Moody's to affirm its current credit rating of Baa2 in Case 2.

Q43. WHAT IS YOUR RECOMMENDATION REGARDING CAPITAL STRUCTURE?

A. I recommend that the Commission authorize an equity ratio of 56.4 percent and long-term debt ratio of 43.6 percent. My recommendation is influenced by the heightened need for external financing and reliance on the issuance of new long-term debt and access to funding under the RCF during the next several years. With high capital expenditures over the coming five years, an authorized equity ratio as low as 51 percent is not assured to sustain Moody's credit rating of Baa2 A higher equity ratio and reduced debt leverage would signal to investors and banks a solid credit foundation. It would increase confidence in EPE's financial capability and financial resilience. On the other hand, if the decision in this proceeding demonstrates a lack of regulatory commitment to maintaining EPE's financial strength and viability, EPE is vulnerable to ratings downgrades from Baa2 to Baa3. Regulatory support for EPE's financial well-being and stable credit quality is especially necessary during the next several years of high capital investment and infrastructure development.

VIII. CONCLUSIONS

Q44. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. The Company's credit ratings by Moody's and Fitch are quite low relative to the ratings of peer utilities, in the bottom fifth of the Moody's U.S. investor-owned utility universe. Furthermore, despite the existence of fuel and purchased power rate adjustment mechanisms in Texas and New Mexico, EPE's cash flow has been subject to extreme fluctuations relating to circumstances outside EPE's control, such as gas price volatility, adverse weather, and regional hazard events. Decisions by the Commission in this rate proceeding may enhance or weaken EPE's ability to withstand periods of under-collections and inconsistent cash flow. Maintaining cash flow credit metrics will support EPE's existing rating and prevent a credit rating downgrade to Baa3. A regulatory decision that supports EPE's credit ratings and financial strength can assure the Company of consistent access to debt capital during the coming period of elevated customer demand growth and high capital expenditures.

A capital structure comprised of 56.4 percent equity and 43.6 percent debt will allow EPE to sustain cash flow leverage by 2027 that is at or slightly above the low end of the level required to maintain its current credit rating by Moody's. This would greatly reduce the likelihood of a credit downgrade during two to three years of very high capital investment needs. I recommend adopting this capital structure to support EPE's financial integrity and sustain the Company's current credit ratings.

Q45. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes.

EXPERIENCE AND QUALIFICATIONS

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LAPSON ADVISORY: Financial Consulting. Expert Testimony. Financial Training.

SUMMARY

Expert on financing utilities and infrastructure projects, with over 50 years of professional
MBA Accounting and finance, NYU Stern School of Business; Chartered Financial Analyst

EMPLOYMENT HISTORY

Lapson Advisory, Trade Resources Analytics	Financial consulting services to utilities and infrastructure project developers. Financial strategy and credit advisory; expert financial witness.	2012 to present
Fitch Ratings Utilities, Power & Gas Managing Director; Senior Director	Manager or primary analyst on credit ratings of over 200 utility, pipeline, and power generation companies and utility tariff securitizations. Chaired rating committees for energy, utility, and project finance committees. Liaison with major fixed income investors.	1994 - 2011
JP Morgan Chase (formerly Chemical NY Corp.) Vice President, 1975-94 Asst. Vice President, 1974-75	Managed financial advisory transactions, structured debt placements, syndicated credit facilities for utilities, mining and metals, project finance. First of its kind stranded cost securitization for Puget Sound P&L, 1992-94. Led financings for utilities in bankruptcy or reorganizations. Divisional controller, 1981-86.	1974-1994
Argus Research Corp. Equity Analyst, Utilities	Equity analysis of U.S. electric and gas utilities, natural gas pipelines, regulated telephone companies. Research coverage and reports; forecasts and models.	1969-1974

EDUCATION & PROFESSIONAL ORGANIZATIONS

Stern School of Business, New York University, MBA.	Accounting major, Finance minor	1975
Barnard College, Columbia University, BA.		1969
Earned CFA Institute Charter, 1978		
Institute of Chartered Financial Analysts		Since 1978
Wall Street Utility Group		Since 1996

ADVISORY COUNCILS AND BOARD SERVICE

Electric Power Research Institute, Advisory Council, 2004-2011; Chair, 2009 and 2010.

MIT Energy Institute, External Advisory Council, The Future of Solar Energy, 2012-2014.

Represented U.S. fixed income investors in responding to proposed financial accounting rules for rate-regulated utilities by the International Accounting Standards Board (IASB) at a panel sponsored by Edison Electric Institute and American Gas Assoc., December, 2014.

EXPERT TESTIMONY

Jurisdiction	Proceeding	Topic
Minnesota Public Utilities Commission	Docket No. E-015/ PA-24-198, Minnesota Power Petition for Acquisition of ALLETE Inc., on behalf of the purchasers and Minnesota Power/ ALLETE Inc. (2025)	Merger application: adequate financial strength and appropriate ring-fencing mechanisms
Federal Energy Regulatory Commission	Docket No.EL 24-80, MISO Transmission Owners' Response to Order to Show Cause (2024)	Risks and financial returns of Transmission Owners' initial funding of Network Upgrades
Federal Energy Regulatory Commission	Docket No.EL 24-81, PJM Transmission Owners' Response to Order to Show Cause (2024)	Risks and financial returns of Transmission Owners' initial funding of Network Upgrades
Federal Energy Regulatory Commission	Docket No.EL 24-82, Southwest Power Pool Transmission Owners' Response to Order to Show Cause (2024)	Risks and financial returns of Transmission Owners' initial funding of Network Upgrades
Federal Energy Regulatory Commission	Docket No.EL 24-83, ISO-New England Transmission Owners' Response to Order to Show Cause (2024)	Risks and financial returns of Transmission Owners' initial funding of Network Upgrades
Public Utilities Commission of Nevada	Dockets 24-02026 and 24-02027, Applications of Sierra Pacific Power Company to change rates (2024)	Capital structure and financial strength.
Public Utilities Commission Texas	Docket No. 55867, Application of LCRA Transmission Services Corp. to change rates, on behalf of LCRA TSC (2024)	Financial strength and access to capital for a public power transmission service provider.
Public Utilities Commission of Colorado	Proceeding No. 22AL-0530E, electric rate case on behalf of Xcel Public Service Colorado (2023)	Financial strength and appropriate capital structure.
California Public Utilities Commission	Docket No.A2211010, Joint application of Corix Infrastructure (US) and SW Merger Acquisition Corp and Suburban. (2022-23)	Merger application: adequate financial strength
Illinois Commerce Commission	Docket No. 22-0670, Joint application of Corix Infrastructure (US) and SW Merger Acquisition Corp and... (2022-23)	Merger application: adequate financial strength
Kentucky Public Service Commission	Docket No.2022-00396, Joint Application of Corix Infrastructure (US) and SW Merger Acquisition Corp and... (2022-23)	Merger application: adequate financial strength
Public Utilities Commission of Nevada	Docket No. 22-11030, Application of Great Basin Water Co.... for Approval of business combination, Corix Infrastructure (US) and SW Merger Acquisition Corp... (2022-23)	Merger application: adequate financial strength
New Jersey Board of Public Utilities	Docket No. WM22110690, Joint Petition for change of control, Corix Infrastructure (US) and SW Merger Acquisition Corp.(2022-23)	Merger application: adequate financial strength
North Carolina Utilities Commission	Docket No. W-354, Sub 412, Application for approval of business combination, Corix Infrastructure (US) and SW Merger Acquisition Corp (2022-23)	Merger application: adequate financial strength
Pennsylvania Public Utility Commission	Docket No. A-2022- 3036744, Joint Application of CUPA Water Systems for Approval of a Business Combination (2022-23)	Merger application: adequate financial strength

Jurisdiction	Proceeding	Topic
Public Utilities Commission Texas	Docket No. 54316, Joint Application of Corix Infrastructure (US), SW Merger Acquisition Corp and Monarch Utilities I LP (2022-23)	Merger application: adequate financial strength
Federal Energy Regulatory Commission	Docket No.ER22-2379, Southwest Power Pool, Inc., supporting Southwestern Public Service Co.'s right under Generator Interconnection Agreement (2022-23)	Application by a transmission owner to fund investment in Network Upgrades
Federal Energy Regulatory Commission	Docket No.ER22-2274, Southwest Power Pool, Inc., supporting Southwestern Public Service Co.'s right under Generator Interconnection Agreement (2022)	Application by a transmission owner to fund investment in Network Upgrades
Massachusetts Department of Public Utilities	DPU Docket No. 22-70, 22-71, 22-72; Long-term purchase contracts for offshore wind energy, on behalf of three MA electric distribution utilities (2022)	Remuneration to distribution utilities for entering into long-term supply contracts
New Jersey Board of Public Utilities	BPU Docket No. GM 2204, Merger Application of South Jersey Industries, Inc. and Boardwalk Merger Sub, Inc. on behalf of Joint Applicants (2022)	Financial strength in the context of merger proceeding and appropriate corporate commitments.
Public Utilities Commission Texas	Docket No. 53601, Application of Oncor Electric Delivery LLC to Change Rates, on behalf of Oncor. (2022)	Financial strength and appropriate capital structure.
Public Utilities Commission Texas	Docket No. 52487, Application of Entergy Texas to Alter its CCN for Orange County Advanced Power Station, on behalf of Entergy Texas, Inc. (2022)	Impact of a power purchase contract on the balance sheet, financial ratios, and credit ratings of the utility purchaser.
Federal Energy Regulatory Commission	Docket No. ER21-2282, Application re Open Access Trans. Tariff, on behalf of PJM Transmission Owners (2022)	Application by Transmission Owners to invest in Network Upgrades
Federal Energy Regulatory Commission	Docket No. EL-20-72, LA Public Service Comm. et al. vs. System Energy Resources, Inc. on behalf of SERI (2022)	Financial impact of the termination of a support agreement; capital structure.
Federal Energy Regulatory Commission	Docket No. RM20-10-000, Electric Transmission Incentive Policy, on behalf of PJM Transmission Owners (2021)	In support of financial incentives for RTO membership
Public Utilities Commission of Colorado	Proceeding No. No. 21R-0314G, NOPR on Purchased Gas Cost Adjustment on behalf of Public Service Company of CO (2021)	Investor and credit rating impact of proposed gas cost recovery rules
New Mexico Public Regulation Commission	Docket No 20-00222-UT, Application of Public Service Co. of NM, PNM Resources, Avangrid Inc., and NM Green Resources on behalf of Applicants (2020-21)	Financial strength and resilience in the context of merger proceeding
Public Utilities Commission Texas	Docket No 51547, Application of Texas-New Mexico Power Co., Avangrid Inc., and NM Green Resources on behalf of the Joint Applicants (2020-21)	Financial strength and resilience in the context of merger proceeding

Jurisdiction	Proceeding	Topic
Massachusetts Department of Public Utilities	DPU 20-16, 20-17, and 20-18, Long-term purchase contract for offshore wind energy, Eversource, National Grid, Unitil (2020)	Remuneration to utilities for entering into long-term contracts
Public Utilities Commission Texas	Docket No. 49849, Joint Application of El Paso Electric, Sun Jupiter Holdings and IIF US Holding 2 to acquire utility (2019-20)	Conditions & commitments for utility merger and formation of holdco; financial strength
New Mexico Public Regulation Commission	Docket No. 19-00234 UT, Joint Application of El Paso Electric, Sun Jupiter Holdings, and IIF US Holding 2 to acquire El Paso Electric (2019-20)	Conditions & commitments for utility merger and formation of holdco; financial strength
Public Utilities Commission of Colorado	Proceeding No. 19AL-0268E, Filing to Revise Electric Tariff, on behalf of Xcel Public Service Co, of Colorado (2019)	Capital structure and cash flow measures
Public Utilities Commission Texas	Docket No. 49421, Application of CenterPoint Energy Houston to change rates, on behalf of CEHE (2019)	Separateness commitments in the context of a rate proceeding; financial strength
Public Utilities Commission Texas	Docket No. 48929, Application of Oncor Electric Delivery Co. LLC, Sharyland Utilities LP, and Sempra Energy, on behalf of Sharyland Utilities (2019)	Appropriate governance conditions and commitments for partner ownership of an electric transmission utility
Public Utilities Commission of Colorado	Proceeding No. 17AL-0363G, Filing to Revise Gas Tariff, on behalf of Xcel Public Service Co. of Colorado (2018)	Cash flow and credit impacts of tax reform; capital structure
South Carolina Public Service Commission	Docket No. 2017-370-E; Joint Application for Merger and for Prudency Determi-nation, on behalf of South Carolina Electric & Gas Company (2018)	Benefits of merger and proposed rate plan; impact on cash flow and access to capital.
U.S. Federal District Court, District of SC	Civil Action No.: 3:18-cv-01795-JMC, Motion for Preliminary Injunction, on behalf of South Carolina Electric & Gas	Financial harm of rate cut compliant with Act
Public Utilities Commission Texas	Docket No. 48401, Texas-New Mexico Power Co. Application to Change Retail Rates, on behalf of TNMP (2018)	Cash flow and credit impacts of tax reform
Public Utilities Commission Texas	Docket No. 48371, Entergy Texas Inc., Application to Change Retail Rates, on behalf of ETI (2018)	Cash flow and credit impacts of tax reform
Public Utilities Commission Texas	Docket No. 47527, Southwestern Public Service Co. Application for Retail Rates, on behalf of SPS Co. (2018)	Adverse cash flow and credit impacts of tax reform; cap structure
New Mexico Public Regulation Commission	Case No. 17-00255-UT, Southwestern Public Service Co. Application for Retail Rates, on behalf of SPS Co. 2018)	Adverse cash flow and credit impacts of tax reform; cap structure
South Carolina Public Service Commission	Docket No. 2017-305-E, Response to ORS Request for Rate Relief, on behalf of S. Carolina Electric and Gas (2017)	Adverse financial implications of rate reduction sought by ORS
DC Public Service Commission	Formal Case No. 1142, Merger Application of AltaGas Ltd. and Washington Gas Light, Inc. (2017)	Financial strength; Conditions and commitments in a utility merger

Jurisdiction	Proceeding	Topic
Public Service Commission of Maryland	Docket No. 9449, In the Matter of the Merger of AltaGas Ltd. and Washington Gas Light, Inc. (2017)	Financial strength; Conditions and commitments in a utility merger
Public Utilities Commission Texas	Docket No. 46957, Application of Oncor Electric Delivery LLC to Change Rates, on behalf of Oncor. (2017)	Appropriate capital structure. Financial strength.
Public Utilities Commission Texas	Docket No. 46416, Application of Entergy Texas, Inc. for a CCN, on behalf of Entergy Texas (2016-2017)	Debt equivalence and capital cost associated with capacity purchase obligations (PPA)
U.S. Federal Energy Regulatory Commission	Dockets No. EL16-29 and EL16-30, NCEMC, et al. vs Duke Energy Carolinas and Duke Energy Progress, on behalf of the Respondents (2016)	Capital market environment affecting the determination of the cost of equity capital
Hawaii Public Utilities Commission	Docket No. 2015-0022, Merger Application on behalf of NextEra Energy and Hawaiian Electric Inc. (2015)	Financial strength and conditions & commitments in merger context
U.S. Federal Energy Regulatory Commission	Dockets No. EL14-12 and EL15-45, ABATE, vs MISO, Inc. et al., on behalf of MISO Transmission Owners (2015)	Capital market environment; capital spending and risk
U.S. Federal Energy Regulatory Commission	Dockets No. EL12-59 and 13-78, Golden Spread Electric Coop., on behalf of Southwestern Public Service Co. (2015)	Capital market environment; capital spending and risk
U.S. Federal Energy Regulatory Commission	Dockets No. EL13-33 and EL14-86, on behalf of New England Transmission Owners. (2015)	Capital market environment affecting the cost of equity capital
U.S. Federal Energy Regulatory Commission	Dockets No. ER13-1508 et alia, Entergy Arkansas, Inc. and other Entergy utility subsidiaries, on behalf of Entergy (2014)	Capital market environment affecting the measurement of the cost of equity capital
Delaware Public Service Commission	DE Case 14-193, Merger of Exelon Corp. and Pepco Holdings, Inc. on behalf of the Joint Applicants (2015)	Financial strength and conditions & commitments in merger context
Maryland Public Service Commission	Case No. 9361, Merger of Exelon Corp. and Pepco Holdings, Inc. on behalf of the Joint Applicants (2015)	Financial strength and conditions & commitments in merger context
New Jersey Board of Public Utilities	BPU Docket No. EM 14060581, Merger of Exelon Corp. and Pepco Holdings, Inc., on behalf of the Joint Applicants (2015)	Financial strength and conditions & commitments in merger context
U.S. Federal Energy Regulatory Commission	Docket ER15-572 Application of New York Transco, LLC, on behalf of NY Transmission Owners (2015)	Incentive compensation for electric transmission; capital market access
U.S. Federal Energy Regulatory Commission	Docket EL 14-90-000 Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency vs. Duke Energy FL on behalf of Duke Energy (2014)	Capital market environment affecting the determination of the cost of equity capital
DC Public Service Commission	Formal Case No. 1119 Merger of Exelon Corp. and Pepco Holdings Inc., on behalf of the Joint Applicants (2014-2015)	Financial strength and conditions & commitments in merger context

Jurisdiction	Proceeding	Topic
U.S. Federal Energy Regulatory Commission	Docket EL14-86-000 Attorney General of Massachusetts et. al. vs. Bangor Hydro-Electric Company, et. al., on behalf of New England Transmission Owners (2014)	Return on Equity; capital market environment
Arkansas Public Service Commission	Docket No. 13-028-U. Rehearing on behalf of Entergy Arkansas. (2014)	Investor and rating agency reactions to ROE set by Order.
Illinois Commerce Commission	Docket No. 12-0560 Rock Island Clean Line LLC, on behalf of Commonwealth Edison Company, an intervenor (2013)	Access to capital for a merchant electric transmission line.
U.S. Federal Energy Regulatory Commission	Docket EL13-48-000 Delaware Public Advocate, et. al. vs. Baltimore Gas and Electric Company and PEPCO Holdings et al., on behalf of (i)Baltimore Gas and Electric; (ii) PEPCO subsidiaries (2013)	Return on Equity; capital market view of transmission investment
U.S. Federal Energy Regulatory Commission	Docket EL11-66-000 Martha Coakley et. al. vs. Bangor Hydro-Electric Company, et. al. on behalf of New England Transmission Owners (2012-13)	Return on Equity; capital market view of transmission investment
New York Public Service Commission	Cases 13-E-0030; 13-G-0031; and 13-S-0032 on behalf of Consolidated Edison Company of New York. (2013)	Cash flow and financial strength; regulatory mechanisms
Public Service Commission of Maryland	Case. 9214 re "New Generating Facilities To Meet Long-Term Demand For Standard Offer Service", on behalf of Baltimore Gas and Electric Co., Potomac Electric Power Co., and Delmarva Power & Light (2012)	Effect of proposed power contracts on the credit and financial strength of MD utility counterparties

CONSULTING & ADVISORY ASSIGNMENTS (1)

Client	Assignment	Objective
Utility Holding Company (undisclosed)	Credit advisory on ratings impact of merger. 2022	Understand credit effects of merger for previously unrated entities.
SouthWest Water Company	Review of proposed debt funding plan.	Appropriate mix of long-term and short-term debt.
Xcel Energy/ Public Service Co. of CO	Studied likely investor and credit impact of the PSC's proposed changes in the recovery of purchased gas cost (Docket 21R-0314G). 2021	Analyze financial impacts of regulatory proposal.
Eversource Energy Inc./Public Service Co. of New Hampshire	Prepared white paper analyzing the financial implications of two methods for recovering costs of energy efficiency programs (related to Docket DE 20-092). 2020	Analyze feasibility and financial impacts of regulatory proposal; prepare white paper
Washington Gas Light Co.	Quantified the effect of merger upon the cost of long-term and short-term debt. 2019	Comply with regulatory requirement
Cravath, Swaine & Moore LLP	Evaluated factors that influenced utility spending decisions on operations, maintenance, and capital projects. 2019	Support litigation strategy in bankruptcy proceedings.
NJ American Water Co.	Analyzed impacts of tax reform on water utility's cash flow and ratings. 2018	Support regulatory strategy
AltaGas Ltd.	Credit advisory on ratings under merger and no-merger cases. 2017	Compare strategic alternatives

Jurisdiction	Proceeding	Topic
Entergy Texas, Inc.	Research study on debt equivalence and capital cost associated with capacity purchase obligations. Impact of new GAAP lease accounting standard on PPAs. 2016	Economic comparison of power purchase obligations and self-build options.
Eversource Energy	Evaluated debt equivalence of power purchase obligations. 2014	Clarify credit impact of various contract obligations.
International Money Center Bank (Undisclosed)	Research study and recommendations on estimating Loss Given Default and historical experience of default and recovery in regulated utility sector. 2014	Efficient capital allocation for loan portfolio.
GenOn Energy Inc.	White Paper on appropriate industry peers for a competitive power generation and energy company. 2012	Appropriate peer comparisons in SEC filings and shareholder communications, compensation studies
Transmission utility (Undisclosed)	Recommended the appropriate capital structure and debt leverage during a period of high capital spending. 2012	Efficient book equity during multi-year capex project; preserve existing credit ratings
Toll Highway (Undisclosed)	Advised on adding debt while minimizing risk of downgrade. Recommended strategy for added leverage and rating agency communications. 2012	Free up equity for alternate growth investments via increased leverage while preserving credit ratings

1.Confidential assignments are omitted or client's identity is masked, at client request.

