WOLF CREEK
NUCLEAR OPERATING CORPORATION

Cleveland Reasoner
Senior Vice President and Chief Nuclear Officer

April 10, 2019
WM 19-0008

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: Docket No. 50-482: Wolf Creek Generating Station (WCGS) Financial Assurance Requirements for Decommissioning Nuclear Power Reactors 10 CFR 50.75(f)(1)

To Whom It May Concern:

Pursuant to 10 CFR 50.75(f)(1), each power reactor licensee is required to report to the Nuclear Regulatory Commission (NRC) the status of its decommissioning funding for each reactor or part of each reactor it owns on a calendar year basis, beginning March 31, 1999, and every two years thereafter. Any licensee for a plant that is involved in a merger or an acquisition shall submit this report annually. Wolf Creek Nuclear Operating Corporation (WCNOC) holds the operating license for Wolf Creek Generating Station (WCGS), which is jointly owned by Kansas Gas and Electric Company (KGE), a wholly-owned direct subsidiary of Westar Energy, Inc. and indirect subsidiary of Evergy, Inc.; Kansas City Power & Light Company (KCPL), a wholly-owned direct subsidiary of Evergy, Inc; and Kansas Electric Power Cooperative, Inc. (KEPCo). Accordingly, WCNOC provides the information for WCGS in accordance with the requirements of 10 CFR 50.75(f)(1).

The Enclosures provide the required financial information to report the status of WCNOC's decommissioning funding, and legal documentation to provide the approval of the 2017 Decommissioning Cost Analysis for WCGS. The Enclosures reflect financial estimates based on the 2017 Cost Analysis.

The NRC Project Manager was contacted regarding not meeting the required due date stated in the regulations. This issue has been captured in WCNOC's Corrective Action Process as condition report 131169. This letter contains no commitments. If you have any questions concerning this matter, please contact me at (620) 364-4000, or Ron Benham at (620) 364-4204.

Sincerely,

Cleveland Reasoner

A001
NRR

COR/rlt

Enclosures:

I	Wolf Creek Nuclear Operating Corporation Decommissioning Funding Status Report as of 3/31/18
II	Commission Order (Docket No. 18-WCNE-107-GIE)
III	Direct Testimony of Adam H. Gatewood (September 12, 2018)
IV	Joint Motion to Approve Stipulation (Docket No. 15-WCNE-093-GIE)
V	Order Approving Unanimous Settlement Agreement (Docket No. 18-KCPE-480-RTS)
VI	Direct Testimony of Adam H. Gatewood (July 9, 2015)
VII	Order Approving Stipulation and Agreement (Docket No. 15-WSEE-115-RTS)
VIII	Order Approving Unopposed Stipulation and Agreement (15-WCNE-093-GIE)
IX	Order Approving Stipulation and Agreement (File No. EO-2018-0062)
X	Non-Unanimous Stipulation and Agreement (File No. EO-2018-0062)
XI	Direct Testimony of Adam H. Gatewood (June 11, 2018)
XII	Application of Kansas City Power & Light Company (KCPL) for Approval of the Accrual and Funding of WCGS Decommissioning Costs at Current Levels
XIII	Annual NRC Certification Update
XIV	Decommissioning Cost Analysis for the Wolf Creek Generating Station (W11-1741-001, Rev. 0)

cc: S. A. Morris (NRC), w/e
B. K. Singal (NRC), w/e
N. H. Taylor (NRC), w/e
Senior Resident Inspector (NRC), w/e

Enclosure I to WM 19-0008

Wolf Creek Nuclear Operating Corporation Decommissioning Funding Status Report as of 3/31/18
(15 pages)

Wolf Creek Nuclear Operating Corporation
Decommissioning Funding Status Report as of 3/31/19
Owned by Kansas Gas & Electric (KGE), Kansas City Power and Light (KCPL) and Kansas Electric Power Cooperative (KEPCo)

	Westar Energy (KGE, 47% ownership)	Great Plains Energy (KCPL, 47% ownership)	KEPCo, 6% ownership	TOTAL	Notes
10 CFR 50.75(f)(1) Requirement					
1) NRC minimum decommissioning estimate pursuant to 10 CFR 50.75(b) and (c) Dollars in Millions.	$242.95	$242.95	$31.02	$516.92	
2) The amount of accumulated funds at the end of the calendar year preceding the date of the report for items included in 10 CFR 50.75 (b) and (c). Dollars in Millions.	$227.46	$244.61	$25.01	$497.07	
3) A schedule of the annual amounts to be collected; for items in 10 CFR 50.75 (b) and (c). Dollars in Millions. See Attached Schedules	$151.54	$87.07	$16.24	$254.85	Current scheduled amounts established in KCC Docket 15-WSEE-115-RTS Testimony of Gatewood. Collection amounts for 2018/2019 have not been established/approved as of 3/31/2019 for KGE/KEPCo, KCC Docket 18-WSEE-328-RTS. KCPL contributions established in KCC Docket 18-KCPE-480-RTS and EO-2018-0062
4) The assumptions used regarding:					
(a) Rates of escalation in decommissioning costs;					
Kansas	2.91%	2.91%	2.91%		New escalation rate approved for Kansas in 2018 @ 2.91%, new Site Specific Methodology Approved from DECON to SAFSTOR as found in KCC Docket 18-WCNE-107-GIE.
Missouri	N/A	3.16%	N/A		Missouri Rates established on EO-2018-062
(b) Rates of earning on decommissioning funds;	Variable. See attached	Variable. See attached	Variable. See attached		Kansas earnings rates not approved as of 3/31/19 by the KCC for KGE/KEPCo. Use rates established in KCC Docket 15-WSEE-115-RTS, Testimony of Gatewood. KCPL earnings rates established on 18-KCPE-480-RTS
(c) Rates of other factors used in funding projections; and	0.00%	0.00%	0.00%		
(d) Real rate of return for current period, rate reduces in subsequent years;					
Kansas	2.69%	1.71%	3.83%		
Missouri	N/A	2.30%	N/A		
5) Any contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v)?	None	None	None		
6) Any modifications to a licensee's current method of providing financial assurance occurring since the last submitted report?	None	None	None		
7) Any material changes to trust agreements?	None	None	None		
Other information; estimated corporate tax rate	20.00%	20.00%	Non-taxable		

WOLF CREEK NUCLEAR OPERATING CORPORATION
Minimum Decommissioning Funds Estimate pursuant to 10 CFR 50.75 (b) and (c)

MINIMUM ESTIMATE

Table (c)(1) - Jan86 dollars in Millions [Wolf Creek is a PWR licensed for 3,565 MWt]	$ 105
Escalation Factor (see calculation below)	4.923
Minimum estimate - Dec18 dollars in Millions	**$ 516.92**

Escalation per paragraph (c)(2)

Escalation Factor = 0.65 Labor + 0.13 Energy + 0.22 Waste Burial

	Share	4Q '18	Report
Labor	65%	2.750	1.788
Energy	13%	2.365	0.307
Waste Burial	22%	12.853	2.828
TOTAL ESCALATION FACTOR			4.923

NOTE: 4Q '18 factors per McDermott, Will & Emery memo dated February 20, 2019.

NEW SITE SPECIFIC STUDY (August 2017)

Decommissioning Alternative	SAFSTOR
Cost escallation rate Obtained from KCC Docket 18-WCNE-107-GIE	2.91%

SAFSTOR Period	(2017 $s) Millions	(Q1 2019 $s) Millions	(2045 $s) Millions	% Total
Radioactive Systems/Structures and License Termination	$ 980.8	$ 1,024.5	$ 2,189.7	90%
Preparation for Decommissioning/Spent Fuel Mgmt	$ 58.1	$ 60.7	$ 129.7	5%
Other Systems/Structures and Site Restoration	$ 54.2	$ 56.7	$ 121.1	5%
Subtotal - Not Applicable to NRC Minimum	$ 112.3	$ 117.3	$ 250.8	10%
TOTAL COST ESTIMATE	$ 1,093.1	$ 1,141.9	$ 2,440.6	100%

August 2017 study is approved by the KCC for the SAFSTOR method.

WOLF CREEK NUCLEAR OPERATING CORPORATION
Decommissioning Funding Status Report as of December 31, 2018
10 CFR 50.75 (b) and (c)
(Dollars in Thousands)

	TOTAL	KGE (47%)	KCPL (47%)	KEPCo (6%)
Market Value of External Sinking Fund as of 12/31/18	$ 497,072.9	$ 227,462.2	$ 244,605.2	25,005.5

Schedule of Amounts to be Collected (as approved by rate-setting authorities based on Site Specific Study)

2019	9,605	5,773	3,317	515
2020	9,613	5,773	3,317	523
2021	9,621	5,773	3,317	531
2022	9,629	5,773	3,317	539
2023	9,637	5,773	3,317	547
2024	9,645	5,773	3,317	555
2025	9,653	5,773	3,317	563
2026	9,662	5,773	3,317	572
2027	9,670	5,773	3,317	580
2028	9,679	5,773	3,317	589
2029	9,688	5,773	3,317	598
2030	9,697	5,773	3,317	607
2031	9,706	5,773	3,317	616
2032	9,715	5,773	3,317	625
2033	9,725	5,773	3,317	635
2034	9,734	5,773	3,317	644
2035	9,744	5,773	3,317	654
2036	9,754	5,773	3,317	664
2037	9,764	5,773	3,317	674
2038	9,774	5,773	3,317	684
2039	9,784	5,773	3,317	694
2040	9,794	5,773	3,317	704
2041	9,805	5,773	3,317	715
2042	9,816	5,773	3,317	726
2043	9,826	5,773	3,317	736
2044	9,838	5,773	3,317	748
2045	2,272	1,443	829	0
	254,848	151,541	87,071	16,236

Assumptions re: Rates/Factors specific to Owner and Jurisdiction

	Prior	Current	Prior	Current	Prior	Current
Cost Escalation Rate						
Obtained from KCC Docket	15-WCNE-093-GIE	18-WCNE-107-GIE	15-WCNE-093-GIE	18-WCNE-107-GIE	15-WCNE-093-GIE	18-WCNE-107-GIE
	3.15%	2.91%	3.15%	2.91%	3.15%	2.91%
Obtained from MPSC Docket			E0-2018-0062	E0-2018-0062		
	N/A	N/A	3.16%	3.16%	N/A	N/A

After Tax Earnings on Funds

Kansas

From KCC Docket 18-KCPE-480-RTS

2012 - 2025	5.60%	TBD	2012 - 2025	5.84%	2018 - 2084	4.62%	2012 - 2025	6.74%	TBD
2026 - 2035	4.83%	TBD	2026 - 2045	decr ~ .25%/year	2085 - 2091	3.95%	2026 - 2035	5.33%	TBD
2036 - 2044	3.83%	TBD	2045 - Decommissioning	decr ~ .13%/year	2092 - 2097	3.45%	2036 - 2044	4.15%	TBD
2045 - Decommissioning	2.31%	TBD			2098 - 2106	2.09%	2045 - Decommissioning	1.93%	TBD

Missouri

-	-	2012 - 2025	5.18%	5.46%	-	-		
-	-	2026 - 2045	decr ~ .154%/year	decr ~ .16%/year	-	-		
		2045 - Decommissioning	decr ~ .022%/year	decr ~ .04%/year				

Power sale contracts	None	None	None	None	None	None
Modifications to method of financial assurance	None	None	None	None	None	None
Material changes to trust agreements	None	None	None	None	None	None

WOLF CREEK NUCLEAR OPERATING CORPORATION
Decommissioning Funding Status Report as of December 31, 2018
10 CFR 50.75 (b) and (c)
(Dollars in Thousands)

	Kansas	FERC	TOTAL	KGE
Market Value of External Sinking Fund as of 12/31/18				$ 227,462.2

Schedule of Amounts to be Collected (as approved by rate-setting authorities based on Site Specific Study)

2019	5,477,274	295,426	5,772,700	5,773
2020	5,477,274	295,426	5,772,700	5,773
2021	5,477,274	295,426	5,772,700	5,773
2022	5,477,274	295,426	5,772,700	5,773
2023	5,477,274	295,426	5,772,700	5,773
2024	5,477,274	295,426	5,772,700	5,773
2025	5,477,274	295,426	5,772,700	5,773
2026	5,477,274	295,426	5,772,700	5,773
2027	5,477,274	295,426	5,772,700	5,773
2028	5,477,274	295,426	5,772,700	5,773
2029	5,477,274	295,426	5,772,700	5,773
2030	5,477,274	295,426	5,772,700	5,773
2031	5,477,274	295,426	5,772,700	5,773
2032	5,477,274	295,426	5,772,700	5,773
2033	5,477,274	295,426	5,772,700	5,773
2034	5,477,274	295,426	5,772,700	5,773
2035	5,477,274	295,426	5,772,700	5,773
2036	5,477,274	295,426	5,772,700	5,773
2037	5,477,274	295,426	5,772,700	5,773
2038	5,477,274	295,426	5,772,700	5,773
2039	5,477,274	295,426	5,772,700	5,773
2040	5,477,274	295,426	5,772,700	5,773
2041	5,477,274	295,426	5,772,700	5,773
2042	5,477,274	295,426	5,772,700	5,773
2043	5,477,274	295,426	5,772,700	5,773
2044	5,477,274	295,426	5,772,700	5,773
2045	1,369,319	73,857	1,443,176	1,443
				151,541

Assumptions re: Rates/Factors specific to Owner and Jurisdiction

		Prior		Current
Cost Escalation Rate				
Obtained from KCC Docket 15-WCNE-093-GIE	Kansas	3.15%	Obtained from KCC Docket 18-WCNE-107-GIE	2.91%
	Missouri	N/A		N/A
After Tax Earnings on Funds				
Kansas				
2015 - 2025		5.60%		TBD
2026 - 2035		4.83%		TBD
2036 - 2044		3.83%		TBD
2045 - Decommissioning		2.31%		TBD
Missouri				
		-		-
		-		-
Power sale contracts		None		None
Modifications to method of financial assurance		None		None
Material changes to trust agreements		None		None

WOLF CREEK NUCLEAR OPERATING CORPORATION
Decommissioning Funding Status Report as of December 31, 2018
10 CFR 50.75 (b) and (c)
(Dollars in Thousands)

	Kansas	Missouri	TOTAL	KCPL
Market Value of External Sinking Fund as of 12/31/18				$ 244,605.2

Schedule of Amounts to be Collected (as approved by rate-setting authorities based on Site Specific Study)

2019	2,036,230	1,281,264	3,317,494	3,317
2020	2,036,230	1,281,264	3,317,494	3,317
2021	2,036,230	1,281,264	3,317,494	3,317
2022	2,036,230	1,281,264	3,317,494	3,317
2023	2,036,230	1,281,264	3,317,494	3,317
2024	2,036,230	1,281,264	3,317,494	3,317
2025	2,036,230	1,281,264	3,317,494	3,317
2026	2,036,230	1,281,264	3,317,494	3,317
2027	2,036,230	1,281,264	3,317,494	3,317
2028	2,036,230	1,281,264	3,317,494	3,317
2029	2,036,230	1,281,264	3,317,494	3,317
2030	2,036,230	1,281,264	3,317,494	3,317
2031	2,036,230	1,281,264	3,317,494	3,317
2032	2,036,230	1,281,264	3,317,494	3,317
2033	2,036,230	1,281,264	3,317,494	3,317
2034	2,036,230	1,281,264	3,317,494	3,317
2035	2,036,230	1,281,264	3,317,494	3,317
2036	2,036,230	1,281,264	3,317,494	3,317
2037	2,036,230	1,281,264	3,317,494	3,317
2038	2,036,230	1,281,264	3,317,494	3,317
2039	2,036,230	1,281,264	3,317,494	3,317
2040	2,036,230	1,281,264	3,317,494	3,317
2041	2,036,230	1,281,264	3,317,494	3,317
2042	2,036,230	1,281,264	3,317,494	3,317
2043	2,036,230	1,281,264	3,317,494	3,317
2044	2,036,230	1,281,264	3,317,494	3,317
2045	509,058	320,316	829,374	829
				87,071

Assumptions re: Rates/Factors specific to Owner and Jurisdiction

Cost Escalation Rate		Prior		Current
Obtained from KCC Docket 15-WCNE-093-GIE	Kansas	3.15%	Obtained from KCC Docket 18-WCNE-107-GIE	2.91%
Obtained from MPSC Docket E0-2018-0062	Missouri	3.16%	Obtained from MPSC Docket E0-2018-0062	3.16%

After Tax Earnings on Funds

Kansas				
	2018 - 2029	5.84%	2018 - 2084	4.62%
	2030 - 2045	decr ~ .25%/year	2085 - 2091	3.95%
	2045 - Decommissioning	decr ~ .13%/year	2092 - 2097	3.45%
			2098 - 2106	2.09%
Missouri				
	2018 - 2027	5.18%		5.46%
	2028 - 2047	decr ~ .154%/year		decr ~ .16%/year
	2048 - Decommissioning	decr ~ .022%/year		decr ~ .04%/year

Power sale contracts	None	None
Modifications to method of financial assurance	None	None
Material changes to trust agreements	None	None

WOLF CREEK NUCLEAR OPERATING CORPORATION
Decommissioning Funding Status Report as of December 31, 2018
10 CFR 50.75 (b) and (c)
(Dollars in Thousands)

	KEPCo
Market Value of External Sinking Fund as of 12/31/18	25,005.5

Schedule of Amounts to be Collected (as approved by rate-setting authorities based on Site Specific Study)

2019	515
2020	523
2021	531
2022	539
2023	547
2024	555
2025	563
2026	572
2027	580
2028	589
2029	598
2030	607
2031	616
2032	625
2033	635
2034	644
2035	654
2036	664
2037	674
2038	684
2039	694
2040	704
2041	715
2042	726
2043	736
2044	748
2045	0
	16,236

Assumptions re: Rates/Factors specific to Owner and Jurisdiction

Cost Escalation Rate		Prior		Current
Obtained from KCC Docket 15-WCNE-093-GIE	Kansas	3.15%	Obtained from KCC Docket 18-WCNE-107-GIE	2.91%
	Missouri	N/A		N/A

After Tax Earnings on Funds			
Kansas			
	2015 - 2025	6.74%	TBD
	2026 - 2035	5.33%	TBD
	2036 - 2043	4.15%	TBD
	2044 - Decommissioning	1.93%	TBD
Missouri			
		-	-
		-	-

Power sale contracts	None	None
Modifications to method of financial assurance	None	None
Material changes to trust agreements	None	None

1010 Grand Boulevard
Kansas City, MO 64106
800.545.6101

------ manifest line ---------

KANSAS GAS AND ELECTRIC COMPANY
ATTN: SUSAN NORTH
% WESTAR ENERGY
P O BOX 889
TOPEKA KS 66601-0889

Account Name	KANSAS GAS & ELECTRIC WOLF CREEK GENERATING STATION DECOM TRUST
Account Number	116889
Statement Period	Dec. 1 - Dec. 31, 2018
Administrator	Anthony Hawkins 816.860.3014 anthony.hawkins@umb.com
Associate Administrator	Melissa Byers McGee 816-860-3202 melissa.byersmcgee@umb.com
Senior Officer	Douglas Hare 816.860.3006 douglas.hare@umb.com

Philomene Bennett
The Ninth Day
Oil on canvas

UMB

You are receiving this statement as an account owner or as a trust beneficiary who is entitled to receive statements, or as a party who is authorized to receive statements. Please contact us if you have any questions regarding your statement, or if you have a change in address, phone number or other information. We have provided some definitions to assist you in understanding this statement.

Definitions

Acquisitions: Purchase or receipt of assets, including money market funds.

Asset Allocation: A pie chart with percentages that shows the breakdown of the various asset classes in the account.

Bond Maturities Schedule (in years): Short - 1 to 3; Intermediate - 3 to 7; Long - 7 +

Capital Gain / (Loss): The difference between sale proceeds and cost basis. A gain or loss may be short or long depending on the holding period (long is greater than one year).

Cash & Equivalents: Cash, money market funds, treasury bills and other short-term investments.

Corporate Actions: Change due to mergers, stock splits or other capital reorganizations.

Cost Basis: Net cumulative cost of the asset. Often referred to as tax basis or tax cost. The original value of an asset for tax purposes (usually the purchase price), adjusted for sales, stock splits and purchases, including reinvestment of dividends and capital gains distributions. Tax lots for a security may be obtained from the account administrator or online.

Dispositions: Sale, maturity, or delivery of assets.

Estimated Annual Income ("EAI"): The gross income an asset is projected to earn annually, expressed in dollars – as of the date of the statement.

Estimated Yield ("EY"): When available, the EAI of the security divided by its market value. Note: EAI and EY are estimates; actual income and yield may be lower or higher. Estimates may also include return of principal or capital gains, which would render them overstated. EY reflects only the income generated by an investment; not changes in its price. These figures are based on mathematical calculations of available data. They have been obtained from information providers believed to be reliable, but no assurance can be made as to accuracy. Since interest and dividend rates are subject to change at any time, and may be affected by current and future economic, political and business conditions, they should not be relied upon for making investment, trading or tax decisions.

Historical Value: A bar graph depicting the value of the account over a period of time.

Market Appreciation / Depreciation: Change in market value from the end of the previous period to the end of the current period.

Market Overview: A summary of the activity that has occurred in the account during the current period and year-to-date.

Market Value: An approximation of the total worth of an asset, obtained by multiplying the unit price by the number of shares/units as of the statement date. The market value of a security, including those priced at par value, may differ from its purchase price and may not closely reflect the value at which the security may be sold or purchased based on various market factors.

Prices: Prices are as of the statement date. For exchange traded securities, the price at which a security is traded. For non-exchange traded securities, the price is an estimate of the value of the asset. Prices are obtained from various sources and may be impacted by the frequency in which such prices are reported; therefore, such prices are not guaranteed. Prices received from pricing vendors are generally based on current market quotes, but when such quotes are not available the pricing vendors use a variety of techniques to estimate value. These estimates, particularly for fixed income securities, may not reflect all of the factors that affect the value of the security, including liquidity risk. The prices provided are not firm bids or offers. Certain securities may reflect "cost basis" where the price for such security is generally not available from a pricing source.

Ratings: Ratings from Moody's and S&P are displayed, if available. If no rating is displayed, the security is not rated by those institutions.

Settlement Date: The date a transaction is finalized.

Statement of Accruals: Dividends and interest that have accrued but have not been paid. When the statement date falls between the record date and a payment date of a dividend, the dividend is reported on the statement of accruals. Interest that has accrued on a bond from the last date of payment until the statement date is reported on the statement of accruals.

Tax-exempt: Refers to federal tax only. This information is believed to be accurate but may not apply to your particular tax situation. Consult your tax advisor.

Trade Date: The date at which an agreement was entered to conduct a transaction. Trade date statements have been adjusted for payables and receivables.

Transaction Schedule: Report of transactions made during the statement period.

Unrealized Gain / (Loss): A gain or loss that has not become actual; a realized gain or loss occurs when the asset is sold.

Yield - Equities: EAI divided by market value.

Yield - Fixed Income: Yield to maturity.

Disclosures

Duty to Make Timely Objections: Please carefully examine this statement. Notify us in writing within 30 calendar days of mailing if you have any questions or objections, and report any errors to us. If you do not object, this statement shall be conclusive. In such case, UMB Financial Corporation, its affiliates, subsidiaries, officers and employees shall be forever released and discharged from any liability with respect to any claim arising out of any action or omission reflected on this statement. Where UMB serves as trustee, this statement provides sufficient information so that the trust beneficiary or representative will know of a potential claim against UMB as trustee or should have inquired into its existence. The trust beneficiary or representative is notified that the time allowed for commencing a proceeding against UMB as trustee is one year after the date the trust beneficiary or representative was mailed this statement, unless applicable law provides otherwise.

Capital Gain / (Loss) Sections: The information contained in this section(s) includes a gain or a loss summary of your account and is not a solicitation or a recommendation to buy or sell. It may however, be helpful for investment and tax planning strategies. It should not be relied upon for filing your tax return as it may not include all taxable transactions. UMB has provided cost basis information wherever possible for most securities. This data may have been provided by other third parties. Although efforts have been made to assure the quality of the information, data may be inaccurate or incomplete and is subject to change. UMB accepts no responsibility for its accuracy, completeness or timely updating. Consequently, all data information in the Capital Gain / (Loss) section(s) of this statement, should be confirmed with your records and your tax advisor.

No Legal or Tax Advice: We are not providing you any legal or tax advice. You are advised to seek whatever legal or tax advice you believe appropriate and to review the account agreement and applicable fee schedules in connection with the account.

Changes in Your Situation or Objectives: Contact us if changes occur in your financial situation or, where permitted, if you wish to alter investment objectives, impose reasonable restrictions on the management of the account assets or modify existing restrictions.

Mutual Funds: UMB may receive additional compensation for providing shareholder servicing and administrative services to mutual funds, as well as 12b-1 fees from various mutual funds in which UMB invests client assets. UMB does not receive compensation with respect to client assets in qualified retirement accounts, including Individual Retirement Accounts. These services may include sub-accounting, statement production, client communication, electronic transmission of orders and automated order-entry. The fees received by UMB range from 0.10% to 1% and are usually calculated as a percentage of the average daily balance of the account assets invested in such funds. These fees are in addition to account fees and are not reflected on account statements.

Ratings information from Standard & Poor's ("S&P") may not be reproduced. S&P credit ratings are statements of opinion and are not statements of fact or recommendations to purchase, hold, or sell securities, nor do they address the suitability of securities for investment purposes, and should not be relied on as investment advice. S&P does not guarantee the accuracy, completeness, timeliness or availability of any information, including ratings, and is not responsible for errors or omissions (negligent or otherwise). S&P GIVES NO EXPRESS OR IMPLIED WARRANTIES, INCLUDING BUT NOT LIMITED TO ANY WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE. S&P SHALL NOT BE LIABLE FOR ANY DIRECT, INDIRECT, INCIDENTAL, EXEMPLARY, COMPENSATORY, PUNITIVE, SPECIAL OR CONSEQUENTIAL DAMAGES, COSTS, EXPENSES, LEGAL FEES, OR LOSSES (INCLUDING LOST INCOME OR PROFITS AND OPPORTUNITY COSTS) IN CONNECTION WITH ANY USE OF RATINGS.

