approved by both the E&O and the executive level Administrative Committees. Except for emergent issues that must be addressed immediately, APS may not spend money or otherwise proceed with project implementation until the project has been reviewed and approved by the applicable Owner Committee(s). This process allows the Owners the opportunity to review and ask questions about proposed projects to help ensure that these investment expenditures serve customer interests and allow the plant to adapt to changing conditions as needed.

Q. DOES EPE COMPARE ACTUAL PVGS CAPITAL COSTS TO BUDGET AMOUNTS?

A. Yes. EPE monitors variance explanations for budgeted amounts on a monthly basis. This monthly analysis allows comparison of individual projects against budget and against the amount approved, in total, for each individual project. EPE can further investigate any material variances and communicate with APS to address any concerns.

Q. WHAT DO YOU CONCLUDE ABOUT THIS PROCESS FOR THE REVIEW AND APPROVAL OF CAPITAL EXPENDITURES?

A. The process of review and approval of capital expenditures is designed to ensure that proposed projects undergo several layers of scrutiny and review to demonstrate they are necessary and reasonable. Review and approval is required by PVGS management and also requires unanimous approval of the Owners. The approval process ensures that capital improvements at PVGS are consistent with the needs of all the Owners and in the interest of their customers.

D. PVGS Capital Additions to Rate Base

Q. WHAT AMOUNT OF PVGS CAPITAL ADDITIONS TO RATE BASE DOES EPE REQUEST?

A. The Company is seeking to include $182.2 million in PVGS total Company capital additions to rate base, which were placed in service during the period October 2016 through

December 2020, the end of the current Test Year.

Q. WHERE IS INFORMATION ABOUT THE CAPITAL PROJECTS THAT WERE ADDED AT PVGS FROM OCTOBER 2016 THROUGH DECEMBER 2020?

A. There are three sources of this information. EPE witness Hancock's capital additions exhibit, which I discussed above, lists Palo Verde plant additions during the period October 2016 through December 2020. Schedule H-5.2a includes a list of all Palo Verde capitalized projects being requested in rate base with actual costs of $100,000 or more (EPE share). Lastly, the testimony of EPE witness Horton describes PVGS major capital additions that support PVGS's philosophy to replace aging plant components from a plant wide perspective utilizing categorization specific to PVGS.

Q. ARE THE PVGS CAPITAL EXPENDITURES INCLUDED IN EPE'S REQUEST REASONABLE AND NECESSARY?

A. Yes. The capital projects represented by these costs have undergone the budget and project review processes discussed above. EPE, as well as all of the other Owners, have concurred that the projects and related costs are reasonable, necessary and prudent for safe, reliable, cost-effective service to our customers.

E. PVGS O&M Expense

1. General Discussion

Q. DOES EPE MONITOR AND REVIEW PVGS O&M COSTS?

A. Yes. EPE reviews the annual O&M budget package, including budget assumptions and O&M budget. EPE reviews the package to ensure that the budget is reasonable based upon expected plant performance and the refueling and maintenance outage schedules and consistent with the budgeted staffing levels and needs (e.g., loads, insurance premiums, and United States Nuclear Regulatory Commission fees). In addition to a total budget, APS provides separate refueling and maintenance outage budgets that EPE reviews to verify that the amounts and scope are both reasonable and consistent with planned outage dates. The reviews and questions submitted by other Owners on the proposed O&M budget are also reviewed and considered by EPE prior to EPE participating in the budget approval process. Unanimous approval of the O&M budget by the Owners is required under the Arizona Nuclear Power Project Participation Agreement.

2. Test Year Costs

Q. WHAT AMOUNT OF PVGS O&M EXPENSE DID EPE INCLUDE IN THE TEST YEAR COST OF SERVICE?

A. EPE included the unadjusted Test Year costs in the amount of $91.4 million for non-fuel O&M expense. The PVGS O&M cost information is included in Schedule G-15 co-sponsored by EPE witnesses Borden and Cynthia S. Prieto. EPE witness Borden also presents adjustments to Test Year O&M costs.

Q. WHAT DOES THIS TEST YEAR AMOUNT REPRESENT?

A. This amount represents EPE's Test Year share of the costs to perform the day-to-day operational activities and maintenance tasks on Units 1, 2, 3, and common plant at PVGS.

Q. ARE THE TEST YEAR EXPENDITURES REASONABLE?

A. Yes. These costs are reasonable and necessary to provide safe, reliable energy to customers and reflect unadjusted Test Year costs. Processes and procedures are in place that allow the Owners to closely scrutinize the O&M budget before it is adopted. Efficiency of a plant, measured by $/O&M per megawatt hour (MWh), can be affected by prudent spending on O&M as well as capital. As discussed in the testimony of EPE witness Horton, the combination of higher capacity factors and lower costs has put PVGS below the industry average on a cost per MWh basis. As discussed in detail by EPE witness Prieto, EPE was ordered to modify its long-term accounting for PVGS costs and to shift Palo Verde-related A&G costs to O&M costs as a result of a FERC audit. This reclassification of the costs, as noted by EPE witness Prieto, does not reflect an actual increase in Test Year expenses. As such, a direct comparison of the 2020 O&M costs to previous years does not produce an adequate analysis of the reasonableness of the 2020 costs.

Q. HOW DOES EPE DETERMINE IF O&M COSTS ARE REASONABLE?

A. As described previously, EPE participates in the review and approval of the PVGS O&M

budget. EPE monitors the PVGS O&M variance explanations and identifies issues throughout the year. EPE makes informal and formal recommendations for corrective action as is necessary. Furthermore, EPE monitors public policy issues such as Arizona property taxes, operational issues affecting plant capacity factor enhancements, and maintenance efficiencies. These steps help to ensure that costs remain reasonable not only when looking at operational budgets but also when costs are measured on a cents per kWh basis.

Q. DOES APS PROVIDE EXPLANATIONS OF ANY PVGS O&M BUDGET VARIANCES?

A. Yes. APS and PVGS personnel provide monthly variance reports and explain variances at E&O Committee meetings. Where necessary, EPE and other Owners seek clarifications in order to make budget recommendations.

Q. FOR ITS BASE RATE REQUEST, IS THE COMPANY PROPOSING ANY ADJUSTMENTS TO THE TEST YEAR PVGS O&M EXPENSES?

A. Yes. As EPE witness Borden discusses in her direct testimony, and as discussed above, the Test Year O&M costs must include the heretofore classified A&G costs.

IX. Summary and Conclusions

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND CONCLUSIONS.