Professional and Executive Training

Southern California Edison Co., Rosemead CA	Designed and delivered in-house training program on evaluation of the credit of energy market counterparties. 2016
Financial Institution, NYC (Undisclosed)	In-house training. Developed corporate credit case for internal credit training program and coordinated use in training exercise. 2016
CoBank, Denver CO	Designed and delivered "Midstream Gas and MLPs: Advanced Credit Training". 2014
Empire District Electric Co., Joppa MO	Designed and delivered in-house executive training session Utility Sector Financial Evaluation. 2014
PPL Energy Corp, Allentown PA	Designed and delivered in-house Financial Training. 2014
SNL Knowledge Center Courses, New York NY	Designed and delivered public courses "Credit Analysis for the Power & Gas Sector", 2011-2014
SNL Knowledge Center Courses, New York NY	Designed and delivered public courses "Analyst Training in the Power & Gas Sectors: Financial Statement Analysis. 2013 -2014
EEI Transmission and Wholesale Markets	Designed and delivered "Financing and Access to Capital". 2012
National Rural Utilities Coop Finance Corp.	Designed and delivered in-house training "Credit Analysis for the Power Sector". 2012
Judicial Institute of Maryland	Designed and delivered "Impact of Court Decisions on Financial Markets and Credit", section of continuing education seminar for MD judges: "Utility Regulation and the Courts", Annapolis MD. 2007
Edison Electric Institute, New York, NY	"New Analyst Training Institute: Fixed Income Analysis and Credit Ratings", 2008; 2004

Exhibit EL-2

Correspondences Among Credit Ratings

Long-Term Credit Ratings

Moody's	Fitch
Aaa	AAA
Aa1	AA+
Aa2	AA
Aa3	AA-
A1	A+
A2	A
A3	A-
Baa1	BBB+
Baa2	BBB
Baa3	BBB-
Investment Grade Boundary	
Ba1	BB+
Ba2	BB
Ba3	BB-
B1	B+
B2	B
B3	B-
Caa1	CCC+
Caa2	CCC
Caa3	CCC-
Ca	CC
C	C
D*	D*
	SD*

*D= In default; SD denotes a selective default on specific debt instruments rather than a general default

Exhibit EL-3

130 US Investor Owned Utility Operating Companies Rated by Moody's*

Company Name	Unsecured Rating *	Outlook	Type
Alabama Power Co.	A1	Stable	Electric
Atmos Energy Corp.	A1	Negative	Gas
Florida Power & Light Co.	A1	Stable	Electric
Gulf Power Co.	A1	No Outlook	Electric
Madison Gas and Electric Co.	A1	Stable	Electric
MidAmerican Energy Co.	A1	Stable	Electric
Spire Missouri Inc.	A1	Stable	Gas
Central Maine Power Co.	A2	Stable	Electric
Connecticut Natural Gas Corp.	A2	Negative	Gas
DTE Electric Co.	A2	Stable	Electric
Duke Energy Carolinas LLC	A2	Stable	Electric
Duke Energy Indiana Inc.	A2	Stable	Electric
East Ohio Gas Co.	A2	Stable	Gas
Northern Illinois Gas Co.	A2	Stable	Gas
Northern States Power Co. - MN	A2	Stable	Electric
NSTAR Electric Co.	A2	Negative	Electric
PECO Energy Co.	A2	Negative	Electric
Peoples Gas Light & Coke Co.	A2	Negative	Gas
Southern California Gas Co.	A2	Stable	Gas
Spire Alabama Inc.	A2	Stable	Gas
Virginia Electric & Power Co.	A2	Negative	Electric
Western Massachusetts Electric	A2	No Outlook	Electric
Wisconsin Electric Power Co.	A2	Stable	Electric
Wisconsin Public Service Corp.	A2	Stable	Electric
Ameren Illinois	A3	Stable	Electric
Baltimore Gas and Electric Co.	A3	Stable	Electric
Berkshire Gas Co.	A3	Stable	Gas
Cleco Power LLC	A3	Stable	Electric
Commonwealth Edison Co.	A3	Negative	Electric
Connecticut Light & Power Co.	A3	Negative	Electric
Consolidated Edison Co. of NY	A3	Stable	Electric
Consumers Energy Co.	A3	Stable	Electric
DTE Gas Co.	A3	Stable	Gas
Duke Energy Florida Inc.	A3	Stable	Electric
Duquesne Light Co.	A3	Stable	Electric
First Energy Pennsylvania Elect	A3	Stable	Electric
Georgia Power Co.	A3	Stable	Electric
Indiana Michigan Power Co.	A3	Stable	Electric
International Transmission Company	A3	Stable	Electric
Jersey Central Power & Light	A3	Stable	Electric
Kentucky Utilities Co.	A3	Stable	Electric
Louisville Gas & Electric Co.	A3	Stable	Electric
Mississippi Power Co.	A3	Stable	Electric
Narragansett Electric Company	A3	Stable	Electric
Northern States Power Co - WI	A3	Stable	Electric
Ohio Edison Co.	A3	Stable	Electric

** As of November 11, 2024*

130 US Investor Owned Utility Operating Companies Rated by Moody's*

Company Name	Unsecured Rating *	Outlook	Type
Oklahoma Gas and Electric Co.	A3	Stable	Electric
ONE Gas Inc.	A3	Stable	Electric
Otter Tail Power Company	A3	Negative	Electric
Piedmont Natural Gas Co.	A3	Stable	Gas
Portland General Electric Co.	A3	Negative	Electric
PPL Electric Utilities Corporation	A3	Stable	Electric
Public Service Co. of CO	A3	Stable	Electric
Public Service Co. of NH	A3	Stable	Electric
Public Service Electric Gas	A3	Stable	Electric
San Diego Gas & Electric Co.	A3	Stable	Electric
South Jersey Gas Co.	A3	Stable	Gas
Southern Connecticut Gas Co.	A3	Negative	Gas
Southern Indiana Gas & Elec Co	A3	Stable	Electric
Tampa Electric Co.	A3	Negative	Electric
Tucson Electric Power Co.	A3	Stable	Electric
UNS Electric Inc.	A3	Negative	Electric
UNS Gas, Inc.	A3	Stable	Gas
Wisconsin Gas LLC	A3	Stable	Gas
Appalachian Power Co.	Baa1	Stable	Electric
Arizona Public Service Co.	Baa1	Stable	Electric
Atlantic City Electric Co.	Baa1	Stable	Electric
Boston Gas Co.	Baa1	Stable	Gas
CenterPoint Energy Houston	Baa1	Negative	Electric
Central Hudson Gas & Electric	Baa1	Stable	Electric
Delmarva Power & Light Co.	Baa1	Stable	Electric
Dominion Energy South Carolina	Baa1	Stable	Electric
Duke Energy Kentucky Inc.	Baa1	Stable	Electric
Duke Energy Ohio	Baa1	Stable	Electric
Empire District Electric Co.	Baa1	Stable	Electric
Entergy Arkansas Inc.	Baa1	Stable	Electric
Entergy Louisiana LLC	Baa1	Stable	Electric
Entergy Mississippi Inc.	Baa1	Stable	Electric
Evergy Kansas Central	Baa1	Stable	Electric
Evergy Kansas South	Baa1	Stable	Electric
Evergy Metro	Baa1	Stable	Electric
Idaho Power Co.	Baa1	Negative	Electric
Indianapolis Power & Light Co.	Baa1	Negative	Electric
Interstate Power & Light	Baa1	Stable	Electric
KeySpan Gas East Corp.	Baa1	Stable	Gas
Massachusetts Electric Co.	Baa1	Stable	Electric
Nevada Power Co.	Baa1	Stable	Electric
Niagara Mohawk Power Corp	Baa1	Stable	Electric
Northern IN Public Svc Co.	Baa1	Stable	Electric
Northwest Nat Gas	Baa1	Stable	Gas
NY State Electric & Gas Corp.	Baa1	Stable	Electric
Ohio Power Co.	Baa1	Stable	Electric
Oncor Electric Delivery	Baa1	Stable	Electric

130 US Investor Owned Utility Operating Companies Rated by Moody's*

Company Name	Unsecured Rating *	Outlook	Type
PacifiCorp	Baa1	Stable	Electric
Potomac Electric Power Co.	Baa1	Stable	Electric
Public Service Co. of NC, Inc.	Baa1	Stable	Gas
Public Service Co. of OK	Baa1	Stable	Electric
Puget Sound Energy Inc.	Baa1	Stable	Electric
Questar Gas Co.	Baa1	Stable	Gas
Rochester Gas & Electric Corp.	Baa1	Stable	Electric
Southern California Edison Co.	Baa1	Stable	Electric
Southwest Gas Corp.	Baa1	Stable	Electric
Superior Water, Light and Power Company	Baa1	Stable	Electric
Texas-New Mexico Power Co.	Baa1	Stable	Electric
Union Electric Co.	Baa1	Stable	Electric
United Illuminating Co.	Baa1	Stable	Electric
Wisconsin Power and Light Co	Baa1	Stable	Electric
Yankee Gas Services Company	Baa1	Stable	Gas
AEP Texas Inc.	Baa2	Negative	Electric
Avista Corp.	Baa2	Stable	Electric
Brooklyn Union Gas Co.	Baa2	Stable	Gas
El Paso Electric Co.	Baa2	Stable	Electric
Entergy Texas Inc.	Baa2	Stable	Electric
Evergy Missouri West	Baa2	Negative	Electric
Monongahela Power Co.	Baa2	Stable	Electric
NorthWestern Corp.	Baa2	Stable	Electric
Orange & Rockland Utlts Inc.	Baa2	Positive	Electric
PNG Companies LLC	Baa2	Negative	Electric
Potomac Edison Co.	Baa2	Stable	Electric
Public Service Co. of NM	Baa2	Stable	Electric
Sierra Pacific Power Co.	Baa2	Stable	Electric
Southwestern Electric Power Co	Baa2	Stable	Electric
Southwestern Public Service Co	Baa2	Stable	Electric
Toledo Edison Co.	Baa2	Stable	Electric
Cleveland Electric Illuminating Inc.	Baa3	Stable	Electric
Dayton Power & Light Co.	Baa3	Stable	Electric
Kentucky Power Co.	Baa3	Stable	Electric
Entergy New Orleans	Ba1	Stable	Electric
Hawaiian Electric Co.	Ba3	Stable	Electric
Pacific Gas and Electric Co.	Ba3	Positive	Electric

** As of November 11, 2024*

PUBLIC

Exhibit EL-4 is a CONFIDENTIAL and/or HIGHLY SENSITIVE PROTECTED MATERIALS attachment.

PUBLIC

Exhibit EL-5 is a CONFIDENTIAL and/or HIGHLY SENSITIVE PROTECTED MATERIALS attachment.

DOCKET NO. 57568

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

DIRECT TESTIMONY

OF

JULISSA I. REZA

FOR

EL PASO ELECTRIC COMPANY

JANUARY 2025

EXECUTIVE SUMMARY

Julissa I. Reza is Manager-Regulatory Accounting for El Paso Electric Company ("EPE" or "the Company"). Her responsibilities include the oversight of the scheduling, preparation, and review of jurisdictional regulatory accounting and reporting, including fuel-related filings with the Public Utility Commission of Texas ("PUCT" or "the Commission").

Ms. Reza sponsors certain of the B (accumulated provision balances), C (nuclear fuel), G (accounting information), and I (fuel and purchased power) schedules and some adjustments made to EPE's October 1, 2023, through September 30, 2024, Test Year costs. These adjustments are to both cost of service (expenses and revenues) and rate base items. Exhibit JIR-2 to her testimony is a list of the pro-forma adjustments that she discusses. In addition, Ms. Reza discusses the Company's new fuel adjustment factor rule proposal.

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EXHIBITS

I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Julissa I. Reza. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. HOW ARE YOU EMPLOYED?

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

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from The University of Texas at El Paso with a Bachelor of Business Administration in Accounting, with honors. I am a Certified Public Accountant in the State of Texas and a member of the Texas Society of Certified Public Accountants and the American Institute of Certified Public Accountants.

Upon graduation, I was employed by KPMG in the audit section from 1990 to 1992. I was employed with EPE from 1992 to 1994 and rejoined EPE in 2002. I have held various positions related to financial accounting and reporting, customer accounting and internal audit. During my twelve years in financial accounting and reporting, my responsibilities included the preparation, review, and analysis of various internal and external financial statements, along with monthly financial closing responsibilities related to the monthly deferred fuel calculation and nuclear fuel accounting. In March 2022, I accepted the position of Manager - Regulatory Accounting.

Q4. WHAT ARE YOUR RESPONSIBILITIES WITH EPE?

A. My responsibilities include the oversight of the scheduling, preparation, and review of jurisdictional regulatory accounting and reporting such as the Company's monthly fuel accounting and reporting and other regulatory filings before the Public Utility Commission of Texas ("PUCT" or "the Commission"), the New Mexico Public Regulation Commission ("NMPRC"), and the Federal Energy Regulatory Commission ("FERC").

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY UTILITY REGULATORY BODIES?

A. Yes, I have previously filed testimony with and testified before the NMPRC in Case No. 23-00046-UT.

II. Purpose of Testimony

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor and describe certain pro-forma adjustments that EPE has made to its Test Year costs, and I sponsor certain schedules filed as part of this case. The Test Year in this case is the twelve -month period from October 1, 2023, through September 30, 2024. In addition, I discuss the Company's new fuel adjustment factor proposal.

Q7. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section III, I discuss certain schedules required by the PUCT's Electric Utility Rate-Filing Package for Generating Utilities ("RFP") that I sponsor in this case. In Section IV, I discuss the pro-forma adjustments made to Test Year expenses and rate base that I sponsor in this case. In Section V, I discuss the Company's new fuel adjustment factor proposal.

III. Schedules Sponsored

Q8. WHAT SCHEDULES FROM THE COMMISSION'S RFP ARE YOU SPONSORING?

A. I sponsor or co-sponsor the schedules listed in Exhibit JIR-1.

Q9. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q10. ARE THE CONTENTS OF THESE SCHEDULES AND EXHIBITS TRUE AND ACCURATE?

A. Yes, they are. These schedules and exhibits are based on the Company's records as of the day they were prepared and are true and accurate to the best of my knowledge.

Q11. ON WHAT BASIS WERE THE RFP SCHEDULES PREPARED?

A. They were prepared from the books and records of EPE, and they are based on an October 1, 2023, through September 30, 2024, Test Year.

A. Schedule B-2 (Accumulated Provision Balances)

Q12. DO YOU SPONSOR OR CO-SPONSOR SCHEDULE B-2 (ACCUMULATED PROVISION BALANCES)?

A. Yes. I co-sponsor Schedule B-2 (Accumulated Provision Balances), specifically page 4, with EPE witnesses Cindy Prieto and Steven Sierra. Schedule B-2 (Accumulated Provision Balances) provides the balances for accumulated provisions accounts.

Q13. WHAT DOES SCHEDULE B-2 (ACCUMULATED PROVISION BALANCES), PAGE 4, PRESENT?

A. Schedule B-2 (Accumulated Provision Balances), page 4, is the summary of balances for account 229 Accumulated Provisions for Rate Refunds. This schedule includes the amount accrued each month and any amounts charged off each month in the Test Year along with ending account balances. The amounts in this schedule represent rates subject to refund related to the Company's FERC transmission rate case filing in Docket No. ER22-282-000 for its FERC jurisdiction.

Q14. IS EPE SEEKING TO INCLUDE THE BALANCE IN SCHEDULE B-2 (ACCUMULATED PROVISION BALANCES), PAGE 4, IN RATE BASE?

A. No. Because the amounts in Schedule B-2 (Accumulated Provision Balances), page 4, relate to amounts that will be refunded for the period of 2022-2024 to FERC jurisdictional customers, and not Texas, EPE is not seeking to include this balance in rate base.

B. C Schedules (Nuclear Fuel))

Q15. WHAT C SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. I sponsor the following C Schedules, some of which are not applicable due to EPE's financing of nuclear fuel through RGRT as described below:

Schedule	Description
Schedule C-6	Nuclear Fuel
Schedule C-6.1	Nuclear Fuel in Process
Schedule C-6.2	Distribution of Costs and Quantities for Account 120.1
Schedule C-6.3	Distribution of Costs and Quantities for Account 120.2
Schedule C-6.4	Distribution of Costs for Account 120.3
Schedule C-6.5	Distribution of Costs for Account 120.4
Schedule C-6.6	Distribution of Costs for Account 120.5
Schedule C-6.7	Distribution of Costs for Account 120.6

Q16. WHAT DOES SCHEDULE C-6 (NUCLEAR FUEL) PRESENT?

A. This schedule lists all account balances for FERC Account 120 (120.1 through 120.6) at the end of the Test Year. Because EPE records nuclear fuel under a capital lease, EPE uses only FERC Account 120.6, Nuclear Fuel under Capital Lease, and FERC Account 120.5, Accumulated Provision for Amortization of Nuclear Fuel as further discussed by EPE witness Richard Gonzalez.

Q17. WHAT INFORMATION IS PRESENTED IN THE OTHER C-6 (NUCLEAR FUEL) SCHEDULES?

A. The C-6 Schedules (extending through Schedule C-6.7), present information about nuclear fuel balances. EPE witness Victor Martinez sponsors Schedule C-6.8 (Allocation of Unassigned Balance) and Schedule C-6.9 (Nuclear Fuel Inventory Policy), and EPE witness Richard Gonzalez sponsors Schedule C-6.10 (Nuclear Fuel Trust/Lease).

C. G Schedules (Accounting Information)

Q18. WHAT G SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. The G Schedules address various categories of accounting information. I sponsor or co-sponsor the following G Schedules:

Schedule	Description
Schedule G-4	Summary of Advertising, Contributions, and Donations
Schedule G-5.4	Analysis of Prior Rate Case Exclusions
Schedule G-5.5	Comparison of Prior Rate Case Exclusions
Schedule G-11	Deferred Expenses from Prior Dockets
Schedule G-14	Regulatory Commission Expenses
Schedule G-14.2	Rate Case Expenses – Prior Rate Applications

1. Summary of Advertising, Contributions & Donations Expenses (Schedule G-4)

Q19. WHAT DOES SCHEDULE G-4 ADDRESS?

A. This schedule summarizes advertising, contributions, and donations expense subject to the 0.3% of revenue limitation required by 16 TAC § 25.231(b)(1)(E). The schedule includes the charged category and the schedule number that details the Test Year expense.

Q20. IS EPE SEEKING RECOVERY OF ANY AMOUNTS FOR ADVERTISING EXPENSES AND CONTRIBUTIONS AND DONATIONS IN ITS TEST YEAR COST OF SERVICE?

A. As discussed by EPE Witness Prieto, EPE is seeking to recover advertising costs, contributions, and donations, subject to and consistent with the limitation prescribed by 16 TAC § 25.231(b)(1)(E).

2. Analysis of Prior Rate Case Exclusions (Schedule G-5.4)

Q21. WHAT DOES SCHEDULE G-5.4 CONTAIN?

A. Schedule G-5.4 is not applicable since the Company's only rate case within the past five years, Docket No. 52195, was resolved by settlement.

3. Comparison of Prior Rate Case Exclusions (Schedule G-5.5)

Q22. WHAT DOES SCHEDULE G-5.5 CONTAIN?

A. Schedule G-5.5 is not applicable to the Company because its two most recent rate cases were resolved by settlement.

4. Deferred Expenses from Prior Dockets (Schedule G-11)

Q23. WHAT INFORMATION IS SET FORTH IN SCHEDULE G-11 (DEFERRED EXPENSES FROM PRIOR DOCKETS)?

A. Schedule G-11 reflects expenses deferred from prior dockets and amortization expense either included in the Test Year or requested in this application. I discuss the amortization of these deferrals later in my testimony.