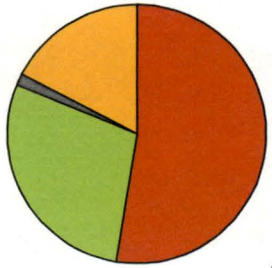
Market Overview

	Current Period	Year-to-Date
	12/01/2018	*01/01/2018*
Beginning Market Value	**238,187,826.57**	**237,102,282.59**
Income		
Dividends	94.86	5,159,589.64
Other Income	97,394.16	893,632.07
Net Contributions/Distributions		
Receipts	97,488.53	14,086,898.23
Disbursements	(97,488.53)	(9,478,868.35)
Expenses/Fees		(6,863,692.42)
Capital Gain Distributions		
Change in Market Value	(10,823,154.69)	(13,437,680.86)
Ending Market Value	**227,462,160.90**	**227,462,160.90**

Capital Gains

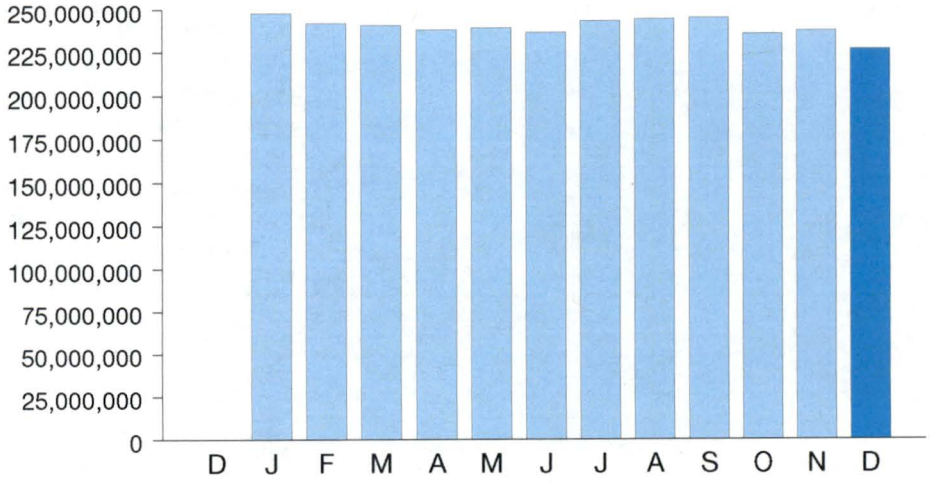
	Current Period	Year-to-Date
Short-term Capital Gain / (Loss)	441,735.37	1,019,557.39
Long-term Capital Gain / (Loss)	4,248,464.01	15,404,117.57

Asset Allocation



	Account Value Percentage	Market Value
Equity Funds	53%	$119,800,451
Fixed Income Funds	29%	$64,923,859
Real Estate / Oil & Gas	1%	$3,241,109
Unique Assets	17%	$39,368,885
Money Markets and Cash	< 1%	$127,857
	100%	**$227,462,161**

Historical Value



Portfolio(s) included in Statement

Portfolio Number:	Portfolio Name:
116889.1	KG&E Wolf Creek Decom Tr CASH AC Pri Usd
116889.2	KG&E Wolf Crk Decom Tr - SEI Inv Mgmt
116889.8	KG&E Wolf Creek Decom Tr-CrossCreek (LP)
116889.16	KG&E Wolf Creek Decom Tr-CrossCreek LLC
116889.24	KG&E Wolf Creek Decom Tr-SEI Struc Cr LP
116889.25	KG&E Wolf Creek Tr-CrossCreekCap III LP
116889.26	KG&E Wolf Creek Tr-CrossCreekCap IV LP
116889.27	KG&E Wolf Creek Decom Tr-SEI Core Prop
116889.28	KG&E Wolf Creek Tr-CrossCreek Cap V L.P.

Transaction Summary

	Income Cash	Principal Cash	Cost	Market Value Including Cash
Beginning Market Value	**0.00**	**0.00**	**222,607,285.31**	**238,187,826.57**
Income				
Dividends		94.86		94.86
Other Income		97,394.16		97,394.16
Additions				
Transfers		97,488.53		97,488.53
Disbursements				
Other		(97,488.53)		(97,488.53)
Purchases		(140,258.98)	5,030,890.73	4,890,631.75
Sales & Maturities		42,769.96	(42,769.96)	
Non Cash Changes			6,105.39	6,105.39
Change in Market Value				(15,719,891.83)
Ending Market Value	**0.00**	**0.00**	**227,601,511.47**	**227,462,160.90**

Statement of Accruals

Units	Asset Description	Payable Date	Rate	Amount
Dividend				
127,857.26	Fidelity Treasury Fund #2016	01/01/2019	0.001	87.04
3,750,296.065	SEI Core Fixed Income Fund	01/01/2019	0.031	115,375.93
2,298,412.64	SEI High Yield Bond Fund	01/02/2019	0.051	117,807.52
718,720.581	SEI SIIT Dynamic Asset Allocation Fund	12/31/2018	0.127	90,990.03
4,123,068.211	SEI SIIT S & P 500 Index Fd Cl A	12/31/2018	0.097	401,586.84

Statement of Accruals (continued)

Units	Asset Description	Payable Date	Rate	Amount
Dividend				
2,590,432.11	SEI SIIT World Equity EX-US Fund Cl A	12/31/2018	0.281	728,170.47
883,840.371	SIIT Emerging Markets Equity Fund	12/31/2018	0.192	169,432.20
	Total Dividend			**1,623,450.03**
	Total Accruals			**1,623,450.03**

Statement of Investment Position

Units	Description	Symbol Cusip	Cost Basis Unit	Cost Basis Total	Market Value Unit	Market Value Total	Unrealized Gain / (Loss)	Estimated Annual Income	Yield %
Equity Funds									
Equity Fund									
718,720.581	SEI SIIT Dynamic Asset Allocation Fund	SDLAX 783980683	11.84	8,508,595.15	17.91	12,872,285.61	4,363,690.46	91,278	0.71
1,685,594.478	SEI SIIT Emerging Market Debt Fund Cl A	SEDAX 783980758	10.23	17,246,972.40	9.15	15,423,189.47	(1,823,782.93)	488,822	3.17
4,123,068.211	SEI SIIT S & P 500 Index Fd Cl A	783980626	15.49	63,877,502.60	13.41	55,290,344.71	(8,587,157.89)	1,364,736	2.47
2,590,432.11	SEI SIIT World Equity EX-US Fund Cl A	WEUSX 783980774	10.33	26,760,954.12	11.08	28,701,987.78	1,941,033.66	727,911	2.54
883,840.371	SIIT Emerging Markets Equity Fund	SMQFX 783980618	9.58	8,464,840.59	8.50	7,512,643.15	(952,197.44)	169,697	2.26
	Total Equity Fund			**124,858,864.86**		**119,800,450.72**	**(5,058,414.14)**	**2,842,444**	
	Total Equity Funds			**124,858,864.86**		**119,800,450.72**	**(5,058,414.14)**	**2,842,444**	
Fixed Income Funds									
Fixed Income Funds									
3,750,296.065	SEI Core Fixed Income Fund	SCOAX 783980204	10.30	38,609,685.70	9.98	37,427,954.73	(1,181,730.97)	1,173,174	3.13
2,298,412.64	SEI High Yield Bond Fund	SGYAX 783980303	8.94	20,540,187.63	8.22	18,892,951.90	(1,647,235.73)	1,248,288	6.61
918,137.888	SEI SIIT Small Mid Cap Equity Fd	SSMAX 783980816	12.75	11,710,348.56	9.37	8,602,952.01	(3,107,396.55)	112,013	1.30
	Total Fixed Income Funds			**70,860,221.89**		**64,923,858.64**	**(5,936,363.25)**	**2,533,475**	
	Total Fixed Income Funds			**70,860,221.89**		**64,923,858.64**	**(5,936,363.25)**	**2,533,475**	
Real Estate / Oil & Gas									
Real Estate / Oil & Gas									
1	Cross Creek Capital, L.P. A Delaware Limited Partnership		2,146,283.85	2,146,283.85	1,729,111.73	1,729,111.73	(417,172.12)	0	
1	Cross Creek Capital Partners LLC a Delaware limited liability company		1,864,283.61	1,864,283.61	1,511,997.43	1,511,997.43	(352,286.18)	0	
	Total Real Estate / Oil & Gas			**4,010,567.46**		**3,241,109.16**	**(769,458.30)**	**0**	
	Total Real Estate / Oil & Gas			**4,010,567.46**		**3,241,109.16**	**(769,458.30)**	**0**	

Statement of Investment Position (continued)

Units	Description	Symbol Cusip	Cost Basis Unit	Cost Basis Total	Market Value Unit	Market Value Total	Unrealized Gain / (Loss)	Estimated Annual Income	Yield %
Unique Assets									
Unique Assets									
1	Cross Creek Capital Partners III LP		1,554,000.00	1,554,000.00	1,970,901.41	1,970,901.41	416,901.41	0	
1	Cross Creek Capital Partners IV LP		1,000,000.00	1,000,000.00	1,043,587.00	1,043,587.00	43,587.00	0	
1	Cross Creek Partners V LP		690,000.00	690,000.00	502,405.00	502,405.00	(187,595.00)	0	
5,108.79	SEI Core Property Fund LP		1,859.54	9,500,000.00	2,304.76	11,774,510.34	2,274,510.34	0	
8,879.44	SEI Structured Credit LP		1,689.30	15,000,000.00	2,711.60	24,077,481.37	9,077,481.37	0	
	Total Unique Assets			**27,744,000.00**		**39,368,885.12**	**11,624,885.12**	**0**	
	Total Unique Assets			**27,744,000.00**		**39,368,885.12**	**11,624,885.12**	**0**	
Money Markets & Cash									
Money Market Funds									
127,857.26	Fidelity Treasury Fund #2016	FTVXX 31607A406	1.00	127,857.26	1.00	127,857.26		2,213	1.73
	Total Money Market Funds			**127,857.26**		**127,857.26**	**0.00**	**2,213**	
	Total Money Markets and Cash			**127,857.26**		**127,857.26**	**0.00**	**2,213**	
	Account Total			**227,601,511.47**		**227,462,160.90**	**(139,350.57)**	**5,378,132**	

BNY MELLON

TRDB58 B58GPLN00000 MONTHLY FINAL 225951 2018-12-31 CYCLE A 22:59:54 RUN DATE: 04-JAN-19

INVESTMENT DETAIL

B58 GPLN000 31 DECEMBER 2018 M1101

KANSAS CITY P&L COMBINED PLAN

KANSAS CITY P&L COMBINED PLAN

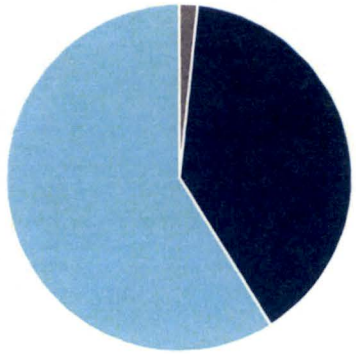
SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	KANSAS CITY POWER & LIGHT				
51,148,786.3580	KCPL WOLF CREEK KAN	71,891,326.09	1.8859	96,462,365.72	24,571,039.63
78,552,140.6470	KCP&L WOLF CREEK MO	106,349,070.65	1.8859	148,142,817.43	41,793,746.78
129,700,927.0050		178,240,396.74		244,605,183.15	66,364,786.41
TOTAL INVESTMENTS UNIT OF PARTICIPATION		178,240,396.74		244,605,183.15	66,364,786.41
TOTAL INVESTMENT		178,240,396.74		244,605,183.15	66,364,786.41

PORTFOLIO OVERVIEW

PORTFOLIO ASSET ALLOCATION

Current Holdings	Cost*	Estimated Annual Income	Estimated Yield at Market**	Market Value***	Percent
Reserves	$441,785.84	$3,417.55	0.77%	$441,785.84	1.77%
Fixed Income	9,963,208.19	249,606.97	2.54	9,834,609.93	39.33
Equities	12,101,687.78	184,815.55	1.25	14,729,141.28	58.90
Total Account	**$22,506,681.81**	**$437,840.07**	**1.75%**	**$25,005,537.05**	**100.00%**

ASSET ALLOCATION CHART



INVESTMENT GUIDELINES

	Minimum	Maximum
Reserves	0%	35%
Fixed Income	35	65
Equities	35	65

YEAR-TO-DATE INFORMATION

Realized Gain/(Loss)	Amount
Short-Term	N/A
Long-Term	N/A
Net Realized Gain/(Loss)	**N/A**

Earned Income	Amount
Past Three Months	$213,959.80
Year-to-Date	$457,984.58

*Amortized cost will be reflected where applicable.

**Estimated Yield at Market is calculated by multiplying the number of shares/units held by the income rate and dividing by the Market Value. Data is supplied by T. Rowe Price Associates, Inc. to existing clients as an update on their current holdings and portfolio.

***Market values include accrued income where applicable.

Note: T. Rowe Price strongly encourages you to reconcile this statement to the statements you receive directly from your custodian, broker, or the Price Funds, as applicable, to ensure consistency. If you have any questions with respect to this statement, please contact your T. Rowe Price Portfolio Manager.

Commission Order (Docket No. 18-WCNE-107-GIE)
(11 pages)

**THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners: Shari Feist Albrecht, Chair
Jay Scott Emler
Dwight D. Keen

In the Matter of the 2017 Wolf Creek Triennial Decommissioning Financing Plan.)) Docket No. 18-WCNE-107-GIE

ORDER

This matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision. Having reviewed the pleadings and record, the Commission makes the following findings:

1. On September 1, 2017, the Wolf Creek Nuclear Operating Corporation (WCNOC), Kansas Gas and Electric Company d/b/a Westar Energy (Westar), Kansas City Power & Light Company (KCP&L), and Kansas Electric Power Cooperative, Inc. (KEPCo) (collectively referred to as the Parties) jointly submitted the Decommissioning Financing Plan for the Wolf Creek Generating Station (Wolf Creek).

2. The decommissioning dockets are designed to approve a methodology, which reasonably estimates the costs to decommission Wolf Creek and set a cost escalation rate.[1] This Docket represents the eleventh review over the last thirty years of the cost to decommission Wolf Creek.[2] The Decommissioning Financing Plan includes the 2017 Triennial Decommissioning Cost Study for Wolf Creek.[3] TLG Services, Inc. prepared the Decommissioning Cost Analysis for WCNOC. TLG's Decommissioning Cost Analysis offered two decommissioning cost estimate

[1] Transcript (Tr.), p. 7.
[2] *Id.*
[3] Joint Pleading Regarding Decommissioning Financing Plan, Sep. 1, 2017.

methods: DECON and SAFSTOR. In past Dockets, the Commission has approved the DECON method.[4]

3. Since Wolf Creek's last Decommissioning Cost Analysis in 2014, the question whether the federal government will remove the spent fuel from Wolf Creek upon its decommissioning remains a major concern.[5] As a result, in the 15-WCNE-093-GIE Docket, the Commission directed WCNOC to provide a cost estimate that includes long-term on-site storage of spent fuel.[6] In response, TLG produced Appendix E, which includes some assumptions that the federal government would not timely remove the spent fuel.[7] TLG included those assumptions in Appendix E of its 2017 Decommissioning Cost Analysis, but noted, "[b]ecause the assumptions used in this Appendix E analysis are so speculative at this point, the hypothetical cost effects shown here have not been included in the overall updated cost estimate in this report."[8] Appendix E gave rise to a third decommissioning scenario: DECON Alternative with Long-Term Spent Fuel Management (DECON ALT).

4. WCNOC's Application contained three decommissioning cost estimate methods and a single cost escalation rate.[9] The cost escalation rate is not disputed. The three cost estimate methods are: (1) DECON; (2) DECON Alternative with Long-Term Spent Fuel Management (DECON ALT); and (3) SAFSTOR.[10] DECON assumes the U.S. Department of Energy will take the spent fuel at the time of decommissioning.[11] DECON ALT includes costs associated with on-

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[4] Direct Testimony of Leo M. Haynos (Haynos Direct), May 15, 2018, p. 6.
[5] Attachment 2 to Triennial Wolf Creek Decommissioning Cost Study (Study Attachment 2), Aug. 2017, p. 130 of 139.
[6] Haynos Direct, p. 11.
[7] *Id.*; Study Attachment 2, p. 130.
[8] *Id.*
[9] Tr., p. 8.
[10] *Id.*
[11] *Id.*

site storage of spent fuel for an extended period of time after decommissioning.[12] Both DECON methods assume the spent fuel will be removed from the plant, whereas under SAFSTOR, the spent fuel remains at the facility.[13] SAFSTOR is a deferred decontamination, where the unit is shut down and safely stored until the unit is removed over a sixty-year timeframe.[14] The total cost for DECON is $814 million (ending in 2053).[15] The total cost for DECON ALT is $1.09 billion (ending in year 2075).[16] The total cost for SAFSTOR is $1.09 billion (ending in 2106).[17] DECON and SAFSTOR have similar engineering, planning, and site preparation requirements.[18]

5. On May 15, 2018, Adam Gatewood and Leo Haynos filed testimony on behalf of Commission Staff (Staff). Gatewood recommended the Commission adopt the inflation forecasts proposed by TLG.[19] Haynos testified that TLG is a nationally renowned engineering firm specializing in decommissioning nuclear plants and that their decommissioning estimates are reasonable.[20] Due to the U.S. Department of Energy's failure to develop a plan to dispose of spent nuclear fuel from commercial nuclear generating plants, Haynos recommended that any estimate should consider the costs of on-site storage.[21] Haynos concluded:

> Because of the uncertainty in DOE accepting spent fuel, I recommend the Commission consider the Appendix E cost estimate [DECON ALT] as the appropriate methodology for accumulating sufficient funds to decommission the Wolf Creek site. In consideration of the industry's hesitancy in acknowledging DOE's failure to date to accept spent fuel, the Commission alternatively could approve the SAFSTOR estimate as the appropriate methodology for the decommissioning financing plan.[22]

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[12] *Id.*
[13] Haynos Direct, p. 7.
[14] *Id.*; Study Attachment 2, pp. 8-9 of 139.
[15] Haynos Direct, p. 13.
[16] *Id.*
[17] *Id.*
[18] Study Attachment 2, pp. 38-39 of 139.
[19] Direct Testimony of Adam H. Gatewood, May 15, 2018, p. 3.
[20] Haynos Direct, pp. 8-9.
[21] *Id.*, p. 12.
[22] *Id.* ,p. 13.

6. On June 12, 2018, Larry Wilkus filed Rebuttal Testimony, explaining that in developing the cost estimate and the resulting impact on rates to fund Westar's and KCP&L's decommissioning trust funds, WCNOC had assumed the Commission would continue to rely on the DECON method.[23] Accordingly, if the Commission adopted either of the methods recommended by Haynos (DECON ALT or SAFSTOR), the utilities would need to collect more money from customers to fund their decommissioning trust funds.[24] Wilkus requested recovery of the additional funds through energy cost adjustments in the pending Westar and KCP&L rate cases.[25]

7. On June 18, 2018, the Citizens Utility Ratepayer Board (CURB)[26] filed the Surrebuttal/Reply Testimony of Stacey Harden, in response to Wilkus's testimony that any increased funding level of the decommissioning trust in this Docket should be recovered through Westar's and KCP&L's RECA Tariffs.[27] Harden testifies that Wilkus's testimony recommending the Commission approve a specific ratemaking treatment for the potential increased funding level is premature and that the Annual Contribution level should continue to be part of base rates, to be determined in the pending KCP&L and Westar rate cases.[28]

8. On June 22, 2018, WCNOC[29] and Staff filed a Joint Motion to Approve Settlement and Agreement. Under the proposed Settlement and Agreement, the Commission would adopt the DECON ALT methodology in its Decommissioning Cost Analysis. Under the DECON ALT methodology, the Signatories agree $1.088 billion in 2017 dollars is the cost for decommissioning funding and for use by Westar, KCP&L and KEPCo in setting funding levels for each company's

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[23] Rebuttal Testimony of Larry Wilkus, June 12, 2018, p. 4.
[24] *Id.*
[25] *Id.*, p. 6.
[26] CURB was granted intervention on September 19, 2017.
[27] Surrebuttal/Reply Testimony of Stacey Harden, June 18, 2018, p. 3.
[28] *Id.*, p. 5.
[29] Westar and KCP&L each own 47% of WCNOC. KEPCo owns the remaining 6%.

respective Decommissioning Trust Account.[30] The owners of Wolf Creek agree to use an annual 2.91% escalation rate to escalate the 2017 decommissioning cost estimate from 2017 dollars to the appropriate dollar amount in the year the decommissioning costs occur.[31] CURB is opposed to the proposed Settlement.

9. On June 27, 2018, Wilkus, Gatewood, and Haynos filed testimony in support of the settlement; and Harden of CURB, filed testimony opposing the settlement. CURB's primary concern in opposing the settlement was the DECON ALT plan results in a significant increase in the decommissioning cost estimate.[32]

10. On June 29, 2018, Wilkus, Gatewood, and Haynos each filed rebuttal testimony in support of the proposed settlement. In his testimony, Wilkus explained adopting the DECON ALT plan would increase Westar's annual revenue requirement by approximately $2 million and KCP&L's by approximately $1.2 million.[33] The increased revenue requirement constitutes about a one-tenth of 1% increase for Westar and less than 0.02% increase for KCP&L.[34]

11. On July 10, 2018, the Commission held an Evidentiary Hearing. WCNOC, Staff, and CURB appeared by counsel. The Commission heard live testimony from a total of five witnesses, including two on behalf of WCNOC, one on behalf of CURB, and two on behalf of Staff.[35] The parties had the opportunity to cross-examine the witnesses at the evidentiary hearing and to redirect their own witnesses. CURB did not dispute the numbers proposed by TLG regarding the Wolf Creek decommissioning costs, but argued the numbers were based on

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[30] Non-Unanimous Settlement Agreement, June 22, 2018, ¶ 4.
[31] *Id.*, ¶ 5.
[32] Testimony in Opposition to Settlement of Stacey Harden, June 28, 2018, p. 4.
[33] Responsive Testimony is Support of Stipulation and Agreement of Larry Wilkus, June 29, 2018, p. 2.
[34] *Id.*, pp. 2-3.
[35] *See* Tr. p. 3.

speculation and assumptions.[36] Accordingly, CURB asserts the Settlement Agreement is not supported by substantial, competent evidence.[37]

12. At the hearing, CURB stated:

> CURB simply requests the Commission to reject the Settlement Agreement as proposed by the parties and instead take a long, hard look at the evidence and all the options presented to the Commission available in the TLG plan and make the best decision possible.[38]

While CURB contends there is not substantial evidence to support using DECON ALT as a decommissioning scenario, it does not contest the 2.91% escalation rate agreed to in the Settlement Agreement. Since the recommended 2.91% escalation rate is uncontested, the Commission finds it appropriate to apply the 2.91% escalation rate to whichever decommissioning scenario it selects.

13. As CURB and Staff note, TLG openly acknowledges the speculative nature of the DECON ALT decommissioning scenario.[39] Similarly, Haynos explains this Docket represents the first time TLG has presented a formal study detailing the DECON ALT scenario.[40] In the last Triennial Review, Haynos recommended considering interim long-term storage, but was unable to recommend a methodology with interim long-term storage because TLG had not presented an in-depth cost estimate for interim long-term storage.[41] Appendix E represents the first time the Commission has been presented with an estimate instead of a conceptual approach.[42]

14. Even though TLG offers a cost estimate for the DECON ALT decommissioning scenario, the Commission remains concerned that DECON ALT is too speculative. All of the parties to the Docket agree that the DECON ALT method is speculative. Rather than adopt a

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[36] Tr., pp. 11-12.
[37] *Id.*, p. 12.
[38] Tr., pp. 13-14.
[39] *See id.*, p. 27; Haynos Direct, p. 11; Study Attachment 2, p. 130 of 139.
[40] Tr., p. 79.
[41] *Id.*, pp. 82-83.
[42] *Id.*

methodology reliant on unsubstantiated speculation, the Commission prefers a methodology that has been endorsed by the Nuclear Regulatory Commission (NRC).

15. In 1988, the NRC announced decommissioning requirements for licensed nuclear power facilities.[43] The NRC defined three acceptable decommissioning alternatives: (1) DECON, (2) SAFSTOR, and (3) ENTOMB. Under DECON, portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level where the property can be used without restriction after the plant closes.[44] Under SAFSTOR, the nuclear facility is safely stored and decontaminated to a level where the property can be used without restriction within 60 years.[45] Under ENTOMB, radioactive contaminants are encased in concrete until the radioactive material decays to a level permitting unrestricted use of the property.[46] In March 2017, the NRC staff proposed removing the ENTOMB option from existing guidance documents, deeming it impracticable.[47] None of the parties advocate for the ENTOMB method. As there is no evidence in the record to support the ENTOMB method, the Commission will not consider it as a viable option.

16. Since 1989, the NRC's Information Digest indicates eighteen reactors have been shut down.[48] DECON was the decommissioning alternative selected for nine of those reactors, SAFSTOR was selected for five, and the remaining four were initially placed in safe-storage before switching to DECON.[49] In choosing between DECON and SAFSTOR, the Commission believes it would be extremely irresponsible to select a methodology that assumes the federal government will be able to accept the spent fuel at the time of decommissioning. There is no evidence that the

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[43] Study Attachment 2, p. 8 of 139.
[44] *Id.*
[45] *Id.*, pp. 8-9.
[46] *Id.*, p. 9.
[47] *Id.*
[48] Attachment 7 to Triennial Wolf Creek Decommissioning Cost Study (Study Attachment 7), Aug. 2017, p. 4 of 20.
[49] *Id.*, pp. 4-5 of 20.

federal government has any plan to collect and remove the spent fuel. Accordingly, the Commission is gravely concerned that adopting any methodology that does not factor in on-site storage would subject future generations to massive unfunded decommissioning costs, resulting in rate shock. To avoid future rate shock, the Commission is left with two options: DECON ALT or SAFSTOR.

17. The cost estimate for SAFSTOR and DECON ALT are roughly the same in today's dollars,[50] but 80% of DECON ALT spending occurs from 2045-2050, shortly after the plant is shut down.[51] Under SAFSTOR, only about 30% of the spending occurs during that timeframe, with 43% of the spending occurring between 2100 and 2106.[52]

18. The Commission finds SAFSTOR is the best cost estimate methodology for decommissioning Wolf Creek. Unlike DECON ALT, SAFSTOR is one of the three cost estimate methodologies recognized by the NRC. The Commission gives great weight to the NRC's recognition of SAFSTOR as an appropriate cost estimate. DECON ALT appears to be a hybrid of DECON and SAFSTOR that has been used in four decommissionings since 1989,[53] but has not been officially recognized by NRC. Therefore, while the Commission finds SAFSTOR is the best cost estimate methodology for decommissioning Wolf Creek based on the available evidence, if WCNOC believes DECON ALT is a better cost estimate methodology, the Commission encourages WCNOC to present a more detailed Appendix E in its next Triennial Review.

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[50] Tr., pp. 32-33; Haynos Direct, p. 13.
[51] *Id.*
[52] *Id.*
[53] *See* Study Attachment 7, p. 4 of 20.

THEREFORE, THE COMMISSION ORDERS:

A. The Joint Motion to Approve Settlement and Agreement is denied.

B. The SAFSTOR cost estimate methodology will be used to calculate decommissioning costs for Wolf Creek. The 2.91% escalation rate agreed to by the parties is approved.

C. Any party may file and serve a petition for reconsideration pursuant to the requirements and time limits established by K.S.A. 77-529(a)(1).[54]

D. The Commission retains jurisdiction over the subject matter and parties to enter further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Albrecht, Chair; Emler, Commissioner; Keen, Commissioner

Dated: 08/02/2018

Lynn M. Retz
Secretary to the Commission

BGF

[54] K.S.A. 66-118b; K.S.A. 77-503(c); K.S.A. 77-531(b).

CERTIFICATE OF SERVICE

18-WCNE-107-GIE

I, the undersigned, certify that the true copy of the attached Order has been served to the following parties by means of electronic service on 08/02/2018.

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/S/ DeeAnn Shupe

DeeAnn Shupe

Direct Testimony of Adam H. Gatewood (September 12, 2018)
(93 pages)

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Services.	**)** **)** **)** **)**	**Docket No. 18-KCPE-480-RTS**

DIRECT TESTIMONY

PREPARED BY

Adam H. Gatewood

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION

September 12, 2018

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Q. Would you please state your name and business address?

A. My name is Adam H. Gatewood. My business address is 1500 Southwest Arrowhead Road, Topeka, Kansas, 66604.

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

A. I am employed in the Utilities Division of the Kansas Corporation Commission as a Managing Financial Analyst.

Q. What is your educational and professional background?

A. I graduated from Washburn University with a B.A. in Economics and a Masters of Business Administration. I have filed testimony on cost of capital and related financial issues before the Commission in more than 120 proceedings. I have also filed testimony on cost of capital issues before the Federal Energy Regulatory Commission in natural gas pipeline and electric transmission dockets.