A. My testimony discusses EPE's system operations activities which require reliable operation of EPE's generation resources during all seasonal load periods. I also discuss the value of capacity that should be imputed to two long-term renewable energy contracts in accordance with the settlement and order in EPE's most recent base rate case, Docket No. 46831. Additionally, I describe the EIM that EPE agreed to join in 2023 and how it will benefit EPE customers. In this proceeding, EPE is not seeking to recover the costs associated with EIM participation. I describe EPE's Transportation Electrification Plan for EVs and how it will benefit EPE customers. I discuss the upgrade of EPE's EMS and the benefits to EPE customers. Finally, I support the reasonableness of the capital additions placed in service at the PVGS from October 2016 through December 2020, together with the reasonableness of the PVGS Test Year O&M expenses.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY D. HAWKINS

Schedule	Description	Sponsorship
C-6.8	ALLOCATION OF UNASSIGNED BALANCE	Co-Sponsor
C-6.9	NUCLEAR FUEL INVENTORY POLICY	Sponsor
E-2.1	FOSSIL FUEL INVENTORY POLICIES	Sponsor
E-2.2	FOSSIL FUEL INVENTORY EVALUATION	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-3.2	NATURAL GAS SUPPLY DISRUPTIONS	Co-Sponsor
H-1	SUMMARY OF TEST YEAR PRODUCTION O&M EXPENSES (NUCLEAR & FOSSIL)	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-2	SUMMARY OF ADJUSTED TEST YEAR PRODUCTION O&M EXPENSES	Co-Sponsor
H-3	SUMMARY OF ACTUAL PRODUCTION O&M EXPENSES INCURRED	Co-Sponsor
H-4	MAJOR O&M PROJECTS	Co-Sponsor
H-5.2a	NUCLEAR CAPITAL COSTS PROJECTS	Co-Sponsor
H-5.3a	NUCLEAR CAPITAL EXPENDITURES (HISTORICAL, PRESENT, PROJECTED)	Co-Sponsor
H-5.3b	FOSSIL CAPITAL EXPENDITURES (HISTORICAL, PRESENT, PROJECTED)	Co-Sponsor
H-6.1a	NUCLEAR UNIT OUTAGE HISTORY	Sponsor
H-6.1b	NUCLEAR UNIT OUTAGE DATA	Sponsor
H-6.1c	NUCLEAR UNIT OUTAGE PLANNING	Sponsor
H-6.2c	FOSSIL UNIT OUTAGE PLANNING	Sponsor
H-6.3a	NUCLEAR UNIT INCREMENTAL OUTAGE COSTS	Sponsor
H-7.1	COMPANY-WIDE STAFFING PLAN	Sponsor

SCHEDULES SPONSORED BY D. HAWKINS

Schedule	Description	Sponsorship
H-7.2	PRODUCTION PLANT / UNIT STAFFING STUDY	Sponsor
H-7.3	PERSONNEL ASSIGNED FOR PLANT/UNIT	Sponsor
H-7.4	AVERAGE PERSONNEL ASSIGNED	Sponsor
H-7.5	PRODUCTION O&M ORGANIZATION CHARTS	Sponsor
H-11.1	O&M EXPENSES PER PRODUCTION PLANT EXPENSES	Co-Sponsor
H-11.3	O&M COST PER MWh	Co-Sponsor
H-12.1	SUPPLY AND LOAD DATA	Co-Sponsor
H-12.2a	MWh PRODUCTION BY UNIT (LIGNITE, COAL & NUCLEAR)	Sponsor
H-12.2a1	MWh PRODUCTION BY UNIT FOR PREVIOUS 5 YRS (LIGNITE, COAL & NUCLEAR)	Sponsor
H-12.2c	MWh PROUCTION BY UNIT (HYDRO & OTHER)	Sponsor
H-12.2c1	MWh PRODUCTION BY UNIT FOR PREVIOUS 5 YEARS (HYDRO & OTHER)	Sponsor
H-12.3a	UNIT DATA	Co-Sponsor
H-12.3b	UNIT CHARACTERISTICS	Co-Sponsor
H-12.3c	EFFICIENCY AND CONTROL SYSTEMS	Co-Sponsor
H-12.4a	FIRM PURCHASED POWER (NET MWh)	Sponsor
H-12.4b	FIRM PURCHASED POWER ENERGY COSTS	Sponsor
H-12.4c	FIRM PURCHASED POWER FIXED COSTS	Sponsor
H-12.4d	FIRM PURCHASED POWER ENERGY COSTS PER MWh	Sponsor
H-12.4e	NON-FIRM PURCHASED POWER (Net MWh)	Sponsor
H-12.4f	NON-FIRM PURCHASED POWER ENERGY COSTS	Sponsor
H-12.4g	NON-FIRM PURCHASED POWER ENERGY COSTS PER MWh	Sponsor
H-12.5b	OFF SYSTEM SALES - ECONOMY AND FIRM (NET MWh)	Sponsor
H-12.5c	OFF SYSTEM SALES REVENUE (ENERGY CHARGE COMPONENT)	Sponsor
H-12.5d	OFF SYSTEM SALES REVENUE (FIXED CHARGE COMPONENT)	Sponsor
H-12.5e	OFF SYSTEM SALES REVENUE (ENERGY CHARGE PER	Sponsor

SCHEDULES SPONSORED BY D. HAWKINS

Schedule	Description	Sponsorship
	KWh)	
I-1.3	FOSSIL FUEL PURCHASED	Sponsor
I-1.4	NON-RECURRING FUEL AND PURCHASED POWER EXPENSES	Sponsor
I-2	FUEL AND PURCHASED POWER PROCUREMENT PRACTICES	Sponsor
I-3	FUEL AND PURCHASED POWER COMMITTEES	Co-Sponsor
I-4	FUEL AND FUEL-RELATED CONTRACTS	Sponsor
I-7	NATURAL GAS STORAGE DESCRIPTION	Sponsor
I-8	FUEL PROPERTIES	Sponsor
I-9	EMPLOYEE ORGANIZATIONAL CHARTS	Sponsor
I-10	EMPLOYEE ETHICS	Sponsor
I-11	FUEL AND PURCHASED POWER ASSUMPTIONS NARRATIVE	Sponsor
I-12	FOSSIL FUEL MIX	Sponsor
I-13	ETHICS - RELATIONSHIP WITH FUEL SUPPLIER	Sponsor
I-15	FUEL CONTRACT ANALYSES - RECONCILIATION PERIOD	Sponsor
I-16	RECONCILABLE FUEL COSTS (NA-fuel rec)	Co-Sponsor
I-16.1	FOSSIL FUEL MIX (BURNED) (NA-fuel rec)	Co-Sponsor
I-16.2	FOSSIL FUEL MIX (PURCHASED) (NA-fuel rec)	Co-Sponsor
I-16.3	COMPETITIVE SPOT FOSSIL FUEL PURCHASES (NA-fuel rec)	Co-Sponsor
I-16.4	OTHER SPOT FOSSIL FUEL PURCHASES	Sponsor
I-17.1	COAL COST BREAKDOWN	Sponsor
I-17.2	LIGNITE COST BREAKDOWN	Sponsor
I-17.3	COAL COST DESCRIPTION	Sponsor
I-18	COAL AND LIGNITE SUPPLIER LOCATIONS	Sponsor
I-19.1	RAIL HAUL DISTANCE	Sponsor
I-19.2	UNIT TRAINS	Sponsor
I-19.3	CYCLE TIME	Sponsor

SCHEDULES SPONSORED BY D. HAWKINS

Schedule	Description	Sponsorship
I-19.4	RAIL CARS	Sponsor
I-19.5	RAIL CAR LEASES	Sponsor
I-19.6	RAIL CAR MAINTENANCE	Sponsor
I-21	FUEL MANAGEMENT	Sponsor
O-1.5	SYSTEM INFORMATION	Sponsor