5. Regulatory Commission Expense (Schedule G-14)

Q24. WHAT INFORMATION IS CONTAINED IN SCHEDULE G-14 (REGULATORY COMMISSION EXPENSE)?

A. Schedule G-14 provides a summary by docket of regulatory commission expenses charged to FERC Account 928 during the Test Year. Schedule G-14 details expenses by docket for regulatory commission expenses related to this application; includes regulatory commission expenses for other cases that were deferred for recovery in EPE's next base rate case, which is this proceeding; and includes rate case expenses that are removed which are being recovered through a separate surcharge that will continue through July 2026. In addition, Schedule G-14 identifies those rate case expenses that are not included in the Texas revenue requirement request. Expenses related to the Schedule S Waiver for this proceeding have been excluded as well.

The Test Year costs for this base rate case, and other rate case expenses for which EPE is seeking recovery, have been adjusted to represent one half of the estimated costs to prepare, file, and litigate this case reflecting a proposed two-year amortization period. Please see EPE witness George Novela's testimony for the Company's proposed recovery of these rate case expenses. These and other adjustments to FERC Account 928 are discussed in more detail later in my testimony.

6. Regulatory Commission Expense (Schedule G-14.2)

Q25. WHAT INFORMATION IS IN SCHEDULE G-14.2?

A. Schedule G-14.2 addresses prior rate case expenses related to a previous rate application which was not previously considered by the Commission. EPE has included rate case expenses, reflecting a proposed two-year amortization period, for Docket No. 52195 incurred after March 31, 2022, and other cases that were deferred for recovery in EPE's next base rate case, which is this proceeding. EPE witness Novela discusses the Company's proposed request to recover these costs in his testimony.

D. The I Schedules (Fuel and Purchased Power Information)

Q26. WHAT DO THE I SCHEDULES ADDRESS?

A. The I Schedules contain fuel and purchased power information.

Q27. IS EPE SEEKING TO RECONCILE ITS FUEL AND PURCHASED POWER COSTS IN THIS CASE?

A. No, it is not. On September 23, 2022, EPE filed an application in Docket No. 54142 to reconcile its fuel and purchased power costs for the period April 2019 through March 2022. The Commission issued a final order in that reconciliation case on April 11, 2024. In addition, on September 27, 2024, EPE filed an application pending in Docket No. 57149 to reconcile its fuel and purchased power costs for the period April 2022 through March 2024.

Q28. WHAT I SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. I sponsor or co-sponsor the following I Schedules, some of which are not applicable as EPE is not seeking to reconcile its fuel and purchased power costs in this case:

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Schedule	Description
Schedule I-1.1	Fuel by Account Number
Schedule I-1.2	Fuel Burned
Schedule I-16	Reconcilable Fuel Costs
Schedule I-16.1	Fossil Fuel Mix (Burned)
Schedule I-16.2	Fossil Fuel Mix (Purchased)
Schedule I-16.3	Competitive Spot Fossil Fuel Purchases
Schedule I-17.1	Coal Cost Breakdown
Schedule I-20	Fuel Management Travel
Schedule I-22	Fuel Cost Over/Under Recovery

Q29. WHAT DOES SCHEDULE I-1.1 ADDRESS?

A. Schedule I-1.1 (Fuel by Account Number) provides fuel expense by account number for each month in the Test Year. All costs in Schedule I-1.1 are considered variable except for Dry Cask Storage costs at PVGS, which are considered semi-variable.

Q30. WHAT DOES SCHEDULE I-1.2 ADDRESS?

A. Schedule I-1.2 (Fuel Burned) provides fuel expense by generating station, and by generating unit for PVGS, for each month in the Test Year. For purposes of Schedule I-1.2, gas burned at Newman Power Plant ("Newman"), Rio Grande Power Plant ("Rio Grande"), Montana Power Station ("MPS"), and Copper Power Plant ("Copper") is estimated monthly, and a true-up of the prior month estimate to actual expense is recorded. In any given month, burns may not equal purchases. However, EPE balances current month differences between burns and purchases in succeeding months.

Q31. WHICH SCHEDULES ARE NOT APPLICABLE IN THIS CASE BECAUSE EPE IS NOT SEEKING TO RECONCILE ITS FUEL AND PURCHASED POWER COSTS IN THIS CASE?

A. Because EPE is not seeking to reconcile its fuel and purchased power costs in this case, the following schedules are not applicable:

Schedule	Description
Schedule I-16	Reconcilable Fuel Costs
Schedule I-16.1	Fossil Fuel Mix (Burned)
Schedule I-16.2	Fossil Fuel Mix (Purchased)
Schedule I-16.3	Competitive Spot Fossil Fuel Purchases
Schedule I-17.1	Coal Cost Breakdown
Schedule I-22	Fuel Cost Over/Under Recovery

Q32. WHAT DOES SCHEDULE I-20 ADDRESS?

A. Schedule I-20 addresses expenses incurred for overnight fuel management travel to non - company facilities charged to any reconcilable fuel account. The Company did not have any expenses for overnight travel to non-Company facilities charged to any reconcilable fuel account during the Test Year.

IV. Summary of Pro-Forma Adjustments

Q33. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe the pro-forma adjustments to the cost of service and rate base that I sponsor or co-sponsor.

Q34. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING THE PRO-FORMA ADJUSTMENTS THAT YOU DISCUSS?

A. Yes, I have. Exhibit JIR-2 is a list of the pro-forma adjustments that I discuss. The adjustments to the cost of service are also shown on Schedule A-3 and associated work papers of EPE's RFP required by Commission rules. Adjustments to rate base are shown on Schedule B-1 and associated workpapers.

A. Adjustments to the Cost of Service

Q35. HAVE YOU MADE ADJUSTMENTS TO THE COMPANY'S TEST YEAR COST OF SERVICE?

A. Yes, I have. Several adjustments have been made to the Test Year per book amounts to adjust those values to reflect known and measurable changes.

Q36. WHICH ADJUSTMENTS INCLUDED IN SCHEDULE A-3 ARE YOU SPONSORING OR CO-SPONSORING?

A. I am sponsoring or co-sponsoring the adjustments discussed below as noted in Exhibit JIR - 2.

1. Fuel and Purchased Power Expense (Adjustment No. 2)

Q37. WHAT WERE THE ADJUSTMENTS TO FUEL EXPENSE?

A. The following adjustments were made to Test Year fuel expense:

1. The Test Year fuel expenses were adjusted to reflect Test Year adjusted kWh sales. The decrease in kWh sales resulting from adjusting the Test Year kWh sales was multiplied by the Test Year average natural gas generation costs. The various adjustments to kWh sales are detailed in EPE witnesses Rene Gonzalez's and Soto's testimonies, including adjustments for year-end customer annualization, energy efficiency, normal weather conditions and other known and measurable changes. This resulted in a decrease of $2,217,564 to fuel expense.
2. The Test Year fuel expenses were decreased by $210,330 for out-of-period adjustments.

The net adjustment to the Test Year fuel expenses was a decrease of $2,427,894.

Q38. WHAT ADJUSTMENT WAS MADE TO PURCHASED POWER EXPENSES?

A. Test Year purchased power expenses were increased by $2,798,119 mainly to add back an out -of -period adjustment related to penalty credits related to a purchase power agreement.

2. Regulatory Asset Amortization (Adjustment No. 11)

Q39. WHAT ADJUSTMENT WAS MADE FOR REGULATORY ASSET AMORTIZATION?

A. The Test Year regulatory asset amortization was reduced by $2,719,782. The majority of this adjustment represents the removal of amortization for regulatory assets that is not recovered in base rates.

3. Regulatory Commission Expense (Adjustment No. 12)

Q40. WHAT ADJUSTMENT WAS MADE FOR REGULATORY COMMISSION EXPENSES?

A. The decrease of $1,093,016 in regulatory commission expenses is to adjust the following Test Year costs:

1. Inclusion of rate case expenses related to this application;
2. Inclusion of rate case expenses for other cases that were deferred for recovery in EPE's next base rate case, which is this proceeding;
3. Removal of rate case expenses that are being recovered through a separate surcharge that will continue through July 2026; and
4. Removal of regulatory commission fees for the Texas and New Mexico jurisdiction. Refer to WP A-3, Adjustment 17, sponsored by EPE witness Tamera Henderson.

EPE witness Novela discusses EPE's proposal for the recovery of costs to prepare, file, and litigate this case in his direct testimony.

4. Recoverable Advertising, Contributions, and Donations Expense (Adjustment No. 26)

Q41. WHAT ADJUSTMENT WAS MADE FOR RECOVERABLE ADVERTISING AND CONTRIBUTIONS EXPENSE?

A. I co-sponsor this schedule with EPE witness Prieto. 16 TAC § 25.231(b)(1)(E) provides for the recovery of advertising, contributions, and donations up to an amount that is equal to 0.3% of requested revenues as calculated on Schedule G-4. EPE witness Prieto discusses the adjustment and the reasonableness of advertising, contributions, and donations in her testimony.

B. Adjustments to Rate Base

Q42. HAVE YOU MADE ADJUSTMENTS TO THE COMPANY'S TEST YEAR RATE BASE?

A. Yes, I have. I have made the adjustments described below.

1. Regulatory Assets and Liabilities and Other Additions/Deductions to Rate Base (Excluding Tax) (Rate Base Adjustment No. 3)

Q43. WHAT REGULATORY ASSETS AND LIABILITIES ARE INCLUDED IN RATE BASE?

A. Regulatory assets and liabilities included in rate base are limited to:

1. Several regulatory assets and liabilities established pursuant to orders issued by the NMPRC and/or FERC and recovered through rates charged to New Mexico and/or FERC customers, respectively;
2. The unrecovered plant and regulatory study costs as discussed in EPE witness Prieto's testimony;
3. Miscellaneous deferred debits; and
4. Other deductions funded by customers.

V. New Fuel Adjustment Factor Proposal

Q44. IS EPE PROPOSING A NEW FUEL ADJUSTMENT FACTOR METHODOLOGY BASED ON THE 88TH LEGISLATURE'S PASSAGE OF HOUSE BILL 2073?

A. Yes. The 88th Legislature passed House Bill 2073 which among other things, provides for more timely collection of fuel and purchased power costs. EPE is proposing a new fuel adjustment factor methodology consistent with the Legislature's authorization. Consistent with current 16 Tex. Admin. Code § 25.237, EPE is seeking this change during this proceeding.[1] Under the new fuel adjustment factor methodology, EPE would no longer utilize the fixed fuel factor to recover fuel expenses, but instead would utilize a combination of a monthly and 12-month rolling average fuel adjustment factor as an estimate to recover fuel expenses. EPE witness Carrasco provides the revised language in the tariffs to refer to the "fuel adjustment factor" instead of the "fixed fuel factor" that is currently used today.

Q45. WHY IS EPE PROPOSING THIS CHANGE?

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[1] 16 Tex. Admin. Code § 25.237(a)(2)(D) ("An electric utility's fuel factor may be changed in any general rate proceeding.").

A. While EPE's current fuel factor is set by a formula and can be adjusted several times a year, EPE has regularly experienced substantial over and under-recoveries because of the volatility of fuel costs and varying amounts of margins on off-system sales. This has resulted in deferred fuel balances, both positive and negative, that are often in the tens of millions of dollars. EPE's proposal is intended to rectify that, which will also benefit customers by avoiding the unpredictability of their fuel costs and total bills, and more timely match the cost of fuel billed to customers with the concurrent cost of fuel EPE is experiencing.

Q46. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF HOW THE NEW FUEL ADJUSTMENT FACTOR METHODOLOGY WILL WORK.

A. Under the Company's new fuel adjustment factor proposal, EPE proposes to replace the current fixed fuel factor with a monthly adjustable fuel adjustment factor. The fuel adjustment factor will operate on a two-month lag, so that fuel and purchased power costs ("fuel costs") on a bill reflect a rolling 12-month average of actual costs, adjusted for prior over/under collections. The recovery of all fuel and purchased power costs through this fuel adjustment factor will ensure that only actual costs are collected, without risk of permanent over/under collection.

The adjusted current month fuel adjustment factor will be composed of two factors: (1) the current month fuel adjustment factor based on the current month over/under collection and (2) a rolling 12-month average factor based on a twelve-month average of actual fuel costs. The first component, the current month fuel adjustment factor, will be calculated by dividing the current month over/under collection by the kWh billed to customers for that month. For the second component, the rolling 12-month average factor, a monthly factor for the past twelve months, including the current month, will be calculated by dividing each of the twelve month's total fuel costs by the corresponding kWh for that month. This monthly fuel factor for each of the twelve months will be summed and divided by 12 to determine the rolling 12-month average factor. The sum of the current month fuel adjustment factor and the rolling 12-month average factor will result in the adjusted current month fuel adjustment factor that will be utilized to bill customers two months later. For example, in March 2024, the customers will be billed on the adjusted current month fuel adjustment factor calculated in January 2024 composed of: (1) the current month fuel adjustment factor based on the January 2024 current month over/under collection and (2) a rolling 12-month average factor based on the February 2023 through January 2024 factors.

In addition, there will be a balancing account to track the cumulative over/under collections. At any point in time, the cumulative balance in the balancing account will equal the sum of the monthly over/under collection for the prior two months. For example, the March 2024 balancing account, or cumulative over/under collection will be the sum of the current month over/under collection for February and March 2024. The balancing account will also be used for interim fuel adjustments that are authorized or directed by the PUCT such as adjustments pursuant to fuel reconciliations.

Please refer to Exhibits JIR-3 and JIR-4 for a sample of the calculation under the new fuel adjustment factor proposal.

Q47. HOW WILL THE CUMULATIVE OVER/UNDER COLLECTION BALANCE BE HANDLED IN THE MONTH OF TRANSITION FROM THE CURRENT FIXED FUEL FACTOR TO THE FUEL ADJUSTMENT FACTOR PER THE NEW FUEL ADJUSTMENT FACTOR PROPOSAL?

A. Depending on the materiality of the cumulative over/under collection balance, including interest, at the time of the transition to the new fuel adjustment factor, the cumulative balance can be included in the first month the fuel adjustment factor is billed to customers, or it can be included over a period of time (e.g., 12 or 24 months) via the balancing account.

Q48. WILL THE ADJUSTED CURRENT MONTH FUEL ADJUSTMENT SYSTEM FACTOR AS CALCULATED BE ADJUSTED BASED ON VOLTAGE LEVEL?

A. Yes. The adjusted current month fuel adjustment system factor will be adjusted by voltage level as discussed by Witness Carrasco in his testimony.

Q49. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY J. REZA

Schedule	Description	Sponsorship
B-2	ACCUMULATED PROVISION BALANCES	Co-Sponsor
C-6	NUCLEAR FUEL	Sponsor
C-6.1	NUCLEAR FUEL IN PROCESS	Sponsor
C-6.2	DISTRIBUTION OF COSTS AND QUANTITIES FOR ACCOUNT 120.1	Sponsor
C-6.3	DISTRIBUTION OF COSTS AND QUANTITIES FOR ACCOUNT 120.2	Sponsor
C-6.4	DISTRIBUTION OF COSTS FOR ACCOUNT 120.3	Sponsor
C-6.5	DISTRIBUTION OF COSTS FOR ACCOUNT 120.4	Sponsor
C-6.6	DISTRIBUTION OF COSTS FOR ACCOUNT 120.5	Sponsor
C-6.7	DISTRIBUTION OF COSTS FOR ACCOUNT 120.6	Sponsor
G-4	SUMMARY OF ADVERTISING, CONTRIBUTIONS & DONATIONS	Co-Sponsor
G-5.4	ANALYSIS OF PRIOR RATE CASE EXCLUSIONS	Sponsor
G-.5.5	COMPARISON OF PRIOR RATE CASE EXCLUSIONS	Sponsor
G-11	DEFERRED EXPENSES FROM PRIOR DOCKETS	Sponsor
G-14	REGULATORY COMMISSION EXPENSE	Sponsor
G-14.2	RATE CASE EXPENSES - PRIOR RATE APPLICATIONS	Sponsor
I-1.1	FUEL BY ACCOUNT NUMBER	Sponsor
I-1.2	FUEL BURNED	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-17.1	COAL COST BREAKDOWN (NA-fuel rec)	Co-Sponsor
I-20	FUEL MANAGEMENT TRAVEL	Sponsor
I-22	FUEL COST OVER/UNDER RECOVERY (NA-fuel rec)	Sponsor

LIST OF PRO-FORMA ADJUSTMENTS

Adjustment	Description	Sponsorship
	Cost of Service Adjustments	
2	Fuel and Purchased Power Expense	Sponsor
11	Regulatory Asset Amortization	Co-Sponsor
12	Regulatory Commission Expense	Sponsor
26	Recoverable Advertising, Contributions, and Donations Expenses	Co-Sponsor
	Rate Base Adjustments	
3	Regulatory Assets and Liabilities and Other Additions/Deductions to Rate Base (Excluding Tax)	Co-Sponsor

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			JANUARY 2024						
I.	**SUMMARY OF FUEL & PURCHASED POWER ADJUSTMENT FACTOR**								
1	BILLING MONTH:	MARCH 2024							
2	CURRENT MONTH:	JANUARY 2024							
3	TYPE OF FACTOR:	MONTHLY							
4	EFFECTIVE DATE OF FACTOR:	MARCH 2024							
5	BILLING MONTH'S SYSTEM FACTOR:	$ (0.000483)							
6	NUMBER OF MONTHS FACTOR IS	ONE							
7	TIME PERIOD USED TO CALCULATE FACTOR:	1/1-1/31/24							
8	CUMULATIVE OVER/(UNDER) COLLECTION AT END OF CURRENT MONTH:	JANUARY 2024							

II. FUEL AND PURCHASED POWER EXPENSE

							Total Company	Texas	
1	KWH @ Source applicable to Fuel and Purchased Power Expenses:						632,582,504	493,545,526	
2	Texas Energy Ratio @ Source (Texas Kwh / Total Company Kwh):							0.7802073609	
	Applicable Fuel & Purchased Power Expenses:								
	Fuel	Gas	Oil	Nuclear	Purchased Power	Other	Total	Texas	
3	Palo Verde	$0	$0	$ 3,086,972			$3,086,972	$2,408,478	
4	Rio Grande	1,315,542	0	0			1,315,542	1,026,396	
5	Newman	5,401,245	0	0			5,401,245	4,214,090	
6	Copper	453,727	0	0			453,727	354,001	
7	Montana	3,348,433	0	0			3,348,433	2,612,472	
8	NOx Emissions	0	0	0			0	0	
9	Environmental Consumables	0	0	0		84,648	84,648	84,648	
10	Fuel Expense	$10,518,948	$0	$3,086,972		$84,648	$13,690,568	$10,700,085	
	Purchased Power								
11	Energy Purchased				$ 6,103,190			$4,761,753	
12	Energy Sold				(15,908,772)			(12,412,141)	
13	Purchased Power				($9,805,582)		($9,805,582)	($7,650,388)	
14	Purchased Power - EIM								
15	Energy Purchases				$ 4,120,816			$3,215,090	
16	Energy Sold				($7,864,930)			(6,136,276)	
17	Purchased Power - EIM				($3,744,114)		($3,744,114)	($2,921,186)	
18	Directly Assigned Energy Purchased- TX				0		0	0	
19	Directly Assigned Environmental Consumables- TX				17,670		17,670	17,670	
20	PV 3 excess sales - credit to customers				($119,812)		(119,812)	(93,478)	
	Other								
21	Deferred Coal Reclamation Expense					$13,009	13,009	0	
22	Total Fuel By Type	$10,518,948	$0	$3,086,972	($13,651,838)	$97,657	$51,739		
23	Texas Fuel Expense	$8,206,960	$0	$2,408,478	($10,647,382)	$84,648	$52,704	$52,703	

III. CALCULATION OF OVER / (UNDER) RECOVERY

1	TX Allocated Fuel & Purchased Power for the Current Month								$52,703
2	Fuel & Purchased Power Exp Adj for		NOVEMBER 2023						
3			518,182,650	KWH X		$0.000000	=	$ -	
4	Fuel & Purchased Power Exp Cum Adj of Prior Balance								
5	Balancing Account Adjustment	Beginning Balance:	$ -						
5a		Less Current Month Amortization	-					$ -	
5b		Ending Balance	$ -						
6	Balancing Account								0
7	Fuel and Purchased Power Expense								$52,703