Executive Summary

Q. What issues are you testifying to in this Docket?

A. My testimony addresses the annual accrual for KCP&L's nuclear decommissioning trust (NDT) and the rate of return used to calculate KCP&L's revenue requirement. With respect to the annual accrual for the Kansas portion of KCP&L's NDT, I recommend that an annual accrual of $2,036,230, an amount equal to its current annual accrual, based on the SAFESTOR decommissioning methodology selected by the Commission in Docket 18-WCNE-107-GIE. With respect to the rate of return, I recommend that the Commission adopt a rate of return of 7.07% that incorporates the 9.30% return on equity set out in the Non-Unanimous Settlement approved in Docket No. 18-KCPE-095-MER (18-095). My analysis in the instant Docket provides substantial competent evidence that 9.30% is a fair and reasonable return for both shareholders and ratepayers and, therefore, it should be adopted by the Commission to set KCP&L's revenue requirement in this Docket.

Q. What documents did you review to prepare your analysis?

A. In preparing my rate of return analysis and recommendation, I reviewed the following documents directly connected to this Docket: 18-KCPE-480-RTS (18-480) Direct

1 Testimony, Application, the 18-095 Non-Unanimous Settlement Agreement (S&A); and
2 data requests response to KCC #84, 85, 86, and 161. In preparing my recommendations
3 for KCP&L's annual NDT accrual, I reviewed the Commission's Order in 18-WCNE-107-
4 GIE (18-107) issued on August 2, 2018; the Application and testimony filed in Docket 18-
5 107; and responses to KCC data requests 162, 163, 164, and 258 in Docket 18-480.

6 **Decommissioning Trust Annual Accrual**

7 **Q. Please summarize your recommendation for KCP&L's annual NDT accrual.**

8 A. With respect to KCP&L's NDT for its Kansas jurisdiction, I recommend its annual accrual
9 remain unchanged from its current level of $2,036,230. My recommendation incorporates
10 the Commission's findings issued in its August 2, 2018 Order in the 18-107 Docket. In
11 that Order, the Commission adopted the SAFESTOR decommissioning methodology.

12 **Q. Describe the triennial review process of the decommissioning cost estimates.**

13 A. The triennial review is done in two phases. In phase one, the Commission reviews the
14 decommissioning cost study, selects the decommissioning methodology, and decides on
15 the inflation rate to apply to the decommission cost estimate. By selecting the
16 methodology, the Commission is selecting a cost estimate that is in current-year dollars.
17 The inflation rate is necessary to escalate those costs to the year they will occur. The sum
18 of those inflated costs is the amount that the nuclear plant's owners must accumulate in
19 their respective NDTs. In the latest triennial review, the Commission selected the
20 SAFESTOR methodology and a 2.91% escalation rate. Phase two determines the annual
21 accrual necessary to fully fund the owner's NDT.

1 **Q. What amount did KCP&L propose for its Kansas NDT annual accrual?**

2 A. KCP&L proposed to keep its NDT annual accrual unchanged at $2,036,230 as set in the
3 previous review in Docket No. 15-KCPE-116-RTS. This position is KCP&L's adjustment
4 CS-37 sponsored by Ronald Klote. KCP&L filed this position prior to the Commission's
5 decision in 18-107. We now have the 18-107 Order which selected the SAFESTOR
6 decommissioning methodology which is lengthier and more expensive than the
7 decommissioning methodology selected in previous investigations. My review
8 incorporates the costs and timing of the SAFESTOR methodology as adopted by the
9 Commission. Even with the additional costs associated with the latest decommissioning
10 cost study filed in the 18-107 Docket, the lower expected returns in the future, and the
11 higher cost decommissioning methodology, I found that KCP&L's current contribution is
12 sufficient to fund its obligations.

13 **Q. What are the forecasted returns you recommend for the NDT?**

14 A. I propose using the expected returns published by J.P. Morgan Asset Management
15 (JPMAM) in the 2018 edition of its Long-Term Capital Market Assumptions (LTCMA).
16 The following table shows the 2018 forecasts for the asset classes used in the NDT and
17 highlights the lowered forecasts. As you can see in the following table, Staff recommends
18 using expected returns that are lower (on average) than those that KCP&L used in its
19 calculations.

Expected Proposed Portfolio Performance		
	KCP&L Expected Returns	2018 JPMAM
Large Company Stocks	9.59%	6.41%
Small Company Stocks	10.65%	7.35%
International Stocks	8.46%	7.61%
Corporate Bonds	2.96%	4.23%
Cash	0.62%	2.00%
Sources:		
KCC-258		
J.P. Morgan Asset Management		
Long-Term Capital Market Assumptions		

These are marked differences in returns for almost every asset class. Under Staff's assumptions, in a portfolio of these assets, this difference results in a 100 basis point lower annual return from many of the years.

Q. Is JPMAM's publication a reasonable source for these types of forecasts?

A. Yes, J.P. Morgan's forecasts in this publication are consistent with forecasted returns by other money management firms and reflect the expected returns of institutional portfolio managers.

Q. Historically, what has KCP&L's NDT earned?

A. I performed an internal rate of return analysis on KCP&L's deposits to its NDT from 1986 through the present. Over that time period, KCP&L's NDT experienced an annual return of 5.94% including the effects of income taxes on unrealized gains, management fees and expenses.

Q. How did you calculate the annual accrual amount?

A. My calculation appears in Schedule AHG-1, which assumes the SAFESTOR methodology,

1 an NDT balance (net of income taxes on unrealized gains) as of June 30, 2018, forecasted
2 returns from the 2018 edition of the JPMAM-LTCMA, and the portfolio management fees
3 reported by KCP&L. The weighted forecasted returns of the portfolio across time appear
4 in Schedule AHG-2. The annual accrual is the amount that equates the cash in-flows
5 (annual accrual plus returns on the portfolio) to the cash out-flows (the decommissioning
6 expenses).

7 **Q. In 18-WSEE-328-RTS you recommended a significant increase in Westar Energy**
8 **Inc.'s (Westar) annual accrual to fund its share of the decommissioning costs. Why**
9 **is KCP&L's annual accrual remaining the same as opposed to increasing at a rate**
10 **similar to that of its co-owner?**

11 A. There could be several factors at work to create this situation. The most direct, simplest,
12 and, therefore most likely, explanation is that KCP&L's portfolio is subject to significantly
13 lower annual expenses (management fees) than Westar's portfolio. Each owners' portfolio
14 management fees directly affect their respective expected returns over the remaining life
15 of their trust funds. To the extent that the current management fees are reflective of those
16 paid in years past, KCP&L's lower annual expenses are the likely reason that its portfolio
17 has experienced a higher historic return than Westar's.

18 **Rate of Return Analysis**

19 **Q. Please discuss the framework of Staff's rate of return (ROR) analysis in this Docket.**

20 A. Staff's ROR analysis in this Docket is, in part, a continuation of the analysis that Staff
21 performed in the 18-095 Merger Docket and 18-WSEE-328-RTS Westar rate case. These

1 Dockets are made interdependent by the 18-095 S&A,[1] where signing parties committed
2 to supporting an allowed return on equity (ROE) of 9.30%[2] in this Docket for KCP&L, as
3 well as the 18-WSEE-328-RTS Docket for Westar Energy (18-328). On May 24, 2018,
4 the Commission approved the Non-Unanimous Stipulation and Agreement filed in the
5 Docket 18-095 S&A.[3] An Order is due in the 18-328 rate case by September 27, 2018.

6 **Q. With regard to KCP&L's ROR in this Docket, what are your findings and**
7 **recommendations?**

8 A. The following table summarizes my recommended ROR and the components of the
9 calculation.

Staff Proposed -- KCP&L Rate of Return
Updated Capital Structure - Section 7 of Application
Test Year Ended September 30, 2017 Updated to June 30, 2018

	Weight	Cost	Weighted Cost
Long-term Debt	50.91%	4.93%	2.51%
Common Equity	49.09%	9.30%	4.57%
			7.07%

Source: 18-KCPE-480-RTS; Response to DR#161

10

11 As a point of comparison, KCP&L's Application is based on the following ROR.

[1] Non-Unanimous Settlement Agreement; 18-KCPE-095-MER; filed March 17, 2018.
[2] Non-Unanimous Settlement Agreement; 18-KCPE-095-MER; filed March 17, 2018; at paragraph 32, iv, 1; p. 15.
[3] Order Approving Merger; 18-KCPE-095-MER; Issued May 24, 2018.

KCP&L Rate of Return
Proposed Rate of Return in Section 7 of Application
Test Year Ended September 30, 2017

	Weight	Cost	Weighted Cost
Long-term Debt	50.25%	4.94%	2.48%
Common Equity	49.75%	9.30%	4.63%
			7.11%

Source: 18-KCPE-480-RTS; Section 7
Supplemental Direct Testimony of Darrin R. Ives; June 26, 2018

KCP&L's Application filed May 1, 2018, incorporated a 9.85% cost of common equity. With the Commission Order in 18-095 accepting the Non-Unanimous Settlement Agreement, KCP&L reduced its recommended cost of equity request from 9.85% to 9.30%.

Setting the rate of return requires decisions on the cost of debt, the cost of equity, and the weight of each in the utility's capital structure. Staff is preparing its revenue requirement incorporating an update to June 30, 2018, from the September 30, 2017, balances used in the Application. The ROR that I recommend is based on the updated account balances and costs for the capital items. The update to Section 7 results in a minor change in the ROR from KCP&L's position due a small change in the capital ratios of debt and equity. I agree with the capital structure and cost of debt contained in KCP&L's update.

Capital Structure

Q. Do you have any adjustments to KCP&L's capital structure?

A. No. I am using the capitalization ratios of June 30, 2018.

Q. Is KCP&L's updated capitalization within the range seen in the electric utility

industry?

A. Yes, healthy, financially sound electric utilities have traditionally employed capitalization policies of about 50% debt and 50% equity. The group of electric utilities selected as the proxy group for my cost of capital analysis follows this same pattern as seen in the following table.

Long-Term Debt Ratios Staff's Proxy Group 18-KCPE-480-RTS							
					Value-Line Forecasts		
		2015	2016	2017	*2018*	*2019*	*'21 - '23*
Allete Inc	ALE	46.3%	42.0%	41.0%	*41.0%*	*39.5%*	*40.0%*
Alliant Energy Corp	LNT	48.6%	52.8%	49.0%	*50.0%*	*50.0%*	*50.0%*
Ameren Corp	AEE	49.3%	47.7%	49.5%	*49.5%*	*49.0%*	*49.0%*
American Electric Power Co.	AEP	49.8%	50.0%	51.5%	*52.5%*	*54.5%*	*50.5%*
Consolidated Edison Inc	ED	47.9%	50.8%	48.9%	*49.0%*	*48.5%*	*48.5%*
Duke Energy Corp New	DUK	48.6%	52.6%	54.0%	*54.0%*	*55.0%*	*56.5%*
Edison International	EIX	45.0%	41.8%	45.6%	*48.0%*	*48.0%*	*47.5%*
El Paso Electric Co	EE	52.7%	52.7%	51.2%	*53.0%*	*52.0%*	*54.5%*
IDACORP Inc	IDA	45.6%	44.8%	43.7%	*44.0%*	*42.0%*	*44.0%*
NorthWestern Corporation	NWE	53.1%	52.0%	50.2%	*49.5%*	*48.5%*	*46.0%*
OGE Energy Corp	OGE	44.3%	41.1%	41.7%	*43.0%*	*44.0%*	*45.5%*
Pinnacle West Capital Corp	PNW	43.0%	45.6%	48.9%	*48.0%*	*48.5%*	*45.5%*
Portland General Electric Co.	POR	47.8%	48.4%	50.1%	*47.0%*	*50.5%*	*48.5%*
Xcel Energy Inc	XEL	54.1%	56.3%	55.9%	*58.0%*	*57.0%*	*58.0%*
	Average	48.3%	48.5%	48.7%	49.0%	49.1%	48.9%
	Median	48.3%	49.2%	49.3%	49.3%	48.8%	48.5%
	Min	43.0%	41.1%	41.0%	41.0%	39.5%	40.0%
	Max	54.1%	56.3%	55.9%	58.0%	57.0%	58.0%
Source: Value-Line Investment Survey (April 27, 2018; May 18, 2018; and June 15, 2018)							

Q. Is KCP&L's updated capitalization consistent with the capital structure limitations discussed in the 18-095 S&A?

A. Yes, it complies with the provisions of Attachment 1 of the 18-095 S&A.

Q. Is this capitalization ratio consistent with the current capitalization of evergy, Inc. the

1 **new merged company?**

2 A. No, immediately post-merger, the holding company for KCP&L has an equity ratio in
3 excess of 61%.[4] evergy management has stated that it intends to reduce the equity ratio to
4 a level close to 50% during the next few years. Regardless of that proposal, I would not
5 recommend using the current holding company equity ratio to establish KCP&L's revenue
6 requirement. It is not the lowest cost capitalization for the utility and it is not within the
7 industry norms.

8 **Cost of Debt**

9 **Q. Do you propose any adjustments to KCP&L's cost of debt?**

10 A. As with the capital structure, I recommend an update from September 31, 2017, to June 30,
11 2018, which captures a very minor change in the embedded cost of debt.

12 **Cost of Equity Analysis**

13 **Q. Please summarize Staff's position on KCP&L's cost of equity?**

14 A. Staff recommends that the Commission authorize a 9.30% ROE, the same as that applied
15 for purposes of the Earnings Review & Sharing Plan (ERSP) that was accepted by the
16 Commission in the 18-095 Docket. KCP&L agrees with Staff's position and has
17 withdrawn its original request for a 9.85% ROE.[5] My analysis of the current capital
18 markets finds that, inclusive of the benefits from the ERSP and other terms of the 18-095

[4] evergy, Inc.; Form-10Q for the period ending June 30, 2018.
[5] Supplemental Direct Testimony of Darrin R. Ives, filed June 26, 2018.

1 S&A, an ROE of 9.30% is reasonable for KCP&L stockholders and consumers. The
2 benefits that accrue to consumers through the 18-095 S&A are made available with some
3 additional risks to the shareholders. My testimony in the 18-095 Docket[6] discussed the
4 benefits and risks related to 18-095 S&A and I will summarize that discussion because they
5 are equally important to deciding the cost of capital issues in this Docket.

6 **Q. Please discuss the additional risks posed by the 18-095 S&A that was approved by the**
7 **Commission on May 24, 2018.**

8 A. The added risks to shareholders include:

9 • a five-year rate moratorium during which KCP&L cannot file a rate case in
10 Kansas;[7]
11 • upfront bill credits to KCP&L Kansas customers totaling $7,514,220;[8]
12 • minimum annual credits to consumers of $2,817,832 by March 31st of 2019, 2020,
13 2021, and 2022;[9]
14 • $7,468,874 million of merger savings built into the revenue requirement in this
15 rate case;[10] and
16 • an Earnings Review and Sharing Plan for excess earnings above the 9.30%
17 allowed return for years 2020, 2021, 2022, and 2023.[11]

18 Staff believes the 18-095 S&A presents additional risks to shareholders because it demands
19 annual credits to consumers that has the effect of lowering KCP&L's earned return; reduces
20 the value of earnings if KCP&L earns above its allowed return; sets a period of five years
21 during which KCP&L cannot file a rate case if its earnings are less than its allowed return;
22 and sets a period of five years during which KCP&L cannot file a rate case if its capital
23 costs increase. With the 18-095 S&A in place that sets a period of five years during which

[6] Testimony of Adam H. Gatewood, 18-KCPE-095-MER filed January 29, 2018; p. 11-15.
[7] Order Approving Merger, issued May 24, 2018; 18-KCPE-095-MER, Attachment A, p. 45; #24.
[8] Order Approving Merger, issued May 24, 2018; 18-KCPE-095-MER, Attachment A, p. 44; #18.
[9] Order Approving Merger, issued May 24, 2018; 18-KCPE-095-MER, Attachment A, p. 44; #18.
[10] Order Approving Merger, issued May 24, 2018; 18-KCPE-095-MER, Attachment A, p. 45; #25.
[11] Order Approving Merger, issued May 24, 2018; 18-KCPE-095-MER, Attachment A, p. 46; #26.

1 KCP&L cannot file a rate case, KCP&L must find cost savings equal to the guaranteed
2 fixed annual credits in order to achieve its authorized return. Consumers could also see
3 additional annual credits if the Applicant's profits exceed the 9.30% threshold. KCP&L's
4 shareholders will retain only a portion of any earnings above the allowed return over the
5 rate moratorium.

6 **Q. Without the 18-095 S&A, would Staff be inclined to recommend a 9.30% ROE for**
7 **KCP&L?**

8 A. Without the 18-095 S&A, Staff would likely be recommending a lower allowed return for
9 KCP&L given the current financial markets. As I discussed earlier, and in my 18-095
10 testimony, there are risks and benefits to the 18-095 S&A, primarily the ERSP, a five-year
11 rate moratorium, and the bill credits to consumers cause me to distinguish this Docket from
12 a traditional rate case. Without the 18-095 S&A, Staff's recommendation – based purely
13 on the results of my financial analysis – could likely be closer to 9.00%. However, Staff's
14 recommendation would also have to consider the fact that a 9.00% recommendation is a
15 full 25 to 30 basis points below the lowest authorized ROE observation in the current
16 national average and would, thus, be a highly contentious recommendation, which would
17 most likely result in litigation. Without the 18-095 S&A, it is likely my recommendation
18 would have been between 9.10% and 9.20% given the plateau seen in allowed returns
19 granted by utility regulatory commissions over the last several quarters and the fact that a
20 9.00% return is well below the lowest observation in the recent national average.[12]

[12] RRA Regulatory Focus Major Rate Case Decisions: January – June 2018; S&P Global Market Intelligence; July 17, 2018; p. 10.

1 **Q. Is Staff recommending an ROE range for the Commission?**

2 A. I recommend the Commission adopt a 9.30% ROE, the same that is used in the ERSP. If
3 for some reason the Commission finds a need to deviate from the 9.30% ROE, then I
4 recommend that a range of 9.10% to 9.50%, which is consistent with the terms of the 18-
5 095 S&A.[13] This range is fully supported by my cost of equity analysis specific to the risks
6 of KCP&L in this Docket.

7 **Q. Do you believe the Commission can deviate from the 9.30% ROE even though it**
8 **adopted the 18-095 S&A?**

9 A. Yes, certainly that is well within the Commission's rights if it believes the evidence cannot
10 support the allowed return sought in the 18-095 S&A. If the Commission adopts an ROE
11 lower than 9.30%, KCP&L has the option of shortening the rate moratorium from five
12 years to three years. Staff believes there are benefits for consumers to the full five-year
13 rate moratorium that may not be present in a three-year moratorium, such as an incentive
14 to capture merger related synergies and a period of relative rate stability. Those are two
15 examples that are not easily quantified but Staff believes them to be beneficial to
16 consumers.

17 **Q. How does a 9.30% ROE compare to recent decisions from around the country?**

18 A. A 9.30% return on equity is at the low-end of recent observations for electric utility rate
19 cases. For the first six months of 2018, the average ROE granted was 9.74% with thirteen

[13] Non-Unanimous Settlement Agreement; 18-KCPE-095-MER filed March 17, 2018; at paragraph 32, iv, 1; p. 15.

1 observations.[14] This group of observations includes only those decisions associated with
2 vertically integrated (generation, transmission, and distribution services) electric utilities
3 and not tied to a limited-issue rider. Over the past decade, allowed returns have declined
4 nationally, although the rate at which those declines have occurred has varied across
5 jurisdictions. That decline happened at a more rapid pace in Kansas than in most other
6 jurisdictions. Reviewing decisions of the past year, there appears to be a plateau in allowed
7 returns; that is the rate of decline has fallen off although clearly the allowed returns are
8 significantly lower than those granted in the past. Graphs of allowed returns appear on
9 page 20 and 21.

Major Rate Case Decisions: January - June 2018

1/18/2018	Kentucky Power Co.	KY	9.70%
1/31/2018	Public Service Company of Oklahoma	OK	9.30%
2/2/2018	Interstate Power and Light Co.	IA	9.98%
2/23/2018	Duke Energy Progress, LLC	NC	9.90%
3/12/2018	ALLETTE (Minn Pwr)	MN	9.25%
3/29/2018	Consumer Energy Co.	MI	10.00%
4/12/2018	Indiana Michigan Power Co.	MI	9.90%
4/13/2018	Duke Energy Kentucky, Inc.	KY	9.73%
4/18/2018	DTE Electric Co.	MI	10.00%
4/26/2018	Avista Corp.	WA	9.50%
5/30/2018	Indiana Michigan Power Co.	IN	9.95%
6/22/2018	Duke Energy Carolina, LLC	NC	9.90%
6/29/2018	Hawaii Electric Light Co., Inc.	HI	9.50%
			9.74%

Source:
Major Rate Case Decision: January - June 2018; S&P Global Market Intelligence; July 17, 2018; p.10 (Electric Utility Decisions)

Removed decisions involving:
Distribution only electric decisions
Limited issue riders

10

11 **Q. Please discuss how Staff arrived at the 9.30% ROE for the ERSP.**

[14] *RRA Regulatory Focus Major Rate Case Decisions: January – June 2018; S&P Global Market Intelligence; July 17, 2018; p. 10.*

1 A. Staff was searching for a productive and fair settlement position for the 18-095 Merger,
2 which led Staff to consider a rate moratorium and a sharing mechanism of earnings above
3 an allowed return. Thus, it was necessary for Staff to perform a fresh and thorough analysis
4 of capital costs to determine the appropriate threshold for measuring earnings. At that time,
5 we were also aware that both KCP&L and Westar would be filing rate cases in 2018 and
6 the two utilities expressed a need to have some level of certainty regarding the cost of
7 equity recommendations in their upcoming rate cases, especially if they were going to
8 commit to an extended rate moratorium or an earnings sharing plan. For that reason, parties
9 agreed that the negotiated ROE applied in the ERSP would also become their
10 recommendation to use in setting the revenue requirements in the 2018 rate cases.

11 As I discussed in my 18-095 testimony,[15] my cost of capital analysis was developed in a
12 manner using conventions identical to those applied in rate cases. The results of my
13 analysis indicated that 9.30% was within a reasonable range for the ERSP. I also found
14 that capital costs were similar to those observed during Westar's and KCP&L's last rate
15 cases, which occurred in 2015. The Commission set KCP&L's ROE at 9.30% and adopted
16 a settlement in which Westar's ROE was about 9.35%. Thus, the cost of capital analysis
17 provided Staff with the position that Westar's and KCP&L's ROE could remain in place
18 from their last rate cases to be used for the ERSP and setting rates in their 2018 rate cases.

19 **Q. If the parties to the 18-095 S&A agreed to support a 9.30% ROE in this Docket, why**
20 **did you perform a new cost of capital study?**

21 A. I did this to provide the Commission with a comprehensive record on which to base its

[15] Testimony of Adam H. Gatewood, 18-KCPE-095-MER filed January 29, 2018; p. 33.

1 decision and to establish facts that demonstrate an ROE of 9.30% is a just and reasonable
2 return to use in determining KCP&L's revenue requirement. The signatories to the 18-095
3 S&A are aware that we cannot make a decision for the Commission. Ultimately, it is the
4 Commission that has to review the evidence and decide if 9.30% is a just and reasonable
5 return for setting KCP&L's revenue requirement. The legal standards that I discuss later
6 still apply to the Commission's decision, regardless of the fact that several parties have
7 reached an agreement on this issue amongst themselves.

8 **Q. How much time has elapsed since you prepared the analysis for the 18-095 Docket?**

9 A. About nine months. The time period of the capital market data I used in the 18-095 analysis
10 was January 1, 2017, through December 31, 2017, and Staff filed its testimony on January
11 29, 2018. For my analysis in this Docket, I relied on financial data gathered from July 6,
12 2017, through July 3, 2018. In developing our position in the 18-095 Docket, Staff was
13 cognizant of the timing of both of these rate filings. Since the timing of the merger docket
14 and the two upcoming rate cases were relatively close together, Staff was comfortable with
15 connecting the three cases while recognizing our responsibility to prove the 9.3% ROE
16 included in the 18-095 Docket is reasonable for both the ERSP and the following rate cases.

17 **Q. Have capital costs for electric utilities changed significantly over this time span?**

18 A. No. Comparing the results of my analyses performed for the 18-095, 18-328, and this
19 Docket demonstrates that capital costs to electric utilities have not changed significantly.
20 The following table summarizes the results from the analysis performed for each docket.
21 In essence, this table condenses results from three capital cost studies performed over three

over-lapping time periods that cover a total of nineteen months from January 1, 2017, through July 3, 2018.

Comparison of Staff Recommendations Across 18-KCPE-095-MER Related Dockets

Interest Rates Observed for Risk Premium Calculations

	30 Year Treasury Bond	Utility Bonds A/A	Baa/BBB	Moody's Corporate Baa	Bond YTM*
18-095	2.97%	4.13%	4.52%	4.58%	4.24%
18-328	2.90%	3.97%	4.28%	4.39%	3.85%
18-480	2.94%	4.01%	4.32%	4.44%	4.12%

Risk Premiums Over Fixed-Income Interest Rates

	30 Year Treasury Bond	Utility Bonds A/A	Baa/BBB	Moody's Corporate Baa	Bond YTM*
18-095	6.33%	5.17%	4.78%	4.72%	5.06%
18-328	6.40%	5.33%	5.02%	4.91%	5.45%
18-480	6.36%	5.29%	4.98%	4.86%	5.18%

Cost of Equity Models

	Discounted Cash-Flow	Internal Rate of Return	Capital Asset Pricing Models Historic Data	Forecasted Data
18-095	8.09%	7.81%	9.29%	6.30%
18-328	8.22%	8.02%	9.00%	6.09%
18-480	8.28%	8.28%	9.00%	6.09%

*Yield to maturities reported on Great Plains and Westar Energy bonds for 18-KCPE-095-MER; Westar Energy bonds for 18-WSEE-328-RTS; and Great Plains Energy bonds for 18-KCPE-480-RTS.

Data period for each docket:
18-KCPE-095-MER January 2017 - December 2017
18-WSEE-328-RTS May 2017 - April 2018
18-KCPE-480-RTS May 2017 - June 2018

Sources: Gatewood Direct, 18-KCPE-095-MER; filed January 29, 2018; pp. 16, 22.
Gatewood Direct, 18-KCPE328-RTS; filed June 11, 2018; pp. 22,26.

This table summarizes substantial evidence that the current cost of capital has remained similar to the range measured in Staff's the 18-095 S&A. This is true for both the cost of equity of the proxy group of electric utilities as well as broader measures of interest rates on U.S. Government 30 Year Bonds, corporate bonds, and public utility bonds. Staff believes this comparison of capital costs across the three dockets supports the use of a 9.30% return on equity agreed to in the 18-095 S&A to set KCP&L's revenue requirement in this Docket.

1 **Q. Please summarize the results of your cost of equity analysis performed for this**
2 **Docket.**

3 A. The following table summarizes the cost of equity estimates from my study in this Docket;
4 the details of each financial model appears later in my testimony. I relied on a discounted
5 cash flow (DCF) model, a variation of the DCF model known as an internal rate of return
6 (IRR) analysis, and the capital asset pricing model (CAPM). These are the models I
7 typically use to estimate a utility's required return on equity. The results in this table are
8 based on the capital markets using data from July 3, 2017, through July 2, 2018.