El Paso Electric Company
Draft Loads & Resources 2021-2030
July 2, 2020

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	170 Solar 100/50 Sol/Batt	Newman 6			48 Geo 100/100 Sol/Batt		130 Solar CT 100 CT 228			48 Geo
1.0 GENERATION RESOURCES[1]										
1 1 RIO GRANDE	271	271	227	227	227	227	227	227	227	227
1 2 NEWMAN	729	729	809	809	809	809	496	496	496	496
1 3 COPPER	63	63	63	63	63	63	63	63	63	63
1 4 MONTANA	352	352	352	352	352	352	352	352	352	352
1 5 PALO VERDE	622	622	622	622	622	622	622	622	622	622
1 6 RENEWABLES[2]	6	6	6	5	5	5	5	5	5	5
1 7 STORAGE	0	0	0	0	0	0	0	0	0	0
1 8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	40	40	40	40	40	40
1 9 INTERRUPTIBLE[4]	43	43	43	43	43	43	43	43	43	43
1 10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	2094	2094	2130	2129	2169	2169	1856	1856	1856	1856
2.0 RESOURCE PURCHASES										
2 1 RENEWABLE PURCHASE[6]	73	72	72	72	71	71	70	70	69	69
2 2 NEW RENEWABLE PURCHASE[7]	0	43	42	42	42	42	41	41	41	41
2 3 NEW RENEWABLE/ BATTERY PURCHASE[8]	0	75	75	75	75	75	74	74	74	74
2 4 NEW BATTERY PURCHASE[9]	0	0	0	0	0	0	0	0	0	0
2 5 MARKET RESOURCE PURCHASE[10]	195	100	95	125	0	20	15	45	100	100
2 0 TOTAL RESOURCE PURCHASES	268	290	284	314	188	208	200	230	284	284
3.0 FUTURE RESOURCES[11]										
3 1 RENEWABLE	0	0	0	0	48	48	81	81	81	129
3 2 RENEWABLE/STORAGE	0	0	0	0	100	100	100	100	100	100
3 3 GAS GENERATION	0	0	0	0	0	0	328	328	328	328
3.0 TOTAL RESOURCE PURCHASES	0	0	0	0	148	148	509	509	509	557
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	2362	2384	2414	2443	2505	2525	2565	2595	2649	2697
5.0 SYSTEM DEMAND[12]										
5 1 NATIVE SYSTEM DEMAND	2079	2113	2145	2174	2217	2257	2298	2333	2385	2433
5 2 DISTRIBUTED GENERATION	(16)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
5 3 ENERGY EFFICIENCY	(12)	(19)	(25)	(31)	(37)	(43)	(49)	(56)	(62)	(68)
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	2051	2072	2098	2121	2158	2192	2227	2255	2301	2343
7.0 MARGIN OVER TOTAL DEMAND (4 0 - 6.0)	311	312	316	322	347	333	338	340	348	354
8.0 PLANNING RESERVE 15% OF TOTAL DEMAND	308	311	315	318	324	329	334	338	345	351
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	3	1	1	4	23	4	4	2	3	3

1. Generation unit retirements are consistent with the 2018 IRP. Rio Grande 6 is classified as inactive reserve
2. Existing EPE owned solar renewables at 70 percent contribution to peak.
3. Emerging technologies may include customer or other distributed resources as well as additional community solar
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2020 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs at 70 percent contribution to peak.
7. New renewable solar PPAs at 25 percent contribution to peak.
8. New solar and battery storage PPAs with solar at 25 percent contribution to peak.
9. 50 MW stand-alone battery was denied in NMPRC Case No 19-00348-UT The resource purchase on line 2.5 was adjusted to replace 50 MW capacity as required to meet the planning reserve margin.
10. Denotes market purchase either spot market or short-term purchased power Amounts greater than 645 MW-PV output will need to come into EPE via exchange (Freeport), through the acquisition of additional transmission or on a non-firm path. Also, availability of such power is not guaranteed.
11. Future Resources from 2025 forward are to address both NM RPS and capacity needs EPE will be initiating its 2021 IRP planning cycle which may result in changes to future planned resources.
12. System demand is based on the 2020 Long Term Forecast dated March 13, 2020.

Planned Generation Additions
100 MW Solar (25 MW at Peak) in 2022
Solar/Batt Combo (100/50 MW) in 2022 (75 MW at Peak)
Newman 6 GT5 (228 MW) in 2023
70 MW Solar (18 MW at Peak) in 2022

Unit Retirements
Rio Grande 6 (45MW) (inactive reserve)
Rio Grande 7 (44MW) - December 2022
Newman 1 (74MW) - December 2022
Newman 2 (74MW) - December 2022
Newman 3 (93MW) - December 2026
Newman 4 CC (220MW) - December 2026
Copper (63MW) - December 2030
Rio Grande 8 (139MW) - December 2033

Company Owned Renewables
Line 1.6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports and Van Horn

Renewable Purchases
Line 2 1 includes SunEdison, NRG, Macho Springs, Juwi, and Hatch solar purchases (70% availability at Peak)

New Renewable Purchase
Line 2 2 includes system solar resource 100 MW Solar (25 at Peak) and NM RPS solar resource 70 MW in 2022 (18 MW at Peak)

Resource Purchase
This purchase is supported by firm transmission through (i) simultaneous buy/sell with (i) Freeport McMoRan (formerly Phelps Dodge), (ii) Four Corners-West Mesa transmission

Future Resources (subject to RFP results)
Line 3 0 includes
48 MW Geothermal NM RPS resource in 2025
100/100 MW Solar/Batt Combo NM RPS in 2025
130 MW Solar (33 MW at Peak) system resource in 2027
100 MW CT system resource in 2027
228 MW CT System Resource in 2027

El Paso Electric Company
Loads & Resources 2021-2030 w/ 2021 Updated Load Forecast
Issued 7/2/2020