	TX Fuel Revenue								
8	Fuel Revenues Billed in	JANUARY 2024	461,691,981	KWH X		$0.015992	=	7,383,186	
9	Total Fuel Revenues:								$7,383,186
	TX Monthly Fuel Recovery								
10	Monthly Over/(Under) Recovery (L8 - L6)								$7,330,483
11	Prior Period Adjustments								0
12	Monthly Over/(Under) Recovery								$7,330,483
13	TX kWh at Meter								461,691,981
14	Current Month Fuel Adjustment Factor		461,691,981	KWH X		$0.015877	=	$7,330,483	0.015877
15	Twelve month average ending	JANUARY 2024	F&PP expense to be billed in		MARCH 2024				(0.015394)
16	Adjusted Current Month Fuel Adjustment Factor								0.000483
	TX Cumulative Fuel Recovery								
17	Cumulative Over/(Under) Recovery - Prior Month								($18,437,703)
18	Second Month Preceding Current Month Recovery								0
19	Current Month Recovery (L11)								7,330,483
20	Adjustment to Cumulative Balance								0
21	(Refund) / Surcharge								(536)
22	Current Month's Over/(Under) Recovery								($11,107,756)

NOTES:
Amounts may not add or tie to other schedules due to rounding.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			FEBRUARY 2024						
I.	**SUMMARY OF FUEL & PURCHASED POWER ADJUSTMENT FACTOR**								
1	BILLING MONTH:	APRIL 2024							
2	CURRENT MONTH:	FEBRUARY 2024							
3	TYPE OF FACTOR:	MONTHLY							
4	EFFECTIVE DATE OF FACTOR:	APRIL 2024							
5	BILLING MONTH'S SYSTEM FACTOR:	$ (0.000813)							
6	NUMBER OF MONTHS FACTOR IS	ONE							
7	TIME PERIOD USED TO CALCULATE FACTOR:	2/1-2/29/24							
8	CUMULATIVE OVER/(UNDER) COLLECTION AT END OF CURRENT MONTH:	FEBRUARY 2024							

II. FUEL AND PURCHASED POWER EXPENSE

		Total Company	Texas
1	KWH @ Source applicable to Fuel and Purchased Power Expenses:	593,123,450	472,441,719
2	Texas Energy Ratio @ Source (Texas Kwh / Total Company Kwh):		0.7965318502

Applicable Fuel & Purchased Power Expenses:

	Fuel	Gas	Oil	Nuclear	Purchased Power	Other	Total	Texas
3	Palo Verde	$0	$0	$ 3,063,511			$3,063,511	$2,440,184
4	Rio Grande	1,847,123	0	0			1,847,123	1,471,292
5	Newman	2,816,443	0	0			2,816,443	2,243,386
6	Copper	123,447	0	0			123,447	98,329
7	Montana	2,970,323	0	0			2,970,323	2,365,957
8	NOx Emissions	0	0	0			0	0
9	Environmental Consumables	0	0	0		93,476	93,476	93,476
10	Fuel Expense	$7,757,336	$0	$3,063,511		$93,476	$10,914,323	$8,712,624
	Purchased Power							
11	Energy Purchased				$ 9,393,665			$7,482,353
12	Energy Sold				(14,408,798)			(11,477,067)
13	Purchased Power				($5,015,133)		($5,015,133)	($3,994,714)
14	Purchased Power - EIM							
15	Energy Purchases				$ 1,432,014			$1,140,644
16	Energy Sold				($5,038,918)			(4,013,658)
17	Purchased Power - EIM				($3,606,904)		($3,606,904)	($2,873,014)
18	Directly Assigned Energy Purchased- TX				0		0	0
19	Directly Assigned Environmental Consumables- TX				31,919		31,919	31,919
20	PV 3 excess sales - credit to customers				(300,079)		(300,079)	(239,023)
	Other							
21	Deferred Coal Reclamation Expense					$13,009	13,009	0
22	Total Fuel By Type	$7,757,336	$0	$3,063,511	($8,890,197)	$106,485	$2,037,135	
23	Texas Fuel Expense	$6,178,965	$0	$2,440,184	($7,074,832)	$93,476	$1,637,793	$1,637,792

III. CALCULATION OF OVER / (UNDER) RECOVERY

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	TX Allocated Fuel & Purchased Power for the Current Month								$1,637,792
2	Fuel & Purchased Power Exp Adj for		DECEMBER 2023						
3			429,257,528	KWH X		$0.000000	=	$ -	
4	Fuel & Purchased Power Exp Cum Adj of Prior Balance								
5	Balancing Account Adjustment	Beginning Balance:	$ -						
5a		Less Current Month Amortization	-					$ -	
5b		Ending Balance	$ -						
6	Balancing Account								0
7	Fuel and Purchased Power Expense								$1,637,792

TX Fuel Revenue

8	Fuel Revenues Billed in	FEBRUARY 2024	441,967,213	KWH X		$0.015984	=	7,064,281	
9	Total Fuel Revenues:								$7,064,281

TX Monthly Fuel Recovery

10	Monthly Over/(Under) Recovery (L8 - L6)								$5,426,489
11	Prior Period Adjustments								0
12	Monthly Over/(Under) Recovery								$5,426,489
13	TX kWh at Meter								441,967,213
14	Current Month Fuel Adjustment Factor		441,967,213	KWH X		$0.012278	=	$5,426,489	0.012278
15	Twelve month average ending	FEBRUARY 2024	F&PP expense to be billed in		APRIL 2024				(0.011465)
16	Adjusted Current Month Fuel Adjustment Factor								0.000813

TX Cumulative Fuel Recovery

17	Cumulative Over/(Under) Recovery - Prior Month	($11,107,756)
18	Second Month Preceding Current Month Recovery	0
19	Current Month Recovery (L11)	5,426,489
20	Adjustment to Cumulative Balance	0
21	(Refund) / Surcharge	2,000
22	Current Month's Over/(Under) Recovery	($5,679,267)

NOTES:
Amounts may not add or tie to other schedules due to rounding.

EL PASO ELECTRIC COMPANY
2025 TEXAS RATE CASE FILING
TEXAS FUEL RULE SAMPLE
JANUARY 2023 - MARCH 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			MARCH 2024						
I.	**SUMMARY OF FUEL & PURCHASED POWER ADJUSTMENT FACTOR**								
1	BILLING MONTH:	MAY 2024							
2	CURRENT MONTH:	MARCH 2024							
3	TYPE OF FACTOR:	MONTHLY							
4	EFFECTIVE DATE OF FACTOR:	MAY 2024							
5	BILLING MONTH'S SYSTEM FACTOR:	$ 0.034429							
6	NUMBER OF MONTHS FACTOR IS	ONE							
7	TIME PERIOD USED TO CALCULATE FACTOR:	3/1-3/31/24							
8	CUMULATIVE OVER/(UNDER) COLLECTION AT END OF CURRENT MONTH:	MARCH 2024							

II. FUEL AND PURCHASED POWER EXPENSE

		Total Company	Texas
1	KWH @ Source applicable to Fuel and Purchased Power Expenses:	534,512,872	426,902,894
2	Texas Energy Ratio @ Source (Texas Kwh / Total Company Kwh):		0.7986765452

Applicable Fuel & Purchased Power Expenses:

	Fuel	Gas	Oil	Nuclear	Purchased Power	Other	Total	Texas
3	Palo Verde	$0	$0	$ 2,831,905			$2,831,905	$2,261,776
4	Rio Grande	852,554	0	0			852,554	680,915
5	Newman	1,338,100	0	0			1,338,100	1,068,710
6	Copper	274,280	0	0			274,280	219,061
7	Montana	1,329,183	0	0			1,329,183	1,061,588
8	NOx Emissions (A)	0	0	0			0	0
9	Environmental Consumables	0	0	0		80,059	80,059	80,059
10	Fuel Expense	$3,794,117	$0	$2,831,905		$80,059	$6,706,081	$5,372,109
	Purchased Power							
11	Energy Purchased				$ 4,092,729			$3,268,767
12	Energy Sold				(8,275,873)			(6,609,746)
13	Purchased Power				($4,183,144)		($4,183,144)	($3,340,979)
14	Purchased Power - EIM							
15	Energy Purchases				$ 1,777,031			$1,419,273
16	Energy Sold				($4,035,143)			(3,222,774)
17	Purchased Power - EIM				($2,258,111)		($2,258,111)	($1,803,501)
18	Directly Assigned Energy Purchased- TX				0		0	0
19	Directly Assigned Environmental Consumables- TX				14,724		14,724	14,724
20	PV 3 excess sales - credit to customers				0		0	0
	Other							
21	Deferred Coal Reclamation Expense					$13,009	13,009	0
22	Total Fuel By Type	$3,794,117	$0	$2,831,905	($6,426,531)	$93,068	$292,559	
23	Texas Fuel Expense	$3,030,273	$0	$2,261,776	($5,129,756)	$80,059	$242,353	$242,353

III. CALCULATION OF OVER / (UNDER) RECOVERY

1	TX Allocated Fuel & Purchased Power for the Current Month						$242,353
2	Fuel & Purchased Power Exp Adj for	JANUARY 2024					
3		461,691,981	KWH X	($0.015877)	=	$ (7,330,483)	
4	Fuel & Purchased Power Exp Cum Adj of Prior Balance					18,438,238	
5	Balancing Account Adjustment — Beginning Balance:	$ -					
5a	Less Current Month Amortization	-				$ -	
5b	Ending Balance	$ -					
6	Balancing Account						11,107,755
7	Total Fuel and Purchased Power Expense for the Current Month						$11,350,108

	TX Fuel Revenue							
8	Fuel Revenues Billed in	MARCH 2024	399,389,315 KWH X		($0.000483)	=	(192,905)	
9	Total Fuel Revenues:							($192,905)
	TX Monthly Fuel Recovery							
10	Monthly Over/(Under) Recovery (L8 - L6)							($11,543,013)
11	Prior Period Adjustments **(A)**							2,380,749
12	Monthly Over/(Under) Recovery							($9,162,264)
13	TX kWh at Meter							399,389,315
14	Current Month Fuel Adjustment Factor		399,389,315 KWH X		($0.022941)	=	($9,162,264)	(0.022941)
15	Twelve month average ending	MARCH 2024	F&PP expense to be billed in	MAY 2024				(0.011488)
16	Adjusted Current Month Fuel Adjustment Factor							(0.034429)
	TX Cumulative Fuel Recovery							
17	Cumulative Over/(Under) Recovery - Prior Month							($5,679,267)
18	Second Month Preceding Current Month Recovery							(7,330,483)
19	Current Month Recovery (L11)							(9,162,264)
20	Adjustment to Cumulative Balance							18,438,238
21	(Refund) / Surcharge							6,547
22	Current Month's Over/(Under) Recovery							($3,727,229)

NOTES:
Amounts may not add or tie to other schedules due to rounding.

(A) Represents the removal of the TX portion of Buena Vista 1 Imputed Capacity Charges from July 2023 through February 2024. BV1 imputed capacity is excluded from TX fuel calculation as it is recovered through base rates.

NOTE: FOR INFORMATION PURPOSES ONLY

March 2024 Cumulative Balance Reconciliation	
Prior Month Recovery	$5,426,489
Prior Month (Refund) / Surcharge	$2,000
Current Month Recovery	($9,162,264)
Current Month (Refund) / Surcharge	6,547
Other	
Cumulative Balance	($3,727,228)
Per Above	($3,727,229)
Variance	$1

El Paso Electric Company
Rolling 12 Month Average Calculation

Month	TX F&PP Costs	TX kWhs	$/kWh
Apr-23	(3,994,370)	461,945,008	-0.008647
May-23	5,534,293	495,861,303	0.011161
Jun-23	11,286,332	624,927,785	0.018060
Jul-23	16,295,468	805,317,973	0.020235
Aug-23	22,321,274	806,358,796	0.027682
Sep-23	22,618,566	746,419,280	0.030303
Oct-23	6,570,049	602,412,585	0.010906
Nov-23	5,538,906	518,182,650	0.010689
Dec-23	5,595,885	429,257,528	0.013036
Jan-24	52,703	461,691,981	0.000114
Feb-24	1,637,792	441,967,213	0.003706
Mar-24	242,353	399,389,315	0.000607
Rolling 12 Month Average			**0.011488**

El Paso Electric Company
KWH @ Supply Calculation
Sum Method - Texas
March 2024

Jurisdiction	KWH @ Meter	Renewable Purchase Direct Assigned KWH **(a)**	Adjusted KWH	**Q** Line Loss Factor	KWH @ Supply
Texas	399,389,315	(131,809) £	399,257,506	1.069242	426,902,894
New Mexico	116,086,489	(21,251,854) ¥	94,834,635	1.072819	101,740,398
FERC:					
Van Horn	2,015,021	0	2,015,021	1.027550	2,070,534
Dell City	3,697,188	0	3,697,188	1.027550	3,799,046
Total System	521,188,013	(21,383,663)	499,804,350		534,512,872

Q: Per final order in PUCT Docket No. 50058, EPE's 2019 Fuel Reconciliation filing, new Line Loss Factors are effective 04/2019. Composite jurisdictional factors were provided by Load Research on 4/12/21.

ALLOCATOR
TEXAS (A)/(B)= **0.7986765452**

(a) NM Direct Assigned KWH is composed of the following:

Buena Vista 1 NM	6,764,113
NMSU	4,985
Solar Road	3,770,871
Sun Edison 1	2,271,857
Sun Edison 2	2,546,765
Hatch	827,815
Buena Vista 2	5,065,448
	21,251,854 ¥

(a) TX Direct Assigned KWH is composed of the following:

Wrangler	229
Stanton	4,078
EPCC	1,311
Van Horn	2,026
TX-Com Solar 1	124,165
	131,809 £

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
1 TX FUEL AND PURCHASED POWER (F&PP) EXP	(12,921,815)	22,762,133	143,980	(3,994,370)	5,534,293	11,286,332
2 BALANCING ACCOUNT						
(a) INCREASED / (DECREASED) F&PP EXPENSE FOR THE MONTH	-	-	-	-	-	-
(b) OTHER F&PP COST ADJUSTMENT	-	-	-	-	-	-
(c) OTHER ADJUSTMENTS	-	-	-	-	-	-
(d) BALANCING ACCOUNT TOTAL	-	-	-	-	-	-
3 (a) APPLICABLE F&PP EXPENSE BEFORE ADJUSTMENT (ITEMS 1 + 2(d))	(12,921,815)	22,762,133	143,980	(3,994,370)	5,534,293	11,286,332
(b) ADJUSTMENT	-	-	-	-	-	-
(c) APPLICABLE FUEL AND PURCHASED POWER EXPENSE	$ (12,921,815)	$ 22,762,133	$ 143,980	$ (3,994,370)	$ 5,534,293	$ 11,286,332
4 APPLICABLE KWH SALES						
(a) TOTAL ENERGY BILLED CURRENT MONTH	489,335,300	447,587,258	437,409,333	461,945,008	495,861,303	624,927,785
5 FUEL REVENUES BILLED (KWH SALES X CURRENT MONTH FUEL ADJUSTMENT FACTOR)						
(a) FUEL REVENUES BILLED CURRENT MONTH	$ 20,860,961	$ 7,275,306	$ 6,945,282	$ 6,676,158	$ 7,926,802	$ 9,994,375
6 (INCREASED) OR DECREASED F&PP EXPENSE						
(a) (INCREASE) / DECREASE F&PP EXPENSE (ITEM 5 (a) - 3 (c))	33,782,776	(15,486,827)	6,801,302	10,670,528	2,392,509	(1,291,957)
(b) PRIOR PERIOD ADJUSTMENTS	-	-	-	-	-	-
(c) TOTAL OVER / (UNDER) RECOVERY	$ 33,782,776	$ (15,486,827)	$ 6,801,302	$ 10,670,528	$ 2,392,509	$ (1,291,957)
7 F&PP COST ADJUSTMENT FACTOR - TO (INCREASE) / DECREASE BILLS						
(a) CURRENT MONTH FUEL ADJUSTMENT FACTOR (ITEM 6 (c) / ITEM 4 (a))	0.069038	(0.034601)	0.015549	0.023099	0.004825	(0.002067)
(b) CURRENT MONTH ACTUAL FUEL EXPENSE 12-MONTH AVERAGE ENDING CURRENT MONTH (EFFECTIVE JAN-24)						
(c) ADJUSTED CURRENT MONTH FUEL ADJUSTMENT FACTOR	0.069038	(0.034601)	0.015549	0.023099	0.004825	(0.002067)
8 CUMULATIVE BALANCE OF OVER/(UNDER)						
(a) PRIOR MONTH'S OVER/(UNDER) RECOVERY BALANCE	9,437,259	45,624,528	32,345,959	41,265,569	51,887,832	54,287,938
(b) OVER/(UNDER) RECOVERY CURRENT MONTH (ITEM 6 (c))	33,782,776	(15,486,827)	6,801,302	10,670,528	2,392,509	(1,291,957)
(c) SECOND PRECEDING MONTH RECOVERY (ITEM 2 (a) or 2 MO PRIOR ITEM 8 (b))						
(d) (REFUND) / SURCHARGE	2,404,493	2,208,258	2,118,308	(48,265)	7,597	(11,803,046)
(e) ADJUSTMENTS TO CUMULATIVE BALANCE	-	-	-	-	-	-
(f) CUMULATIVE OVER / (UNDER) RECOVERY BALANCE	$ 45,624,528	$ 32,345,959	$ 41,265,569	$ 51,887,832	$ 54,287,938	$ 41,192,935
9 CURRENT MONTH F&PP FACTOR FOR USE IN 12-MONTH AVERAGE FACTOR ((ITEM 1 / ITEM 4 (a)) *	0.026407	(0.050855)	(0.000329)	0.008647	(0.011161)	(0.018060)

Amounts may not add or tie to other schedules due to rounding.

		Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24
1	TX FUEL AND PURCHASED POWER (F&PP) EXP	16,295,468	22,321,274	22,618,566	6,570,049	5,538,906	5,595,885	52,703
2	BALANCING ACCOUNT							
	(a) INCREASED / (DECREASED) F&PP EXPENSE FOR THE MONTH	-	-	-	-	-	-	-
	(b) OTHER F&PP COST ADJUSTMENT	-	-	-	-	-	-	-
	(c) OTHER ADJUSTMENTS	-	-	-	-	-	-	-
	(d) BALANCING ACCOUNT TOTAL	-	-	-	-	-	-	-
3	(a) APPLICABLE F&PP EXPENSE BEFORE ADJUSTMENT (ITEMS 1 + 2(d))	16,295,468	22,321,274	22,618,566	6,570,049	5,538,906	5,595,885	52,703
	(b) ADJUSTMENT	-	-	-	-	-	-	-
	(c) APPLICABLE FUEL AND PURCHASED POWER EXPENSE	$ 16,295,468	$ 22,321,274	$ 22,618,566	$ 6,570,049	$ 5,538,906	$ 5,595,885	$ 52,703
4	APPLICABLE KWH SALES							
	(a) TOTAL ENERGY BILLED CURRENT MONTH	805,317,973	806,358,796	746,419,280	602,412,585	518,182,650	429,257,528	461,691,981
5	FUEL REVENUES BILLED (KWH SALES X CURRENT MONTH FUEL ADJUSTMENT FACTOR)							
	(a) FUEL REVENUES BILLED CURRENT MONTH	$ 12,901,465	$ 12,936,476	$ 12,021,521	$ 9,647,092	$ 8,292,128	$ 6,859,379	$ 7,383,186
6	(INCREASED) OR DECREASED F&PP EXPENSE							
	(a) (INCREASE) / DECREASE F&PP EXPENSE (ITEM 5 (a) - 3 (c))	(3,394,003)	(9,384,798)	(10,597,045)	3,077,043	2,753,222	1,263,494	7,330,483
	(b) PRIOR PERIOD ADJUSTMENTS	(87,075)	-	-	-	-	-	-
	(c) TOTAL OVER / (UNDER) RECOVERY	$ (3,481,078)	$ (9,384,798)	$ (10,597,045)	$ 3,077,043	$ 2,753,222	$ 1,263,494	$ 7,330,483
7	F&PP COST ADJUSTMENT FACTOR - TO (INCREASE) / DECREASE BILLS							
	(a) CURRENT MONTH FUEL ADJUSTMENT FACTOR (ITEM 6 (c) / ITEM 4 (a))	(0.004323)	(0.011638)	(0.014197)	0.005108	0.005313	0.002943	0.015877
	(b) CURRENT MONTH ACTUAL FUEL EXPENSE 12-MONTH AVERAGE ENDING CURRENT MONTH (EFFECTIVE JAN-24)							(0.015394)
	(c) ADJUSTED CURRENT MONTH FUEL ADJUSTMENT FACTOR	(0.004323)	(0.011638)	(0.014197)	0.005108	0.005313	0.002943	0.000483
8	CUMULATIVE BALANCE OF OVER/(UNDER)							
	(a) PRIOR MONTH'S OVER/(UNDER) RECOVERY BALANCE	41,192,935	23,166,018	(3,569,759)	(25,591,217)	(22,575,735)	(19,698,443)	(18,437,702)
	(b) OVER/(UNDER) RECOVERY CURRENT MONTH (ITEM 6 (c))	(3,481,078)	(9,384,798)	(10,597,045)	3,077,043	2,753,222	1,263,494	7,330,483
	(c) SECOND PRECEDING MONTH RECOVERY (ITEM 2 (a) or 2 MO PRIOR ITEM 8 (b))							
	(d) (REFUND) / SURCHARGE	(14,545,839)	(17,350,979)	(11,424,413)	(61,561)	124,070	(2,753)	(536)
	(e) ADJUSTMENTS TO CUMULATIVE BALANCE	-	-	-	-	-	-	-
	(f) CUMULATIVE OVER / (UNDER) RECOVERY BALANCE	$ 23,166,018	$ (3,569,759)	$ (25,591,217)	$ (22,575,735)	$ (19,698,443)	$ (18,437,702)	$ (11,107,755)
9	CURRENT MONTH F&PP FACTOR FOR USE IN 12-MONTH AVERAGE FACTOR ((ITEM 1 / ITEM 4 (a)) *	(0.020235)	(0.027682)	(0.030303)	(0.010906)	(0.010689)	(0.013036)	(0.000114)

Amounts may not add or tie to other schedules due to rounding.