Summary of Staff's Cost of Equity Estimates
18-KCPE-480-RTS

	Mean	Low	High
Discounted Cash Flow Analyses			
Two-Stage Growth DCF Model: Based on the Average of Short-Term Growth Forecasts & Long-Term nGDP Forecasts	8.28%	7.84%	8.71%
Internal Rate of Return-Multi-Stage DCF Analysis: Using Short-Term Growth EPS Growth & Long-Term nGDP Forecast	8.28%	7.39%	9.47%
Capital Asset Pricing Models			
Based on Historical Return Data; gathered from 1926 - 2017; Reported by SBBI; Duff & Phelps	9.00%	7.83%	10.93%
Based on Forecasted Return Data Published by J.P. Morgan Asset Management (2018 edition)	6.09%	5.43%	7.17%

9

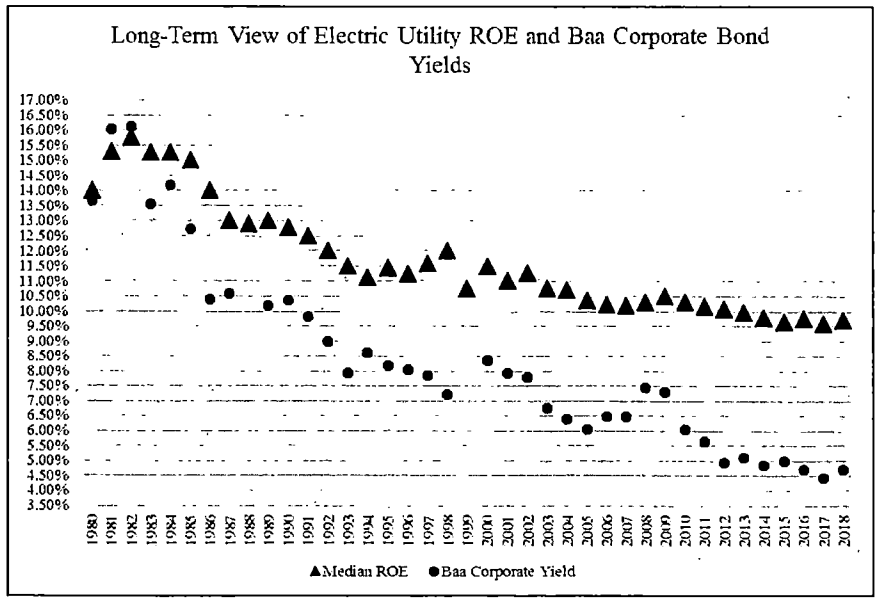
10 **Q. For a point of comparison, please summarize return on equity decisions by this**
11 **Commission and Commissions across the country?**

12 A. The first table contains allowed return on equity decisions made by this Commission in
13 litigated rate cases. As a point of reference to the prevailing capital markets at that time, I

included the yield on the Baa rated corporate bonds as of the month of the Commission's decision.

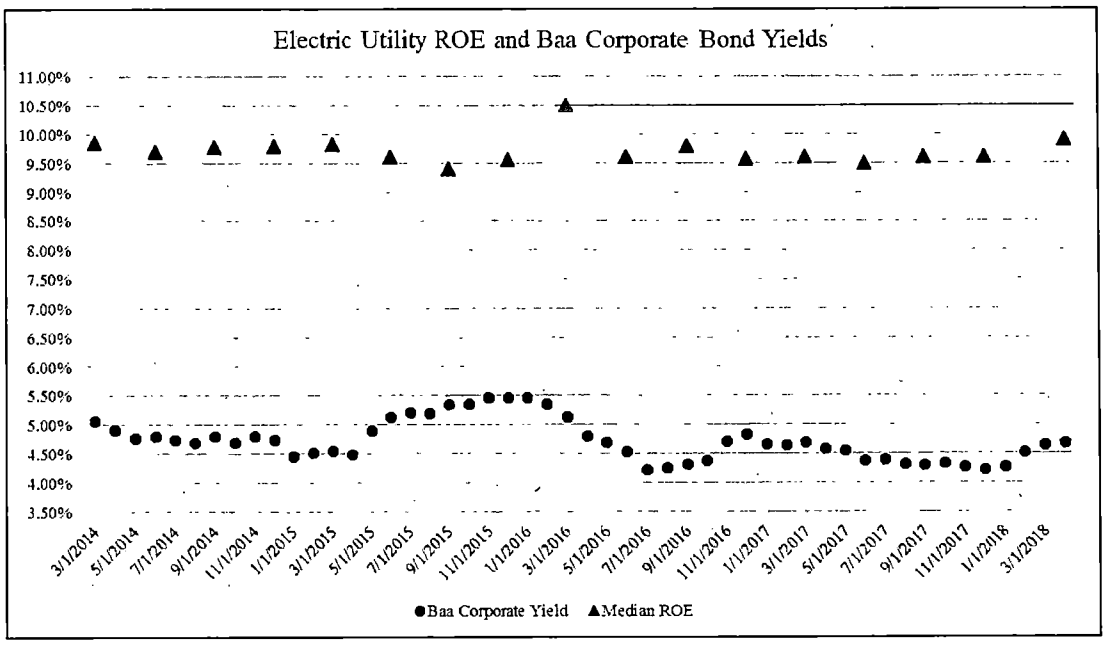
Commission Determined Allowed ROEs -- Kansas Utilities					
Company	Docket	Order Date	Requested ROE	Ordered ROE	Baa Bond Yield
Kansas City Power & Light	15-KCPE-116-RTS	9/10/2015	10.30%	9.30%	4.86%
Atmos Energy Corp.	14-ATMG-320-RTS	9/4/2014	10.53%	9.10%	4.89%
Kansas City Power & Light	12-KCPE-764-RTS	12/13/2012	10.40%	9.50%	4.80%
Kansas City Power & Light	10-KCPE-415-RTS	11/22/2010	10.75%	10.00%	5.56%
Westar Energy Inc.	05-WSEE-981-RTS	12/28/2005	11.50%	10.00%	6.10%
Westar Energy Inc.	01-WSRE-436-RTS	7/25/2001	12.75%	11.02%	7.97%
Kansas Gas Service Co.	193,305-U	4/15/1996	12.00%	10.50%	7.77%
Sources: SNL/RRA; Federal Reserve Bank of St. Louis, FRED					

The following chart is broader in both the time period and reporting scope. It indicates the median return on equity granted in fully-litigated rate cases across the nation from 1980 through June of 2018. As a point of reference to the prevailing capital markets, I included the average yield to maturity of Baa corporate bonds.



The next chart highlights a shorter time period, the last four years from early 2014 through

June of 2018. Compared to the decline seen in the chart of the long-term changes, the past four years show a plateau in the median allowed return granted.



Q. How does Staff's recommendation compare to the returns available on other investments?

A. The following table shows that Staff's recommendation of a 9.30% return on equity allows investors a risk premium over less risky debt investments. These types of income producing securities are viewed as alternatives to investments to utility stocks because, like utility stocks, bonds offer stable valuations and higher current income relative to the equity market. Risk premiums vary over time and across market conditions; thus, there is not a benchmark risk premium or formula that sets a reasonable return on equity at a given interest rate. Nor has the Commission set a definitive spread over bond yields, but the Commission's Order in 15-KCPE-115-RTS (15-116) noted that its decision allowed

1 KCP&L a risk premium of 525 basis points over the yield on its long-term debt.[16] In that
2 Docket, Staff argued that a 525 basis point risk premium over the bond yield was
3 reasonable as it offered stockholders a higher return than available on the lower risk debt
4 securities. The Commission agreed and applied Staff's risk premium to arrive at an
5 allowed return for KCP&L.

KCC Staff's Risk Premium Over Fixed Income Yields
Based on a 9.30% Return on Equity
Fixed Income Yield Observations July 2017 through June 2018
18-KCPE-480-RTS

	30 Year (1)	Utility Bonds (2)		Moody's (3)	KCP&L (4)
	Treasury Bond	A/A	Baa/BBB	Corporate Baa	Bonds YTM
Jun-18	3.03%	4.23%	4.58%	4.83%	4.33%
May-18	3.14%	4.27%	4.62%	4.83%	4.37%
Apr-18	3.07%	4.17%	4.50%	4.71%	4.29%
Mar-18	3.09%	4.12%	4.45%	4.65%	4.22%
Feb-18	3.13%	4.14%	4.42%	4.47%	4.21%
Jan-18	2.88%	3.87%	4.14%	4.25%	3.98%
Dec-17	2.77%	3.80%	4.08%	4.22%	3.94%
Nov-17	2.81%	3.84%	4.11%	4.06%	4.00%
Oct-17	2.88%	3.92%	4.21%	4.32%	4.03%
Sep-17	2.78%	3.89%	4.19%	4.30%	3.95%
Aug-17	2.80%	3.87%	4.20%	4.32%	3.99%
Jul-17	2.88%	3.99%	4.31%	4.40%	4.13%
Average	2.94%	4.01%	4.32%	4.44%	4.12%

Risk Premiums Over Fixed Income Securities

KCC Staff's Recommended ROE	9.30%
Average Yield on 30 Year Treasury Bond	2.94%
Equity Risk Premium Over the 30-Year Treasury Bond Yield	**6.36%**
KCC Staff's Recommended ROE	9.30%
Average Yield on "A" Rated Utility Bonds	4.01%
Equity Risk Premium Over "A" Utility Bond Yield	**5.29%**
KCC Staff's Recommended ROE	9.30%
Average Yield on "BBB/Baa" Rated Utility Bonds	4.32%
Equity Risk Premium Over "Baa/BBB" Utility Bond Yield	**4.98%**
KCC Staff's Recommended ROE	9.30%
Average Yield on "BBB/Baa" Rated Utility Bonds	4.44%
Equity Risk Premium Over Moody's "Baa/BBB" Corporate Bond Yield	**4.86%**
KCC Staff's Recommended ROE	9.30%
Average Yield to Maturity on KCP&L Bonds	4.12%
Equity Risk Premium over Yield on KCP&L Bonds	**5.18%**

1) Board of Governors of the Federal Reserve System (US), 30-Year Treasury Constant Maturity (Federal Reserve Bank of St. Louis; Release H.15)
2) Yield on A and BBB/Baa Rated Public Utilty Bonds 25 to 30 Maturity Reported weekly in Value-Line Investment Survey, Selection & Opinion Section.
3) Yield on Moody's Baa Corporate Bonds reported at FRED (Federal Reserve Bank of St. Louis Electronic Data)
4) Average yield to maturity reported by FINRA on KCP&L 6.05%, 2035; KCP&L 5.30%, 2041; KCP&L 4.20%, 2047, and KCP&L 4.20%, 2048

6

7 **Standards for a Just & Reasonable Rate of Return**

[16] Order issued on KCP&L's Application on Rate Change; 15-KCPE-116-RTS; September 10, 2015; para. 34.

1 **Q. What is the role of rate of return in setting a revenue requirement for public utilities?**

2 A. The standards for setting a just and reasonable rate of return require that, to be reasonable,
3 the allowed return must reflect the risks associated with an equity investment in the utility.
4 For the allowed return to be in that reasonable range, it must compensate for those added
5 risks while capturing a fair proportion of benefits for consumers. The terms of the 18-095
6 S&A, although beneficial to all stake-holders, possess several risks to shareholders not seen
7 in a traditional rate case and the Commission must consider these risks.

8 The allowed ROE is best described as the forward-looking discount rate that is necessary
9 to induce equity investors to commit their capital to the enterprise. The courts have
10 articulated standards for regulatory agencies to use to gauge the fairness and
11 reasonableness of an allowed ROE. Financial analysts and policy-makers rely on the
12 courts' decisions as a guide in estimating the appropriate cost of capital. The opinions do
13 not articulate precisely how to estimate or model a reasonable cost of capital. Instead, the
14 decisions provide critical questions for policy makers and analysts to consider in
15 determining a reasonable return for a regulated utility.

16 In general, United States Supreme Court decisions state that returns granted to regulated
17 public utilities should: 1) be commensurate with returns on investments of similar risk; 2)
18 be sufficient to assure the financial integrity of the utility under efficient economic
19 management; and 3) change over time with changes in the money market and business
20 conditions.[17] An important take-away from these decisions is that the Supreme Court of

[17] Smyth v. Ames, 169 U.S. 466 (1898); Wilcox v. Consolidated Gas Co., 212 U.S. 19, 48-49 (1909); Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-3 (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

1 the United States has afforded regulatory agencies a significant amount of latitude in
2 establishing an appropriate ROR and ROE for a utility. The Kansas Supreme Court has
3 recognized and follows this body of law.[18] This Commission has noted this fact in Orders
4 issued in previous dockets.[19]

5 **Q. Discuss how financial analysts apply the standards established by the Court.**

6 A. For an allowed ROE to meet the legal standards, the return should be as specific as possible
7 to the utility in question. There are several court cases that, as a group, are viewed as the
8 keystone to measuring the adequacy of a utility's allowed return. The earliest of these
9 decisions go back to an era when it was not only the "rate of return" at issue but also the
10 fundamental measurement of the investment in the utility enterprise, commonly referred to
11 as rate base. This is less of an issue today as regulators, utility management, and investors
12 readily accept actual historic-depreciated value as the measure of investment to estimate
13 the value of a utility's rate base (as opposed to reproduction cost or market value). The
14 Court's decision in *Bluefield* addressed both rate base and ROR.[20] Treatises on rate of
15 return for public utilities, such as The Cost of Capital – A Practitioner's Guide, agree that
16 *Bluefield* lays out the four standards for a fair return:

17 *1) Comparable Earnings* – a utility is entitled to a return similar to that being earned by
18 other enterprises with similar risks, but not as high as those earned by highly profitable
19 or speculative ventures;
20 *2) Financial Integrity* – a utility is entitled to a return level reasonably sufficient to assure
21 financial soundness;

[18] Kansas Gas & Elec. Co. v. State Corp. Comm'n, 239 Kan. 483, 491, 720 P. 2d 1063, 1072 (1986).
[19] Order: 1) Addressing Prudence; 2) Approving Application, in Part; & 3) Ruling on Pending Requests, Docket No. 10-KCPE-415-RTS; November 22, 2010; 37-38.
[20] Bluefield Water Works & Improvement Co. v. Pub. Svc. Comm'n of West Virginia, 262 U.S. 679, 692-3 (1923).

1 3) *Capital Attraction* – a utility is entitled to a return sufficient to support its credit and
2 raise capital; and
3 4) *Changing Level of Returns* – a fair return can change along with economic conditions
4 and capital markets.[21]

5 As a financial analyst formulating rate of return analyses for our state commission, I take
6 from *Bluefield* that the Court requires a rate order that allows a utility an opportunity to
7 earn a return consistent with the utility's risk profile and consistent with observations in
8 the capital markets. The Court's decision in *Hope,*[22] like that in *Bluefield,* dealt with both
9 valuation of rate base, as well as rate of return on that rate base. With respect to the rate of
10 return, the Court in *Hope* affirmed the four standards set out in *Bluefield.*

11 **KCC Proxy Group**

12 **Q. How did you select a proxy group for your cost of equity analysis?**

13 A. To narrow the universe of potential proxy companies, I used the following selection
14 criteria:

15 • Has publicly traded common stock
16 • Is an electric utility followed by Value-Line Investment Survey
17 • No recent spin-offs, mergers or distressed assets

[21] The Cost of Capital – A Practitioner's Guide by David C. Parcell; Prepared for the Society of Utility and Regulatory Financial Analysts; 1997; pp. 3-13 to 3-14.

[22] *Federal Power Comm'n. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). "The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint."

- Exhibits stable dividends—No recent dividend cuts
- Possesses an investment grade bond rating between A3/A- and Baa2/BBB
- Earns at least 70% of its annual revenues by providing regulated electric utility services

These parameters are identical to those that I used in the 18-095 Docket and 18-328 Docket and support using the same group of electric utility companies as a proxy group in this analysis as was used in those two previous dockets. Both before and after the merger, Westar and KCP&L possess nearly identical risk profiles, thus it is expected that we would use the same proxy group for both utilities.

Stock-price data is critical to a cost of equity analysis as that price data encapsulates the market participants' valuation of the company. Selecting companies that investment research companies like Value-Line categorize as electric utilities focuses the analysis on companies facing similar types of business risks and opportunities and ensures that publically available financial data is available. As a starting point, this parameter is important as it assures us the companies generally derive their earnings in electric utility industry. The following table contains all of the electric utilities followed by Value-Line. The bold and boxed cells indicate the primary reason for rejection from the proxy group.

1	2	3	4	5	6	7	8	9	10
					No	Dividends		2017	
Value-Line: Electric Utilities		***Bond Rating***			Announced	No Planned	2017	Electric Operations	
Company Name		Moody's	S&P		Merger	Reductions	History	%Rev	%Assets*
Allete Inc	ALE	A3	BBB+	Yes	x	x	x	74.9%	
Alliant Energy Corp	LNT	Baa1	A-	Yes	x	x	x	85.6%	82.6%
Ameren Corp	AEE	Baa1	BBB+	Yes	x	x	x	86.0%	85.0%
American Electric Power Company Inc	AEP	Baa1	A-	Yes	x	x	x	86.7%	94.1%
~~AVANGRID Inc~~	AGR	Baa1	BBB+	Yes	x	x	x	81.0%	85.7%
~~Avista Corp~~	AVA				*Hydro-One Merger*				
~~Black Hills Corp~~	BKH				*Selling oil & gas assets*				
~~CenterPoint Energy Inc~~	CNP	Baa1	A-	Yes	x	x	x	31.7%	45.4%
~~CMS Energy Corp~~	CMS	Baa1	BBB+	Yes	x	x	x	67.5%	60.3%
Consolidated Edison Inc	ED	A3	A-	Yes	x	x	x	76.6%	73.3%
~~Dominion Energy~~	D				*Acquiring SCANA*				
~~DTE Energy Company~~	DTE	Baa1	BBB+	Yes	x	x	x	40.5%	62.7%
Duke Energy Corp New	DUK	Baa1	A-	Yes	x	x	x	90.5%	86.6%
Edison International	EIX	A3	BBB+	Yes	x	x	x	99.0%	89.9%
El Paso Electric Co	EE	Baa1	BBB	Yes	x	x	x	100.0%	
~~Entergy Corp~~	ETR	Baa2	BBB+	Yes	Closing 4 non-reg nuclear plants				
~~Eversource Energy~~	ES	Baa1	A+	SPLT	x	x	x	71.5%	53.0%
~~Exelon Corp~~	EXC	Baa2	BBB	Yes	x	x	x	44.4%	
~~FirstEnergy Corp~~	FE	Baa3	BBB-	NO	Sub. Bankruptcy/elim. non-reg	x	x	69.4%	64.2%
~~Fortis, Inc~~	FTS.TO	Baa3	A-			x	x	54.0%	
~~Great Plains Energy Inc~~	GXP	Baa2	BBB+	Yes	Westar				
~~Hawaiian Electric Industries Inc~~	HE		BBB-	NO	x	x	x	88.0%	47.0%
IDACORP Inc	IDA	Baa1	BBB	Yes	x	x	x	99.0%	99.0%
~~MGE Energy Inc~~	MGEE	A1	AA-	NO	x	x	x	73.5%	56.2%
~~NextEra Energy Inc~~	NEE	Baa1	A-	Yes	x	x	x	69.0%	51.4%
NorthWestern Corporation	NWE	Baa1	BBB	Yes	x	x	x	79.3%	80.1%
OGE Energy Corp	OGE	A3	A-	Yes	x	x	x	100.0%	
~~Otter Tail Corp~~	OTTR	Baa2	BBB	Yes	x	x	x	51.0%	84.3%
~~Pacific Gas and Electric Company~~	PCG	Baa1	BBB+	Yes	x	Suspended			
Pinnacle West Capital Corp	PNW	A3	A-	Yes	x	x	x	99.0%	98.0%
~~PNM Resources Inc~~	PNM	Baa3	BBB+	SPLIT	x	x	x	100.0%	
Portland General Electric Company	POR	A3	BBB	Yes	x	x	x	100.0%	
~~PPL Corporation~~	PPL	Baa2	A-	Yes	Forex risk	x	x	71.9%	59.2%
~~Public Service Enterprise Group Inc~~	PEG	Baa1	BBB+	Yes	x	x	x	68.1%	66.9%
~~SCANA Corporation~~	SCG				Construction issues/ACQ				
~~Sempra Energy~~	SRE	Baa1	BBB+	Yes	Onocor acquisition	x	x	39.4%	35.7%
~~Southern Co~~	SO	Baa2	A-	Yes	Construction issues	x	x	73.0%	65.8%
~~Vectren Corp~~	VVC		A-	Yes	x	x	x	21.4%	29.1%
WEC Energy Group	WEC	A3	A-	Yes	x	x	x	60.0%	
~~Westar Energy Inc~~	WR	Baa1	BBB+	Yes	Great Plains			100.0%	
Xcel Energy Inc	XEL	A3	A-	Yes	x	x	x	84.9%	

1) Electric utilities followed by Value-Line Investment Survey (U.S. companies)
2) Ticker symbol
3) Moody's credit rating (LTR) data from S&P Global Market Intelligence
4) S&P credit rating (LTR) data from S&P Global Market Intelligence
5) Within credit rating range of both rating agencies
6) No merger, acquistion, or sale of assets (Value-Line & S&P Global Market Intelligence)
7) No forecasted dividend reduction (Value-Line) — x = no reduction
8) No dividend reduction in 2017 (Value-Line & S&P Global Market Intelligence) — x = no forecasted reduction
9) Revenues from regulated electric operations--% of total revenues (S&P Global Market Intelligence) — 70% of Revenues from electric utility industry
10) Assets of regulated electric operations (S&P Global Market Intelligence)

I reviewed the potential proxy companies that were considered in the 18-WSEE-328-RTS Docket. I found that the selection screens applied in the 18-328 analysis to be a reasonable guide for selecting a proxy group for KCP&L in this Docket. Credit ratings shown in columns three and four are the first screen applied to the population. The current ratings for KCPL is Baa1 by Moody's and A- by S&P; these ratings are firmly in the mid-range of the investment-grade ratings. The selection criteria uses a range that is one notch either

1 side of KCPL's ratings which is a range of A3/A- to Baa2/BBB.[23]

2 In column six, I listed any merger or acquisitions in process or any significant financial
3 issues that make it difficult to assess the utility's long-term earnings prospects. In this
4 criteria, I found there are several utilities involved in acquisitions. SCANA and Southern
5 Co. are excluded due to their construction problems with nuclear power plants; SCANA
6 has also signed in acquisition plan with Dominion. I excluded utilities involved in
7 acquisitions and those with significant construction issues because both types of events
8 cause uncertainty around future earnings. I also excluded PPL Corp. due to its investments
9 overseas. PPL reports that 30% of its revenues are subject to foreign exchange risk. This
10 is an atypical situation in the U.S. electric utility industry and a risk that is distinct from
11 KCP&L. The filter in column six focuses the study on electric utilities with known
12 prospective earnings power.

Credit Rating Table

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

23

1 Columns seven and eight are similar to column five in that these criteria would eliminate
2 firms that have or are forecasted to reduce annual dividends. In the public utility sectors
3 where management and boards strive for a record of stable dividend growth, a dividend
4 reduction signals major change in ongoing operations and is probably a sign that
5 managements cannot expect stable earnings growth in the foreseeable years. Such
6 candidates should not be in the proxy group for KCP&L because that situation is not
7 consistent with KCP&L's prospects. Pacific Gas & Electric is the only utility eliminated
8 with this criteria; it suspended its dividend payments in December of 2017.

9 The criteria in columns nine and ten attempt to ascertain whether providing regulated
10 electric utilities services is the primary business of the company. I set the threshold for
11 revenues from electric utility service at 70% of total revenues. This is a subjective cutoff,
12 but it works for this analysis because meeting that threshold means that the company is
13 largely focused on, and earnings are derived from, providing regulated electric utility
14 services. The following table contains Staff's proxy group of 14 electric utilities for the
15 cost of equity and capital structure analyses.

1	2	3	4	5	6	7	8	9	10
					No	Dividends		2017	
Value-Line: Electric Utilities		***Bond Rating***			Announced	No Planned	2017	Electric Operations	
Company Name		Moody's	S&P		Merger	Reductions	History	%Rev	%Assets*
Allete Inc	ALE	A3	BBB+	Yes	x	x	x	74.9%	
Alliant Energy Corp	LNT	Baa1	A-	Yes	x	x	x	85.6%	82.6%
Ameren Corp	AEE	Baa1	BBB+	Yes	x	x	x	86.0%	85.0%
American Electric Power Company Inc	AEP	Baa1	A-	Yes	x	x	x	86.7%	94.1%
Consolidated Edison Inc	ED	A3	A-	Yes	x	x	x	76.6%	73.3%
Duke Energy Corp New	DUK	Baa1	A-	Yes	x	x	x	90.5%	86.6%
Edison International	EIX	A3	BBB+	Yes	x	x	x	99.0%	89.9%
El Paso Electric Co	EE	Baa1	BBB	Yes	x	x	x	100.0%	
IDACORP Inc	IDA	Baa1	BBB	Yes	x	x	x	99.0%	99.0%
NorthWestern Corporation	NWE	Baa1	BBB	Yes	x	x	x	79.3%	80.1%
OGE Energy Corp	OGE	A3	A-	Yes	x	x	x	100.0%	
Pinnacle West Capital Corp	PNW	A3	A-	Yes	x	x	x	99.0%	98.0%
Portland General Electric Company	POR	A3	BBB	Yes	x	x	x	100.0%	
Xcel Energy Inc	XEL	A3	A-	Yes	x	x	x	84.9%	

1) Electric utilities followed by Value-Line Investment Survey (U.S. companies)
2) Ticker symbol
3) Moody's credit rating (LTR) data from S&P Global Market Intelligence
4) S&P credit rating (LTR) data from S&P Global Market Intelligence
5) Within credit rating range of both rating agencies
6) No merger, acquistion, or sale of assets (Value-Line & S&P Global Market Intelligence)
7) No forecasted dividend reduction (Value-Line)
8) No dividend reduction in 2017 (Value-Line & S&P Global Market Intelligence)
9) Revenues from regulated electric operations 70% of total revenues (S&P Global Market Intelligence)
10) Assets of regulated electric operations (S&P Global Market Intelligence)

Q. Have bond ratings for Westar or KCP&L changed since the cost of equity studies in the 18-095 and 18-328 Dockets?

A. Yes, with the close of the merger of Westar and Great Plains Energy, Standard & Poor's raised its rating of Great Plains Energy and each of its subsidiaries one notch from BBB+ to A-. Moody's did not change its ratings of any of the companies. Because this was a one-notch change and by just one of the two rating agencies, I did not alter the proxy company selection criteria from that used in the previous two dockets.

Bond Ratings of Evergy, Inc. & Kansas Jurisdictional Subsidiaries		
Pre-Merger Rating / Post-Merger Bond Rating		
	Standard & Poors'	Moody's
Evergy, Inc./Great Plains Energy	BBB+ / A-	Baa2 / Baa2
Kansas City Power & Light	BBB+ / A-	Baa1 / Baa1
Westar Energy	BBB+ / A-	Baa1 / Baa1
Kansas Gas & Electric	BBB+ / A-	Baa1 / Baa1
Source: S&P Global Market Intelligence		

Return on Equity Analysis

Q. How did you perform the cost of equity analysis?

A. I am using discounted cash flow models and capital asset pricing models; identical to the methods used in recent rate cases: the 18-095 Docket and 18-328 Docket to establish the 9.30% threshold for the ERSP.

Q. Does the DCF model meet the legal standards discussed earlier in your testimony?

A. Yes, a cost of equity estimate derived from the DCF model meets the legal standards discussed above if the model incorporates current information from the capital markets via current stock prices and accurate data that investors use to establish their discount rate. This market-based information ensures the cost of equity estimates evaluate investors' required rate of return or discount rate that reflects the current economic environment.

The DCF model is a valuation model used by investors to value different types of investments such as real estate, bonds, and equity securities. The DCF model is a useful tool to value any investment that involves regular, periodic cash flows. The notion of

discounting a future receipt of cash back to the present so as to place a price or value on an investment goes back centuries.[24] The premise of the DCF model in the valuation of common stock is that investors determine the value of a company's common stock by discounting its future dividend payments back to the present. The cornerstone of the DCF model is the process of discounting those future cash flows back to the present at the investors' required return. An investor's required rate of return is risk-sensitive and sensitive to the returns available on investments of comparable risk throughout the global capital markets. In other words, as the risk of the investment increases, so will the investors' required return. A higher required rate of return decreases the present value of the stream of dividends that equates to the price of the stock. So, all other variables being equal, investors price the riskier of two common stocks lower because the cash flows or dividends are discounted back to the present at a higher rate.