		170 Solar 100/50 Sol/Batt	Newman 6		48 Geo 100/100 Sol/Batt		130 Solar CT 100 CT 228			48 Geo
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1.0 GENERATION RESOURCES[1]										
1 1 RIO GRANDE	271	271	227	227	227	227	227	227	227	227
1 2 NEWMAN	729	729	809	809	809	809	496	496	496	496
1 3 COPPER	63	63	63	63	63	63	63	63	63	63
1 4 MONTANA	352	352	352	352	352	352	352	352	352	352
1 5 PALO VERDE	622	622	622	622	622	622	622	622	622	622
1 6 RENEWABLES[2]	6	6	6	5	5	5	5	5	5	5
1 7 STORAGE	0	0	0	0	0	0	0	0	0	0
1 8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	40	40	40	40	40	40
1 9 INTERRUPTIBLE[4]	56	56	56	56	56	56	56	56	56	56
1 10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1 0 TOTAL GENERATION RESOURCES	2107	2107	2143	2142	2182	2182	1869	1869	1869	1869
2.0 RESOURCE PURCHASES										
2 1 RENEWABLE PURCHASE[6]	73	72	72	72	71	71	70	70	69	69
2 2 NEW RENEWABLE PURCHASE[7]	0	43	42	42	42	42	41	41	41	41
2 3 NEW RENEWABLE/ BATTERY PURCHASE[8]	0	75	75	75	75	75	74	74	74	74
2 4 NEW BATTERY PURCHASE[9]	0	0	0	0	0	0	0	0	0	0
2 5 MARKET RESOURCE PURCHASE[10]	195	100	95	125	0	20	15	45	100	100
2.0 TOTAL RESOURCE PURCHASES	268	290	284	314	188	208	200	230	284	284
3.0 FUTURE RESOURCES[11]										
3 1 RENEWABLE	0	0	0	0	48	48	81	81	81	129
3 2 RENEWABLE/STORAGE	0	0	0	0	100	100	100	100	100	100
3 3 GAS GENERATION	0	0	0	0	0	0	328	328	328	328
3.0 TOTAL RESOURCE PURCHASES	0	0	0	0	148	148	509	509	509	557
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	2375	2397	2427	2456	2518	2538	2578	2608	2662	2710
5.0 SYSTEM DEMAND[12]										
5 1 NATIVE SYSTEM DEMAND[13]	2138	2189	2227	2255	2296	2335	2379	2417	2471	2522
5 2 DISTRIBUTED GENERATION	(9)	(19)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
5 3 ENERGY EFFICIENCY	(8)	(15)	(23)	(31)	(38)	(46)	(54)	(62)	(69)	(77)
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	2121	2155	2182	2202	2236	2267	2303	2334	2380	2423
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	254	242	245	254	282	271	275	274	282	287
8.0 PLANNING RESERVE 15% OF TOTAL DEMAND	318	323	327	330	335	340	345	350	357	364
9.0 MARGIN OVER RESERVE (7.0 - 8 0)	(64)	(81)	(82)	(76)	(53)	(70)	(71)	(76)	(75)	(77)

1. Generation unit retirements are consistent with the 2018 IRP Rio Grande 6 is classified as inactive reserve
2. Existing EPE owned solar renewables at 70 percent contribution to peak.
3. Emerging technologies may include customer or other distributed resources as well as additional community solar
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2020 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours
6. Existing renewable solar PPAs at 70 percent contribution to peak.
7. New renewable solar PPAs at 25 percent contribution to peak.
8. New solar and battery storage PPAs with solar at 25 percent contribution to peak.
9. 50 MW stand-alone battery was denied in NMPRC Case No 19-00348-UT The resource purchase on line 2.5 was adjusted to replace 50 MW capacity as required to meet the planning reserve margin
10. Denotes market purchase either spot market or short term purchased power Amounts greater than 645 MW PV output will need to come into EPE via exchange (Freeport), through the acquisition of additional transmission or on a non-firm path. Also, availability of such power is not guaranteed.
11. Future Resources from 2025 forward are to address both NM RPS and capacity needs EPE will be initiating its 2021 IRP planning cycle which may result in changes to future planned resources
12. System demand is based on the 2020 Long-Term Forecast dated April 1, 2021.
13. Native System Demand includes added load due to Electric Vehicles.

Planned Generation Additions
100 MW Solar (25 MW at Peak) in 2022
Solar/Batt Combo (100/50 MW) in 2022 (75 MW at Peak)
Newman 6 GT5 (228 MW) in 2023
70 MW Solar (18 MW at Peak) in 2022

Unit Retirements
Rio Grande 6 (45MW) (inactive reserve)
Rio Grande 7 (44MW) - December 2022
Newman 1 (74MW) - December 2022
Newman 2 (74MW) - December 2022
Newman 3 (93MW) - December 2026
Newman 4 CC (220MW) - December 2026
Copper (63MW) - December 2030
Rio Grande 8 (139MW) - December 2033

Company Owned Renewables
Line 1 6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports and Van Horn

Renewable Purchases
Line 2 1 includes SunEdison, NRG, Macho Springs, Juwi, and Hatch solar purchases (70% availability at Peak)

New Renewable Purchase
Line 2.2 includes system solar resource 100 MW Solar (25 at Peak) and NM RPS solar resource 70 MW in 2022 (18 MW at Peak)

Resource Purchase
This purchase is supported by firm transmission through (i) simultaneous buy/sell with
(I) Freeport McMoRan (formerly Phelps Dodge),
(II) Four Corners-West Mesa transmission

Future Resources (subject to RFP results)
Line 3 0 Includes
48 MW Geothermal NM RPS resource in 2025
100/100 MW Solar/Batt Combo NM RPS in 2025
130 MW Solar (33 MW at Peak) system resource in 2027
100 MW CT system resource in 2027
228 MW CT System Resource in 2027

Exhibit DCH-3
Page 1 of 1

DOCKET NO. ______

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

DIRECT TESTIMONY

OF

J KYLE OLSON

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

J Kyle Olson is El Paso Electric Company's ("EPE" or "Company") Manager of Power Generation Engineering. He is responsible for all capital and large maintenance engineering projects to support all EPE's local generation fleet.

Mr. Olson describes EPE's generation fleet and supports the recovery of the costs of new investments in the local fleet and of the costs to operate and maintain it. EPE's generation fleet consists of its local units and the remote generation at Palo Verde.

In addition, Mr. Olson addresses the capital additions to EPE's local generation fleet that EPE placed in service from October 2016 through December 2020. These capital additions were reasonable and are used and useful.

Lastly, Mr. Olson addresses the operations and maintenance ("O&M") expenses and practices that EPE employs to manage its local generation fleet, together with the level of O&M expenses that should be included in rates.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is J Kyle Olson, and 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") as the Manager of Power Generation Engineering.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated from Georgia Tech with a Bachelor of Science degree in Electrical Engineering in 2012. Upon graduation, I was employed by EPE as a Power Plant Engineer at the Newman Power Station. In May 2014, I was laterally moved onto the Generation Projects Team to help oversee the design, construction, and commissioning of the Montana Power Station. During this time, I completed my Master of Business Administration degree at The University of Texas at El Paso.

In late June 2016, I was promoted to Assistant Manager at EPE's Newman Power Station. I became a licensed Professional Engineer in New Mexico in March 2017 and in Texas in May 2017.

In April 2019, I was promoted to Manager of Power Generation Engineering. This team is responsible for all capital and large maintenance engineering projects to support all EPE's local generation.

Q. PLEASE DESCRIBE YOUR PRINCIPAL AREAS OF RESPONSIBILITY.

A. My primary areas of responsibility are the fiscal and technical oversight of capital projects, technical support, engineering standards, large maintenance projects and plant thermal performance programs at all of EPE's local generation.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE A REGULATORY BODY?

A. No. I have not.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe EPE's local generation fleet and to support recovery of the costs of new investments in that fleet and of the costs to operate and maintain it. EPE's generation fleet consists of its local gas-fired units, which I discuss below in section III, and remote generation at the Palo Verde Generating Station ("Palo Verde" or "PVGS"), which EPE witnesses David C. Hawkins and Todd Horton discuss.

Specifically, I address the reasonableness and prudence of the costs of capital additions and improvements to the local generation fleet that entered service from October 1, 2016, through December 31, 2020. This period begins after the end of the test-year end in EPE's last base rate proceeding, Docket No. 46831, and runs through the end of the Test Year in this case.

In addition, I address the operations and maintenance ("O&M") practices that EPE employs to manage its local generation fleet, and the reasonable and prudent O&M expenses incurred during the Test Year that should be included in rates.

Throughout, I present total Company costs.