		Feb-24	Mar-24	Total	Source:
1	TX FUEL AND PURCHASED POWER (F&PP) EXP	1,637,792	242,353	103,683,549	FR-21-2 TEXAS FUEL EXPENSE
2	BALANCING ACCOUNT				
	(a) INCREASED / (DECREASED) F&PP EXPENSE FOR THE MONTH	-	(7,330,483)	(7,330,483)	Effective March 2024, calc = two month prior line 8 (b) * (1)
	(b) OTHER F&PP COST ADJUSTMENT	-	18,438,238	18,438,238	Effective Mar-24 includes Jan-24 beginning cumulative recovery balance = Jan-24 (refund) / surcharge = (Jan-24 ITEM 8 a) = 8 d)) * (1)
	(c) OTHER ADJUSTMENTS	-	-	-	Manual input
	(d) BALANCING ACCOUNT TOTAL	-	11,107,755	11,107,755	Calc sum
3	(a) APPLICABLE F&PP EXPENSE BEFORE ADJUSTMENT (ITEMS 1 + 2(d))	1,637,792	11,350,108	114,791,304	Calc
	(b) ADJUSTMENT	-	-	-	Manual input
	(c) APPLICABLE FUEL AND PURCHASED POWER EXPENSE	$ 1,637,792	$ 11,350,108	$ 114,791,304	Calc sum
4	APPLICABLE KWH SALES				
	(a) TOTAL ENERGY BILLED CURRENT MONTH	441,967,213	399,389,315	8,168,063,308	kWh billed to TX customers
5	FUEL REVENUES BILLED (KWH SALES X CURRENT MONTH FUEL ADJUSTMENT FACTOR)				
	(a) FUEL REVENUES BILLED CURRENT MONTH	$ 7,064,281	$ (192,905)	$ 136,591,507	FR-21-2 Fuel Revenues-Billed through Feb-24; Mar-24 = current month kWh line 4 (a) * adjusted current month fuel adjustment factor, Jan-24 line 7 (c))
6	(INCREASED) OR DECREASED F&PP EXPENSE				
	(a) (INCREASE) / DECREASE F&PP EXPENSE (ITEM 5 (a) - 3 (c))	5,426,489	(11,543,013)	21,800,203	Calc
	(b) PRIOR PERIOD ADJUSTMENTS	-	2,380,749	2,293,674	FR 21-2 Monthly Over / (Under) Recovery Adjustments
	(c) TOTAL OVER / (UNDER) RECOVERY	$ 5,426,489	$ (9,162,264)	$ 24,093,877	Calc sum
7	F&PP COST ADJUSTMENT FACTOR - TO (INCREASE) / DECREASE BILLS				
	(a) CURRENT MONTH FUEL ADJUSTMENT FACTOR (ITEM 6 (c) / ITEM 4 (a))	0.012278	(0.022941)		Calc; positive = credit to customers; negative = charge to customers
	(b) CURRENT MONTH ACTUAL FUEL EXPENSE 12-MONTH AVERAGE ENDING CURRENT MONTH (EFFECTIVE JAN-24)	(0.011465)	(0.011488)		Calc effective Jan-24 = avg of ITEM 9 for 12 months prior including current month; positive = credit to customers; negative = charge to customers
	(c) ADJUSTED CURRENT MONTH FUEL ADJUSTMENT FACTOR	0.000813	(0.034429)		Calc sum; positive = credit to customers; negative = charge to customers
8	CUMULATIVE BALANCE OF OVER/(UNDER)				
	(a) PRIOR MONTH'S OVER/(UNDER) RECOVERY BALANCE	(11,107,755)	(5,679,266)	9,437,259	FR-21-2 Cumulative Recovery - Current Period; Jan-23 balance includes (refunds) / surcharges for prior periods along with interest as of the end of Mar-22
	(b) OVER/(UNDER) RECOVERY CURRENT MONTH (ITEM 6 (c))	5,426,489	(9,162,264)	24,093,877	Calc
	(c) SECOND PRECEDING MONTH RECOVERY (ITEM 2 (a) or 2 MO PRIOR ITEM 8 (b))		(7,330,483)	(7,330,483)	Effective Mar-24 = ITEM 2 (a) = second preceding month recovery * (1) = 2 month prior ITEM 8 (b) * (1)
	(d) (REFUND) / SURCHARGE	2,000	6,547	(48,366,119)	FR 21-2 Interim (Refund) / Surcharge
	(e) ADJUSTMENTS TO CUMULATIVE BALANCE	-	18,438,238	18,438,238	Item 2 (b)
	(f) CUMULATIVE OVER / (UNDER) RECOVERY BALANCE	$ (5,679,266)	$ (3,727,228)	$ (3,727,228)	Calc
9	CURRENT MONTH F&PP FACTOR FOR USE IN 12-MONTH AVERAGE FACTOR ((ITEM 1 / ITEM 4 (a)) *	(0.003706)	(0.000607)		Calc = ((ITEM 1 / ITEM 4 (a))* (1)); positive = credit to customers; negative = charge to customers

Amounts may not add or tie to other schedules due to rounding.

DOCKET NO. 57568

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

DIRECT TESTIMONY

OF

LORI A. GLANDER

OF

TLG SERVICES, LLC

ON BEHALF OF

EL PASO ELECTRIC COMPANY

JANUARY 2025

EXECUTIVE SUMMARY

Ms. Glander's testimony presents the most recent decommissioning cost analysis prepared by TLG Services, LLC for El Paso Electric Company, which provides the estimated costs associated with the decommissioning of the Palo Verde Generating Station Units 1, 2, and 3 beginning in the years 2045, 2046, and 2047, respectively, using the DECON (dismantling) scenario. Ms. Glander also provides decommissioning costs associated with several of the supporting facilities on the Palo Verde site, as well as on-site storage of the spent nuclear fuel.

In support of her testimony, Ms. Glander sponsors Exhibit LAG-1 – Resume of Lori A. Glander and Exhibit LAG-2 – 2023 Decommissioning Cost Study for the Palo Verde Nuclear Generating Station.

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SUBJECT PAGE

EXHIBITS

I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lori A. Glander. My business address is TLG Services, LLC, 148 New Milford Road East, Bridgewater, Connecticut 06752.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by TLG Services, LLC ("TLG"), as Vice President, Decommissioning. TLG is a wholly owned subsidiary of Entergy Nuclear, Inc. ("ENI").

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of El Paso Electric Company ("EPE" or the "Company").

Q4. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I completed my Bachelor of Science in Organizational Management from Manhattan College, Riverdale, New York, in 2004. I have been Certified by the American Board of Health Physics as a Health Physicist since 2006. I joined TLG in May of 2017. I was employed by Entergy Nuclear Operations, Indian Point Energy Center from 2001 through 2017 in the areas of Radiation Protection ("Health Physics") and Emergency Preparedness. I also previously worked for Orange County, New York ("Government") as Radiological Officer, Nuclear Energy Services ("NES")/Scientech in Danbury, Connecticut as Decommissioning Project Manager, and Cintichem, Inc. as Decommissioning Health Physics Supervisor and Radiation Safety Officer. I have over 30 years of experience in the areas of nuclear plant decommissioning and Health Physics.

Q5. WHAT IS YOUR EXPERIENCE IN NUCLEAR DECOMMISSIONING?

A. My decommissioning experience began as a Health Physics Supervisor and Radiation Safety Officer for Cintichem, Inc., at its research reactor in Tuxedo, New York, that was decommissioned in the 1990s. In that capacity, I supervised and managed various aspects of the Radiological Site Decommissioning and represented Cintichem for Nuclear Regulatory Commission ("NRC") and the State of New York ("SNY") inspections through final survey compliance and license termination. I supervised a staff of Health Physicists and Technicians who supported radiological characterization, decontamination, instrumentation, final survey design, final site release, and license termination for the reactor decommissioning project.

Following the Cintichem license termination, I was employed by NES/Scientech in Danbury, Connecticut as Project Manager, Radiological Decommissioning Services. There I worked as a consultant for several decommissioning projects and assisted in the preparation of Decommissioning Cost Estimates ("DCEs"). I left NES/Scientech to work for Entergy Nuclear, Inc. at Indian Point Energy Center, where I worked in various Radiological and Emergency Preparedness positions of increasing responsibility.

At TLG, I have been responsible for the Technical Staff, including three managers, and am actively engaged in developing engineering and planning studies for nuclear plant decommissioning. These studies evaluate the decommissioning options available and provide the licensees/owners of the facilities with both the technical and financial resource requirements associated with site remediation and facility disposition. I have been involved in approximately forty decommissioning studies since 2017. During this time, I was involved with the detailed decommissioning planning for several nuclear plant owners including Entergy (Pilgrim and Indian Point Energy Center), Duke (Crystal River), and First Energy (Davis-Besse). I have also provided written testimony for several external clients related to TLG's decommissioning work products.

Q6. HAVE YOU PREVIOUSLY FILED TESTIMONY WITH A REGULATORY AGENCY?

A. Yes. I most recently provided direct written testimony in support of the 2024 Arkansas Nuclear One (ANO) Decommissioning Cost Study on behalf of Entergy Arkansas for the Arkansas 2024 rate case, Arkansas Public Service Commission Docket No. 87-166-TF-Doc.388. I have also provided direct written testimony for the Duke Energy Fleet, River Bend, and South Texas Project (STP), in support of TLG's estimates in rate making proceedings. Additionally, I participated in-person as a panelist in a hearing before the State of New Hampshire Nuclear Decommissioning Financing Committee for Seabrook Station.

II. Purpose of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting the results of the 2023 decommissioning cost study prepared by TLG for the Palo Verde Generating Station ("Palo Verde") located in Tonopah, Arizona. My testimony summarizes the results of the update, identifies major changes from the previous estimate, and provides an overview of the decommissioning process.

Q8. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. I sponsor Exhibit LAG-2: 2023 Decommissioning Cost Study for the Palo Verde Nuclear Generating Station - TLG Document A04-1851-001 Revision 0. I am also sponsoring my resume, which is attached to my direct testimony as Exhibit LAG-1.

III. Decommissioning Study

Q9. PLEASE DESCRIBE THE DECOMMISSIONING STUDY THAT HAS BEEN PERFORMED FOR PALO VERDE GENERATING STATION.

A. TLG prepared a decommissioning cost analysis for Palo Verde under contract to Arizona Public Service Company ("APS"), the operating agent for the Palo Verde owners, in 2023.

The TLG analysis represents a site-specific cost estimate, at a specific point in time (2023), of the removal, packaging, transportation, and disposal of all radioactive material above the U.S. Nuclear Regulatory Commission ("NRC") release limits from the Palo Verde site, using the NRC-approved DECON scenario that is based upon prompt dismantling of the facility. In support of this primary objective, the estimate also includes various additional costs for engineering, project management, site security, and operations during the decommissioning program. In parallel with the decommissioning of the power station, the remaining spent fuel is removed from the three units and placed into dry storage on site. Costs for the final transfer of spent fuel have been included in this estimate.

Following termination of the operating licenses by the NRC, demolition of the physical structures of the site will be performed. Costs for these site restoration activities are included in this estimate. Site restoration activities do not include the electrical switchyard, which is assumed to remain operational in support of the regional grid.

Q10. BRIEFLY DESCRIBE PALO VERDE AND EXPLAIN THE COMPANY'S INTEREST IN THE FACILITIES.

A. Palo Verde consists of three identical pressurized water reactors that each generate approximately 1,335 MW electrical power output. The plant is located approximately 50 miles west of Phoenix, in Tonopah, Arizona. The operating licenses were issued in 1984, 1985, and 1987 for Units 1, 2, and 3, respectively. In April 2011, the NRC issued license renewals for all three Palo Verde units, extending their license expiration dates to the years 2045, 2046, and 2047 for Units 1, 2, and 3, respectively. The site has numerous support features, such as a water processing facility, settling ponds, and a dry storage facility for spent nuclear fuel. EPE has a 15.8 percent ownership interest in the Palo Verde station.

Q11. ARE THERE ANY FEDERAL REGULATIONS SPECIFICALLY APPLICABLE TO DECOMMISSIONING?

A. Yes. The NRC published the Final Rule entitled "General Requirements for Decommissioning Nuclear Facilities" in the Federal Register of June 27, 1988, (53 Fed. Reg. 24018) to establish technical and financial criteria for decommissioning licensed facilities. The regulations addressed decommissioning planning needs, timing, funding methods, and environmental review requirements with the intent of assuring that decommissioning of all licensed facilities would be accomplished in a safe and timely manner, and that adequate licensee funds would be available for this purpose. In 1996, the NRC published revisions to the Final Rule. The amended regulations clarified ambiguities and codified procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The amendments allow for greater public participation and better define the transition process from operations to decommissioning. The decommissioning cost analysis prepared for Palo Verde fully satisfies the requirements set forth in the NRC regulations.

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site. A legacy site is defined as a site having insufficient financial resources needed for decommissioning. The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details, including the decommissioning estimate for Independent Spent Fuel Storage Installation ("ISFSI") are included in this analysis. The ISFSI is a facility designed and constructed for the interim storage of spent nuclear fuel and associated radioactive materials.

Q12. WHAT IS THE DECON DECOMMISSIONING ALTERNATIVE AND WHY HAS IT BEEN APPLIED FOR PALO VERDE?

A. The DECON decommissioning alternative is the process under which radioactive material that exceeds the NRC release criteria is removed from the site promptly after shutdown. This will release the vast majority of the Palo Verde site for other uses in less time than the other NRC-approved decommissioning alternatives. The use of the DECON alternative for Palo Verde enables the use of the existing plant personnel who are already trained and familiar with the plant conditions. Many of the plant systems will remain fully functional and able to support the decommissioning process with minimal modifications or repairs.

Generally, DECON has been the preferred option for the decommissioning of shutdown units in the United States. APS has selected the DECON alternative for the 2023 study.

IV. Summary of Estimated Costs

Q13. PLEASE SUMMARIZE THE DECOMMISSIONING COSTS IDENTIFIED IN YOUR STUDY.

A. Dismantling and demolition of the three power units and all support facilities at Palo Verde is estimated to cost $3,814 million in 2023 dollars. A summary of the costs is presented in the following table.

Table 1

Summary of Palo Verde Decommissioning Costs

(Thousands of 2023 Dollars)*

	Total Cost
Unit 1	1,011,251
Unit 2	1,005,448
Unit 3	1,004,106
Independent Spent Fuel Storage Facility	506,725
Stored Steam Generators and Storage Facility	88,185
Water Reclamation Facility	12,998
Water Reclamation Supply System Pipeline & Structures	75,452
Evaporation Ponds	77,061
Make-up Water Reservoir	6,259
Stored Reactor Closure Heads & Storage Facility	9,898
ISFSI Campaign Costs	16,750
Station Total	3,814,123

*Note: May not add due to rounding; taken from Exhibit LAG-2, Decommissioning Cost Summary, page xi of xvi.

The estimate includes an overall contingency component of 19.18 percent, based upon a line-item analysis as described in the Atomic Industrial Forum/National Environmental Studies Project Report AIF/NESP-036 "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates".

Q14. WHAT WAS THE BASIS OF THE COST ESTIMATE IN THE 2023 DECOMMISSIONING STUDY?

A. The 2023 study was developed primarily using the technical database (inventory of the physical plant) from prior estimates for Palo Verde. This database was updated, as required, to include changes in the site inventory and for compatibility with the latest cost modeling software.

Decommissioning is a labor-intensive program. Accordingly, representative 2023 craft labor costs were provided by the site. Utility salaries, overhead and benefits, site operating costs, as well as corporate contributions were also provided by the site and/or APS headquarters personnel for inclusion in the cost model.

Low-level radioactive waste, for purposes of this cost analysis, was assumed to be shipped to the Energy*Solutions* disposal site in Clive, Utah, with some higher-level radioactive waste assumed to be shipped to the Waste Control Specialists ("WCS") site in Andrews County, Texas. Costs for the disposal of the radioactive waste streams generated by decommissioning were based upon then-current contracts with the associated vendors, service providers, and/or published rates/tariffs.

The spent fuel management requirements identified by APS were also incorporated into the decommissioning program and reflected APS experience in the handling and storage of spent fuel and the available information on the development of a federal waste management system for fuel from commercial nuclear generators.

Q15. WHAT IS THE NATURE OF THE CHANGES IN DECOMMISSIONING ESTIMATE OVER TIME?

A. Over time, there are three drivers that influence the decommissioning costs. The first is the general economic changes in the price of labor, cost of electricity, changes in property taxes, etc. These all tend to track with inflation as provided by the U.S. Bureau of Labor Statistics Consumer Price Index. For this driver, a nuclear power plant decommissioning is no different from any other activity in the general economy.

The second driver which influences decommissioning costs is what could be described as changes in the work scope. Examples of such changes are included in the 2023 estimate for Palo Verde. These include additional spent fuel management costs due to the application of lessons-learned from the San Onofre Nuclear Generating Station (SONGS) decommissioning, additionally, security force costs increased with added security staffing to accommodate the dry fuel storage period.

The third driver is waste disposal rates. While increases in rates for the disposal of various packages can be attributed to inflation (see the discussion below), the variations in waste disposal rates have several causes. Some drivers for these fluctuations are negotiated life-of-plant contracts; new disposal facilities; and/or revised packaging requirements.

Q16. HAS THE COST IDENTIFIED IN THIS STUDY INCREASED SINCE YOUR LAST STUDY CONDUCTED IN 2019?

A. Yes, there is an overall increase from 2019 to 2023 of approximately 29% from \$2.96 billion to \$3.81 billion. This represents an annual increase of 6.56% per year versus an annual CPI escalation rate of 4.28% per year. This shows that the total increase from 2019 to 2023 is greater when compared to the CPI rate. The cost for the decommissioning of the 3 units and common facilities, excluding the items in appendices G through N increased by approximately 15.61 or 3.69%/year which is less than CPI. The cost associated with the ISFSI (Appendix L) increased by approximately 247.1% or 36.49%/year while the cost for Appendices G through K and M increased by approximately 35.87% or 7.96%/year. The 2023 study also included one-time campaign costs related to the ISFSI (e.g. ISFSI transfer equipment, instrumentation for five ISFSI pads, installation of ISFSI shield wall, relocation of the unit 1 crane to the ISFSI) in Appendix N. The

Appendix N costs were not included prior to the current 2023 study. Table 2 provides a summary of this data.

Table 2

Cost Category	2019, $s (thousands)	2023, $s (thousands)	% Change	Annual % Change
Units 1, 2, & 3 and Common	2,612,986	3,020,805	15.6	3.69
ISFSI (Appendix L)	145,994	506,724	247.1	36.49
Appendix G – K & M	198,607	269,843	35.9	7.96
Appendix N	0	16,750	N/A	N/A
Total	2,957,587	3,814,123	29.0	6.56

Q17. WHAT CHANGED BETWEEN THE 2019 STUDY AND THE CURRENT 2023 STUDY?

A. The following is a description of the main factors responsible for the increases in the 2023 study:

As seen in Table 2, the costs for Units 1, 2, 3 & Common increased slightly less than the CPI rate.

The ISFSI (Appendix L) costs increased significantly at 247.1%. This increase in "ISFSI" costs from 2019 to 2023 is due to the addition of costs not previously included in the study. These items consist of the following costs: Spent fuel canisters & overpacks (~$60.7M); Transfer of fuel from the spent fuel pool to ISFSI (~$9.3M); Maintenance of the ISFSI during the Dry Fuel Storage period (i.e. Insurance, Property Taxes, ISFSI Licensing Fees, ISFSI Operating Costs, Oversight Staff, and Security) (~$315M); Property taxes during the ISFSI License Termination period (~$517k); Property taxes and energy costs during the ISFSI Demolition and Site Restoration period (~$197k).