The form of the DCF model that regulatory agencies are accustomed to seeing is often referred to as the Gordon Growth Model, which is a model that values the security at the present value of a stream of cash flows (dividends) growing at a constant rate into perpetuity. The basic form of this DCF equation is:

$$P_0 = \frac{D_0(1+g)}{(Ke-g)}$$

Where:

P_0 = the value of the common stock or asset

[24] The formal presentation of the DCF model as we use it today dates back to the 1930's in Irving Fisher's book: The Theory of Interest and John Burr Williams' 1938 text: The Theory of Investment Value. These two authors expressed the DCF model in modern economic terms.

D_0 = the current dividend of the stock or annual cash flow from the asset

g = the annual growth rate of the dividend or cash flow forever

Ke = cost of equity or required rate of return for the stockholders

Or

Stock Price = Annual Dividend / (Req'd Rate of Return – Dividend Growth Rate)

This is the form of the equation commonly found in texts regarding finance, investments, and asset valuation. Such texts are inclusive of both theory and practical application.

Regulatory agencies responsible for setting rates and revenue requirements want to know the investors' required rate of return or Ke in the equation. So, we solve the equation for that variable. The equation below shows the algebraic isolation of the investors' required rate of return. By isolating investors' required rate of return in the equation, we can estimate it by knowing the stock's dividend yield and the annual dividend growth rate expected by investors. That form of the equation is:

$$Ke = \frac{D_0(1+g)}{P_0} + g$$

This equation is frequently written out as:

Req'd Rate of Return = (Dividend/Current Stock Price) + Dividend Growth Rate

or

Req'd Rate of Return = Dividend Yield + Dividend Growth Rate

Or as commonly abbreviated by regulatory agencies

$$Ke = y + g$$

Where: y = Dividend Yield

g = Expected Dividend Growth

Through a handful of inputs, the DCF model distills down to an equation, a complex process performed by investors to arrive at a discount rate and valuation of the security. As with any equation that attempts to model behavior, there are a host of assumptions that come along with it. Those assumptions are:

- Ke corresponds only to the specific stream of future dividends, rather than earnings, and that constitutes the source of value.
- The discount rate (Ke) must exceed the growth rate (g).
- The constant growth rate will continue for an indefinite future.
- Investors require the same discount rate (Ke) each year.
- There is no external financing.

Q. Why is it reasonable to accept these assumptions?

A. The DCF model is attempting to emulate investors' behavior; distilling human behavior into a handful of inputs demands simplifying assumptions. The question becomes whether the assumptions are so contrary to investors' behavior in the real-world that the model output becomes meaningless or illogical. There is no strong evidence that leads me to believe the assumptions of the DCF model are contrary to investor behavior. Moreover, there are methods I use to evaluate whether an output falls outside of the realm of reality. For example, the output can be compared with the returns available on other investments such as long-term corporate bonds. There were no observations eliminated using this

1 screen.[25]

2 **Discounted Cash Flow Model**

3 **Q. How did you calculate the dividend yield (y) component of the DCF model?**

4 A. The dividend yield (y) is the easier of the two components to measure as it is easily
5 observable in daily stock price reports. It is calculated by dividing the stock's annual
6 dividend payment per share by its market price per share.

7 **Q. What is the source of the dividend information?**

8 A. Historic and current dividend information is easily obtained from public sources or
9 subscription services such as Value-Line. The DCF model requires a forward-looking
10 dividend payment which is often the current year's dividend payment increased by the
11 forecasted growth rate for next year. In lieu of forecasting, I obtained the 2019 forecasted
12 dividend per share information from Value-Line Investment Survey. The Value-Line
13 reports for each of the proxy companies are attached as Schedule AHG-3. I obtained the
14 stock prices for the dividend yields from YahooFinance. For this analysis, I used weekly
15 stock price observations taken from July 2, 2017, through July 3, 2018. The stock prices
16 for each of the proxy companies appears on Schedule AHG-4. My DCF analysis
17 incorporates a dividend yield based on forecasted 2019 dividend payments.

[25] Staff applies this screen using the interest rates of Baa Utility Bonds and the yields on utility specific debt shown in the Risk Premium Table. Staff adds 100 basis points to these yields as a minimum risk premium test. Cost of equity observations below this level are eliminated from the average. FERC proceedings apply a similar test for outliers.

Staff Proxy Group
Dividend Yields Based on Prices from July 2, 2017 through July 3, 2018
18-KCPE-480-RTS

		1	2	3	4	5	6	7
		DPS	Stock Prices				Dividend Yield	
		2019	Min	Max	Mid-Point	Mean	Min	Max
Allete Inc	ALE	$ 2.34	$ 66.64	$ 81.24	$ 73.94	$ 74.78	2.88%	3.51%
Alliant Energy Corp	LNT	$ 1.42	$ 36.84	$ 45.55	$ 41.19	$ 41.56	3.12%	3.85%
Ameren Corp	AEE	$ 1.94	$ 51.89	$ 64.89	$ 58.39	$ 58.17	2.99%	3.74%
American Electric Power Co.	AEP	$ 2.63	$ 62.71	$ 78.07	$ 70.39	$ 70.22	3.37%	4.19%
Consolidated Edison Inc	ED	$ 2.96	$ 71.12	$ 89.70	$ 80.41	$ 80.75	3.30%	4.16%
Duke Energy Corp New	DUK	$ 3.80	$ 71.96	$ 91.80	$ 81.88	$ 81.78	4.14%	5.28%
Edison International	EIX	$ 2.57	$ 57.63	$ 83.38	$ 70.50	$ 69.71	3.08%	4.46%
El Paso Electric Co	EE	$ 1.52	$ 48.05	$ 61.15	$ 54.60	$ 54.44	2.49%	3.16%
IDACORP Inc	IDA	$ 2.56	$ 79.59	$ 100.04	$ 89.81	$ 89.08	2.56%	3.22%
NorthWestern Corporation	NWE	$ 2.30	$ 50.01	$ 64.47	$ 57.24	$ 56.88	3.57%	4.60%
OGE Energy Corp	OGE	$ 1.54	$ 29.59	$ 37.32	$ 33.46	$ 34.06	4.13%	5.20%
Pinnacle West Capital Corp	PNW	$ 3.02	$ 73.41	$ 92.48	$ 82.95	$ 83.23	3.27%	4.11%
Portland General Electric Co.	POR	$ 1.50	$ 39.02	$ 50.11	$ 44.57	$ 43.97	2.99%	3.84%
Xcel Energy Inc	XEL	$ 1.60	$ 41.51	$ 52.22	$ 46.86	$ 46.77	3.06%	3.85%
						Range:	2.49%	5.28%

1) Dividends per Share for 2019 Forecasted by Value-Line Investment Survey
2) Minimum 12 month price observed from July 2, 2017 through July 3, 2018
3) Maximum 12 month price observed from July 2, 2017 through July 3, 2018
4) Mid-point is the average of minimum price and maximum price
5) Mean price for the time period of July 2, 2017 through July 3, 2018 (weekly observations)
6) Minimum dividend yield available from time period
7) Maximum dividend yield available from time period

Forecasted Growth Rates for the DCF Model

Q. Please discuss the importance of the second component, the growth rate (g), in the DCF equation.

A. The "g" represents the anticipated annual growth rate in cash-flows that investors expect to receive through dividends from the stock. This is a challenging and contentious issue in a DCF analysis for two reasons. First, it is a key element in the DCF model or any form of a discounted cash flow analysis because the growth rate has a one-for-one effect on the required return produced by the model. All other factors being equal, a higher growth rate results in an equally higher return on equity for the utility. Second, there is a strong element of subjectivity to the growth rate, due to the uncertainty about future earnings and

1 dividends.

2 **Q. How did you estimate the growth rate in the DCF model?**

3 A. The appropriate growth estimate is that which is expected by the market and factored into
4 investors' analyses to estimate stock prices. That is, it is the growth estimate investors
5 used to determine the stock price. Earnings per share growth forecasts are commonly
6 incorporated into the DCF model. Investment firms that publish growth forecasts typically
7 publish three to five-year annual growth estimates for earnings. Value-Line Investment
8 Survey also provides dividend growth rate forecasts; it is the only firm that I am aware of
9 that does so. Three to five years is as far into the future as analysts forecast for a specific
10 company.

11 **Q. How do investors estimate the dividend growth rate beyond the three to five-year**
12 **horizon of the short-term growth forecasts?**

13 A. For a long-term perspective of potential growth, investors rely on forecasts of the broad
14 economy as measured by annual changes forecasted for the nation's gross domestic product
15 (GDP). There are sources for long-term growth estimates of this country's GDP that extend
16 out more than 20 years. Academic texts and investment professionals use these forecasts
17 in DCF models as a forecast of potential long-term growth of corporate dividend payments.

18 GDP refers to the market value of all final goods and services produced within a country
19 in a given period. Nominal GDP (nGDP) is that measure of goods and services which
20 *includes* effects of price changes - better known as inflation. Inflation must be included
21 for our forecast because the DCF analysis is interested in the nominal required return. That

1 is to say, investors' expectations of inflation are contained in their required return. Keep
2 in mind that the "headline" GDP reported in the media is *real* GDP, which is GDP less the
3 inflation experienced over the measurement period.

4 **Q. Is it accepted practice in securities valuation to use nGDP growth estimates in the**
5 **DCF model?**

6 A. Yes, in the federal regulatory arena, similar to the responsibilities of the KCC, the Federal
7 Energy Regulatory Commission (FERC) uses nGDP to estimate the cost of equity. FERC
8 has reviewed the issue of long-term growth estimates used in DCF models. It took
9 comments from stakeholders that included state commissions, customers, investment
10 bankers, and interstate pipeline companies.[26] Testimony from these parties made it clear
11 that long-term estimates of nGDP are a common component of valuation analyses
12 conducted by investment professionals. From that proceeding, FERC concluded that long-
13 term growth estimates of nGDP should be the estimate of long-term growth in the DCF
14 models used to estimate required returns for interstate pipeline companies because that is
15 consistent with investor behavior.[27] In June of 2014, FERC concluded that the same
16 methodology should be used in setting the required returns for electric transmission
17 companies.[28] Although the Commission has never explicitly endorsed long-run GDP
18 growth as an input, it is clear that the growth estimate used by Staff in the 15-116 Docket
19 were considered credible by the Commission.[29] In that analysis, I relied on the same

[26] Transcript from Technical Conference held on January 23, 2008: FERC Docket PL07-2-000.
[27] Policy Statement, FERC Docket PL07-2-000 (April 17, 2008); FERC Opinion No. 486, FERC Docket RP04-274 (Oct. 19, 2006).
[28] Opinion No. 531; June 19, 2014; 147 FERC 61,234; para 36.
[29] Order issued September 10, 2015; Docket 15-KCPE-116-RTS; para. 34; p. 15-16.

1 sources for long-term nGDP growth as I am using in this analysis.

2 **Q. Is there academic support for this issue?**

3 A. Yes, academic research has shown that nGDP growth forecasts are an important input to
4 valuation studies because the analyst has to consider whether a company's annual earnings
5 can grow as fast as, or even faster than, the broad economy. In two of his books devoted
6 to the subject of asset valuation, Dr. Aswath Damodaran discusses the nature of a stable
7 growth rate for DCF models.[30] He argues for viewing nominal economic growth as the
8 absolute maximum when using a stable-growth model, such as the DCF model we are
9 using.

10 *"The stable growth rate cannot exceed the growth rate of the economy in*
11 *which a firm operates, but it can be lower. There is nothing that prevents*
12 *us from assuming that mature firms will become a smaller part of the*
13 *economy and it may, in fact, be the more reasonable assumption to make.*
14 *Note that the growth rate of an economy reflects the contributions of both*
15 *young, higher growth firms and mature, stable growth firms. If the former*
16 *grow at a rate much higher than the growth rate of the economy, the latter*
17 *have to grow at a rate that is lower."* (Damodaran on Valuation: Security
18 Analysis for Investment and Corporate Finance, 2nd edition; Aswath
19 Damodaran; p. 148)

20 *"The growth rate of a company cannot be greater than that of the economy*
21 *but it can be less. Firms can become smaller over time relative to the*
22 *economy. Thus, even though the cap on the growth rate may be the nominal*
23 *growth rate of the economy, analysts may use growth rates much lower than*
24 *this value for individual companies."* (Damodaran on Valuation: Security
25 Analysis for Investment and Corporate Finance, 2nd edition; Aswath
26 Damodaran; p.159)

[30] Investment Valuation: Tools and Techniques for Determining the Value of Any Asset, 2nd Edition and Damodaran on Valuation: Security Analysis for Investment and Corporate Finance, 2nd Edition.

1 It is worth noting that Professor Damodaran cites the nGDP growth projection as a *ceiling*
2 for long-term growth in most valuation studies. Certainly, there are industries that will
3 exceed the average for a period of time, but even for those industries, rapid growth cannot
4 continue forever.

5 **Q. Does the view that nGDP growth is a ceiling on long-term earnings growth exist**
6 **outside of academia?**

7 A. Yes, valuation analysts carefully consider the long-run growth rates used to value assets
8 very carefully because using an incorrect growth estimate will lead to incorrectly valuing
9 an asset. The authors of the previous discussion, Peter L. Bernstein and Robert D. Arnott,
10 have both been published in peer-reviewed academic journals and books on investment
11 strategy, as well as building careers in the field of asset management and investment
12 strategy.

13 Furthermore, institutions directly involved in asset valuation and asset management that
14 apply valuation models to analyze potential acquisition and merger transactions recognize
15 that estimates of firm-specific growth are a driver to the value of an asset; overstating
16 growth would cause a model to overestimate the value of the asset which would result in
17 an economic loss to the investor. These experts also warn of a ceiling to earnings growth
18 rates as being no more than that of broad economic growth.

19 *"Growth rate: Few companies can be expected to grow faster than the*
20 *economy for long periods. The best estimate is probably the expected long-*
21 *term rate of consumption growth for the industry's products, plus inflation."*
22 (Valuation: Measuring and Managing the Value of Companies; Tim Koller,
23 Mark Goedhart, and David Wessels; McKinsey & Co; 4th ed; p. 275.)

1 The following quote from J.P. Morgan Asset Management (JPMAM) addresses the macro
2 or economy-wide measures of profits, and it is consistent with the firm-specific view
3 expressed by asset valuation experts in that analysts must be aware of the forecasted growth
4 rates applied in valuation models and how those growth forecasts comport with broad
5 measures of forecasted economic growth.

> 6 *"One common mistake is to assume that earnings and dividends received*
> 7 *by investors can grow in line with—or even in excess of—overall economic*
> 8 *growth (GDP) in perpetuity. Granted, it is almost a truism that aggregate*
> 9 *earnings must grow at the same pace as the overall economy in the very*
> 10 *long run; otherwise, profits would eventually outstrip the size of the entire*
> 11 *economy or dwindle to an insignificant share of it. But not all of this*
> 12 *earnings growth accrues to existing shareholders. On the contrary, a large*
> 13 *portion of economic growth comes from the birth of new enterprises. Some*
> 14 *commentators suggest (for example, Bernstein and Arnott, 2003; Cornell,*
> 15 *2010) that new enterprises account for more than half of GDP growth in*
> 16 *the U.S., while in some rapidly developing economies new enterprises may*
> 17 *account for the lion's share of overall economic growth."*[31]

18 Goldman Sachs Asset Management explains to its clients, "Our analysis reveals that the
19 link between GDP growth and equity returns is, in fact, very strong."[32] The asset pricing
20 formula of a dividend discount model shows how GDP growth influences the return they
21 earn on equity assets: "...the dividend growth rate will equate to the growth rate in
22 earnings. Assuming that earnings growth is equal to, or just associated with GDP growth,
23 a direct link with equity returns is established."[33] Goldman Sachs also states that research
24 has demonstrated that GDP growth is a proxy for earnings growth.

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[31] Long-term Capital Market Return Assumptions: 2015 Estimates and Thinking Behind the Numbers; J.P. Morgan Asset Management; p. 25; https://am.jpmorgan.com/us/institutional/ltcmra.

[32] "Linking GDP Growth and Equity Returns"; Monthly Insights: From the Office of the Chairman; Goldman Sachs Asset Management; May 2011; p. 1.

[33] "Linking GDP Growth and Equity Returns"; Monthly Insights: From the Office of the Chairman; Goldman Sachs Asset Management; May 2011; p. 2.

1 **Q. Do you believe this evidence justifies incorporating long-run nGDP growth forecasts**
2 **into cost of equity analyses of utility companies?**

3 A. Yes, because we have to ascertain the discount rate investors apply to the future cash flows
4 from an investment in these utilities. Therefore, the Commission should emulate investors'
5 analytical practices as closely as possible to determine investors' discount rate. As noted
6 above, investment professionals include a long-run growth forecast for the general
7 economy (in addition to company-specific short-run growth estimates) when applying the
8 DCF and capital asset pricing model, and that measure of macro-economic growth serves
9 as the upper bounds of a firm-specific analysis. Therefore, the Commission should
10 consider the same information when estimating a utility's required return.

11 **Q. How did you estimate long-run nominal GDP growth?**

12 A. I averaged the long-run nGDP forecasts of the Energy Information Agency (EIA) and the
13 Social Security Administration (SSA). The average of these two forecasts composes the
14 long-run growth estimate in the DCF analysis. The nGDP growth forecasts published by
15 EIA and SSA-OADSI are the same sources that I have relied on over the past decade.

Nominal GDP Estimates		
Energy Information Agency (EIA) 2015 - 2050		4.19%
Social Security Administration (SSA)		
OADSI Trustees Report 2017 - 2095		4.41%
	Average	4.30%
Additional GDP Estimates		
Exxon-Mobile 2017 Outlook for Energy 2015 - 2040		
2.2% Real GDP + 2.2 GDP Deflator from SSA		4.40%
Congresssional Budget Office Nominal GDP Forecast		
2019 - 2020		3.50%
2021 - 2027		3.90%
Federal Reserve Open Market Committee Long-run Forecast		
2.2% Real GDP + 2.0 PCE Inflation		4.20%

Q. Are these two the only two sources for long-run GDP forecasts?

A. There are other source shown in the table and they are wholly consistent with the EIA and SSA forecasts.

DCF Results

A. Please discuss the results of your DCF analysis.

Q. The results of my DCF analysis appear in the following table. The results seen in this DCF analysis are very much the same as the DCF results in my 18-095 analysis. As I have set out the foundations for the DCF analysis in the previous pages, in this section, I will discuss the specific information that I relied on for the DCF model and interpret the results.

Staff Proxy Group
Discounted Cash Flow (DCF) Analysis
18-KCPE-480-RTS

		1	2	3	4	5
		Dividend Yields		Growth	DCF Estimated	
		Min	Max	Rate	Required Return	
Allete Inc	ALE	2.88%	3.51%	4.91%	7.79%	8.42%
Alliant Energy Corp	LNT	3.12%	3.85%	5.18%	8.30%	9.04%
Ameren Corp	AEE	2.99%	3.74%	5.38%	8.37%	9.12%
American Electric Power Co.	AEP	3.37%	4.19%	4.80%	8.17%	8.99%
Consolidated Edison Inc	ED	3.30%	4.16%	3.78%	7.08%	7.95%
Duke Energy Corp New	DUK	4.14%	5.28%	4.45%	8.59%	9.74%
Edison International	EIX	3.08%	4.46%	4.62%	7.71%	9.08%
El Paso Electric Co	EE	2.49%	3.16%	4.88%	7.36%	8.04%
IDACORP Inc	IDA	2.56%	3.22%	4.33%	6.89%	7.55%
NorthWestern Corp.	NWE	3.57%	4.60%	3.92%	7.49%	8.52%
OGE Energy Corp	OGE	4.13%	5.20%	4.95%	9.08%	10.15%
Pinnacle West Capital Corp	PNW	3.27%	4.11%	4.50%	7.77%	8.62%
Portland General Electric Co.	POR	2.99%	3.84%	4.11%	7.10%	7.95%
Xcel Energy Inc	XEL	3.06%	3.85%	4.97%	8.03%	8.82%
				Average of each column	7.84%	8.71%
				Average of all observations	8.28%	
				Range of all observations	6.89%	10.15%

1) 2018 annual dividend divided by maximum price observed from July 2, 2017 through July 3, 2018
2) 2018 annual dividend divided by minimum price observed July 2, 2017 through July 3, 2018
3) Forecasted EPS growth
4) Low-end estimate = col 1 + col 3
5) High-end estimate = col 2 + col 3

Pricing data was gathered from YahooFinance for each of the proxy companies from the time period of July 2, 2017, through July 3, 2018, on a weekly basis. The low dividend yield is computed using the projected 2019 dividend divided by the average of the weekly high prices while the high dividend yield is computed using the average weekly low prices.

Q. How did you arrive at a growth rate for each proxy company?

A. The growth rate is the average of the short-term growth rates[34] and the long-run forecast of nGDP of 4.30%. The following table summarizes all of the observed growth forecasts,

[34] For each proxy company, I gathered three short-run, three to five-year growth forecasts for earnings and dividend from Value-Line Investment Survey, as well as analysts' earnings growth projections by Thomson Financial Network (I/B/E/S) reported by YahooFinance. I/B/E/S aggregates analysts' earnings forecasts and reports the mean of those estimates. FactSet is a service similar to I/B/E/S in that it aggregates analysts' forecasts and publishes the mean and median of estimates. FactSet data was obtained through S&P Global Market Intelligence.

1 both historical and forecasted.

2 **Q. How is the long-run nGDP forecast applied in your DCF analysis?**

3 A. The long-run nGDP growth forecast of 4.30% is averaged with the short-run growth
4 forecasts. In my DCF analysis, I give equal weight to short-run and long-run growth
5 forecasts. The weighting is certainly debatable because we cannot know precisely how
6 investors weight the two forecast horizons. At FERC, in both natural gas pipeline and
7 electric transmission rate cases, the short-run growth is afforded a two-thirds weighting
8 and the nGDP forecast a one-third weighting. Whatever the weighting an analyst applies
9 between the short-term and long-term growth forecasts, the analysis needs to be
10 constructed in a manner that distinguishes between the growth potential of each time
11 horizon.

Staff Proxy Group
Growth Rate Summary
18-KCPE-480-RTS

		1	2	3	4	5	6	7	8	9	10	11
		Value-Line Historic Data				Forecasted Growth Rates						
		10 Year		5 Year		Value Line		Thomson	FactSet	Short-run	Long-term	DCF
		EPS	DPS	EPS	DPS	EPS	DPS	EPS	EPS	Average	nGDP	Growth Rate
Allete Inc.	ALE	1.50%	3.50%	5.50%	3.00%	5.00%	4.50%	6.00%	6.60%	5.53%	4.30%	4.91%
Alliant Energy Corp.	LNT	5.00%	7.50%	6.50%	6.50%	6.50%	6.00%	5.85%	5.91%	6.06%	4.30%	5.18%
Ameren Corp.	AEE	-1.00%	-4.00%	0.50%	2.00%	7.50%	5.50%	6.30%	6.57%	6.47%	4.30%	5.38%
American Electric Power Co.	AEP	3.00%	4.00%	5.50%	4.50%	4.50%	5.00%	5.79%	5.92%	5.30%	4.30%	4.80%
Consolidated Edison Inc.	ED	2.50%	1.50%	2.00%	2.00%	3.00%	3.50%	3.39%	3.18%	3.27%	4.30%	3.78%
Duke Energy Corp.	DUK	2.50%	10.00%	0.50%	2.50%	5.50%	4.50%	4.22%	4.21%	4.61%	4.30%	4.45%
Edison International	EIX	2.50%	6.00%	2.50%	9.00%	4.50%	8.00%	3.19%	4.10%	4.95%	4.30%	4.62%
El Paso Electric Co.	EE	6.50%	0.00%	0.00%	18.00%	4.50%	7.00%	5.20%	5.10%	5.45%	4.30%	4.88%
IDACORP Inc.	IDA	7.50%	5.50%	4.50%	10.50%	3.50%	6.50%	3.55%	3.91%	4.37%	4.30%	4.33%
NorthWestern Corp.	NWE	8.00%	5.50%	7.00%	7.00%	3.50%	4.50%	3.16%	3.01%	3.54%	4.30%	3.92%
OGE Energy Corp.	OGE	4.50%	5.50%	1.00%	8.50%	6.00%	8.00%	4.30%	4.10%	5.60%	4.30%	4.95%
Pinnacle West Capital Corp.	PNW	4.00%	2.50%	5.00%	2.50%	5.00%	5.50%	3.78%	4.54%	4.70%	4.30%	4.50%
Portland General Electric Co.	POR	4.00%	9.00%	3.50%	3.50%	4.00%	6.00%	2.65%	3.02%	3.92%	4.30%	4.11%
Xcel Energy Inc.	XEL	5.50%	4.50%	5.00%	5.50%	5.50%	5.50%	5.86%	5.67%	5.63%	4.30%	4.97%
	Min	-1.00%	-4.00%	0.00%	2.00%	3.00%	3.50%	2.65%	3.01%	3.27%		3.78%
	Max	8.00%	10.00%	7.00%	18.00%	7.50%	8.00%	6.30%	6.60%	6.47%		5.38%
	Mean	4.00%	4.36%	3.50%	6.07%	4.89%	5.71%	4.52%	4.70%	4.96%		4.63%

1) Historic 10-year earning per share annual growth rate reported by Value-Line
2) Historic 10-year divdend per share annual growth rate reported by Value-Line
3) Historic 5-year earnings per share annual growth rate reported by Value-Line
4) Historic 5-year dividend per share annual growth rate reported by Value-Line
5) 3 to 5-year forecasted annual earnings per share growth rate by Value-Line
6) 3 to 5-year forecasted annual dividends per share growth rate by Value-Line
7) 5-year forecasted annual earnings per share growth rate. Consensus forecasts gatherd by Thomson-Reuters and reported at YahooFinance on July 17, 2018
8) Long-term forecasted annual earnings per share growth rate. Consensus forecasts gathered by FactSet and reported at S&P Global Market Intelligence (fka: SNL Financial) on July 17, 2018
9) Average of 3 to 5-year forecasted annual growth rates
10) Long-term forecasted nominal GDP growth rate
11) Average of short-term and long-term growth rates

Q. What are your observations of the short-run growth forecasts?

A. The average of the short-run growth forecasts for the proxy group is 4.96% with a range of 3.27% to 6.47%.

Internal Rate of Return (IRR) Analysis

Q. Please discuss the internal rate of return (IRR) analysis that you performed.

A. An IRR analysis of an investment is a form of a discounted cash flow analysis, only with a more complex equation than the Gordon Growth Model that we applied in the previous section. In the IRR analysis, we are able to apply the five-year growth forecasts to only

the intended next five years of dividends, with the remaining years growing at the long-run nGDP forecasted growth rate. In the age of spreadsheets, the IRR equation is not that much harder to manage than the basic dividend yield plus growth DCF model (a.k.a. Gordon Growth Model) and, as the IRR model allows us to apply the growth forecasts to their respective forecast periods, the IRR model provides important information to policy makers because it recognizes the respective time spans of both the short-run (three to five-year earnings growth) and long-run (nGDP growth rate) forecasts. The full output of the IRR calculations appears in Schedule AHG-5; the following table summarizes the results. In the IRR model, short-term growth forecasts are given much less weight than in the two-stage DCF analysis; five years of a several hundred year time horizon or five percent as opposed to a weighting of 50 percent that I applied in the two-stage DCF model. As a result of the greater weighting of the long-term growth estimate, the average for the proxy group in the IRR analysis is 16 basis points lower than the two-stage DCF results.