Q. WHAT DOES YOUR TESTIMONY DEMONSTRATE?

A. My testimony demonstrates that the capital additions to EPE's local generation fleet placed into service from October 1, 2016 through December 31, 2020, Test Year end were prudent and reasonable and are used and useful in providing safe, reliable, and efficient power to meet customers' needs.

I also demonstrate that EPE maintains effective cost controls at its local generating facilities. The O&M practices that EPE employs to manage its local generation fleet are reasonable, and the Test Year O&M costs, as adjusted, are reasonable and necessary and should be included in rates.

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

A. The schedules that I sponsor or co-sponsor are listed in Exhibit JKO-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. EPE's Generating Facilities

Q. WHAT ARE EPE'S GENERATING FACILITIES?

A. EPE meets the bulk of its customers' electrical requirements with power produced at its generating stations, which are fueled by a mix of natural gas, uranium, and solar resources. Table JKO-1 identifies EPE's generating stations, with nominal capacities and fuel types, as of the December 31, 2020 Test Year end. The table reflects the net peak capacity of these resources that EPE includes in its planning reserve margin analyses.

Table JKO-1

Generating Station	Net Peak Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Duty
Palo Verde (Units 1, 2, and 3)	622	Uranium	N/A	Base load
Rio Grande (Units 7, 8, 9)	271	Natural Gas	N/A	Peaking and Load-following
Newman (Units 1, 2, 3, 4, and 5)	729	Natural Gas	N/A	Peaking and Load-following; for Unit 5, load following and base load in combined cycle mode
Copper (Unit 1)	63	Natural Gas	N/A	Peaking
MPS (Units 1, 2, 3, and 4)	352	Natural Gas	Diesel	Peaking and load-following
Holloman Air Force Base Solar Facility	5	Solar	N/A	Dedicated Facility for Holloman Air Force Base
Community Solar Facility	3	Solar	N/A	Dedicated Facility for Customers in the Community Solar Program
Total	2,045			

EPE also owns several small solar facilities with a combined capacity of less than one megawatt ("MW").

The Newman and Copper Power Stations are located in EPE's Texas service area within the City of El Paso, Texas. The Rio Grande Power Station is located in EPE's southern New Mexico service area adjacent to the City of El Paso. The Montana Power Station ("MPS") is located in EPE's Texas service territory just east of the City of El Paso in unincorporated El Paso County. MPS and the Copper, Newman, and Rio Grande Power Stations are considered EPE's local generation. Exhibit JKO-2 is a map depicting the location of EPE's generation.

Palo Verde, which is located in Arizona, is considered EPE's remote generation. EPE witnesses Hawkins and Horton address the costs and operations of Palo Verde.

Q. DOES THE RIO GRANDE POWER STATION HAVE ANY GENERATION NOT REFLECTED IN THE TABLE ABOVE?

A. Yes, it does. Rio Grande Unit 6 is a 45 MW gas-fired generation unit that entered service in 1957 and entered inactive reserve status on November 17, 2015. It has not been considered available capacity for planning reserve margin purposes since 2015. Rio Grande Unit 6 was temporarily reactivated during the summers of 2016, 2017, and 2018 due to system constraints.

EPE has taken steps to have Rio Grande Unit 6 available for service during the 2021 summer peak season because of the record peak demand of approximately 2,173 MW in 2020 that far exceeded EPE's 2020 load forecast of 2,015 MW. In fact, to add some perspective, the 2,173 MW peak load actually exceeded EPE's 2026 load forecast of 2,156 MW. EPE has typically utilized market purchases to address load growth in order to defer resource additions until an economically sized generating unit could be placed in service; however, this amount of load growth was unprecedented. EPE felt it would be prudent to prepare Rio Grande Unit 6 for the 2021 summer to support peak loads in combination with purchased power. The last generation unit added to EPE's local fleet was MPS Unit 4 which went commercial in 2016 and EPE's next resource additions are planned for 2022 and 2023. The reactivation of Rio Grande Unit 6 will help meet customer load requirements until planned generation is added and help ensure that EPE can reliably serve load.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS ASSOCIATED WITH THE RIO GRANDE UNIT 6 IN THIS CASE?

A. No. It is not.

Q. ARE ANY OF THE UNITS LISTED IN THE TABLE ABOVE COMBINED CYCLE UNITS?

A. Yes. Newman Unit 4 and Unit 5 are two-on-one combined cycle units. These two-on-one combined cycle units consist of two gas turbines and one steam turbine. Newman Unit 4 consists of Newman Unit 4-GT1, Unit 4-GT2 and Unit 4 Steam Turbine. Newman Unit 5 consists of Newman Unit 5-GT3, Unit 5-GT4 and Unit 5 Steam Turbine. A combined-cycle power facility uses both gas-fired combustion turbines (GT1 and GT2 in Unit 4 and GT3 and GT4 in Unit 5) and a steam turbine together to produce more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the combustion turbines is routed to the nearby steam turbine, which generates extra power. The individual combustion turbines can be operated individually, apart from the steam turbines. Throughout my testimony, I will use Newman Unit 4 and Newman Unit 5 to refer to the entire two-on-one combined cycle units.

Q. DID EPE ADD ANY NEW GENERATION UNITS FROM OCTOBER 1, 2016, THROUGH DECEMBER 31, 2020 (THE END OF THE TEST YEAR IN THIS DOCKET)?

A. No. EPE did not. The most recent generation units that EPE added were MPS Units 3 and 4, which entered service in 2016 and were included in rates in EPE's last base rate case in Docket No. 46831.

IV. EPE's Local Generation Fleet—Capital Additions

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe and support cost recovery of the capital additions to EPE's local generation fleet that EPE requests in this case. The scope of this request is those capital additions placed in service from October 1, 2016, through the Test Year ending December 31, 2020.

Q. WHAT IS EPE'S APPROACH FOR CAPITAL ADDITIONS TO ITS LOCAL GENERATING FLEET?

A. EPE strives to maintain efficient and reliable power plant operations. This requires capital projects that maintain or improve performance, availability, and reliability. In addition, some projects will be required to comply with laws or regulations, including environmental requirements.

Q. FOR CAPITAL ADDITION PROJECTS AT ITS EXISTING LOCAL GENERATION UNITS, DOES EPE USE COMPETITIVE BIDDING?

A. Yes, it does. Competitive procurement lies at the heart of EPE's procurement strategy.

Q. WHAT COMPANY PROCEDURES AND PROCESSES ARE IN PLACE TO MANAGE THE REASONABLENESS OF THE COSTS ASSOCIATED WITH POWER GENERATION PROJECTS?

A. Non-stock materials and construction services for power generation projects exceeding $50,000 are solicited through a formal competitive bidding process. Excluding professional services, competitive bids are required for all non-stock purchases when the total value of the goods or services equals or exceeds $25,000. Informal telephone and email bids are acceptable for purchases up to $50,000. Requests for competitive bid negotiations are forwarded to EPE's Supply Chain Management group for further processing and review.

A purchase requisition with all necessary information and approvals will then be submitted to EPE's Supply Chain Management group for processing. All requests for bids, with appropriate EPE bid number and bid due date, will be sent to a minimum of three qualified and approved suppliers, provided that three qualified and approved suppliers for that particular service or material exist.