The cost for Appendix G – K & M increased by 36% over the time period. The main reason for the increase in Appendix G – K & M is the increased cost for large component burial waste rates, this was offset by a 4.8% decrease in laborer rates and a less than 1% increase in craft labor rate along with only an 11% increase in the Health Physics (HP) Technician rate over the same time period. Further explanation is provided below.

In addition to the changes to established cost categories, Appendix N represents a new category that captures costs for one-time ISFSI costs. These costs were summarized in a separate category and include ISFSI transfer equipment, instrumentation for five ISFSI pads, installation of ISFSI shield wall, and the relocation of the Unit 1 crane to the ISFSI.

<u>Waste Disposal</u>

There was a $174.1 million or a 57% increase in the overall cost reported for "LLRW Disposal" from 2019 to 2023. In 2023, the Large Component Class A waste disposal rate increased by 237% to $280.57/CF. While the 2019 rate was $83.16/CF, it's important to note that the 2016 disposal rate was $325/CF for the same Large Component Class A category. The cost for Class A containerized waste increased by 31% and the Class A bulk disposal rate increased by 99%. Dry Active Waste (DAW) disposal rate increased by 109%. Class A Resin increased by 67%. Table 3 provides a summary of this data.

WCS Andrews TX price structure was applied to the majority of the waste streams (Containerized Class A wastes, Large Components, Class B/C Resins and Irradiated Hardware). *EnergySolutions* Clive UT price structure was applied to concrete, DAW wastes, and Class A resins. The NRC publishes costs for nuclear low level wastes on a semi-annual basis in NUREG-1307.[2]

Table 3

Waste Category	2019		2023	
Large Component Containerized Class A Rate	83.16	$/ CF	280.57[1]	$/ CF
Class A containerized	201.60	$/ CF	264.44	$/ CF
Bulk Class A	58.85	$/ CF	117.16	$/ CF
Class A Resin	3.50	$ / LB	5.83	$ / LB
DAW Processing	1.48	$ / LB	3.09	$ / LB

[1] Average of Steam Generator, Pressurizer, and Reactor Coolant Pump rates

(2) NUREG-1307, Rev. 19, February 2023 "Report on Waste Burial Charges: Changes in Decommissioning Waste Disposal Costs at Low-Level Waste Burial Facilities"

Utility Staff

There was a $170.6 million or a 23% increase in the cost reported for "Utility Staff" from 2019 and 2023. The average increase in staff base salaries from 2019 to 2023 was 11.9%. The overhead rate applied to the base salaries increased from 47.8% to 49.9%. The non-labor overhead increased by 26.8%. In addition to these changes, the major contributor to the $170.6M increase is due to the inclusion of Utility Staff costs during the dry fuel storage period (~$64.5M) as noted in the previous Appendix L discussion. The changes in average hourly rates are provided in Table 4.

Security

There was a $163.3 million or a 72% increase in the cost reported for "Security" from 2019 to 2023. In 2023, the average security staff salary increased 0.6% (Table 4) from 2019. In addition to this change, the major contributor to the $163.3M increase is due to the inclusion of Security costs during the dry fuel storage period (~$161.1M) as referenced in the discussion of Appendix L above. The changes in average hourly rates are provided in Table 4.

Table 4

Labor Category	Hourly Cost, $		Change
	2019	2023	%
Utility Staff	77.24	86.45	11.9
Security Staff	55.55	55.86	0.6
Engineering Services	75.97	84.69	11.5
Security Officer	48.41	53.74	11.0

Property Tax

There was a $45.8 million or a 397% increase in the cost reported for "Property Taxes" from 2019 to 2023. Both the 2019 and 2023 estimates assumed $1M in property taxes per year. The reason for the increase is due to the inclusion of Property Taxes during dry fuel storage, ISFSI License Termination, ISFSI Demolition and Site Restoration periods (~$45.8M) as referenced in the discussion of Appendix L above.

Removal

There was a $53.7 million or a 12% increase in the overall cost reported for "Removal" from 2019 to 2023. This increase is consistent with the increase in the equipment and materials costs. The change in the aggregate craft labor rate was negligible. The HP technician rate increased by 11.0%. Health physics supplies, heavy equipment rental, small tool allowance, and pipe cutting equipment also contribute to the increase. Table 5 provides a summary of the craft labor rate changes.

Table 5

	Hourly Cost (dollars)		Change
Craft Labor Category	2019	2023	%
Laborer	$20.77	$19.78	-4.8%
Craftsman	$40.68	$40.87	0.5%
Foreman	$43.95	$43.95	0.0%
General Foreman	$47.02	$47.02	0.0%
HP Tech	$60.55	$67.20	11.0%

Appendices G–K & M

Appendix G Steam Generator Storage Facility and Appendix M Stored RX Closure Heads increased primarily due to the large component burial waste rates used in the 2023 estimate. Appendix I Water Reclamation Supply increased due to backfill costs, primarily due to higher equipment costs, with increased materials and labor rates contributing as well. Table 6 provides a summary of this data.

The schedule of annual expenditures in Appendix B for costs associated with Appendices H, I, and K also show a significant change in years of expenditure. This is due to changing the timeframe for decommissioning these structures to support ensuring there is a makeup water source for the spent fuel pools. In the 2019 estimate, these expenditures were spread across the years, 2047-2055. In the 2023 estimate, the timeframe has been compressed to the years 2053-2056, with the majority of expenditures occurring in 2054 and 2055.

Table 6

Appendix	2019	2023	Change	% Change
APPENDIX G: Steam Generator Storage Facility	$57,074	$88,185	$31,110	54.5
APPENDIX H: Water Reclamation Facility	$11,027	$12,988	$1,961	17.8
APPENDIX I: Water Reclamation Supply	$54,024	$75,452	$21,428	39.7
APPENDIX J: Evaporation Ponds	$66,009	$77,061	$11,053	16.7
APPENDIX K: Makeup Water Reservoir	$5,069	$6,259	$1,191	23.5
APPENDIX M: Stored RX Closure Heads	$5,405	$9,898	$4,493	83.1

Q18. IS IT APPROPRIATE TO CONSIDER THE 2023 DECOMMISSIONING COST STUDY IN EPE'S DETERMINATION OF DECOMMISSIONING FUNDING IN THIS CASE?

A. Yes. The 2023 estimate, Rev 0, for Palo Verde represents the best available cost estimate for the decommissioning of the Palo Verde facility.

V. Methodology for Estimating Decommissioning and Dismantling Costs

Q19. WHAT METHODOLOGY WAS USED TO PREPARE THE COST ESTIMATE?

A. The methodology used to develop the cost estimate followed the basic approach presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," and the DOE's "Decommissioning Handbook." The estimating techniques have been augmented to reflect experience gained in decommissioning at several of the large commercial units over the past 30 years.

The two references describe a unit cost factor method for estimating decommissioning activity costs to standardize the estimating calculations. Unit cost factors for activities such as concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) were developed from the labor information provided by the site. Material information was taken in large part from RSMeans, "Building Construction Cost Data 2023." The activity-dependent costs for decontamination, removal, packaging, shipping, and burial were estimated using the item quantity (cubic yards, tons, inches, etc.) originally developed from Palo Verde plant drawings and inventory documents. The activity duration critical path derived from such key activities, e.g., the disposition of the nuclear steam supply system ("NSSS"),[1] was used to determine the total decommissioning program schedule.

The program schedule is used to determine the period-dependent costs such as program management, administration, field engineering, equipment rental, quality assurance, and security. The salary and hourly rates are typical for personnel associated with period-dependent costs.

The costs for conventional demolition of non-radioactive structures, materials, backfill, landscaping, and equipment rental were obtained from conventional demolition references.

In addition, collateral costs were included for heavy equipment rental or purchase, safety equipment and supplies, energy costs, permits, taxes, and insurance.

The activity-dependent, period-dependent, and collateral costs were added to develop the total decommissioning costs. An overall contingency was added to allow for the effects of unpredictable program problems.

One of the primary objectives of every decommissioning program is to protect public health and safety. The cost estimates for the Palo Verde decommissioning activities include the necessary planning, engineering, and implementation to provide this protection to the public.

Q20. HAS THE NRC APPROVED SITE-SPECIFIC COST ESTIMATES UTILIZING THE TLG COST ESTIMATING METHODOLOGY?

[1] The NSSS is the collection of equipment, including the reactor vessel, which produces the high-pressure steam used to drive the turbines. This equipment, together with supporting cleanup systems, is where most of the highly radioactive components reside.

A. Yes. The NRC has reviewed TLG's cost estimating methodology. The NRC approved the decommissioning plan proposed by TLG for the Pathfinder Atomic Power Station. Funding provisions were based upon a site-specific estimate developed by TLG. TLG was also selected by the following utilities to prepare site-specific cost estimates for inclusion within the decommissioning plans or Post-Shutdown Decommissioning Activity Reports ("PSDAR") submitted to the NRC for the following nuclear units:

Long Island Lighting Company/Long Island Power Authority .... Shoreham
Sacramento Municipal Utility District ....Rancho Seco
Portland General Electric ....Trojan
Yankee Atomic Electric Company ....Rowe
Maine Yankee Atomic Power Company .... Maine Yankee
Pacific Gas & Electric...Humboldt Bay-3
Southern California Edison ....San Onofre-1
Consumer Power Company ....Big Rock Point
Duke Energy Florida...Crystal River Unit 3
Exelon Generation .... Oyster Creek
Entergy Nuclear Vermont Yankee... Vermont Yankee
Entergy Nuclear Pilgrim Station..Pilgrim Nuclear
Omaha Public Power District... Fort Calhoun

The NRC has also approved preliminary cost studies for nuclear units prepared by TLG, including Indian Point, Cooper, and Perry. These studies were submitted by their owners as part of the financial planning required five years prior to a scheduled cessation of operations.

Q21. WHAT ARE THE FINANCIAL COMPONENTS OF THE TLG COST MODEL?

A. The cost model considers three financial components. The first is the base cost estimate, calculated using the site-specific inventory, and labor, materials costs, equipment rental costs, radioactive waste disposal costs, and other costs consistent with the current site operations at Palo Verde.

The second financial component is the contingency values applied against each of the line items in the estimate; this is discussed later in my testimony.

A third component, financial risk, is discussed in the cost estimate report, but is not applied in the cost estimate. As discussed in the report, financial risk is addressed by performing frequent updates to the estimate to account for such changes as regulatory revisions, industry experience, changes in the availability of radioactive waste disposal facilities, and revised DOE performance schedules for pick-up of spent fuel from the site.

Q22. HOW IS THE CONTINGENCY CALCULATED?

A. The purpose of the contingency is to allow for the costs of high probability program problems occurring in the field where the frequency, duration, and severity of such problems cannot be predicted accurately and have not been included in the basic estimate. The Association for the Advancement of Cost Engineering, International ("AACEI") (in their Cost Engineers' Notebook) defines contingency as follows:

> Contingency - specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events, which will increase costs, are likely to occur.

Past decommissioning experience has shown that unforeseeable elements of cost are likely to occur in the field and may have a cumulative effect. In the AIF/NESP-036 Guidelines Study, TLG examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, shipping, and burial) with respect to reasons for contingency. Individual activity contingencies ranged from 10 percent to 75 percent of the related base cost, depending on the degree of difficulty judged to be appropriate from our actual decommissioning experience. The overall contingency, when applied to the appropriate components of all three generating units, and other site support features of the Palo Verde estimate, on a line-item basis, results in an average of approximately 19.2 percent.

Q23. IS IT FAIR TO VIEW CONTINGENCY AS A "SAFETY FACTOR" OR CUSHION AGAINST FUTURE PRICE INCREASES?

A. No. There is a general misconception on the use and role of contingency within decommissioning estimates, sometimes incorrectly viewed as a "safety factor." Safety factors provide additional security and address situations that may never occur. Contingency dollars are expected to be fully expended throughout the program. They also provide assurance that sufficient funding is available to accomplish the intended tasks. An estimate without contingency, or from which contingency has been removed or reduced, can disrupt the orderly progression of events and jeopardize a successful conclusion to the decommissioning process. Contingency, as used in these estimates, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the unit. Thus, the contingency is expected to be spent; however, since contingency dollars are intended to address complexities in the performance of the field decontamination and dismantling activities, it is difficult to identify today those activities most likely to be affected in the future.

Q24. DOES THE ESTIMATED COST INCLUDE THE PERMANENT DISPOSAL OF SPENT NUCLEAR FUEL?

A. No. It is important to note that, although decommissioning of a site cannot be complete without the removal of all spent fuel, the final disposition of spent nuclear fuel is outside the scope of decommissioning. In accordance with the Nuclear Waste Policy Act, the DOE is required to enter into contracts with owners and/or generators of spent fuel, pursuant to which the DOE is contractually responsible for final disposition of spent fuel as high-level nuclear waste. Additionally, because there is no burial alternative for a select quantity of highly radioactive non-fuel waste generated near the reactor core, the DOE is also responsible for this radioactive material that is termed Greater than Class C (GTCC). Unlike fuel, the DOE has not collected any disposal costs for the GTCC waste from licensees to-date; therefore, an allowance is included in the 2023 estimate.

In summary, the cost of disposal of spent fuel is accounted for separately and is specifically excluded from the decommissioning cost estimates.

VI. Decommissioning Processes

Q25. WHAT IS THE PROCESS OF DECOMMISSIONING A NUCLEAR POWER REACTOR USING THE DECON ALTERNATIVE?

A. The conceptual approach that the NRC has identified in its amended regulations is to divide decommissioning into three phases. The initial phase commences with the effective date of permanent cessation of operations and involves the transition of both plant and licensee from reactor operations, i.e., power production to facility de-activation and closure. Phases II and III pertain to the activities involved in reactor decommissioning and license termination.

TLG's estimate for the Palo Verde site uses the DECON decommissioning method. This estimate addresses Phase I activities in Period 1. Phases II and III activities are included in Period 2. Period 3 and Post-Period 3 are added for site restoration and long-term spent fuel management; while these activities are outside the scope of the NRC decommissioning requirements, they are necessary activities to bring the Palo Verde Site to closure.

A. Period 1 – Planning and Engineering

This period begins upon shutdown of the facility and involves site preparations to initiate decommissioning. The reactor would be defueled with the fuel placed in the spent fuel pool until it is cooled sufficiently to be transferred to DOE or an alternative storage facility. Notification is provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessel; the licensee would then be prohibited from reactor operation. As noted earlier, transportation and disposal of spent fuel at a DOE facility is not considered part of decommissioning and no costs associated with these activities are included in the decommissioning estimates. (These expenses have been funded by the owner throughout the plant's operating life, payable to DOE for future rendering of these services.) However, the impact on the decommissioning schedule due to the presence of the spent fuel on site has been addressed in the study through the schedule. Wastes remaining from plant operations would be removed from the site and all systems nonessential to decommissioning would be isolated and drained.

Within two years of notification to cease reactor operations, the licensee is required to provide a Post-Shutdown Decommissioning Activities Report ("PSDAR"). This report would provide a description of the licensee's planned decommissioning activities, a corresponding schedule and an estimate of expected costs. The PSDAR would also address whether environmental impacts associated with the proposed decommissioning scenario have already been considered in a previously prepared environmental statement(s). Ninety days following the NRC's receipt of the PSDAR, the licensee can initiate certain decommissioning activities without specific NRC approval under a modified 10 C.F.R. § 50.59 review process. The rule permits the licensee to expend up to 3 percent of the generic decommissioning cost for planning, with an additional 20 percent available following the 90-day waiting period and certification of permanent defueling. Remaining funds would be available to the licensee with submittal of a detailed, site-specific cost estimate.

B. Period 2 - Decommissioning Operations

This period commences once the PSDAR has been submitted to the NRC for review and with the mobilization of the decontamination and dismantling workforce. This phase addresses the removal of radioactivity from the site and concludes with termination of the NRC's operating license. Activities include selective decontamination of contaminated systems, e.g., using aggressive chemical solvents to dissolve corrosion films holding radionuclides, thereby reducing radiation levels.

While effective, the on-site decontamination processes are not expected to reduce residual radioactivity to the levels necessary to release the material as clean scrap. Therefore, all contaminated components will have to be removed for controlled burial. However, decontamination will reduce personnel exposure and will permit workers to operate in the immediate vicinity of most components, cutting and removing them for controlled disposition at a low-level radioactive waste burial facility.

Contaminated piping to and from major components will be cut and removed. Selected major components such as the reactor coolant pumps, steam generators, pressurizers, and other large components will then be removed intact and sealed so that they may be transported off-site. Smaller components, such as sampling system pumps, filters, filter housings, strainers, etc., will be loaded into containers and shipped for controlled disposal.

The reactor vessel and its internals will be segmented and remotely loaded into steel liners for transport to the burial facility in heavily shielded shipping casks. The reactor vessel and internals will have sufficiently high radiation levels to require all cutting to be done underwater or behind heavy shields, using cutting tools operated by remote control to reduce radiation exposure to the workers.

Concrete immediately surrounding the reactor vessel is expected to be radioactive and will be removed by controlled blasting. This blasting process is well developed, safe, and is the most cost-effective way to remove the heavily-reinforced concrete from the structure.

Some surfaces of sections of interior floors within areas of the Containment and other buildings in the power block are expected to be contaminated from exposure to contaminated air/water as a result of plant operations. This contamination will be removed by scarification (surface removal) so that the remaining surfaces will be cleaned to release levels and will not require disposal as Class A radioactive waste.

Contaminated process equipment, pipe hangers, supports, and electrical components will be removed and routed for controlled disposal.

Finally, an extensive radiation survey will be performed to ensure all radioactive materials above the levels specified by the NRC have been removed from the site. With NRC confirmation, the NRC license for most of the site (excluding the ISFSI) will be terminated.

C. Period 3 – Site Restoration

This period begins once license termination activities have concluded and involves the demolition of all remaining structures, typically to a depth of three feet below grade. Clean concrete rubble would be used on-site for fill and additional soil would be used to cover each subgrade structure. Excess rubble is trucked off-site for disposal.

D. Post Period 3 – Spent Fuel Storage

The ISFSI will continue to operate under a Part 50 license following the transfer of the spent fuel inventory from the Fuel Building. Transfer of spent fuel to a DOE or interim facility will be exclusively from the ISFSI once the fuel pools have been emptied and the structures released for decommissioning. Palo Verde will continue shipping spent fuel canisters to DOE through the year 2097.

At the conclusion of the spent fuel transfer process, the ISFSI will be decommissioned. TLG's estimate includes the cost to decommission the ISFSI. In the ISFSI, the spent fuel assemblies are contained within stainless steel canisters. On the ISFSI pad, these canisters are housed within reinforced concrete and steel shield cylinders known as overpacks. The canisters are assumed to be removed, shipped, and disposed of by the DOE. The steel overpack liners are assumed to have some level of neutron-induced activation as a result of the long-term storage of the fuel, i.e., to levels exceeding free-release limits. As an allowance, seven overpacks per unit (site total of 21) are assumed to require remediation, equivalent to the number of overpacks required to accommodate the final core offloads at Palo Verde (241 assemblies per unit for a site total of 723 assemblies). The cost of the disposition of this material, as well as the demolition of the ISFSI facility, is included in the estimate. The NRC will terminate the remaining license if it determines that site remediation has been performed in accordance with a license termination plan and the terminal radiation survey and associated documentation demonstrate that the facility meets the release criteria. Once the requirements are satisfied, the NRC can terminate the remaining license for the ISFSI.

The remaining reinforced concrete dry storage modules are then demolished, the concrete storage pad is removed, and the area graded and landscaped to conform to the surrounding environment.

Q26. HOW DOES THE PRESENCE OF SPENT FUEL ON SITE AFTER PLANT SHUTDOWN AFFECT THE DECOMMISSIONING PROCESSES?

A. Although the study does not address the transport or disposal of spent fuel from the Palo Verde site, it does consider the constraint that the presence of spent fuel on the site can impose on other decommissioning activities. In particular, the decommissioning scheduling developed in support of the last four cycles of cost updates for the Palo Verde estimates incorporates an APS request for a six-year minimum cooling prerequisite for off-loading the fuel from the storage pools. As such, these spent fuel management activities will necessarily delay the final release of the power blocks for alternative/unrestricted use. This delay is reflected in the increased cost of the period-dependent activities. To the extent possible, the decommissioning estimates were structured around the spent fuel areas of the units and their availability for decontamination, such that delays in decommissioning other portions of the facility could be minimized. Decommissioning would proceed on the surrounding facilities and non-essential systems during the approximately six-year pool off-load period. The operating licenses can then be amended with the remaining fuel placed in dry storage.