Staff Proxy Group Internal Rate of Return (IRR) 18-KCPE-480-RTS	
Allete Inc.	7.82%
Alliant Energy Corp.	8.23%
Ameren Corp.	8.19%
American Electric Power Co.	8.51%
Consolidated Edison Inc.	8.12%
Duke Energy Corp.	9.44%
Edison International	8.39%
El Paso Electric Co.	7.42%
IDACORP Inc.	7.39%
NorthWestern Corp.	8.58%
OGE Energy Corp.	9.47%
Pinnacle West Capital Corp.	8.28%
Portland General Electric Co.	7.93%
Xcel Energy Inc.	8.18%
Mean	8.28%
Min	7.39%
Max	9.47%

In this instance, as is usually the case with public utilities, there is not a wide difference between the short-term growth rates and long-term nGDP growth, therefore, the difference in weighting of the two growth rates between the DCF and IRR analyses do not cause a large difference in results.

Capital Asset Pricing Model (CAPM) Analysis

Q. Please describe the capital asset pricing model (CAPM).

A. The CAPM offers an explanation of the positive relationship between risk and ROR required by investors.[35] It is appealing to regulators because it meets the legal standards I discussed above, as it can be structured to incorporate current data from the financial

[35] The theoretical support for the CAPM is the work done by Harry Markowitz ("Portfolio Selection," Journal of Finance, March, 1952). W.F. Sharpe added the concept of a risk-free rate of return to the Markowitz model ("A Simplified Model of Portfolio Analysis," Management Science, January, 1963).

markets and the unique risks of the utility in question.

$$Ke = Rf + Beta\ (Rm - Rf) \quad \text{or}$$

$$Ke = Rf + Beta\ (Rp)$$

Where:

Ke = required return on equity

Rf = return on a risk-free security

Rm = an expected return from the market as a whole

Rp = risk premium available to investors through purchasing common stocks instead of risk-free securities often calculated as Rm - Rf

Beta = volatility of the security's or portfolio's return relative to the volatility of the market's return with the market beta equal to 1.0

Rf

The Rf estimate is the interest rate investors believe represents a riskless return. Although it is a simple concept, the answer is not universally agreed upon. It is widely accepted that a debt instrument issued by the U.S. Government is a risk-free instrument. An investment in U.S. Treasury Bonds is a risk-free investment if the investor plans to hold it until maturity. The risk-free instrument chosen will have an effect on the results of the CAPM analysis. Whichever instrument is selected, it should be used consistently in the equation.

Beta

The beta coefficient measures the volatility of the return earned by the utility's stock relative to the volatility of the returns earned by the broader equity market. The broad equity market is frequently measured using the S&P 500 Index. This measure provides a

1 look at the risk and volatility of a stock relative to other investments. A stock with a beta
2 of 1 is equally as volatile as the market as a whole. A stock with a beta of 0.5 is half as
3 volatile as the market. Value-Line's last report on Great Plains Energy, prior to the merger
4 closing, reported a beta coefficient of 0.70; similar to the average for the proxy group of
5 0.67.

6 **Rm**

7 Rm is the expected return on the stock market as measured by a broad market index such
8 as the S&P 500. This represents the total return consisting of the price change of the index
9 plus dividends earned for the year.

10 **Rp**

11 The risk premium is the difference between investors' expected return from the stock
12 market and their expected return from the risk-free investment over the same time period.
13 The risk premium is written as Rm-Rf. The market return and the risk-free return should
14 be taken from the same time period so as to accurately measure the additional return
15 required by investors to take on the risk of common stocks over the risk-free investment.

16 **Q. Please discuss your CAPM analysis.**

17 A. I took two distinct approaches to the CAPM analysis. I performed one analysis using
18 purely historic measures of returns from the stock and bond markets and a second analysis
19 using forecasted returns. The results using historic returns are drastically higher, 9.38%,
20 when compared to results using forecasted returns of 6.93%.

1 Both forms of my CAPM analysis incorporate the high and low beta coefficients observed
2 in the proxy group. This beta indicates that the volatility of the proxy group is about 65%
3 of that exhibited by the broad market and, accordingly, investors would expect a relatively
4 lower return from stocks of public utilities than the broad market. This is a clear indication
5 that public utility companies like KCP&L and the proxy group are less risky than the broad
6 stock market, and investors expect a return lower than that expected of the market.
7 Reviewing the high and low beta coefficients observed in the proxy group provides a
8 picture of the range that the new company could exhibit in the future.

Beta Coefficients, Staff's Proxy Group
Updated on July 24, 2018
18-KCPE-480-RTS

Allete Inc	ALE	0.75
Alliant Energy Corp	LNT	0.70
Ameren Corp	AEE	0.65
American Electric Power Co Inc	AEP	0.65
Consolidated Edison Inc	ED	0.50
Duke Energy Corp New	DUK	0.60
Edison International	EIX	0.60
El Paso Electric Co	EE	0.75
IDACORP Inc	IDA	0.70
NorthWestern Corp	NWE	0.65
OGE Energy Corp	OGE	0.95
Pinnacle West Capital Corp	PNW	0.65
Portland General Electric Co	POR	0.65
Xcel Energy Inc	XEL	0.60
	Min	0.50
Source: Value-Line Investment Survey	Max	0.95
	Mean	0.67
	Median	0.65

9

10 **Q. Please describe the forecasted CAPM analysis.**

11 A. For the forecasted CAPM, I relied on the expected returns published by JPMAM in its
12 annual publication, Long-Term Capital Market Assumptions for 2018, to establish the
13 expected return for the market. JPMAM publishes 10 to 15-year forecasts of expected

1 returns on dozens of investment asset classes in its annual publication, the Long Term
2 Capital Market Return Assumptions (LTCMRA). JPMAM forecasts an annual return on
3 common stocks of 6.93%. The JPMAM's forecasted returns on common stocks has
4 declined over the past two years; generally a product of the increase in stock prices over
5 the past two years.

6 Following the calculations and inputs through the CAPM equation in line 2 of the following
7 table, the forecasted return on a risk-free investment, 10-Year U.S. Treasury Bonds, is
8 subtracted from the expected return on common stocks resulting in a risk premium of
9 3.86%. This risk premium is the additional return necessary to induce investors to take on
10 the added risk associated with common stocks over the risk-free investment. The beta
11 coefficient is applied to the risk premium to ascertain how much of a risk premium is
12 necessary for investors to take on risks of investing in utility stocks as opposed to the risk-
13 free U.S. Treasury Bond.

Capital Asset Pricing Model -- Forecasted Risk Premium
Using Forecasted Market Returns & Treasury Bond Yields
18-KCPE-480-RTS

		Low Beta	High Beta	Avg Beta
1) Forecasted Returns on Common Stocks		6.93%	6.93%	6.93%
2) Forecasted Total Return on 10-Year T-Bonds	-	3.07%	3.07%	3.07%
3) Resulting Risk Premium		3.86%	3.86%	3.86%
4) Beta Coefficient	x	0.50	0.95	0.67
5) Risk Premium		1.93%	3.67%	2.59%
6) Forecasted Yield on 10-Year T-Bonds	+	3.50%	3.50%	3.50%
7) For Cost of Equity		5.43%	7.17%	6.09%
		6.30%		

1) Forecasted 10 to 15-year annual arithmetic return on stocks for mid-sized companiesby J.P. Morgan Asset Management, 2018 Edition
2) Forecasted 10 to 15-year annual arithmetic return on intermediate term U.S. Government bonds by J.P. Morgan Asset Management, 2018 Edition
3) Resulting risk premium (1-2)
4) Beta coefficient range of proxy group reported by Value-Line
5) Row 3 x Row 4 = asset specific risk premium
6) Forecasted yield on 10-Year U.S. Treasury bonds forecasted by J.P. Morgan Asset Management, 2018 Edition (page 55)
7) Forecasted cost of equity capital row 5 + row 6

Sources:
J.P. Morgan Asset Management, Long-term Capital Market Return Assumptions, 2018 Edition; J.P. Morgan Asset Management (published October of 2017)
www.jpmorganinstitutional.com/pages/jpmorgan/am/ia/research_and_publications/long-term_capital_market

The expected risk-free yield of 3.50% forecasted by JPMAM is added to the beta specific risk premium to arrive at the cost of equity for the given beta coefficient of 0.70 - about 60 basis points less than the returns JPMAM is forecasting for the broad stock market indexes. These results appear low by historic measures of the past 40 years. The results are in line with the returns offered on other investments in the current capital markets. For instance, investors in KCP&L's long-term bonds are purchasing bonds with the expectation for returns of less than 4.00%.

Q. Please discuss the historical CAPM analysis.

A. I performed a CAPM analysis incorporating historic data of returns earned from 1926 through 2014. The process is the same as that applied in the Forecasted CAPM.

Capital Asset Pricing Model -- Historic Risk Premium
Based on Historic Risk Premiums from 1926 to 2015
18-KCPE-480-RTS

		Low Beta	High Beta	Avg Beta
1) Total Returns on Common Stocks		12.10%	12.10%	12.10%
2) Total Return on Government Bonds	-	5.20%	5.20%	5.20%
3) Resulting Risk Premium		6.90%	6.90%	6.90%
4) Beta Coefficient	x	0.50	0.95	0.67
5) Risk Premium		3.45%	6.56%	4.62%
6) Historic Yield on Government Bonds	+	4.38%	4.38%	4.38%
7) Forecasted Cost of Equity Based on Historic Returns		7.83%	10.93%	9.00%
		9.38%		

1) Historic returns on common stocks 1926-2017 (SBBI; Exhibit 2-3)
2) Historic returns on intermediate-term government bonds 1926-2017
3) Resulting risk premium (1-2)
4) Beta coefficient of the proxy group (Reported by Value-Line)
5) Row 3 x Row 4 = Asset Specific Risk Premium
6) Historic year-end yield on intermediate-term government bonds 1926-2017
7) Forecasted cost of equity capital; row 5 + row 6

Sources:
Ibbotson SBBI: 2018 Classic Yearbook (Duff & Phelps) & Value-Line Investment Survey

In relying on purely historic data, we are assuming that certain trends observed in the past 80 years will continue in the future. Most notably, we would be assuming that the returns observed on common stocks from decades past will continue in the future, which of course assumes this historical data accurately measures the past returns. There is strong evidence that these frequently-quoted returns do not present a complete picture of historic returns.[36] The simple step of beginning measurement period in 1926 brings questions as to whether the time period represents all of the modern-era securities trading. The historic returns are reported and might influence expectations despite warnings that surround historic economic growth rates. There are well regarded financial publications that focus solely on this type of historic data and how to apply it in cost of capital studies. Thus, I have to argue

[36] McQuarrie, Edward F; "The Myth of 1926: How Much Do We Know Long-Term Returns on U.S. Stocks?"; The Journal of Investing; Winter 2009; p. 96.

that the historic data is part of the cost of capital universe, although given only light consideration in the final decision.

Q. Does that conclude your testimony?

A. Yes, thank you.

				*** Escalation Rate ***					Weighted Composite			
	2.80%		1.80%		2.60%		5.70%		2.30%		2.91%	
*** Table 3.2 SAFESTOR Alternative (thousands, 2017 $'s) Cost Categories ***										Time	Escalated Costs From 2017 Dollars	
Year	Labor	Equip & Materials	Energy	Burial	Other	Total				from 2017	Total Inflated Costs	KCP&L KS Allocated
2045	$ 50,301	$ 1,936	$ 1,969	$ 33	$ 9,446	$ 63,685				28	$ 134,230,644	$ 27,638,208
2046	$ 52,967	$ 10,775	$ 1,832	$ 1,389	$ 23,599	$ 90,562				29	$ 192,477,968	$ 39,631,383
2047	$ 28,085	$ 6,228	$ 486	$ 15	$ 6,065	$ 40,879				30	$ 88,071,073	$ 18,133,912
2048	$ 28,162	$ 6,245	$ 487	$ 16	$ 6,082	$ 40,992				31	$ 90,623,909	$ 18,659,543
2049	$ 28,085	$ 6,228	$ 486	$ 15	$ 6,065	$ 40,879				32	$ 92,731,922	$ 19,093,585
2050	$ 20,521	$ 4,415	$ 411	$ 13	$ 4,624	$ 29,984				33	$ 69,834,217	$ 14,378,927
2051	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				34	$ 12,975,580	$ 2,671,683
2052	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				35	$ 13,352,715	$ 2,749,336
2053	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				36	$ 13,670,261	$ 2,814,719
2054	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				37	$ 14,031,645	$ 2,889,128
2055	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				38	$ 14,402,734	$ 2,965,536
2056	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				39	$ 14,821,931	$ 3,051,849
2057	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				40	$ 15,175,096	$ 3,124,566
2058	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				41	$ 15,576,923	$ 3,207,302
2059	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				42	$ 15,989,562	$ 3,292,265
2060	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				43	$ 16,455,607	$ 3,388,224
2061	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				44	$ 16,848,473	$ 3,469,116
2062	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				45	$ 17,295,365	$ 3,561,131
2063	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				46	$ 17,754,307	$ 3,655,627
2064	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				47	$ 18,272,546	$ 3,762,333
2065	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				48	$ 18,709,681	$ 3,852,340
2066	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				49	$ 19,206,804	$ 3,954,698
2067	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				50	$ 19,717,364	$ 4,059,823
2068	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				51	$ 20,293,775	$ 4,178,506
2069	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				52	$ 20,780,288	$ 4,278,680
2070	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				53	$ 21,333,426	$ 4,392,571
2071	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				54	$ 21,901,550	$ 4,509,548
2072	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				55	$ 22,542,816	$ 4,641,586
2073	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				56	$ 23,084,431	$ 4,753,105
2074	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				57	$ 23,700,055	$ 4,879,862
2075	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				58	$ 24,332,401	$ 5,010,063
2076	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				59	$ 25,046,004	$ 5,156,994
2077	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				60	$ 25,649,136	$ 5,281,180
2078	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				61	$ 26,334,497	$ 5,422,296
2079	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				62	$ 27,038,525	$ 5,567,256
2080	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				63	$ 27,832,842	$ 5,730,807
2081	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				64	$ 28,504,690	$ 5,869,141
2082	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				65	$ 29,267,916	$ 6,026,290
2083	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				66	$ 30,051,993	$ 6,187,732
2084	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393				67	$ 30,936,415	$ 6,369,835
2085	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				68	$ 31,685,059	$ 6,523,982
2086	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379				69	$ 32,535,274	$ 6,699,041

						Weighted Composite
*** Escalation Rate ***	2.80%	1.80%	2.60%	5.70%	2.30%	2.91%

*** Table 3.2 SAFESTOR Alternative (thousands, 2017 $'s) Cost Categories ***

Year	Labor	Equip & Materials	Energy	Burial	Other	Total	Time from 2017	Escalated Costs From 2017 Dollars: Total Inflated Costs	KCP&L KS Allocated
2087	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	70	$ 33,408,789	$ 6,878,899
2088	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393	71	$ 34,393,851	$ 7,081,724
2089	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	72	$ 35,228,375	$ 7,253,554
2090	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	73	$ 36,175,823	$ 7,448,634
2091	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	74	$ 37,149,327	$ 7,649,079
2092	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393	75	$ 38,246,858	$ 7,875,062
2093	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	76	$ 39,177,485	$ 8,066,679
2094	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	77	$ 40,233,688	$ 8,284,152
2095	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	78	$ 41,319,046	$ 8,507,628
2096	$ 3,446	$ 323	$ 243	$ 7	$ 1,374	$ 5,393	79	$ 42,542,342	$ 8,759,506
2097	$ 3,437	$ 322	$ 243	$ 7	$ 1,370	$ 5,379	80	$ 43,580,588	$ 8,973,281
2098	$ 8,030	$ 526	$ 530	$ 10	$ 1,416	$ 10,512	81	$ 91,483,641	$ 18,836,562
2099	$ 39,843	$ 3,003	$ 2,428	$ 35	$ 1,725	$ 47,034	82	$ 430,839,660	$ 88,710,266
2100	$ 51,668	$ 21,348	$ 2,352	$ 19,715	$ 11,194	$ 106,277	83	$ 2,662,274,613	$ 548,164,690
2101	$ 52,224	$ 26,356	$ 2,272	$ 29,879	$ 16,007	$ 126,738	84	$ 3,922,244,251	$ 807,593,549
2102	$ 43,514	$ 7,481	$ 1,821	$ 10,054	$ 5,614	$ 68,484	85	$ 1,662,739,234	$ 342,359,474
2103	$ 43,514	$ 7,481	$ 1,821	$ 10,054	$ 5,614	$ 68,484	86	$ 1,741,171,137	$ 358,508,672
2104	$ 36,028	$ 4,171	$ 1,047	$ 4,233	$ 3,422	$ 48,901	87	$ 978,573,603	$ 201,489,168
2105	$ 19,989	$ 11,805	$ 289	$ 6	$ 1,828	$ 33,917	88	$ 300,897,026	$ 61,954,963
2106	$ 11,872	$ 9,571	$ 164	$ -	$ 1,237	$ 22,844	89	$ 196,446,660	$ 40,448,540
Total	$ 676,450	$ 142,715	$ 29,816	$ 75,796	$ 168,376	$ 1,093,153			

Source: Decommissioning Cost Analysis for the Wolf Creek Generating Station; prepared by TLG Services; August 2017; Table 3.2; p68 of 139

Kansas allocator for Wolf Creek; KCC DR #164	43.8%
KCP&L Ownership	47.0%

Kansas City Power & Light-Ks SAFESTOR Decommissioning

$ 2,036,766 Annual Payment

Time	Year	Annual Inflow	Annual Outflow	Annual Earnings	Balance	Annual Return
1	2018	$ 2,036,766	$ -		**$ 96,010,166**	4.62%
2	2019	$ 2,036,766	$ -	$ 4,483,728	$ 102,530,660	4.62%
3	2020	$ 2,036,766	$ -	$ 4,785,043	$ 109,352,468	4.62%
4	2021	$ 2,036,766	$ -	$ 5,100,281	$ 116,489,515	4.62%
5	2022	$ 2,036,766	$ -	$ 5,430,087	$ 123,956,368	4.62%
6	2023	$ 2,036,766	$ -	$ 5,775,133	$ 131,768,268	4.62%
7	2024	$ 2,036,766	$ -	$ 6,136,124	$ 139,941,158	4.62%
8	2025	$ 2,036,766	$ -	$ 6,513,797	$ 148,491,721	4.62%
9	2026	$ 2,036,766	$ -	$ 6,908,922	$ 157,437,408	4.62%
10	2027	$ 2,036,766	$ -	$ 7,322,305	$ 166,796,480	4.62%
11	2028	$ 2,036,766	$ -	$ 7,754,792	$ 176,588,038	4.62%
12	2029	$ 2,036,766	$ -	$ 8,207,264	$ 186,832,067	4.62%
13	2030	$ 2,036,766	$ -	$ 8,680,644	$ 197,549,478	4.62%
14	2031	$ 2,036,766	$ -	$ 9,175,900	$ 208,762,144	4.62%
15	2032	$ 2,036,766	$ -	$ 9,694,042	$ 220,492,952	4.62%
16	2033	$ 2,036,766	$ -	$ 10,236,127	$ 232,765,845	4.62%
17	2034	$ 2,036,766	$ -	$ 10,803,263	$ 245,605,874	4.62%
18	2035	$ 2,036,766	$ -	$ 11,396,606	$ 259,039,246	4.62%
19	2036	$ 2,036,766	$ -	$ 12,017,367	$ 273,093,379	4.62%
20	2037	$ 2,036,766	$ -	$ 12,666,814	$ 287,796,959	4.62%
21	2038	$ 2,036,766	$ -	$ 13,346,272	$ 303,179,997	4.62%
22	2039	$ 2,036,766	$ -	$ 14,057,129	$ 319,273,892	4.62%
23	2040	$ 2,036,766	$ -	$ 14,800,834	$ 336,111,492	4.62%
24	2041	$ 2,036,766	$ -	$ 15,578,906	$ 353,727,165	4.62%
25	2042	$ 2,036,766	$ -	$ 16,392,934	$ 372,156,864	4.62%
26	2043	$ 2,036,766	$ -	$ 17,244,577	$ 391,438,208	4.62%
27	2044	$ 2,036,766	$ -	$ 18,135,576	$ 411,610,550	4.62%
28	2045	$ -	$ (27,638,208)	$ 19,020,688	$ 402,993,030	4.62%
29	2046	$ -	$ (39,631,383)	$ 18,622,469	$ 381,984,115	4.62%
30	2047	$ -	$ (18,133,912)	$ 17,651,639	$ 381,501,843	4.62%
31	2048	$ -	$ (18,659,543)	$ 17,629,353	$ 380,471,653	4.62%
32	2049	$ -	$ (19,093,585)	$ 17,581,747	$ 378,959,815	4.62%
33	2050	$ -	$ (14,378,927)	$ 17,511,885	$ 382,092,773	4.62%
34	2051	$ -	$ (2,671,683)	$ 17,656,660	$ 397,077,750	4.62%
35	2052	$ -	$ (2,749,336)	$ 18,349,122	$ 412,677,536	4.62%
36	2053	$ -	$ (2,814,719)	$ 19,069,994	$ 428,932,811	4.62%
37	2054	$ -	$ (2,889,128)	$ 19,821,157	$ 445,864,840	4.62%
38	2055	$ -	$ (2,965,536)	$ 20,603,593	$ 463,502,897	4.62%
39	2056	$ -	$ (3,051,849)	$ 21,418,654	$ 481,869,702	4.62%
40	2057	$ -	$ (3,124,566)	$ 22,267,392	$ 501,012,528	4.62%
41	2058	$ -	$ (3,207,302)	$ 23,151,989	$ 520,957,215	4.62%
42	2059	$ -	$ (3,292,265)	$ 24,073,641	$ 541,738,592	4.62%
43	2060	$ -	$ (3,388,224)	$ 25,033,957	$ 563,384,325	4.62%
44	2061	$ -	$ (3,469,116)	$ 26,034,215	$ 585,949,424	4.62%
45	2062	$ -	$ (3,561,131)	$ 27,076,957	$ 609,465,251	4.62%
46	2063	$ -	$ (3,655,627)	$ 28,163,633	$ 633,973,256	4.62%
47	2064	$ -	$ (3,762,333)	$ 29,296,158	$ 659,507,081	4.62%

Kansas City Power & Light-Ks SAFESTOR Decommissioning

$ 2,036,766 Annual Payment

Time	Year	Annual Inflow	Annual Outflow	Annual Earnings	Balance	Annual Return
48	2065	$ -	$ (3,852,340)	$ 30,476,086	$ 686,130,827	4.62%
49	2066	$ -	$ (3,954,698)	$ 31,706,380	$ 713,882,509	4.62%
50	2067	$ -	$ (4,059,823)	$ 32,988,796	$ 742,811,483	4.62%
51	2068	$ -	$ (4,178,506)	$ 34,325,616	$ 772,958,592	4.62%
52	2069	$ -	$ (4,278,680)	$ 35,718,726	$ 804,398,639	4.62%
53	2070	$ -	$ (4,392,571)	$ 37,171,583	$ 837,177,650	4.62%
54	2071	$ -	$ (4,509,548)	$ 38,686,314	$ 871,354,416	4.62%
55	2072	$ -	$ (4,641,586)	$ 40,265,636	$ 906,978,466	4.62%
56	2073	$ -	$ (4,753,105)	$ 41,911,838	$ 944,137,199	4.62%
57	2074	$ -	$ (4,879,862)	$ 43,628,958	$ 982,886,295	4.62%
58	2075	$ -	$ (5,010,063)	$ 45,419,569	$ 1,023,295,801	4.62%
59	2076	$ -	$ (5,156,994)	$ 47,286,908	$ 1,065,425,715	4.62%
60	2077	$ -	$ (5,281,180)	$ 49,233,748	$ 1,109,378,284	4.62%
61	2078	$ -	$ (5,422,296)	$ 51,264,814	$ 1,155,220,802	4.62%
62	2079	$ -	$ (5,567,256)	$ 53,383,215	$ 1,203,036,761	4.62%
63	2080	$ -	$ (5,730,807)	$ 55,592,810	$ 1,252,898,764	4.62%
64	2081	$ -	$ (5,869,141)	$ 57,896,953	$ 1,304,926,576	4.62%
65	2082	$ -	$ (6,026,290)	$ 60,301,179	$ 1,359,201,466	4.62%
66	2083	$ -	$ (6,187,732)	$ 62,809,243	$ 1,415,822,977	4.62%
67	2084	$ -	$ (6,369,835)	$ 65,425,746	$ 1,474,878,888	4.62%
68	2085	$ -	$ (6,523,982)	$ 58,309,632	$ 1,526,664,538	3.95%
69	2086	$ -	$ (6,699,041)	$ 60,356,988	$ 1,580,322,485	3.95%
70	2087	$ -	$ (6,878,899)	$ 62,478,365	$ 1,635,921,951	3.95%
71	2088	$ -	$ (7,081,724)	$ 64,676,502	$ 1,693,516,728	3.95%
72	2089	$ -	$ (7,253,554)	$ 66,953,523	$ 1,753,216,698	3.95%
73	2090	$ -	$ (7,448,634)	$ 69,313,773	$ 1,815,081,836	3.95%
74	2091	$ -	$ (7,649,079)	$ 71,759,623	$ 1,879,192,381	3.95%
75	2092	$ -	$ (7,875,062)	$ 64,743,439	$ 1,936,060,758	3.45%
76	2093	$ -	$ (8,066,679)	$ 66,702,714	$ 1,994,696,794	3.45%
77	2094	$ -	$ (8,284,152)	$ 68,722,890	$ 2,055,135,531	3.45%
78	2095	$ -	$ (8,507,628)	$ 70,805,173	$ 2,117,433,077	3.45%
79	2096	$ -	$ (8,759,506)	$ 72,951,498	$ 2,181,625,069	3.45%
80	2097	$ -	$ (8,973,281)	$ 75,163,092	$ 2,247,814,880	3.45%
81	2098	$ -	$ (18,836,562)	$ 47,024,287	$ 2,276,002,605	2.09%
82	2099	$ -	$ (88,710,266)	$ 47,613,974	$ 2,234,906,314	2.09%
83	2100	$ -	$ (548,164,690)	$ 46,754,240	$ 1,733,495,864	2.09%
84	2101	$ -	$ (807,593,549)	$ 36,264,733	$ 962,167,048	2.09%
85	2102	$ -	$ (342,359,474)	$ 20,128,535	$ 639,936,109	2.09%
86	2103	$ -	$ (358,508,672)	$ 13,387,463	$ 294,814,900	2.09%
87	2104	$ -	$ (201,489,168)	$ 6,167,528	$ 99,493,260	2.09%
88	2105	$ -	$ (61,954,963)	$ 2,081,399	$ 39,619,696	2.09%
89	2106	$ -	$ (40,448,540)	$ 828,844	$ (0)	2.09%

Estimates of Returns on Nuclear Decommissioning Trusts Across Investment Periods

JPMAM Long-Term Capital Market Assumptions

	2017 Arithmatic	2018 Arithmatic
Equities-Large Cap	7.63%	6.41%
Equities-Small Cap	8.67%	7.35%
Equities-International (EAFE)	7.95%	7.61%
Core Bonds	3.44%	3.67%
High Yield Bonds	6.13%	5.59%
Real Estate	7.32%	7.42%
Cash & Equivalents	2.00%	2.00%
Equity Management Fees	0.11%	see DR KCC-258
Fixed Income Management Fees	0.22%	
Tax Rate	20.00%	

SAFESTOR Methodology 2018-2106

		Pre-Tax	Post-Tax
Time Period 1	2017-2084	5.78%	4.62%
Time Period 2	2085-2091	4.94%	3.95%
Time Period 3	2092-2097	4.31%	3.45%
Time Period 4	2098-2106	2.62%	2.09%