Q. WHAT INFORMATION IS INCLUDED IN THE REQUEST FOR BIDS THAT EPE PROVIDES FOR CONTRACTOR SERVICES?

A. Bid specifications will include a statement of work and clearly state the supplier's obligations and responsibilities for all areas of the work or services to be performed. This includes but is not limited to safety, sanitation, and all other aspects of the work to be performed or provided. Bid specifications will include a time frame for the completion of the necessary work or service. Specifications may also include a detailed performance guarantee clause, if applicable. Pre-bid meetings and tours of the project site will be conducted when appropriate.

Q. DOES EPE FOLLOW A PROCESS WHEN IT RECEIVES THE BIDS FROM SUPPLIERS?

A. Yes, it does. Upon receipt of the bids, the Supply Chain Management group will issue a summary report to the user who requested the bid. It will include price quotes by supplier, copies of the bids, the recommended supplier, and the reason for the selection. All information received pertaining to bid packages will remain strictly confidential. Supplier pricing and services will never be discussed with other competing suppliers. Supply Chain Management may notify all participants as to which supplier the bid was awarded. Work performed by contractors or consultants will not begin until a purchase order ("PO") has been issued. In all cases, contractors and consultants, including subcontractors, must provide proof of required insurance before a PO will be issued.

The Company reserves the right to reject any or all bids. Additionally, the Company reserves the right to deviate from written policies and related procedures when, upon a showing of good cause and with the approval of senior management, it is in the best interest of the Company and its customers.

Q. IS THERE A LIST OF THE MAJOR PRODUCTION PLANT CAPITAL ADDITIONS TO THE LOCAL GENERATION FLEET THAT EPE SEEKS TO INCLUDE IN RATE BASE?

A. Yes, EPE witness Larry J. Hancock includes a list of all plant additions that EPE made from October 2016 through December 2020 for local generation in his Exhibit LJH-2.

The local generation capital additions fall under the "Steam Production" and "Other Production" categories in his exhibit. The total Company amount of local generation capital additions is $178,486,580. This includes $19,761,915 spent for generation plant additions at Holloman Air Force Base and for the Texas Community Solar facility that are not allocated to Texas rate base. In addition, as discussed in the testimony of EPE witness Hancock, EPE received insurance proceeds that offset a portion of the capital additions at Newman Unit 5. The insurance proceeds were recorded in accumulated depreciation. As previously stated, I sponsor the reasonableness and prudence of the construction expenditures for these projects.

Q. WHAT ARE SOME OF THE LARGER LOCAL GENERATION CAPITAL ADDITIONS THAT EPE SEEKS TO INCLUDE IN RATE BASE?

A. To identify a large capital addition, I use the threshold of $5 million. The capital additions over $5 million, as identified in EPE witness Hancock's Exhibit LJH-2, that EPE is requesting, to be included in rate base are as follows:

1. Newman Lake Liner Replacement and Upgrade - $13.1 million;
2. Newman Capital Improvement Blanket - $12.6 million;
3. Newman Unit 4/GT1 Hot Gas Path Improvements - $9.8 million;
4. Montana Acquisition of Critical Spare Parts - $7.6 million;
5. Newman Unit 4 GT1 and GT2 Improvements - $7.0 million; and
6. MPS Warehouse and Access Road – $5.4 million.

Q. WHY WAS NEWMAN UNIT 5 STEAM TURBINE PROJECT NOT INCLUDED IN THE LIST OF LARGEST LOCAL GENERATION CAPITAL ADDITIONS?

A. The largest addition included in EPE witness Hancock's Exhibit LJH-2 is the Newman Unit 5 Steam Turbine Project at $21,630,507. The Newman 5 Steam Turbine Project was the capital additions and improvements resulting from the Unit 5 Steam Turbine lubrication oil control system failure, which resulted in loss of lubrication-oil supply-pump pressure. This loss of pressure resulted in a trip from unit full load operation with no supply of lubricating oil to the turbine and generator bearings. However, as noted on EPE witness Hancock's exhibit, the cost of this project was offset by insurance proceeds in the amount of $18,146,155, reducing EPE's requested amount to include in invested capital to $3,484,352. With that offset, this capital addition is not one of the larger investments that EPE is requesting.

Q. ARE THERE OTHER PROJECTS WITH A COST EXCEEDING $5 MILLION THAT ARE NOT INCLUDED IN THE LIST OF LARGST LOCAL GENERATION CAPITAL ADDITIONS?

A. Yes. Projects GE184, GE183, GE182, and GE181 on Exhibit LJH-2 to EPE witness Hancock's testimony are a result of reallocating MPS Common costs to specific MPS units, which he discusses in his direct testimony. The reallocation can be seen in Project GE180.

Q. THE FIRST PROJECT IN YOUR LIST OF LARGE CAPITAL ADDITIONS IS THE NEWMAN LAKE LINER REPLACEMENT PROJECT. WHAT IS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. Newman Lake is a permitted wastewater evaporation pond for the Newman Power Station and is essential to plant operations. In July 2016, EPE initiated an environmental, health, and safety compliance audit of Newman Lake pursuant to applicable law and identified integrity issues with the lake's synthetic liner, which was over 40 years old. The audit indicated the need to replace the liner in a manner that allowed continuous operation of the plant during the project. EPE utilized the competitive bidding process for the design and construction of the liner replacement project, including disposal of the existing liner and accumulated sediment as well as earthwork so as to maintain the lake's permitted capacity. EPE partitioned the lake and replaced the synthetic liner in two phases. Phase 1 was completed in December 2018 and Phase 2 was completed in June 2019.

Q. WERE THE COSTS FOR THE NEWMAN LAKE LINER REPLACEMENT PROJECT JUST AND REASONABLE?

A. Yes, they were. This project ensured that the plant could continue to operate in compliance with environmental regulations while avoiding any interruption to EPE's service to its customers. The costs for this project were established through a competitive bidding process, ensuring that the project was completed at a reasonable cost.

Q. THE SECOND PROJECT LISTED ABOVE IS THE NEWMAN CAPITAL IMPROVEMENT BLANKET. WHAT ARE THE TYPES OF PROJECTS INCLUDED IN THE NEWMAN CAPITAL IMPROVEMENT BLANKET WORK ORDER?

A. The Newman Capital Improvement Blanket (the Blanket) includes capital improvements at Newman Power Station, including small capital projects that do not receive individual capital project numbers and small continual improvement capital expenditures. Examples of the small capital projects include generator re-wedging, upgrading wood cooling tower sections to fiberglass, replacement of turbine components, drum level instrumentation improvements, control valve improvements, Programmable Logic Controller upgrades, and redundant boiler oxygen analyzer installations. Small continual improvement capital expenditures include upgrading the plant lightning to LED lights and protective relay upgrades.

Q. IS THERE A LISTING OF CAPITAL PROJECTS INCLUDED IN THE NEWMAN CAPITAL IMPROVEMENT BLANKET WORK ORDER?

A. Yes. Exhibit JKO-4 contains a list of all the Blanket projects over $200,000 with descriptions.

Q. CAN YOU PLEASE EXPLAIN HOW MANAGEMENT DETERMINES THE NEED FOR A PROJECT ASSIGNED TO THE BLANKET?

A. Projects are assigned to the blanket when the total projected project costs are estimated to be below $100,000, when the project is a result of discovery work (unexpected work as a result of an inspection or outage), or when the project is a continual improvement project with yearly costs below $100,000. These projects often originate from the findings of inspections, such as generation or turbine inspections during scheduled or unscheduled outages, and also result from repetitive failure analysis and critical equipment evaluation.