Some small portion of the existing Palo Verde site will continue to be licensed by the NRC under the existing Part 50 license for the ISFSI. The endpoint of this storage period is estimated to be in 2097. Following this, the ISFSI will be decommissioned, the license terminated, and the concrete storage casks and pads crushed and removed.

Q27. DOES THE PROCESS OF DECOMMISSIONING EXTEND BEYOND REMOVAL OF CONTAMINATED AND ACTIVATED MATERIAL FROM THE SITE?

A. Yes. There are additional activities beyond the removal of contaminated material that will be undertaken in the process of releasing the site for alternative use. This work includes costs for the remaining dismantling and grading operations and is generally referred to as site restoration.

Q28. PLEASE DESCRIBE THE SITE RESTORATION ACTIVITIES.

A. These activities begin once license termination activities have concluded and involve the demolition of all remaining structures, typically to a depth of three feet below grade. Clean concrete rubble generated from the demolition of the Containment, Auxiliary, Fuel, Radwaste, and Turbine Buildings, etc., would be used on-site for fill and additional soil would be used to cover each subgrade structure. Excess rubble is trucked off-site for disposal. Either any below grade structures will be removed, or voids below grade, such as the 31-mile buried water line from Phoenix to the Water Reclamation Facility, will be filled with sand or concrete. The object is to prevent any future surface subsidence.

Once the below grade features of the site have been addressed, the surface of the site will be graded to conform to the surrounding environs. The evaporation and makeup water reservoir walls will be breached to prevent retaining water. At this point, the site is available for reuse, except for the footprint of the ISFSI.

Q29. WHY WERE THE REMAINING STRUCTURES ON SITE ASSUMED TO BE DISMANTLED?

A. Efficient removal of the contaminated materials and verification that the radionuclide concentrations are below the stringent NRC limits will require substantial damage to many of the structures. Blasting, coring, drilling, scarification (surface removal), and the other decontamination work will damage power block structures including the Containment, Radwaste, Auxiliary, and Fuel Buildings. Verifying that subsurface radionuclide concentrations meet NRC site release requirements may require removal of grade slabs and lower floors, potentially weakening footings and structural supports.

It is also important to remember that the Palo Verde structures were custom designed and built to support a specific nuclear unit design that went into service in the 1980s. They would most likely be an impediment rather than a benefit to any potential future plant, if one were ever to be constructed at the site. Moreover, the facility's infrastructure degrades without continual maintenance. Unless the site is redeveloped shortly after release of its NRC license, the value in reusing plant facilities quickly diminishes.

As demonstrated by U.S. experience, dismantling is clearly the most appropriate and cost-effective option and should serve as the foundation for the decommissioning cost estimates. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed.

Q30. WHAT ASSURANCE IS THERE THAT THE ESTIMATED COST FOR DECOMMISSIONING WILL REFLECT FUTURE DEVELOPMENTS AND INCREASES OR DECREASES IN COSTS?

A. The cost estimate prepared for Palo Verde is based on present technology, the current information available on decommissioning costs, and on existing federal regulations. No provision is made to include future costs or savings due to the uncertainties in improvements in technology, major regulatory changes, inflation factors, etc. It should be noted that the contingency, as used in the estimates, only covers uncertainties within the decommissioning schedule timeframe.

VII. Recommendations

Q31. IS IT NECESSARY TO SELECT A SPECIFIC DECOMMISSIONING METHOD AT THIS TIME?

A. No. The actual method or combination of methods selected to decommission Palo Verde should be based on a detailed economic, engineering, and environmental evaluation of the alternatives considering the site and surroundings at the time of decommissioning and reflecting the latest experience in the decommissioning of similar nuclear power facilities. The owners of Palo Verde will make such evaluations near the time of final shutdown of the units.

Q32. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that, for planning purposes, the decommissioning cost funding be based upon removal of Palo Verde using the DECON alternative. This alternative provides the most reasonable means for amending/terminating the license for the site in the shortest possible time. Furthermore, this alternative avoids the long-term costs and commitments associated with the maintenance, surveillance and security requirements of the conventional delayed dismantling alternatives.

The DECON alternative also allows use of the plant's knowledgeable operating staff, a valuable asset to a well-managed, efficient decommissioning program. Equipment needed to support decommissioning operations such as cranes, ventilation systems, and radwaste processing equipment would be fully operational. In addition, the site would be available for other use in the near term, with the exception of the area immediately surrounding the plant's fuel storage facility.

VIII. Conclusion

Q33. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In 2023, TLG performed site-specific cost estimates for the decommissioning of Palo Verde. The total estimated cost for the decommissioning in 2023 dollars was $3,814 million. The study shows an increase of approximately $856 million dollars, or 29 percent, from the 2019 estimate. These amounts include costs to remove all radioactive materials from the site which exceed the release criteria, terminate the NRC operating licenses, remove all structures above the three foot below grade elevation and backfill all below grade voids to the surface elevation, transfer all spent fuel from all three Fuel Buildings to the on-site ISFSI, operate this ISFSI until 2097 (excluding ISFSI security and operating staff and ISFSI operating expenses, which are assumed to be recovered from the DOE and therefore not included), and decommission the ISFSI following removal of all spent fuel and GTCC material by the DOE, currently estimated to occur in the year 2098.

Q34. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

LORI A. GLANDER, CHP

Vice President, Nuclear Decommissioning Services

Profile

Accomplished executive leader with over 30 years of experience in the nuclear power industry. Specializing in nuclear decommissioning, radiation protection, and health physics. As the Vice President of Nuclear Decommissioning Services at TLG Services, LLC, Ms. Glander brings a wealth of technical expertise, project management skills, and regulatory knowledge to oversee the company's Engineering and Technical teams. With a proven track record of success in various leadership roles at Entergy's Indian Point Energy Center and hands-on experience in nuclear decommissioning projects, her focus is to continuously hone the company's performance and industry expertise, delivering consistently exceptional results to clients. Practical Certified Heath Physicist.

Education

Manhattan College
Riverdale, NY
B.S., Organizational Management

Certifications

American Academy of Health Physics
Certified Health Physicist

Organizations

Nuclear Energy Institute (NEI)

- *NEI Decommissioning Working Group*
- *NEI Decommissioning Radiation Protection Working Group*

Health Physics Society (HPS)
Plenary Member

Greater NY Chapter HPS
Plenary Member
Past President
Past Treasurer

American Nuclear Society
Plenary Member

Industry Experience:

Fleet decommissioning studies for major utility clients: (select list)

- Entergy Nuclear – 4 sites / 5 units
- Duke Energy – 6 sites / 11 units
- Energy Harbor – 3 sites / 4 units

New nuclear and other nuclear work:

- Conducted 3rd party assessment of ongoing decommissioning projects
- NRC ADAMS published: Entergy Pilgrim Nuclear Power Plant 2018 PSDAR (Post-Shutdown Decommissioning Activities Report)
- CVN-65: Feasibility study to assess commercial decommissioning and dismantlement of nuclear aircraft carrier
- Preliminary Decommissioning Plan and cost estimate BWRX-300
- Preliminary Decommissioning Plan and cost estimate ARC-100

International Work:

- Ontario Power Generation (OPG) Nuclear – 3 sites / 20 units
- Hydro-Quebec (HQ) – 1 site/1 unit
- New Brunswick Power – 1 site /1 unit
- Koeberg Nuclear Power Station – 1 site / 2 units

Expert Testimony:

- *Testimony Filed*: July 2023, before the Public Utility Commission of Texas for Entergy Texas, Inc. for the River Bend Station. Not called at hearing.
- *Testimony Filed*: July 2023, before the Public Utility Commission of Texas for on behalf of CPS Energy, for the South Texas Project Electric Generating Station. Not called at hearing.
- *In-person Testimony with Transcription*: September 2023, before the State of New Hampshire Nuclear Decommissioning Financing Committee. Representing NextEra Energy Seabrook, LLC for the Seabrook Station. Docket No. NDFC2023-1
- *Testimony Filed*: March 2024, before the Arkansas Public Service Commission for Entergy Arkansas, LLC for the Arkansas Nuclear One Generating Station. Hearing pending. APSC docket No. 87-166-TF

Organizations (cont'd)

Institute of Nuclear Power Operations
ACAD Qualified Instructor

Participated in Several INPO Nuclear Plant Assessments in Varied Disciplines

Professional Experience

TLG Services, LLC (an Entergy Company)
Vice President, Nuclear Decommissioning Services
May 2017 to Present

- Executive leader responsible for commercial and internal client business, fostering relationships, coordinating schedules, and ensuring product quality
- Oversees TLG's Engineering and Technical organization, providing expert guidance and direction
- Serves as an expert witness in support of TLG work products
- Quality and Technical Manager for client-contracted cost studies, ensures regulatory compliance and the production of high-quality comprehensive reports and deliverables
- Provides comprehensive industry expertise in decommissioning planning and cost estimates that fulfill requirements for regulatory compliance and funding commitments for new and evolving technologies.

Entergy / Indian Point Energy Center
September 1999 – May 2017
Various leadership positions for a commercial two-unit Pressurized Water Reactor:

- Emergency Preparedness Manager
- Supervisor, Radiation Support
- Sr. Emergency Planner
- Supervisor, ALARA/Technical Support
- Supervisor, Radiation Protection (Unit Ops)
- Supervisor, Nuclear Environmental Monitoring and Respiratory Protection
- Supervisor, Dosimetry

Scientech, NES, Inc.
Project Manager - Radiological and Decommissioning Services (1999)
Consultant for several decommissioning projects, prepared commercial Nuclear Decommissioning Cost Estimates (DCEs)

Cintichem, Inc.
1983 –1999
Various positions supporting the operation and decommissioning of a 5 MW research reactor and hot lab facility.
Oversaw operational and decommissioning Radiation Protection groups, led Interim and final survey activities for license (NRC and NYS) termination(s). Positions include:

- Radiation Safety Officer
- Health Physics Supervisor
- Health Physics Technician III, II, I
- Radiopharmaceutical Production Technician
- Administrative Assistant Indonesian Project

Document A04-1815-001, Rev. 0

2023 DECOMMISSIONING COST STUDY

for the

PALO VERDE NUCLEAR GENERATING STATION

Prepared for

Arizona Public Service Company

prepared by

TLG Services, LLC
Bridgewater, Connecticut

December 2023

APPROVALS

Project Manager	**Corey J. Munz**	12/19/2023 **Date**
Project Engineer	Mark S. Houghton **Mark S. Houghton**	12/19/23 **Date**
Project Engineer	Amara M. Falotico **Amara M. Falotico**	12/19/2023 **Date**
Technical Manager	John Carlson **John A. Carlson**	12/19/2023 **Date**

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TABLES

APPENDICES

REVISION LOG

No.	Date	Item Revised	Reason for Revision
0	12/19/2023		Original Issue

ACRONYMS / DEFINITIONS

- AIF Atomic Industrial Forum
- ALARA As-Low-As-Reasonably Achievable
- APS Arizona Public Service
- CERCLA Comprehensive Environmental Response, Compensation, and Liability Act
- CWS Circulating Water System
- DAW Dry Active Waste
- DCE Decommissioning Cost Estimate (Used interchangeably with Decommissioning Cost Study)
- DOC Decommissioning Operations Contractor
- DOE Department of Energy
- DOT Department of Transportation
- EPA Environmental Protection Agency
- FA Fuel assembly
- GTCC Greater Than Class C
- IPs Industrial Packages
- ISFSI Independent Spent Fuel Storage Installation
- kW Kilowatt
- LLRW Low Level Radioactive Waste
- LTP License Termination Plan
- LSA Low Specific Activity
- MARSSIM Multi-Agency Radiation Survey & Site Investigation Manual
- MOU Memorandum of Understanding
- MW Megawatt
- NESP National Environmental Studies Project
- NRC Nuclear Regulatory Commission
- NSSS Nuclear Steam Supply Systems
- NWPA Nuclear Waste Policy Act
- OA Operating Agent (This term may transition to Decommissioning Agent (DA) upon cessation of plant operations.)
- P&IDs Piping & Instrument Diagrams
- PERT Program Evaluation and Review Technique
- PSDAR Post-Shutdown Decommissioning Activities Report
- Palo Verde Palo Verde Nuclear Generating Station
- RPV Reactor Pressure Vessel
- SCO Surface Contaminated Object
- TEDE Total Effective Dose Equivalent
- TLG TLG Services, LLC.
- UFSAR Updated Final Safety Analysis Report

EXECUTIVE SUMMARY

This analysis, prepared for the Operating Agent (OA) of the Palo Verde Nuclear Generating Station (Palo Verde) by TLG Services, LLC. (TLG), evaluates the cost to decommission Palo Verde following the final cessation of plant operations. The total projected station cost for the DECON alternative is estimated at $3.81 billion, reported in 2023 dollars. The cost estimate includes the decommissioning of the three Palo Verde nuclear units, plus the decommissioning of the Water Reclamation Facility, the Water Reclamation Supply System Pipeline & Structures, the Evaporation Ponds, the Make-up Water Reservoirs, the Independent Spent Fuel Storage Facility (ISFSI), the Stored Steam Generators & Storage Facility (facility for storage of six retired steam generators), and the Stored Reactor Closure Heads & Storage Facility.

The major cost contributors to the overall decommissioning cost are labor, radioactive waste disposal, and other removal-related activities (e.g., engineering, support equipment, capital expenditures for spent fuel containers). The costs are based on several key assumptions, including regulatory requirements, estimating methodology, contingency requirements, low-level radioactive waste disposal availability, high-level radioactive waste disposal options, and site restoration requirements.

It should be noted that the estimating methodology was modified to align costs more evenly across Palo Verde Units 1, 2, and 3. Early planning and pre-shutdown costs for utility staff between 2040 and 2045 were allocated only to Unit 1 in previous DCEs, due to it being the first unit that shuts down. In the 2023 DCE, these costs have been allocated evenly where possible across the three units. Also, in previous DCEs, costs for dismantling the common systems and structures were allocated only to Unit 3, since it is the last unit to shut down. In the 2023 DCE, these costs have been allocated as evenly as possible across the three units.

The costs to decommission Palo Verde are evaluated for the DECON decommissioning alternative. The estimate assumes the eventual removal of all the contaminated and activated plant components and structural materials, such that the facility operator may then have unrestricted use of the site with no further requirement for an operating license.

This study provides an estimate for decommissioning Palo Verde under current requirements and is based on present-day costs and available technology. Cost summaries for the various facilities are provided at the end of this section for the major cost components. In addition, the estimate includes the costs to transfer spent fuel from the spent fuel storage pools to the DOE, and to transfer fuel from the ISFSI to the DOE. These costs are shown in Appendix L. This is consistent with the OA's assumption that most ISFSI / spent fuel related operational, maintenance and capital costs will be paid by reimbursements from the DOE. Costs for the transfer of spent fuel from the spent fuel storage pool to the ISFSI are also shown in appendix L.

The decommissioning scenario analyzed for this estimate is described in Section 2. The assumptions are presented in Section 3. A decommissioning timeline and sequence of decommissioning activities are provided in Section 4 and Appendix D. The major cost contributors are identified in Section 6, and schedules of annual expenditures provided in Appendix B and Appendix O.

Detailed activity costs for each nuclear unit are provided in Appendix C. Detailed costs for the other facilities are provided in Appendices G, H, I, J, K, L, M, and N.

DECOMMISSIONING COST SUMMARY

		Cost, 2023$ [1] (thousands)	Schedule (years)
UNIT 1 (Appendix C-1)			
PRE-SHUTDOWN			
Early Planning Prior to Shutdown		2,424	5.0
PREPARATIONS			
Post-Shutdown Transition		129,263	1.0
Decommissioning Preparations		81,706	0.5
DECOMMISSIONING			
NSSS Removal		345,963	1.9
Site Decontamination		278,051	2.6
Decontamination Following Wet Fuel		36,740	0.5
Delay Before License Termination		18,262	2.5
License Termination		29,367	0.8
SITE RESTORATION			
Site Restoration		64,454	1.9
GTCC shipping		25,020	0.04
	Subtotal	1,011,251	16.7
UNIT 2 (Appendix C-2)			
PRE-SHUTDOWN			
Early Planning Prior to Shutdown		2,424	5.0
PREPARATIONS			
Post-Shutdown Transition		97,854	0.7
Decommissioning Preparations		52,252	0.3
DECOMMISSIONING			
NSSS Removal		383,278	1.9
Site Decontamination		303,056	3.1
Decontamination Following Wet Fuel		36,622	0.5
Delay Before License Termination		11,413	1.6
License Termination		29,158	0.8
SITE RESTORATION			
Site Restoration		64,370	1.9
GTCC shipping		25,020	0.04
	Subtotal	1,005,448	15.8

[1] Columns may not add due to rounding

DECOMMISSIONING COST SUMMARY
(continued)

	Cost, 2023$ [1] (thousands)	Schedule (years)
Unit 3 (Appendix C-3)		
PRE-SHUTDOWN		
Early Planning Prior to Shutdown	2,424	5.0
PREPARATIONS		
Post-Shutdown Transition	97,854	0.7
Decommissioning Preparations	52,252	0.3
DECOMMISSIONING		
NSSS Removal	348,366	1.9
Site Decontamination	342,292	3.1
Decontamination Following Wet Fuel	42,193	0.5
License Termination	29,157	0.8
SITE RESTORATION		
Site Restoration	64,547	1.9
GTCC shipping	25,020	0.04
Subtotal	1,004,106	14.2
ISFSI (Appendices L and N)		
ISFSI Operations / Spent Fuel Transfer (Unit 1, 2, & 3 Shutdown until End of Spent Fuel Transfer to DOE	467,642	n/a
ISFSI License Termination	21,024	n/a
ISFSI Demolition and Site Restoration	15,058	n/a
ISFSI Campaign Costs	16,750	n/a
Subtotal	523,475	

[1] Columns may not add due to rounding

DECOMMISSIONING COST SUMMARY
(continued)

	Cost, 2023$ [1] (thousands)	Schedule (years)
OTHER FACILITIES		
Stored Steam Generators & Storage Facility (Appendix G)	88,185	n/a
Water Reclamation Facility (Appendix H)	12,988	n/a
Water Reclamation Supply System Pipeline & Structures (Appendix I)	75,452	n/a
Evaporation Ponds (Appendix J)	77,061	n/a
Make-up Water Reservoirs (Appendix K)	6,259	n/a
Stored Reactor Closure Heads & Storage Facility (Appendix M)	9,898	n/a
Subtotal	269,843	
STATION TOTAL	**3,814,123**	

[1] Columns may not add due to rounding

SUMMARY TABLE: LICENSE TERMINATION, SPENT FUEL MANAGEMENT AND NON-NUCLEAR COST

	License Termination		Spent Fuel Management		Site Restoration		Total Cost[1] (thousands)
Unit 1 (Appendix C-1)	915,877	(91%)	24,534	(2%)	70,840	(7%)	1,011,251
Unit 2 (Appendix C-2)	913,798	(91%)	22,495	(2%)	69,155	(7%)	1,005,448
Unit 3 (Appendix C-3)	914,246	(91%)	19,006	(2%)	70,855	(7%)	1,004,106
Independent Spent Fuel Storage Facility (Appendix L)	-	(0%)	506,724	(100%)	-	(0%)	506,724
ISFSI Campaign Costs (Appendix N)	-	(0%)	16,750	(100%)	-	(0%)	16,750
Stored Steam Generators and Storage Facility (Appendix G)	87,513	(99%)	-	(0%)	672	(1%)	88,185
Water Reclamation Facility (Appendix H)	-	(0%)	-	(0%)	12,988	(100%)	12,988
Water Reclamation Supply System Pipeline & Structures (Appendix I)	-	(0%)	-	(0%)	75,452	(100%)	75,452
Evaporation Ponds (Appendix J)	-	(0%)	-	(0%)	77,061	(100%)	77,061
Make-up Water Reservoirs (Appendix K)	-	(0%)	-	(0%)	6,259	(100%)	6,259
Stored Reactor Closure Heads & Storage Facility (Appendix M)	9,765	(99%)	-	(0%)	132	(1%)	9,898
Station Total	**2,841,199**	(75%)	**589,509**	(15%)	**383,415**	(10%)	**3,814,123**