Sources: J.P.Morgan Asset Management
2018 & 2017 Long-term Asset Returns

Time Period 1	Asset Weight	w/Fees Proj. Return	Pre-Tax Weighted Return	After Tax
Equities-Large Cap	27.00%	6.30%	1.70%	1.36%
Equities-Small Cap	6.00%	7.24%	0.43%	0.35%
Equities-International (EAFE)	20.00%	7.50%	1.50%	1.20%
Core Bonds	25.00%	3.45%	0.86%	0.69%
High Yield Bonds	17.00%	5.37%	0.91%	0.73%
Real Estate	5.00%	7.31%	0.37%	0.29%
Cash & Equivalents	0.00%	1.78%	0.00%	0.00%
Time Period 2				
Equities-Large Cap	20.00%	6.30%	1.26%	1.01%
Equities-Small Cap	5.00%	7.24%	0.36%	0.29%
Equities-International (EAFE)	12.00%	7.50%	0.90%	0.72%
Core Bonds	44.00%	3.45%	1.52%	1.21%
High Yield Bonds	8.00%	5.37%	0.43%	0.34%
Real Estate	5.00%	7.31%	0.37%	0.29%
Cash & Equivalents	6.00%	1.78%	0.11%	0.09%
Time Period 3				
Equities-Large Cap	10.00%	6.30%	0.63%	0.50%
Equities-Small Cap	5.00%	7.24%	0.36%	0.29%
Equities-International (EAFE)	5.00%	7.50%	0.38%	0.30%
Core Bonds	57.00%	3.45%	1.97%	1.57%
High Yield Bonds	8.00%	5.37%	0.43%	0.34%
Real Estate	5.00%	7.31%	0.37%	0.29%
Cash & Equivalents	10.00%	1.78%	0.18%	0.14%
Time Period 4				
Equities-Large Cap	0.00%	6.30%	0.00%	0.00%
Equities-Small Cap	0.00%	7.24%	0.00%	0.00%
Equities-International (EAFE)	0.00%	7.50%	0.00%	0.00%
Core Bonds	50.00%	3.45%	1.73%	1.38%
High Yield Bonds	0.00%	5.37%	0.00%	0.00%
Real Estate	0.00%	7.31%	0.00%	0.00%
Cash & Equivalents	50.00%	1.78%	0.89%	0.71%

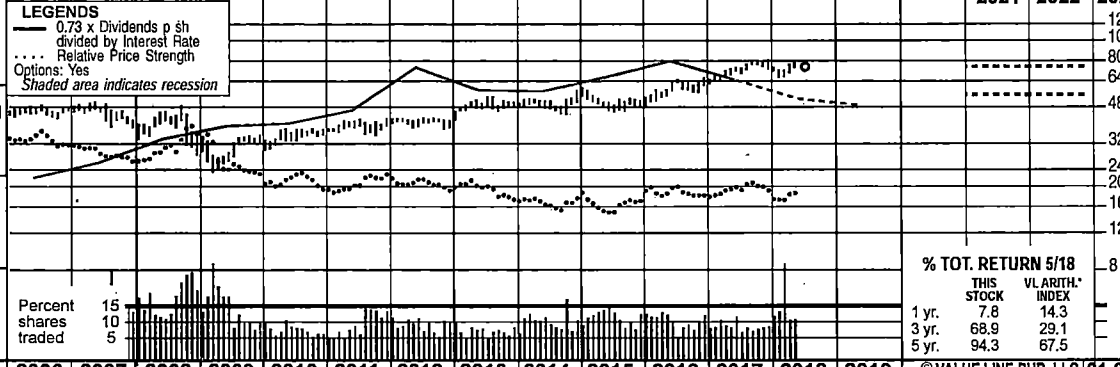
ALLETE NYSE-ALE

RECENT PRICE 75.02 | P/E RATIO 22.1 (Trailing: 23.8 Median: 16.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 4 Lowered 5/25/18
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 6/15/18
BETA .75 (1.00 = Market)

High:	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2	79.9
Low:	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(Nil)	3%
Low	55	(-25%)	-3%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	8	8	1	0
to Sell	0	0	0	0	0	0	0	1	1

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	118	117	132
to Sell	124	98	140
Hld's(000)	44573	38769	38170

Percent shares traded 15 10 5

% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.8	14.3
3 yr.	68.9	29.1
5 yr.	94.3	67.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	*27.95*	*28.65*	Revenues per sh	*31.25*
--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	*6.85*	*7.20*	"Cash Flow" per sh	*8.50*
--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	*3.40*	*3.60*	Earnings per sh A	*4.25*
--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	*2.24*	*2.34*	Div'd Decl'd per sh B ■ †	*2.70*
--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	*6.30*	*6.90*	Cap'l Spending per sh	*6.75*
--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	*41.75*	*43.00*	Book Value per sh C	*47.25*
--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	*51.50*	*52.00*	Common Shs Outst'g D	*53.50*
--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.14	*Value Line*		Relative P/E Ratio	*.85*
--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	*1440*	*1490*	Revenues ($mill)	*1670*
						82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	*175*	*185*	Net Profit ($mill)	*225*
						34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	*NMF*	*NMF*	Income Tax Rate	*NMF*
						5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
						41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	*41.0%*	*39.5%*	Long-Term Debt Ratio	*40.0%*
						58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	*59.0%*	*60.5%*	Common Equity Ratio	*60.0%*
						1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	*3645*	*3700*	Total Capital ($mill)	*4225*
						1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	*3970*	*4140*	Net Plant ($mill)	*4350*
						6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
						10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
						10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.5%*	Return on Com Equity E	*9.0%*
						3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						61%	93%	81%	66%	71%	72%	67%	60%	66%	68%	*65%*	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $1502.7 mill. **Due in 5 Yrs** $450.5 mill.
LT Debt $1396.5 mill. **LT Interest** $58.5 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $14.2 mill.

Pension Assets-12/17 $628.2 mill. **Oblig** $793.2 mill.

Pfd Stock None

Common Stock 51,271,007 shs.

MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-8.9	-2.3	+8.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.40	NA	NA
Capacity at Peak (Mw)	1942	NA	NA
Peak Load, Winter (Mw)	1631	1520	1599
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	381	318	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	2.5%	*1.5%*
"Cash Flow"	5.0%	7.5%	*3.5%*
Earnings	1.5%	5.5%	*5.0%*
Dividends	3.5%	3.0%	*4.5%*
Book Value	6.0%	6.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	320.0	323.3	462.5	380.6	1486.4
2016	333.8	314.8	349.6	341.5	1339.7
2017	365.6	353.3	362.5	337.9	1419.3
2018	358.2	*351.8*	*380*	*350*	*1440*
2019	*365*	*360*	*400*	*365*	*1490*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.85	.46	1.23	.83	3.38
2016	.93	.50	.81	.89	3.14
2017	.97	.72	.88	.56	3.13
2018	.99	*.61*	*.95*	*.85*	*3.40*
2019	*1.05*	*.65*	*1.00*	*.90*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56	.56			

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 41%; wind, 12%; other, 6%; purchased, 41%. Fuel costs: 28% of revs. '17 deprec. rate: 3.2%. Has 2,000 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's primary utility subsidiary has appealed its rate order. In the first quarter of 2018, Minnesota Power was granted a rate increase of $13 million (retroactive to the start of 2017), based on a return of 9.25% on a common-equity ratio of 53.81%. The utility was disappointed with some aspects of the decision (including the allowed ROE), and asked the Minnesota Public Utilities Commission (MPUC) for reconsideration. It is seeking changes that, if granted, would provide an additional $20 million-$25 million in annual revenues. The MPUC's ruling is expected in mid-2018. Whatever happens, the utility is unlikely to earn its allowed ROE this year, despite cost-reduction measures it is taking. Even so . . .

Earnings are likely to advance solidly this year and next. Minnesota Power is benefiting from full production at the taconite mines in its service area. The utility is booking income from a $330 million transmission line it is constructing in order to import power from Manitoba Hydro. ALLETE's main nonutility subsidiaries, ALLETE Clean Energy and U.S. Water Services, are growing rapidly (due in part to acquisitions), and should benefit (by $0.10 a share) from the lower federal tax rate. (ALLETE will probably have a negative tax rate due to the effects of tax credits for renewable energy.) Our 2018 estimate of $3.40 a share is within the company's targeted range of $3.20-$3.50. We look for profit growth in 2019 in line with management's goal of 5%-7% annually.

The company's utility in Wisconsin plans to file a rate case later this year. Superior Water, Light & Power got a more fruitful result in its last application, when it was granted an allowed ROE of 10.5%. However, this utility is much smaller than Minnesota Power.

ALLETE is proposing to build a gas-fired plant. The company's 50% stake in the project would cost an estimated $350 million. Minnesota Power would purchase half of the plant's output. A decision from the MPUC is expected by yearend.

This untimely stock is priced expensively. The dividend yield is below the utility mean. With the recent quotation at the top of our 2021-2023 Target Price Range, total return potential is zero.

Paul E. Debbas, CFA *June 15, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '17: $11.95/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '17: 8.0%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	85

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ALLIANT ENERGY NYSE-LNT

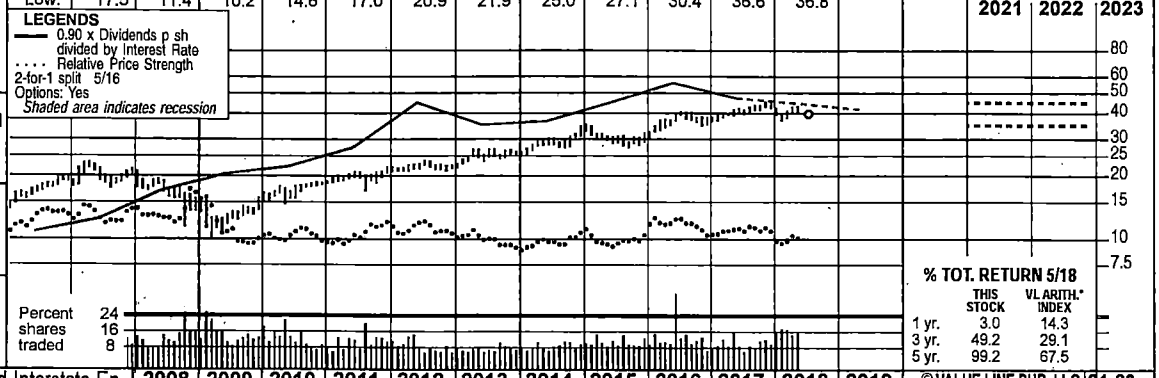
RECENT PRICE 39.75 | P/E RATIO 18.9 (Trailing: 19.2 Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 4/13/18
SAFETY 2 Raised 9/28/07
TECHNICAL 1 Raised 6/1/18
BETA .70 (1.00 = Market)

High:	23.3	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	45.6	43.5
Low:	17.5	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	35	(-10%)	1%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	5	0	0
to Sell	0	1	0	0	0	0	0	1	0

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	194	190	170
to Sell	187	165	239
Hld's(000)	182717	166325	168237

Percent shares traded 24 16 8

% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.0	14.3
3 yr.	49.2	29.1
5 yr.	99.2	67.5

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	*15.30*	*15.55*	Revenues per sh	*17.75*
2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97	*4.25*	*4.45*	"Cash Flow" per sh	*5.00*
1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	*2.10*	*2.25*	Earnings per sh A	*2.60*
.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	*1.34*	*1.42*	Div'd Decl'd per sh B ■ †	*1.66*
3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	*6.75*	*7.10*	Cap'l Spending per sh	*5.30*
12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	*19.00*	*20.25*	Book Value per sh C	*22.85*
220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	*233.00*	*235.00*	Common Shs Outst'g D	*235.00*
13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.01	*Value Line*		Relative P/E Ratio	*.85*
4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*
3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	*3560*	*3650*	Revenues ($mill)	*4175*
280.0	208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	455.9	*490*	*530*	Net Profit ($mill)	*610*
33.4%	--	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
--	--	--	--	--	--	--	6.5%	7.0%	7.3%	*7.5%*	*7.5%*	AFUDC % to Net Profit	*7.5%*
36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	51.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	*8300*	*8400*	Total Capital ($mill)	*8700*
5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	10797.9	*11125*	*11645*	Net Plant ($mill)	*12900*
7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	5.6%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.5%*
9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	10.9%	*11.0%*	*11.0%*	Return on Com Equity E	*11.5%*
3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
62%	88%	64%	67%	64%	57%	59%	65%	72%	63%	*64%*	*63%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $5248.9 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $4056.8 mill. **LT Interest** $180.0 mill.
(LT interest earned: 4.0x)

Pension Assets-12/17 $950.7 mill. **Oblig.** $1303.1 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 231,481,828 shs.

MARKET CAP: $9.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	+2.0	1.0
Avg. Indust. Use (MWH)	11735	11987	12102
Avg. Indust. Revs. per KWH (¢)	6.92	7.04	7.16
Capacity at Peak (Mw)	5385	5615	5375
Peak Load, Summer (Mw)	5385	5615	5375
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	+.4
Fixed Charge Cov. (%)	315	295	319

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	.5%	-1.5%	*3.5%*
"Cash Flow"	3.5%	6.5%	*7.0%*
Earnings	5.0%	6.5%	*6.5%*
Dividends	7.5%	6.5%	*6.0%*
Book Value	4.0%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	897.4	717.2	898.9	740.1	3253.6
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	765.3	906.9	856.1	3382.2
2018	916.3	*790*	*1050*	*803.7*	*3560*
2019	*935*	*815*	*1025*	*875*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.44	.30	.80	.15	1.69
2016	.43	.37	.57	.28	1.65
2017	.44	.41	.73	.41	1.99
2018	.52	*.43*	*.82*	*.33*	*2.10*
2019	*.54*	*.45*	*.88*	*.38*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.255	.255	.255	.255	1.02
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335	.335			

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 38%; IA, 61%; MN, 1%. Elect. rev.: residential, 36%; commercial, 24%; industrial, 30%; wholesale, 8%; other, 2%. Fuel sources, 2017: coal, 40%; gas, 17%; other, 43%. Fuel costs: 45% of revs. 2017 depreciation rate: 5.5%. Estimated plant age: 15 years. Has approximately 3,989 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

We think Alliant Energy's earnings will advance steadily in 2018 and 2019. Each year, the utility is expected to benefit from electric and gas rate increases at Interstate Power and Light (IPL) and Wisconsin Power and Light (WPL). At the start of 2018, electric tariffs were boosted by $130 million (11.6%), while gas rates are now in the process of being hiked (see below). Our 2018 share-net estimate ($2.10) is near the midpoint of management's targeted guidance range of $2.04-$2.18. For 2019, we envision earnings of $2.25 a share, representing year-on-year growth of around 7%.

The company's largest utility subsidiary has filed a rate case. Interstate Power and Light is asking the Iowa Utilities Board for an annual gas increase of $19.8 million (8.0%), based on a return of 9.8% on a common-equity ratio of 49.6%. An interim hike of approximately $11.3 million went into effect last month while the IUB debates the proposal. Alliant has said that the tariff is needed to cover natural gas improvements made over the past six years. A formal hearing should take place in the fall and a final decision from the IUB is expected in around 10 months.

Regulators have approved another 500 megawatts of wind energy expansion for Alliant. Combined with ongoing projects in western Iowa, the company expects to add 1,000 megawatts of wind energy by 2020, bringing its total renewable energy mix in that state to at least 30%.

Progress continues at the West Riverside Energy Center. The 730 megawatt facility is approximately one-third complete and is on track to be placed into service by early 2020. The plant will power nearly 500,000 homes upon completion.

The company has some financing needs. Alliant plans to issue $1 billion of long-term notes this year to help fund its construction projects and refinance $595 million of term loans that are coming due this year. The utility also said it would issue up to $200 million in equity in 2018.

This neutrally ranked stock has a dividend yield that is about equal to the average for a utility. In addition, with the recent price well within our 2021-2023 Target Price Range, total return potential is subpar.

Daniel Henigson, CFA *June 15, 2018*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '08, 4¢; '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings report due early August. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '17: $69.7 mill., $0.30/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '17: 10.5%; in WI in '17 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

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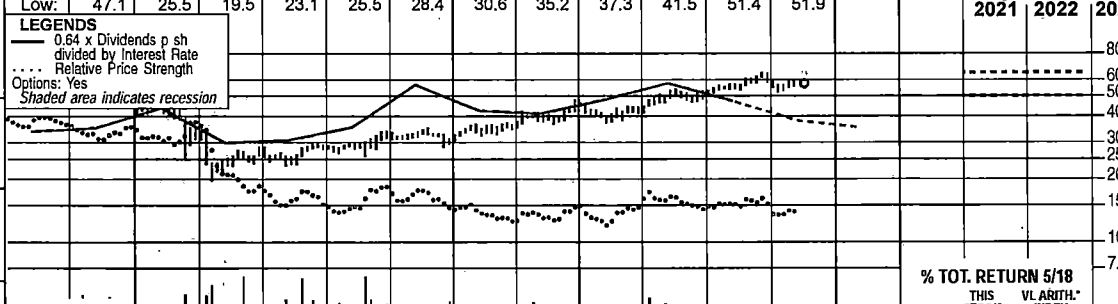
AMEREN NYSE-AEE

RECENT PRICE 57.41 | P/E RATIO 18.8 (Trailing: 19.3 Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 2 Raised 3/2/18
SAFETY 2 Raised 6/20/14
TECHNICAL 2 Raised 6/15/18
BETA .65 (1.00 = Market)

High:	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8	54.1	64.9	59.8
Low:	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+15%)	7%
Low	50	(-15%)	1%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	21	11	5	1
to Sell	0	0	0	1	0	0	0	4	0

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	229	212	234
to Sell	215	192	243
Hld's(000)	186752	171005	170335

Percent shares traded 15 10 5

% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.6	14.3
3 yr.	63.4	29.1
5 yr.	110.1	67.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	*26.45*	*27.10*	Revenues per sh	*29.50*
5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	*7.40*	*7.90*	"Cash Flow" per sh	*9.50*
2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	*3.05*	*3.25*	Earnings per sh A	*4.00*
2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	*1.85*	*1.94*	Div'd Decl'd per sh B ■	*2.35*
5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	*9.80*	*11.25*	Cap'l Spending per sh	*9.50*
24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	*31.00*	*32.50*	Book Value per sh C	*37.50*
154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	*244.00*	*245.50*	Common Shs Outst'g D	*250.00*
15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.02	*Value Line*		Relative P/E Ratio	*.80*
6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $8896 mill. **Due in 5 Yrs** $3338 mill.
LT Debt $6766 mill. **LT Interest** $348 mill.
(LT interest earned: 4.3x)
Leases, Uncapitalized Annual rentals $10 mill.
Pension Assets-12/17 $4293 mill. **Oblig** $4827 mill.
Pfd Stock $142 mill. **Pfd Div'd** $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 243,653,807 shs. **as of 4/30/18**
MARKET CAP: $14 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	*6450*	*6650*	Revenues ($mill)	*7400*
615.0	624.0	669.0	602.0	589.0	518.0	593.0	585.0	659.0	683.0	*755*	*810*	Net Profit ($mill)	*1000*
33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	3.5%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	*49.5%*	*49.0%*	Long-Term Debt Ratio	*49.0%*
50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	*49.5%*	*50.0%*	Common Equity Ratio	*50.0%*
13712	15991	15185	14738	13384	12190	12975	13968	13840	14420	*15225*	*15950*	Total Capital ($mill)	*18700*
16567	17610	17853	18127	16096	16205	17424	18799	20113	21466	*22800*	*24425*	Net Plant ($mill)	*27900*
5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
88%	56%	56%	63%	66%	76%	67%	70%	64%	64%	*60%*	*59%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.1	-4.2	-3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	343	351	362

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-3.0%	-3.5%	*2.5%*
"Cash Flow"	.5%	1.5%	*6.5%*
Earnings	-1.0%	.5%	*7.5%*
Dividends	-4.0%	2.0%	*5.5%*
Book Value	-1.0%	-1.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1556	1401	1833	1308	6098.0
2016	1434	1427	1859	1356	6076.0
2017	1514	1538	1723	1402	6177.0
2018	1585	*1600*	*1765*	*1500*	*6450*
2019	*1650*	*1650*	*1800*	*1550*	*6650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.45	.40	1.41	.12	2.38
2016	.43	.61	1.52	.13	2.68
2017	.42	.79	1.18	.39	2.77
2018	.62	*.63*	*1.40*	*.40*	*3.05*
2019	*.60*	*.70*	*1.50*	*.45*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.40	.40	.41	1.61
2015	.41	.41	.41	.425	1.66
2016	.425	.425	.425	.44	1.72
2017	.44	.44	.44	.4575	1.78
2018	.4575				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Acq'd CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric rev. breakdown: residential, 46%; commercial, 35%; industrial, 8%; other, 11%. Generating sources: coal, 71%; nuclear, 19%; hydro & other, 4%; purchased, 6%. Fuel costs: 27% of revs. '17 reported deprec. rates: 3%-4%. Has 8,600 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We estimate that Ameren will post a strong earnings increase in 2018. Positive factors include a full year's effect of the rate increase the utility received in Missouri last April; spending on Ameren's electric transmission system; and winter weather that was much colder than a year earlier. Our estimate is at the midpoint of Ameren's guidance of $2.95-$3.15 a share.

Ameren filed a gas rate application in Illinois. The utility is seeking a rate increase of $44 million, which incorporates agreements with the staff of the Illinois commission for a 9.87% return on equity and a common-equity ratio of up to 50%. An order is expected in December, with new tariffs taking effect in January.

We look for another strong earnings increase in 2019. Additional transmission spending and rate relief in Illinois should help. Our $3.25-a-share estimate would produce profit growth of 7%, which is at the top end of Ameren's annual goal of 5%-7%.

A new regulatory law in Missouri will help utilities in the state. Regulatory lag there has been a problem historically, but the new law (effective August 28th) will increase the ability of utilities to earn a reasonable return on their investments. It will also encourage utilities to increase their capital spending. As a result, Ameren plans to initiate a project (roughly $1 billion through 2023) to modernize the electric grid. This should boost the company's long-term earnings growth rate. Management will likely provide more information with its earnings call for the third or fourth quarter of 2018.

Ameren is planning to acquire a 400-megawatt wind farm. This is part of the company's potential $1 billion of wind generation investments by 2020. The Missouri commission must approve this proposed acquisition. An associated transmission project is already under construction. This is expected to cost $250 million and be in service in December of 2019.

This timely stock has a dividend yield that is slightly below the utility mean. Although we have raised our sights for the 3- to 5-year period, with the recent price within our 2021-2023 Target Price Range, total return potential over that time frame is unspectacular.

Paul E. Debbas, CFA *June 15, 2018*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '16-'17 EPS don't sum due to rounding. Next egs. report due early Aug. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '17: $6.76/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '17: elec., none spec.; in '11: gas, none spec.; in IL in '14: elec., 8.7%, in '16: gas, 9.6%; earned on avg. com. eq., '17: 9.3%. Reg. Climate: Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

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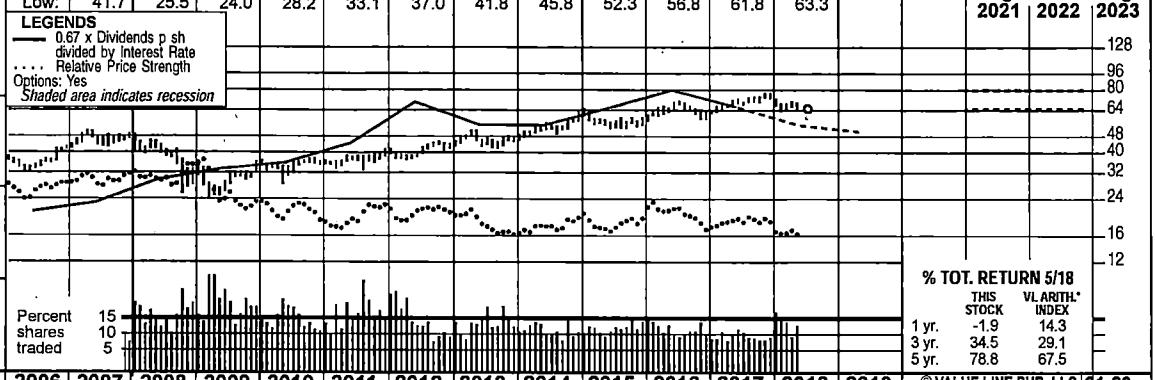
AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 65.29 | P/E RATIO 17.0 (Trailing: 18.1 Median: 14.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Lowered 5/4/18
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Raised 5/25/18
BETA .65 (1.00 = Market)

High:	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	78.1	73.4
Low:	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8	63.3

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+25%)	9%
Low	65	(Nil)	4%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	388	371	406
to Sell	351	342	468
Hld's(000)	382879	352776	357126

Percent shares traded 15 10 5

% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.9	14.3
3 yr.	34.5	29.1
5 yr.	78.8	67.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	*32.00*	*32.85*	Revenues per sh	*34.50*
6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	*8.45*	*8.90*	"Cash Flow" per sh	*10.25*
2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	*3.85*	*4.10*	Earnings per sh A	*5.00*
2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	*2.51*	*2.63*	Div'd Decl'd per sh B ■	*3.05*
5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	*12.50*	*12.95*	Cap'l Spending per sh	*11.25*
20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	*38.60*	*40.20*	Book Value per sh C	*46.50*
338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	*493.50*	*495.00*	Common Shs Outst'g D	*516.00*
12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.96	*Value Line*		Relative P/E Ratio	*.80*
6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $24121 mill. **Due in 5 Yrs** $10714 mill.
LT Debt $18845 mill. **LT Interest** $777 mill.
Incl. $1410.5 mill. securitized bonds. Incl. $294 mill. capitalized leases.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $245.9 mill.
Pension Assets-12/17 $5174.1 mill. **Oblig** $5215.8 mill.
Pfd Stock None

Common Stock 492,523,470 shs.
as of 4/26/18
MARKET CAP: $32 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
14440	13489	14427	15116	14945	15357	17020	16453	16380	15425	*15800*	*16250*	Revenues ($mill)	*17750*
1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	*1850*	*1970*	Net Profit ($mill)	*2465*
31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*6.0%*
59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	*52.5%*	*54.5%*	Long-Term Debt Ratio	*50.5%*
40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	*47.5%*	*45.5%*	Common Equity Ratio	*49.5%*
26290	28958	29184	29747	30823	32913	33001	35633	34775	37707	*40275*	*43750*	Total Capital ($mill)	*48700*
32987	34344	35674	36971	38763	40997	44117	46133	45639	50262	*54150*	*58175*	Net Plant ($mill)	*67600*
6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
55%	56%	66%	60%	63%	62%	61%	60%	54%	67%	*67%*	*66%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.2	+.3	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	NA	NA
Fixed Charge Cov. (%)	356	374	354

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	--	1.5%	*1.0%*
"Cash Flow"	2.5%	4.0%	*4.0%*
Earnings	3.0%	5.5%	*4.5%*
Dividends	4.0%	4.5%	*5.0%*
Book Value	4.0%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4580	3827	4431	3615	16453
2016	4045	3893	4652	3790	16380
2017	3933	3577	4105	3810	15425
2018	4048	*3652*	*4200*	*3900*	*15800*
2019	*4150*	*3750*	*4350*	*4000*	*16250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.27	.88	1.04	.41	3.59
2016	1.02	1.03	1.43	.76	4.23
2017	.94	.76	1.11	.81	3.62
2018	.92	*.85*	*1.23*	*.85*	*3.85*
2019	*1.00*	*.90*	*1.30*	*.90*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	2.15
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62	.62			

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 34% of revenues. '17 reported depreciation rates (utility): 1.6%-9.2%. Has 17,700 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

We estimate that American Electric Power's earnings will increase nicely in 2018 and 2019. As usual, AEP is benefiting from rate relief. So far this year, the company's utilities in Michigan, Kentucky, Oklahoma, and Texas have been granted tariff increases. Other rate cases are pending (see below). AEP's extensive electric transmission system obtains revenues annually for $3 billion in capital spending. Moreover, the utilities are experiencing some load growth, thanks to the improving economies in their service territories. Our 2018 and 2019 share-earnings estimates are at the midpoint of the company's targeted ranges of $3.75-$3.95 and $4.00-$4.20, respectively. Management's goal for yearly profit growth is 5%-7%, and our estimates, if attained, would produce increases within this range.