Q. WERE THE COSTS FOR THE NEWMAN CAPITAL IMPROVEMENT BLANKET REASONABLE AND NECESSARY?

A. Yes, these costs were reasonable and necessary for EPE to continue to provide customers with safe, efficient and reliable service from EPE's local generation fleet. Maintaining, modifying and improving plant equipment is a necessary undertaking to improve plant reliability, reduce costs, and extend the useful life of existing equipment. The costs incurred for these projects were reviewed under strong budget controls and informed by reasonable management decision making.

Q. CAN YOU PLEASE DESCRIBE THE STRONG BUDGET CONTROLS MENTIONED IN YOUR PREVIOUS ANSWER?

A. As addressed earlier in my testimony, all capital blanket projects follow EPE's procurement policies. In addition, the Blanket is regularly reviewed and approved by EPE's Capital Planning Committee.

Q. TURNING TO THE THIRD LARGE LOCAL GENERATION CAPITAL ADDITION PROJECT, WHAT WAS THE NEWMAN UNIT 4 GT1 HOT GAS PATH IMPROVEMENTS PROJECT AND WHY WAS IT UNDERTAKEN?

A. This capital project included the procurement and installation of new capital parts for Newman Unit 4 GT1 and GT2 and Copper, which comprise EPE's Westinghouse 501 gas turbine fleet (the 501B Units). These parts included turbine blades and vanes, combustor baskets, transition cylinders and a torque converter. These parts were installed in Newman Unit 4 GT1 during the spring 2019 scheduled hot gas path inspection outage and in Newman Unit 4 GT2 during the spring 2019 combustor inspection.

Q. WHY DID EPE PURCHASE THE REPLACEMENT PARTS FOR NEWMAN UNIT 4 GT1?

A. The capital parts were purchased to replace parts that were at the end of their usable life due to service hours beyond the original equipment manufacturer ("OEM") recommended replacement interval.

Q. WERE THE COSTS FOR THE NEWMAN UNIT 4 GT1 IMPROVEMENTS REASONABLE AND NECESSARY?

A. Yes, they were. The existing parts were past the OEM recommended replacement life and could not be refurbished. Lead times for these parts ranged from seven months to two years so continuing to run parts past the OEM recommended replacement interval was not prudent due to the risk of an extended forced outage. Given the age of the 501B Units, spare parts are not readily available. To minimize costs, EPE purchased a combination of new parts from the OEM and available remaining stock that required refurbishment and modification. By supplementing with refurbished and modified stock, EPE was able to minimize costs compared to buying all new parts from the OEM.

Q. WHAT WAS THE MONTANA ACQUISITION OF CRITICAL SPARE PARTS PROJECT AND WHY WAS IT UNDERTAKEN?

A. This project addresses two of the critical components of MPS Units 1 through 4 and Rio Grande Unit 9: a booster and a power turbine. Working with General Electric ("GE"), the manufacturer of these five LMS100 generation units, through EPE's Multi-Year Service Agreement, GE and EPE identified critical LMS parts that were likely to have long lead times due to part availability and could thus result in long forced outages. In an effort to reduce the potential of having these units unavailable to serve load, EPE purchased a spare LMS100 booster and a spare LMS100 power turbine. Both the booster and power turbine can be utilized in any one of EPE's five LMS100 units.

The power turbine is a stacked assembly of five stages of disks, blades, and nozzles, connected to the generator and driven by the exhaust gas from the supercore. The booster, or low-pressure compressor, is an axial flow compressor, which is the first of two compressors on each LMS100. Having both a spare booster and a spare power turbine for these long lead items results in improved availability and shortened outage times.

Q. CAN YOU PLEASE PROVIDE MORE INFORMATION ABOUT EPE'S MULTI-YEAR SERVICE AGREEMENT WITH GE?

A. EPE's Multi-Year Service Agreement ("MYA") with GE is an extended (28+ years) service plan for EPE's five LMS100 units and the one spare supercore. Under the MYA, GE provides for the repair and replacement of parts and components of the LMS100 gas turbines, generators, and certain auxiliary systems in accordance with prudent industry practices and GE service bulletins and addresses unplanned events involving the units. Additionally, the MYA requires GE to furnish parts and services for the repair of collateral damage to the LMS100 gas turbines caused by failing parts or defective GE services.

Maintenance costs for the LMS100 units are effectively flattened and relatively predictable because of the MYA's quarterly maintenance fees and periodic run-time-based installments and its transference and apportionment of risk for unplanned outages and collateral damage. These collateral damage risk-shifting and allotment provisions also help stabilize insurance costs for casualty loss coverage for the units.

Further, the MYA calls for GE to provide remote diagnostics and monitoring for the Company's LMS100 fleet. The benefits of this service are discussed later in my testimony.

Q. WERE THE COSTS FOR THE MONTANA ACQUISITION OF CRITICAL SPARE PARTS PROJECT REASONABLE AND NECESSARY?

A. Yes, they were. Having these spare critical components available to be used on any of the Company's five LMS100 units is prudent and beneficial to EPE's customers. Without these spare components on hand and at the ready, the Company risks potential supply constraints and long lead times during high peak demand. These critical spare components strengthen the availability of EPE's local generation fleet. The critical spare components were purchased at costs established in the previously negotiated MYA.

Q. WHAT WAS THE NEWMAN UNIT 4 GT1 AND GT2 IMPROVEMENTS PROJECT AND WHY WAS IT UNDERTAKEN?

A. The project involved the procurement of replacement spare turbine component parts for the Company's 501B Units. These capital spares included turbine blades and vanes, specialty tooling, and interstage seals. These spare components were placed into EPE's inventory to be used during the next scheduled outage or forced outage. This occurred during the spring of 2020 when they were installed in Newman Unit 4 GT1 and GT2.

Q. WHY DID EPE PURCHASE THE REPLACEMENT PARTS FOR NEWMAN UNIT 4 GT1 AND GT2 AND COPPER?

A. The spare components were purchased to replace parts that are at the end of their usable life due to service hours beyond the OEM recommended replacement interval.

Q. HOW DO YOU EXPECT TO UTILIZE THE REPLACEMENT PARTS IN THE FUTURE?

A. The parts were installed in the 2020 outage cycle. In the future, they will be part of EPE's turbine parts inventory. As they are removed from service during a future outage, they will be sent off for inspection and repair, as necessary, to be reused in an upcoming outage. This will continue until they reach the end of their service lives.

Q. WERE THE COSTS FOR THE NEWMAN UNIT 4 GT1 AND GT2 IMPROVEMENTS REASONABLE AND NECESSARY?

A. Yes, they were. Having these spare turbine components available to be used on any of the three 501B Units is prudent and beneficial to EPE's customers. Without having these spare components on hand and at the ready, the Company risks potential supply constraints and long lead times during high peak demand. These critical spare components strengthen the availability of EPE's local generation fleet and were purchased in accordance with EPE's procurement policy discussed above.