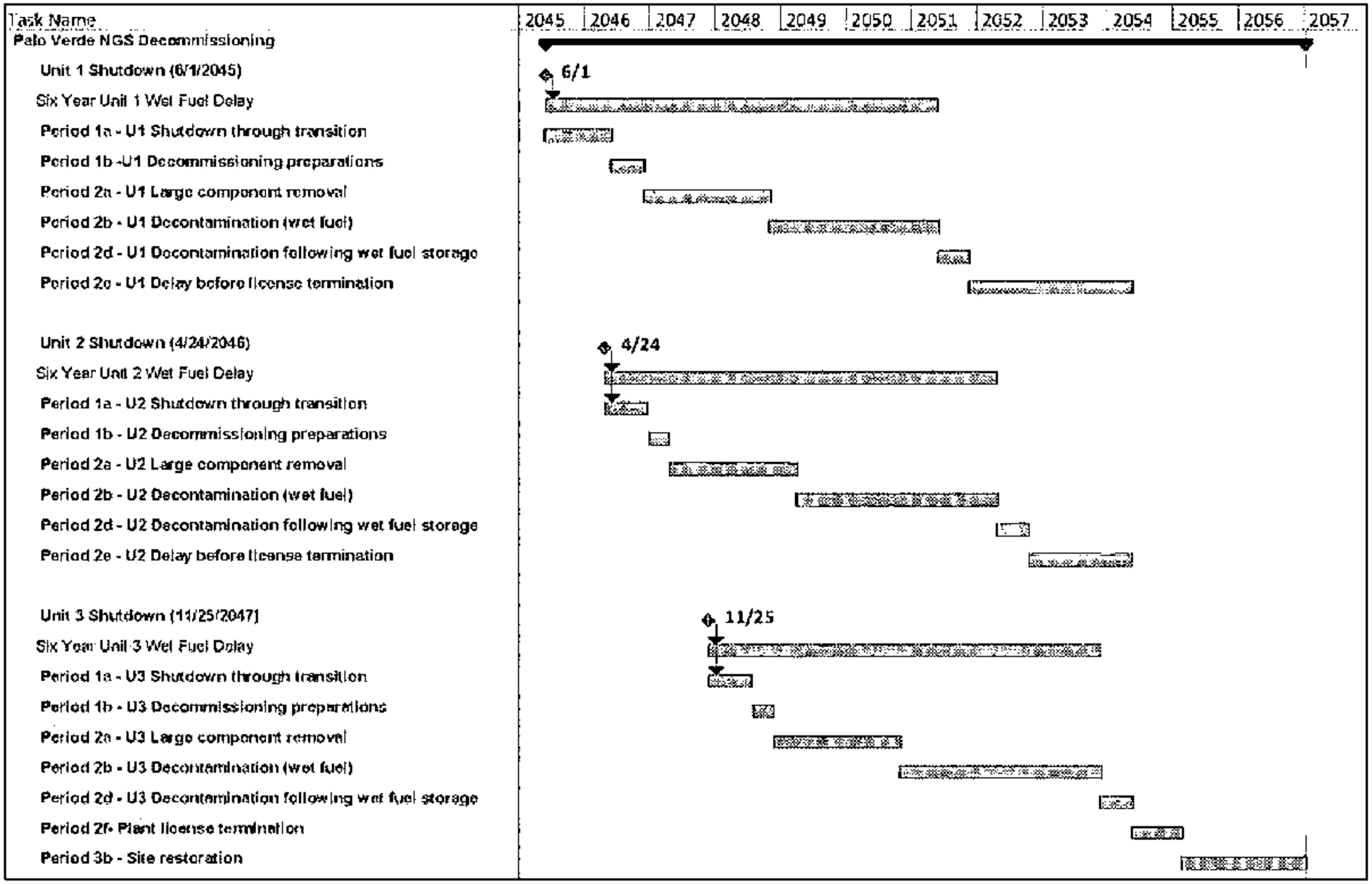
[1] Columns may not add due to rounding

2019 vs. 2023 DECOMMISSIONING COST ESTIMATE COMPARISON

	2019 Study Cost, 2019$ (thousands)	2019 Study Cost, 2023$ (thousands)	2023 Study Cost, 2023$ (thousands)	Change '19 -'23 (thousands)	% chg.
Unit 1 (Appendix C-1)					
Pre-shutdown	12,943	15,049	2,424	-12,624	-84%
Preparations	189,566	220,403	210,969	-9,434	-4%
Decommissioning	573,445	666,728	708,383	41,655	6%
Site Restoration	77,429	90,024	89,474	-550	-1%
Subtotal [1]	853,384	992,204	1,011,251	19,046	2%
Unit 2 (Appendix C-2)					
Pre-shutdown	n/a	n/a	2,424	2,424	100%
Preparations	140,454	163,301	150,106	-13,195	-8%
Decommissioning	617,636	718,107	763,527	45,419	6%
Site Restoration	77,233	89,797	89,391	-406	0%
Subtotal [1]	835,323	971,205	1,005,448	34,243	4%
Unit 3 (Appendix C-3)					
Pre-shutdown	n/a	n/a	2,424	2,424	100%
Preparations	140,271	163,089	150,106	-12,983	-8%
Decommissioning	667,827	776,463	762,008	-14,454	-2%
Site Restoration	116,181	135,081	89,568	-45,513	-34%
Subtotal [1]	924,279	1,074,632	1,004,106	-70,526	-6.6%
Subtotal Units 1, 2, & 3	2,612,986	3,038,042	3,020,805	-17,237	-1%
Independent Spent Fuel Storage Installation (Appendix L)	145,994	169,743	506,724	336,981	199%
ISFSI Campaign Costs (Appendix N)	n/a	n/a	16,750	16,750	100%
Other Facilities					
Stored Steam Generators and Storage Facility (Appendix G)	57,074	66,359	88,185	21,826	33%
Water Reclamation Facility (Appendix H)	11,027	12,821	12,988	168	1%
Water Reclamation Supply System Pipeline & Structures (Appendix I)	54,024	62,812	75,452	12,640	20%
Evaporation Ponds (Appendix J)	66,009	76,746	77,061	315	0%
Make-up Water Reservoirs (Appendix K)	5,069	5,893	6,259	366	6%
Stored Reactor Closure Heads & Storage Facility (Appendix M)	5,405	6,284	9,898	3,614	58%
Subtotal [1]	198,607	230,914	269,843	38,929	17%
Station Total [1]	**2,957,587**	**3,438,700**	**3,814,123**	375,423	**11%**

[1] *Columns may not add due to rounding*

SUMMARY LEVEL MILESTONE SCHEDULE



Note: Removal of the Water Reclamation Facility, Water Reclamation Supply System Pipeline & Structures, and Make-Up Water Reservoirs can begin after spent nuclear fuel is placed in dry storage or transferred to the DOE. Evaporation Ponds, Retired Steam Generators & Storage Facility, and the Stored Reactor Closure Heads & Storage Facility can begin any time after Unit 3 shutdown and must be completed by the end of the site license termination period for the nuclear units.

1. INTRODUCTION

This report presents estimates of the cost to decommission the Palo Verde Nuclear Generating Station (Palo Verde), for the DECON scenario described in Section 2, following a scheduled and permanent cessation of plant operations. The analysis is designed to provide the OA with sufficient information to assess its financial obligations as they pertain to the eventual decommissioning of the nuclear station. It is not a detailed engineering document, but a financial analysis prepared in advance of the detailed engineering that will be required to carry out the decommissioning.

This study incorporates two decommissioning cost reduction alternatives. These alternatives were initially evaluated as part of the 1998 decommissioning cost study, and they have been included in subsequent studies up to and including the 2023 Decommissioning Cost Estimate (DCE). Appendix A is an excerpt from the 1998 study summarizing these alternatives. Two alternatives were approved by the OA for use in conjunction with the 1998 study: On-site disposal of clean fill, and OA to act as Decommissioning Operations Contractor (DOC). As DOC, the OA will provide contract management of the decommissioning labor force, including subcontractors, as well as direct all decontamination and dismantling activities.

Isolation of the spent fuel pool was also first incorporated into the 1998 base estimate and has been retained in the subsequent studies. Section 2.2 contains a further description of this activity. A complete discussion of the assumptions used in this estimate is presented in Section 3.

1.1 OBJECTIVES OF STUDY

The objective of this study is to prepare an estimate of the cost, schedule, and waste volume generated to decommission Palo Verde, including all common and supporting facilities. The study considered the integration of the three-unit dismantling, and the dismantling of the Water Reclamation Facility, the Water Reclamation Supply System Pipeline & Structures, the Evaporation Ponds, the Make-up Water Reservoirs, the Independent Spent Fuel Storage Installation (ISFSI), the Stored Steam Generators and Storage Facility, and the Stored Reactor Closure Heads & Storage Facility. The site Transmission and Distribution System will remain in place and is not considered part of this decommissioning estimate.

Although essentially identical, the three units on the Palo Verde site were designed and constructed using the "slide along" concept, i.e., the second and third units followed along as the design of the first unit was finalized. The interconnection between the units was minimal since they were not built simultaneously. This schedule resulted in a differential in the start dates of commercial power operation, i.e., Unit No. 3 began commercial operation approximately two years after Unit No. 1. This differential is reflected in the dates for final shutdown and, correspondingly, the initiation of decommissioning activities. Since there are advantages to sequential decommissioning (e.g., a learning curve may increase the overall program efficiency), the offset in shutdown dates was retained in the decommissioning schedule. Consequently, the decommissioning sequence for the three units made use of this offset in integrating the dismantling program for the entire station.

Operating licenses were issued on December 31, 1984 for Unit 1; December 9, 1985 for Unit 2; and March 25, 1987 for Unit 3[1]*. Based upon the license renewal for all the units in 2011, the shutdown dates are June 1, 2045 for Unit 1; April 24, 2046 for Unit 2; and November 25, 2047 for Unit 3. These dates were used as an input to scheduling the decommissioning activities.

1.2 SITE DESCRIPTION

Palo Verde is located approximately 34 miles west of the nearest boundary of the city of Phoenix, in Maricopa County, Arizona. The three Nuclear Steam Supply Systems (NSSS) are standardized designs marketed by ABB/Combustion Engineering as "System 80s." A stretch power program to increase output has been implemented on all three units.

The NSSS of each unit consists of a pressurized water reactor with two independent primary coolant loops, each of which has two reactor coolant pumps and a steam generator. An electrically heated pressurizer and connecting piping complete the system. These systems are housed within seismic Category I reinforced concrete dry structures. Each such containment is a steel-lined, pre-stressed concrete cylinder with a hemispherical dome and a flat, reinforced concrete foundation mat. A welded stainless steel liner plate, anchored to the inside face of the containment, serves as a leak-tight membrane.

Heat produced in each reactor is converted to electrical energy by a Main Steam Supply System. A turbine-generator system converts the thermal energy of steam produced in the steam generators into mechanical shaft power and then into electrical energy. The turbine-generators are each tandem compound, four-element units. They consist of one high-pressure double-flow and three low-pressure double-flow elements driving a direct-coupled generator at 1800 rpm.

* Annotated references for citations in Sections 1-6 are provided in Section 7.

The turbines are operated in a closed feedwater cycle that condenses the steam; the heated feedwater is returned to the steam generators. Heat rejected in the main condensers is removed by the Circulating Water System (CWS).

The CWS provides the heat sink required for removal of waste heat in the thermal cycle. The system has the principal function of removing heat by absorbing this energy in the main condenser. The circulating water pumps take suction from the intake structure and pump the circulating water through the main condensers. The cooling water is returned from the main condensers to the cooling towers.

1.3 REGULATORY GUIDANCE

The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule "General Requirements for Decommissioning Nuclear Facilities," issued in June 1988[2]. This rule set forth financial criteria for decommissioning licensed nuclear power facilities. The regulation addressed decommissioning planning needs, timing, funding methods, and environmental review requirements. The intent of the rule was to ensure that decommissioning would be accomplished in a safe and timely manner and that adequate funds would be available for this purpose. Subsequent to the rule, the NRC issued Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," [3] which provided additional guidance to the licensees of nuclear facilities on the financial methods acceptable to the NRC staff for complying with the requirements of the rule. The regulatory guide addressed the funding requirements and provided guidance on the content and form of the financial assurance mechanisms indicated in the rule.

The rule defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB. The DECON alternative, the option evaluated for this analysis, assumes that any contaminated or activated portion of the plant's systems, structures, and facilities are removed or decontaminated to levels that permit the site to be released for unrestricted use shortly after the cessation of plant operations.

The rule also placed limits on the time allowed to complete the decommissioning process. For SAFSTOR, the process is restricted in overall duration to 60 years, unless it can be shown that a longer duration is necessary to protect public health and safety. The guidelines for ENTOMB are similar, providing the NRC with both sufficient leverage and flexibility to ensure that these deferred options are only used in situations where it is reasonable and consistent with the definition of decommissioning. At the conclusion of a 60-year dormancy period (or longer for ENTOMB if the NRC approves such a case), the site would still require significant remediation to meet the unrestricted release limits for license termination.

The 60-year restriction has limited the practicality for the ENTOMB alternative at commercial reactors that generate significant amounts of long-lived radioactive material. In 2017, the NRC's staff issued the regulatory basis for proposed new regulations on the decommissioning of commercial nuclear power reactors. In the regulatory basis, the NRC staff proposed removing any discussion of the ENTOMB option from existing guidance documents "since the method is not deemed practically feasible for current U.S. power reactors, and the timeframe for decommissioning completion using the ENTOMB method is generally inconsistent with current regulations."[4]

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants.[5] When the regulations were originally adopted in 1988, it was assumed that the majority of licensees would decommission at the end of the facility's operating licensed life. Since that time, several licensees permanently and prematurely ceased operations. Exemptions from certain operating requirements were required once the reactor was defueled to facilitate the decommissioning. Each case was handled individually, without clearly defined generic requirements. The NRC amended the decommissioning regulations in 1996 to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The new amendments allow for greater public participation and better define the transition process from operations to decommissioning.

Under the revised regulations, licensees will submit written certification to the NRC within 30 days after the decision to cease operations. Certification will also be required once the fuel is permanently removed from the reactor vessel. Submittal of these notices will entitle the licensee to a fee reduction and eliminate the obligation to follow certain requirements needed only during operation of the reactor. Within two years of submitting a notice of permanent cessation of operations, the licensee is required to submit a Post-Shutdown Decommissioning Activities Report (PSDAR) to the NRC. The PSDAR describes the planned decommissioning activities, the associated sequence and schedule, and an estimate of expected costs. Prior to completing decommissioning, the licensee is required to submit an application to the NRC to terminate the license, which will include a License Termination Plan (LTP).

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[6] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their DCE as well as requiring additional financial reporting and assurances. These additional details, including an ISFSI decommissioning estimate, are included in this analysis.

1.3.1 High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act" [7] (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. It was to begin accepting spent fuel by January 31, 1998; however, to date no progress in the removal of spent fuel from commercial generating sites has been made.

Today, the country is at an impasse on high-level waste disposal, even with the License Application for a geologic repository submitted by the DOE to the NRC in 2008. The Obama Administration cut the budget for the repository program while promising to "conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle … and make recommendations for a new plan." Towards this goal, the Obama administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[8]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing several recommendations on nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"

- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste"[9]

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel."[10]

"With the appropriate authorizations from Congress, the Administration currently plans to implement a program over the next 10 years that:

- Sites, designs and licenses, constructs, and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Obama administration significantly reduced the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013)[11] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application to the extent of previously appropriated funding for the review. That review is now complete with the publication of the five-volume safety evaluation report. A supplement to DOE's environmental impact statement and an adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made. Although the DOE proposed it would start fuel acceptance in 2025, no progress has been made in the repository program since DOE's 2013 strategy was issued except for the completion of the Yucca Mountain safety evaluation report

Holtec International submitted a license application to the NRC on March 30, 2017 for a consolidated interim spent fuel storage facility in southeast New Mexico called HI-STORE CIS (Consolidated Interim Storage) under the provisions of 10 CFR Part 72. The application is currently under NRC review.

Waste Control Specialists submitted an application to the NRC on April 28, 2016, to construct and operate a Consolidated Interim Storage Facility (CISF) at its West Texas facility. On April 18, 2017, WCS requested that the NRC temporarily suspend all safety and environmental review activities, as well as public participation activities associated with WCS's license application. In March 2018, WCS and Orano USA, announced their intent to form a joint venture to license the facility. The joint venture, named Interim Storage Partners (ISP), requested that the NRC resume its review of the original CISF license application. Subsequently, in September 2021, NRC issued a license to ISP for its WCS CISF to construct and operate the facility for spent nuclear fuel and GTCC storage. However, the facility is not yet operational.

Completion of the decommissioning process is dependent upon the DOE's ability to remove spent fuel from the site in a timely manner. DOE's repository program had originally assumed that spent fuel allocations would be accepted for disposal from the nation's commercial nuclear plants, with limited exceptions, in the order (the "queue") in which it was discharged from the reactor. However, the Blue Ribbon Commission, in its final report, noted that: "[A]ccepting spent fuel according to the OFF [Oldest Fuel First] priority ranking instead of giving priority to shutdown reactor sites could greatly reduce the cost savings that could be achieved through consolidated storage if priority could be given to accepting spent fuel from shutdown reactor sites before accepting fuel from still-operating plants. .... The magnitude of the cost savings that could be achieved by giving priority to shutdown sites appears to be large enough (i.e., in the billions of dollars) to warrant DOE exercising its right under the Standard Contract to move this fuel first." [12]

This estimate assumes, based upon the oldest fuel receiving the highest priority and an annual maximum rate of transfer of 3,000 metric tons of uranium, DOE would commence pickup of spent fuel from commercial generators no later than 2034, with fuel completely removed from the site by 2097. For the first 19 years of this period (2034-2052), the annual fuel pickup rate is aligned with DOE/RW-0567, Acceptance Priority Ranking and Annual Capacity Report [39]. Beginning in year 20 (2053) and continuing until 2097, the annual fuel pickup rate is based on a schedule provided by the OA.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE.[13] Interim storage of the fuel, until the DOE has completed the transfer, will be at an on-site ISFSI.

An ISFSI, operated under a 10 CFR Part 50 General License (in accordance with 10 CFR 72, Subpart K [14]), has been constructed to support continued plant operations. The facility is assumed to be available to support future decommissioning operations. As such, following the final cessation of plant operations, the fuel from the wet storage pools, including the final cores, is either transferred to the DOE or packaged for interim storage at the ISFSI (depending upon the shutdown date assumed). Once the fuel handling building wet storage pools are emptied, the buildings can be either decontaminated and dismantled or prepared for long-term storage.

For cost estimating purposes, the spent fuel storage scenario developed by the OA assumes that the existing ISFSI facility will be available to support decommissioning operations. The current OA spent fuel storage plan projects that spent fuel will be in dry storage at Palo Verde through the year 2097. All costs to operate and maintain the ISFSI along with the costs for transfer of the fuel from the spent fuel pool to the ISFSI and the DOE, and from the ISFSI to the DOE are shown in Appendix L. Also included in this appendix are the purchase costs for the canisters and overpacks required to store the fuel transferred from the pool to the ISFSI post-shutdown. A separate appendix, Appendix N, is included to show one-time costs associated with ISFSI operations (cask handling equipment, instrumentation, crane relocation, and ISFSI shield wall costs).

DOE has breached its obligations to remove fuel from reactor sites and has also failed to provide the plant owners with information about how it will ultimately perform. DOE officials have stated that DOE does not have an obligation to accept already-canistered fuel without an amendment to DOE's contracts with plant licensees to remove the fuel (the "Standard Contract"), but DOE has not explained what any such amendment would involve. Consequently, the OA has no information or expectations on how DOE will remove fuel from the site in the future. In the absence of information about how DOE will perform, and for purposes of this analysis only, it is assumed that DOE will accept already-canistered fuel. If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers.

1.3.2 Low-Level Radioactive Waste Management

The contaminated and activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980, [15] and its Amendments of 1985, [16] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

Arizona is a member of the Southwest Compact, which currently does not have an operational disposal site. For the purposes of the decommissioning estimate, the existing waste disposal options available for the Palo Verde site are used for this estimate.

Except for Texas, no new compact facilities have been successfully sited, licensed, and constructed. The Texas Compact disposal facility is now operational, and waste is being accepted from generators within the Compact by the operator, Waste Control Specialists (WCS).

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to Palo Verde. The majority of the low-level radioactive waste designated for direct disposal (Class A[17] containerized) is sent to WCS. Therefore, disposal costs for Class A waste were based on Palo Verde's STARS Alliance Agreement with WCS. Class A bulk waste is sent to the *EnergySolutions* facility in Clive Utah. These disposal costs are based on Palo Verde's STARS Alliance Agreement with Energy*Solutions*.

The WCS facility can also receive the Class B and C waste. As such, for this analysis, Class B and C waste is shipped to the WCS facility. Disposal costs for the waste are based on current rates paid by Palo