Q. WHAT WAS THE MPS WAREHOUSE AND ACCESS ROAD PROJECT?

A. The MPS Warehouse and Access Road project was the installation of a new warehouse and access road at the MPS. Before this project, there was no warehouse at MPS. The new warehouse now stores the spare supercore, spare booster, spare power turbine, and other critical plant spares and components. As part of the warehouse design, a dedicated supercore storage room was built that includes fire protection. Additionally, the warehouse includes a dedicated lubricant storage area with the containment required by

EPE's Spill Prevention, Control and Countermeasure Program and the EPA Spill Prevention, Control and Countermeasure Regulation (40 CFR Part 112). Further, the warehouse includes an office for a purchasing agent and a service counter for warehouse staff. The access road was added to divert trucks and deliveries away from the plant. Instead of driving through the plant, trucks and deliveries now take a dedicated access road built on the south side of the units. See Exhibit JKO-3 for an overhead drawing of the new MPS Warehouse and Access Road.

Q. HOW WILL THE COMPANY UTILIZE THE MPS WAREHOUSE AND ACCESS ROAD?

A. EPE expects to utilize the MPS Warehouse and Access road as the primary storage facility for the MPS and its LMS100 units, and the primary means to access this facility. By having a centralized LMS100 warehouse, EPE can storage and protect the critical spares while providing quick access in the event of an urgent need.

Q. WERE THE COSTS FOR THE MPS WAREHOUSE AND ACCESS ROAD NECESSARY AND REASONABLE?

A. Yes, they were. EPE's facilities team led the project management which included competitive bidding of the procurement and construction.

Q. HAVE YOU PROVIDED A SUMMARY OF THE REMAINDER OF THE LOCAL FLEET PROJECTS LISTED ON EPE WITNESS HANCOCK'S EXHIBIT LJH-2?

A. Yes. These remaining local fleet Steam Production and Other Production projects are listed in Schedule H-5.2b with a brief description of each project and its cost classification. Excluding the projects discussed above as well as the Newman Unit 5 steam generator and the Holloman and Community solar projects, these remaining projects totaled $81.1 million.

Q. PLEASE DESCRIBE THE REMAINDER OF THE LOCAL FLEET STEAM PRODUCTION AND OTHER PRODUCTION PROJECTS LISTED ON EPE WITNESS HANCOCK'S EXHIBIT LJH-2.

A. The remaining local fleet Steam Production and Other Production projects, excluding projects less than $100,000, can be grouped into four of the ten categories specified in the instructions for Rate Filing package Schedule H-5.2b. I use those four categories in describing these projects below.

A. Plant Efficiency Improvement

These are projects that primarily replace components that have reached the end of their useful life or are no longer operable. These can also be projects that improve a plant's heat rate. Projects in this category include boiler tube replacements, air compressor replacement, generation rewinds, and valve replacements. The total for this category is $16,109,065.

B. Productivity Improvement

These are general plant improvement items. The largest projects in this category are the blanket accounts for the Newman, Rio Grande, Copper, and Montana Power Stations. The blankets include items such as control system upgrades, water treatment upgrades, gas metering skid installation, and voltage regulator upgrades. The total for this category is $40,913,025.

C. Reliability

Since the local units must be available to start and run when called on to ensure service to customers, EPE must make reliability improvements to ensure adequate generation resources are available to serve load. For the most part, these costs were incurred for general plant improvement projects, such as turbine parts, boiler tube repairs, and critical spares. The total for this category is $22,625,732

D. Habitability

These projects were to improve the working conditions at the Newman and Rio Grande Power Stations. These projects include control room renovations, office expansions and employee access improvements. The total for this category is $1,440,400.

Q. WERE THE COSTS FOR THE PROJECTS MENTIONED ABOVE REASONABLE AND NECESSARY?

A. Yes, these costs were reasonable and necessary for EPE to continue to provide safe, efficient and reliable service through EPE's local generation fleet. Projects within the categories are reviewed and challenged by management before being considered for budget approval and are the result of reasonable management decisions.

Q. WERE ALL OF EPE CAPITAL ADDITIONS PROJECTS ADDED FROM OCTOBER 2016 THROUGH DECEMBER 2020 REASONABLE, NECESSARY, BENEFICIAL, PRUDENT AND USED AND USEFUL TO THE LOCAL GENERATION FLEET?

A. Yes, they were. All of these additions were necessary, helpful, or both in maintaining the local generation fleet. In addition, they were the product of sound management decisions and were developed with strong budget and procurement controls.

V. EPE'S Local Generation Fleet - Operation and Maintenance

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe how EPE's local fleet of power plants is operated and maintained and the measures used to analyze the power plants' performance (e.g., heat rate), together with EPE's O&M practices and rate recovery request.

A. Local Unit General

Q. PLEASE BRIEFLY DESCRIBE THE TYPICAL USAGE OF EPE'S LOCAL GENERATION.

A. EPE's local fleet is dispatched by EPE's System Operations Group. As a whole, EPE's local units are used to follow load—adjust their power outputs as demand for electricity fluctuates throughout the day—and support the import of low-cost Palo Verde remote generation, although Newman Unit 5 also operates as a base load unit at times. For the most part, each of the local units can be used interchangeably to satisfy these functions. EPE's load demands are such that, under normal conditions, the local units typically operate at low loads during the night (off-peak periods) and high loads during the day (on-peak periods), particularly during the summer, except for Rio Grande Unit 9 and MPS Units 1 through 4, which are EPE's LMS100 units and are routinely cycled to meet the varying load demands or to displace less efficient generation.

Q. HOW DOES EPE MATCH ITS LOCAL UNITS TO LOAD REQUIREMENTS TO ENSURE THAT UNITS ARE AVAILABLE TO MEET DEMAND?

A. For daily operations, the Company's load demand profile requires that Newman Units 1 through 4 and Rio Grande Units 7 through 9 be used primarily as load-following units. Rio Grande Unit 8 is also used for voltage and reactive support for the system. Rio Grande Unit 9 and MPS Units 1 through 4 are fast-start units that are primarily used for peaking but can also be used for load following. Copper Power Station is a simple-cycle combustion turbine generator that is typically used as a daily peaking unit. It is subject to start-stop cycles, but it is also used for load following and to meet spinning reserve requirements. Newman Unit 5, when operating in combined cycle mode, is mostly base loaded during the day and reduced to minimum load during the night. It also has the ability to return to simple cycle peaking mode if needed.

Q. DOES THE OPERATION OF EPE'S LOCAL GENERATION FOR PRIMARILY LOAD FOLLOWING AND VOLTAGE SUPPORT PURPOSES AFFECT THE UNIT EFFICIENCY LEVELS?

A. Yes. Units that are cycled or dispatched to follow daily load are subjected to increased stress due to the constant changes in thermal gradients. These thermal cycles increase the level of normal wear and tear experienced by the generating unit, which, in turn, causes losses in efficiency and availability. Also, reducing output to lower loads during off-peak hours causes the unit to operate less efficiently. It is important to note that Rio Grande Units 7 and 8 and Newman Units 1 through 4 were originally designed and built to serve as base load units. EPE's resource mix has changed over time, as has the cost of fuels, and these local units are now called upon to serve in a role different than their original design. However, Rio Grande Unit 9 and MPS Units 1 through 4 are designed to be