AEP is proposing a huge wind project that would serve four states. Although there has been some opposition, the project has been approved in Arkansas, and the utilities in Louisiana and Oklahoma have reached regulatory settlements that await commission approval. The Texas regulators must have their say, as well. The 2,000-megawatt facility would cost $4.5 billion and is targeted for completion in the fourth quarter of 2020. This project is *not* reflected in AEP's capital budget, or in our figures.

Rate cases are pending in Indiana and West Virginia. Indiana & Michigan Power reached a settlement (subject to regulatory approval) for a rate hike of $97 million, based on a 9.95% return on equity. New tariffs are expected to take effect at the start of July. Appalachian Power is asking the West Virginia commission for an increase of $115 million, based on a 10.22% ROE. New rates should take effect by March. Another petition might well occur in Oklahoma, where Public Service of Oklahoma was disappointed with the ruling it received earlier this year. Cost-control measures have become even more important here in view of this.

This high-quality stock is untimely, but offers an attractive dividend yield. This is about a half percentage point above the utility mean. Total return potential to 2021-2023 is somewhat above average for this industry.

Paul E. Debbas, CFA *June 15, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; disc. ops.: '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). '15-'16 EPS don't sum due to rounding. Next egs. report due late July. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '17: $12.59/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.3%-10.9%; earn. on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

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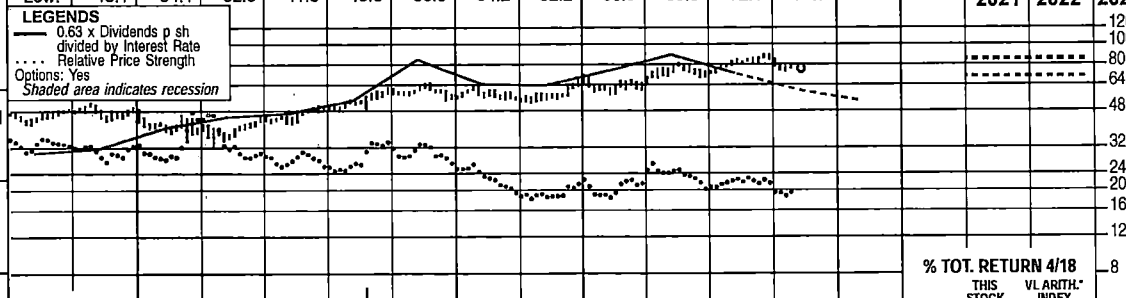
CON. EDISON NYSE-ED

RECENT PRICE 76.23 | P/E RATIO 17.9 (Trailing: 18.2 Median: 15.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 3/2/18
SAFETY 1 New 7/27/90
TECHNICAL 4 Raised 5/18/18
BETA .50 (1.00 = Market)

High:	52.9	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9
Low:	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5	72.1	73.7

Target Price Range 2021 | 2022 | 2023



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+10%)	7%
Low	70	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	11	8	8	11	8	8	11	8	8
Options	0	0	0	2	2	0	8	12	0
to Sell	0	1	0	0	0	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	330	335	298
to Sell	323	322	284
Hld's(000)	196270	197384	178532

Percent shares traded 21 14 7

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.6	9.5
3 yr.	45.4	25.8
5 yr.	53.1	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	*38.80*	*39.80*	Revenues per sh	*43.25*
5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	*8.75*	*9.15*	"Cash Flow" per sh	*10.50*
3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	*4.25*	*4.40*	Earnings per sh A	*4.75*
2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	*2.86*	*2.96*	Div'd Decl'd per sh B ■	*3.30*
5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	*12.50*	*11.15*	Cap'l Spending per sh	*11.25*
27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	*51.70*	*53.25*	Book Value per sh C	*58.00*
213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	*317.00*	*318.00*	Common Shs Outst'g D	*321.00*
13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	.99	*Value Line*		Relative P/E Ratio	*.90*
5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $17410 mill. **Due in 5 Yrs** $4935 mill.
LT Debt $14730 mill. **LT Interest** $670 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $63 mill.

Pension Assets-12/17 $14274 mill.
Oblig $15536 mill.

Pfd Stock None

Common Stock 310,730,465 shs.
as of 4/30/18
MARKET CAP: $24 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
13583	13032	13325	12938	12188	12381	12919	12554	12075	12033	*12300*	*12650*	Revenues ($mill)	*13850*
933.0	868.0	992.0	1062.0	1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	*1340*	*1405*	Net Profit ($mill)	*1550*
36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	*21.5%*	*21.5%*	Income Tax Rate	*21.5%*
1.7%	2.6%	2.4%	1.6%	.5%	.5%	.3%	.7%	1.3%	1.5%	*2.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	*49.0%*	*48.5%*	Long-Term Debt Ratio	*48.5%*
50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	*51.0%*	*51.5%*	Common Equity Ratio	*51.5%*
19160	20330	21952	21794	21933	22735	24207	25058	29033	30149	*32150*	*32900*	Total Capital ($mill)	*36200*
20874	22464	23863	25093	26939	28436	29827	32209	35216	37600	*40150*	*42075*	Net Plant ($mill)	*47800*
6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	*8.0%*	*8.5%*	Return on Shr. Equity	*8.5%*
9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	*8.0%*	*8.5%*	Return on Com Equity E	*8.5%*
3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	*2.5%*	*2.5%*	Retained to Com Eq	*2.5%*
67%	71%	65%	66%	62%	62%	69%	61%	64%	63%	*67%*	*67%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.9	-.4	-2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NA	NA
Peak Load, Summer (Mw)	13721	NA	NA
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	370	352	354

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.5%	-1.5%	*1.0%*
"Cash Flow"	4.0%	4.0%	*4.5%*
Earnings	2.5%	2.0%	*3.0%*
Dividends	1.5%	2.0%	*3.5%*
Book Value	4.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3616	2788	3443	2707	12554
2016	3157	2794	3417	2707	12075
2017	3228	2633	3211	2961	12033
2018	3364	*2750*	*3436*	*2750*	*12300*
2019	*3450*	*2850*	*3500*	*2850*	*12650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.26	.74	1.45	.60	4.05
2016	1.05	.77	1.47	.64	3.94
2017	1.27	.57	1.48	.78	4.10
2018	1.37	*.63*	*1.60*	*.65*	*4.25*
2019	*1.40*	*.65*	*1.65*	*.70*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.63	.63	.63	.63	2.52
2015	.65	.65	.65	.65	2.60
2016	.67	.67	.67	.67	2.68
2017	.69	.69	.69	.69	2.76
2018	.715				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.7 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16. Purchases most of its power. Fuel costs: 22% of revenues. '17 reported depreciation rates: 2.9%-3.1%. Has 15,000 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

We estimate that Consolidated Edison's earnings will rise 3%-4% this year and next. ConEd's largest subsidiary, Consolidated Edison Company of New York, is benefiting from rate relief. At the start of 2018, electric and gas tariffs were boosted by $155.3 million (2.0%) and $92.3 million (5.6%), respectively. Increases of $155.2 million (1.9%) for electricity and $89.4 million (5.1%) for gas will take effect at the beginning of 2019. Orange and Rockland Utilities might also obtain a rate increase next year (see below). Customer growth is another plus. And oil-heating users continue to convert to the use of gas heat. Our 2018 earnings estimate, which we raised by a nickel a share, is at the midpoint of the company's targeted range of $4.15-$4.35 a share. We lifted our 2019 estimate by $0.10 a share, to $4.40.

Orange and Rockland has a rate case pending. The utility is asking the New York State Public Service Commission for electric and gas increases of $22.5 million and $2.7 million, respectively, based on a return of 9.75% on a common-equity ratio of 48%. New rates should take effect at the start of 2019.

A natural gas pipeline project is under way, and another is being proposed. ConEd's 12.5% stake in the pipeline represents an investment of $400 million for the company. This is scheduled for completion by yearend. ConEd also has a 6.375% stake in a much-shorter pipeline proposal.

The company has some financing needs. The utilities plan to issue $1.3 billion-$1.8 billion of long-term debt this year. ConEd will issue up to $450 million of common equity, over and above what will be raised through the dividend reinvestment and other stock plans (perhaps $80 million).

ConEd's renewable-energy subsidiary continues to add projects. A 25-megawatt wind facility went into effect in the first quarter. The company has 1,561 mw of wind and solar projects in service or under construction.

High-quality ConEd stock has a dividend yield that is a bit above average for a utility. However, with the recent price well within our 2021-2023 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *May 18, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; '16, 15¢; '17, 84¢; gain on discontinued operations: '08, $1.01. '16 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '17: $16.04/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '17: 9.0%; O&R in '15: 9.0%; earned on avg. com. eq., '17: 8.6%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	95

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DUKE ENERGY NYSE-DUK

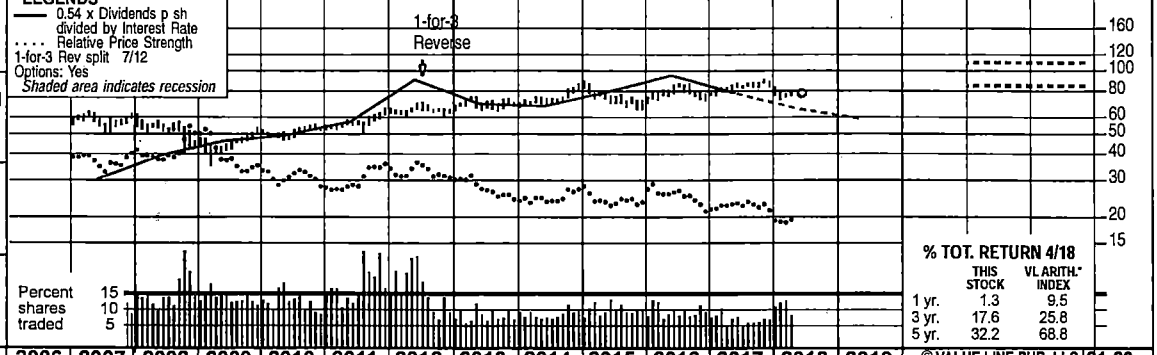
RECENT PRICE 77.88 | P/E RATIO 16.2 (Trailing: 17.8 Median: 18.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 3/2/18
SAFETY 2 New 6/1/07
TECHNICAL 4 Raised 5/18/18
BETA .60 (1.00 = Market)

High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	91.8	84.4
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.9

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.54 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+40%)	13%
Low	85	(+10%)	7%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	8	9
to Sell	0	1	0	0	1	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	528	531	531
to Sell	509	494	467
Hld's(000)	435858	442941	402762

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.3	9.5
3 yr.	17.6	25.8
5 yr.	32.2	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	--	--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	*33.45*	*34.20*	Revenues per sh	*36.50*
--	--	--	--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	*11.15*	*11.70*	"Cash Flow" per sh	*13.25*
--	--	--	--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	*4.80*	*5.00*	Earnings per sh A	*5.50*
--	--	--	--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	*3.64*	*3.80*	Div'd Decl'd per sh B ■	*4.40*
--	--	--	--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	*15.05*	*15.00*	Cap'l Spending per sh	*11.75*
--	--	--	--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	*61.05*	*62.35*	Book Value per sh C	*66.00*
--	--	--	--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	*727.00*	*731.50*	Common Shs Outst'g D	*745.00*
--	--	--	--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
--	--	--	--	--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	.99	*Value Line*		Relative P/E Ratio	*1.00*
--	--	--	--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $54442 mill. **Due in 5 Yrs** $19439 mill.
LT Debt $49035 mill. **LT Interest** $1790 mill.
Incl. $1000 mill. capitalized leases.
(LT interest earned: 3.1x)

Leases, Uncapitalized Annual rentals $218 mill.
Pension Assets-12/17 $9003 mill.
Oblig $8448 mill.

Pfd Stock None

Common Stock 700,092,667 shs.
as of 1/31/18
MARKET CAP: $55 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
13207	12731	14272	14529	19624	24598	23925	23459	22743	23565	*24300*	*25000*	Revenues ($mill)	*27200*
1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	*3435*	*3640*	Net Profit ($mill)	*4100*
32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	*15.5%*	*15.5%*	Income Tax Rate	*15.5%*
16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*10.0%*
38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	*54.0%*	*55.0%*	Long-Term Debt Ratio	*56.5%*
61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	*46.0%*	*45.0%*	Common Equity Ratio	*43.5%*
34238	37863	40457	41451	77307	79482	78088	77222	86609	90774	*97000*	*101475*	Total Capital ($mill)	*112500*
34036	37950	40344	42661	68558	69490	70046	75709	82520	86391	*92675*	*98725*	Net Plant ($mill)	*108700*
4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.5%*
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	*7.5%*	*8.0%*	Return on Com Equity E	*8.5%*
.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	1.2%	*2.0%*	*2.0%*	Retained to Com Eq	*1.5%*
89%	84%	73%	72%	82%	78%	76%	79%	91%	83%	*76%*	*76%*	All Div'ds to Net Prof	*80%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.6	-.3	-2.0
Avg. Indust. Use (MWH)	2883	2908	2914
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.2	+1.4	+1.3
Fixed Charge Cov. (%)	317	264	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.0%	1.5%	*1.5%*
"Cash Flow"	2.0%	3.5%	*5.5%*
Earnings	2.5%	.5%	*5.5%*
Dividends	10.0%	2.5%	*4.5%*
Book Value	.5%	2.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	6065	5589	6483	5322	23459
2016	5377	5213	6576	5577	22743
2017	5729	5555	6482	5799	23565
2018	6135	*5650*	*6665*	*5850*	*24300*
2019	*6300*	*5750*	*6950*	*6000*	*25000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.87	1.44	.70	4.10
2016	.83	.90	1.44	.54	3.71
2017	1.02	.98	1.36	.86	4.22
2018	1.17	*1.03*	*1.55*	*1.05*	*4.80*
2019	*1.20*	*1.10*	*1.60*	*1.10*	*5.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018	.89				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.4 mill. elec. customers in NC, FL, IN, SC, Oh, & KY, and 1.5 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 41%; commercial, 29%; industrial, 14%; other, 16%. Generating sources: coal, 27%; nuclear, 27%; gas, 23%; other, 1%; purchased, 22%. Fuel costs: 30% of revs. '17 reported deprec. rate: 2.8%. Has 29,100 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy has received rate increases in two states. The settlement for its Progress Energy unit was approved by the North Carolina regulators. Rates were raised by $193 million, based on a return of 9.9% on a common-equity ratio of 52%. However, certain costs were disallowed, including some associated with coal ash basin remediation. (Ongoing coal ash costs will be deferred, to be considered for recovery in the utility's next rate case.) This forced Duke to take a pretax charge of $100 million (*included* in our earnings presentation) in the first quarter. Separately, the utility was granted a tariff increase of $8.4 million in Kentucky, based on a return of 9.725% on a common-equity ratio of 49%.

Other regulatory matters are pending. Duke Energy Carolinas is seeking a hike of $647 million, based on a return of 10.75% on a common-equity ratio of 53%. New tariffs should take effect soon. In Ohio, Duke reached a settlement that would boost electric distribution rates by $19 million, based on a return of 9.84% on a common-equity ratio of 50.75%. The company is asking for new rates to take effect on June 1st.

Earnings are likely to advance significantly in 2018 and more modestly in 2019. The third-quarter comparison should be easy, as profits in that period of 2017 were hurt by mild weather patterns and some unusual (but not nonrecurring) costs. Our 2018 estimate of $4.80 a share is near the upper end of Duke's guidance of $4.55-$4.85 a share. Besides the easy comparison, rate relief should benefit the bottom line this year and next. We figure profits will advance 4%, to $5.00 a share, in 2019.

Duke executed a forward sale of common stock. The closing, by yearend, will raise more than $1.5 billion and will increase the share count by more than 21 million. The proceeds will be used for general corporate purposes.

This stock offers an attractive dividend yield. The yield is more than one percentage point above the utility mean. The respectable dividend growth we project over the 3- to 5-year period should produce total returns that are above average for a utility, as well.

Paul E. Debbas, CFA *May 18, 2018*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 11¢; gain (losses) on disc. ops.: '14, (80¢); '15, 5¢; '16, (60¢). '16 EPS don't sum due to rounding. Next egs. due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '17: $45.48/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC: 10.2%; in '17 in SC: 10.1%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earn. avg. com. eq., '17: 7.1%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	85

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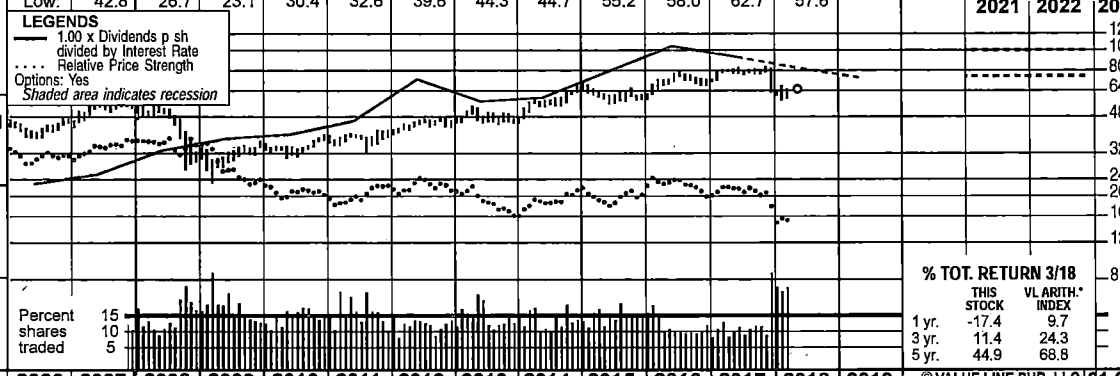
EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 65.22 | P/E RATIO 14.3 (Trailing: 14.5 Median: 12.0) | RELATIVE P/E RATIO 0.76 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Lowered 3/2/18
SAFETY 2 Raised 5/3/13
TECHNICAL 4 Raised 4/20/18
BETA .60 (1.00 = Market)

High:	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	83.4	67.6
Low:	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	62.7	57.6

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+55%)	14%
Low	75	(+15%)	8%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	1	0	0	1	0	1	1
to Sell	2	0	1	0	0	1	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	299	274	278
to Sell	236	258	225
Hld's(000)	290101	288374	267652

Percent shares traded 15 10 5

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-17.4	9.7
3 yr.	11.4	24.3
5 yr.	44.9	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	*38.35*	*40.20*	Revenues per sh	*46.75*
4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	*11.45*	*12.05*	"Cash Flow" per sh	*14.25*
1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	*4.55*	*4.70*	Earnings per sh A	*5.50*
--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	*2.45*	*2.57*	Div'd Decl'd per sh B ■	*3.10*
4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	*13.30*	*15.05*	Cap'l Spending per sh	*15.75*
13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	*37.35*	*38.90*	Book Value per sh C	*44.50*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
7.8	7.0	37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.43	.40	1.99	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.85	*Value Line*		Relative P/E Ratio	*.85*
--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $14516 mill. **Due in 5 Yrs** $4793 mill.
LT Debt $11642 mill. **LT Interest** $569 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $335 mill.
Pens. Assets-12/17 $3616 mill. **Oblig** $4179 mill.
Pfd Stock $2193 mill. **Pfd Div'd** $124 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 2/20/18**
MARKET CAP: $21 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
14112	12374	12409	12760	11862	12581	13413	11524	11869	12320	*12500*	*13100*	Revenues ($mill)	*15200*
1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	*1620*	*1670*	Net Profit ($mill)	*1970*
30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	*10.0%*	*10.0%*	Income Tax Rate	*10.0%*
8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*47.5%*
44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	*44.0%*	*44.5%*	Common Equity Ratio	*45.5%*
21374	21185	23861	24773	20422	21516	23216	24352	24362	25506	*27500*	*28525*	Total Capital ($mill)	*31800*
18969	21966	24778	32116	30273	30455	32981	35085	37000	39050	*41125*	*43675*	Net Plant ($mill)	*50700*
7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	*11.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	*12.5%*	*12.0%*	Return on Com Equity E	*12.5%*
8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
35%	41%	40%	43%	32%	40%	37%	44%	53%	52%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.4	-2.6	+.2
Avg. Indust. Use (MWH)	703	664	NA
Avg. Indust. Revs. per KWH (¢)	9.07	6.51	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23079	23091	23508
Annual Load Factor (%)	52.2	50.7	NA
% Change Customers (yr-end)	+.6	+.5	+.7
Fixed Charge Cov. (%)	247	246	241

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	-.5%	*4.0%*
"Cash Flow"	4.0%	3.5%	*5.0%*
Earnings	2.5%	2.5%	*4.5%*
Dividends	6.0%	9.0%	*8.0%*
Book Value	4.5%	3.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2512	2908	3763	2341	11524
2016	2440	2777	3767	2885	11869
2017	2463	2965	3672	3220	12320
2018	*2500*	*3000*	*3800*	*3200*	*12500*
2019	*2600*	*3150*	*4000*	*3350*	*13100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.91	1.15	1.15	.94	4.15
2016	.85	.86	1.27	.96	3.94
2017	1.11	.85	1.43	1.12	4.51
2018	*1.10*	*.90*	*1.45*	*1.10*	*4.55*
2019	*1.15*	*.90*	*1.50*	*1.15*	*4.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.355	.355	.355	.355	1.42
2015	.4175	.4175	.4175	.4175	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425	.5425	2.17
2018	.605	.605			

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 6%; nuclear, 6%; hydro, 5%; purchased, 83%. Fuel costs: 38% of revs. '17 reported depr. rate: 3.8%. Has 12,500 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Investors remain concerned about the possible wildfire liability of Edison International's utility subsidiary. Southern California Edison's service area had wildfires in the fall of 2017. The cause of the wildfires has not yet been determined, but SCE has already been hit with some lawsuits alleging that its power lines were at fault. (It has $1 billion in liability insurance.) Under California's inverse condemnation law, a utility can be held liable if its power lines contributed to the wildfires, even if the utility followed accepted inspection and safety rules. If this occurs, there is no assurance that the utility will be allowed to pass these costs through to ratepayers. So, the company is pursuing a three-pronged strategy to address this risk, seeking legislative, regulatory, and judicial solutions to this problem.

SCE is awaiting an order on its general rate case. The utility has revised its request to pass through to customers the benefits of federal tax reform. SCE is asking for a reduction of $106 million in 2018 and increases of $431 million and $503 million at the start of 2019 and 2020, respectively. (The order will be retroactive to the beginning of 2018.) The utility's three-year capital spending plan calls for $1.4 billion for grid modernization, which is somewhat controversial because the California commission has not been asked to approve such spending in previous rate cases. An order is expected by yearend.

Tax reform is slightly negative for the company. Edison International has about $1.75 billion of long-term debt at the parent level, so corporate interest and other expenses will have a lower tax shield. This is also true for the company's nonutility energy-services subsidiary, Edison Energy, which is still in its start-up phase and is in the red. Management estimates that the corporate and nonutility drag on earnings will amount to $0.25-$0.30 a share this year. Note that the company is not providing earnings guidance as long as the general rate case is pending.

The wildfire risks hurt the stock last year, and the price has risen just slightly in 2018. The dividend yield and 3- to 5-year total return potential are above average for this industry.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); gains (loss) from discontinued operations: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢. Next earnings report due late July. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '17: $15.08/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '17: 12.2%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	60

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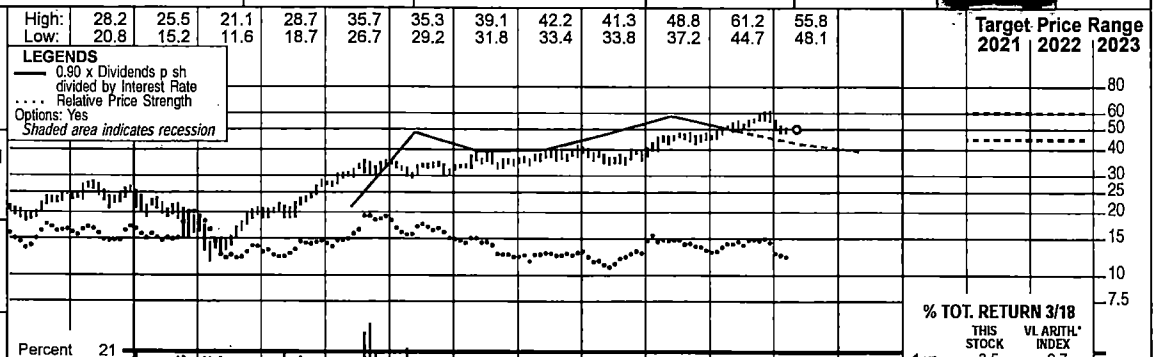
EL PASO ELECTRIC NYSE-EE

RECENT PRICE 50.25 | P/E RATIO 20.4 (Trailing: 20.8 Median: 15.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 1/26/18
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Lowered 4/6/18
BETA .75 (1.00 = Market)

High:	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	61.2	55.8
Low:	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	44.7	48.1

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	3	4	0	0	4	0	0	4	7
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	117	96	86
to Sell	78	83	67
Hld's(000)	45099	45123	39640

Percent shares traded 21 14 7

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.5	9.7
3 yr.	43.5	24.3
5 yr.	75.1	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.89	22.59	*22.80*	*23.35*	Revenues per sh	*25.00*
2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.98	6.17	*6.35*	*6.60*	"Cash Flow" per sh	*7.50*
.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.39	2.42	*2.45*	*2.60*	Earnings per sh A	*3.00*
--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	1.32	*1.42*	*1.52*	Div'd Decl'd per sh B	*1.85*
1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.03	5.91	*6.80*	*6.85*	Cap'l Spending per sh	*7.25*
9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.52	28.14	*29.20*	*30.25*	Book Value per sh C	*33.50*
49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.52	40.58	*40.60*	*40.70*	Common Shs Outst'g D	*41.00*
23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	18.7	21.8	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	.98	1.10	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	2.7%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1369.5 mill. **Due in 5 Yrs** $218.5 mill.
LT Debt $1196.0 mill. **LT Interest** $72.3 mill.
(LT interest earned: 2.9x)

Pension Assets-12/17 $304.4 mill. **Oblig** $362.0 mill.

Pfd Stock None

Common Stock 40,661,003 shs. as of 1/31/18

MARKET CAP: $2.0 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	886.9	916.8	*925*	*950*	Revenues ($mill)	*1025*
77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	96.8	98.3	*100*	*105*	Net Profit ($mill)	*125*
32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	35.8%	34.2%	*24.5%*	*24.5%*	Income Tax Rate	*24.5%*
20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	17.6%	11.2%	*13.0%*	*12.0%*	AFUDC % to Net Profit	*14.0%*
53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	52.7%	51.2%	*53.0%*	*52.0%*	Long-Term Debt Ratio	*54.5%*
46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	47.3%	48.8%	*47.0%*	*48.0%*	Common Equity Ratio	*45.5%*
1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2269.9	2338.2	*2530*	*2575*	Total Capital ($mill)	*3025*
1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2821.2	2928.4	*3045*	*3160*	Net Plant ($mill)	*3550*
6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.8%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	4.4%	3.9%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
--	--	--	26%	43%	47%	49%	57%	51%	54%	*57%*	*58%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+2.3	+.1	+.4
Avg. Indust. Use (MWH)	21687	21036	21553
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2055	2080	2082
Peak Load, Summer (Mw)	1794	1892	1935
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.6	+1.7
Fixed Charge Cov. (%)	218	267	263

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.0%	--	*2.5%*
"Cash Flow"	5.5%	1.0%	*4.0%*
Earnings	6.5%	--	*4.5%*
Dividends	--	18.0%	*7.0%*
Book Value	7.5%	6.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	163.8	219.5	289.7	176.9	849.9
2016	157.8	217.9	323.2	188.0	886.9
2017	171.3	251.8	297.5	196.2	916.8
2018	*170*	*255*	*305*	*195*	*925*
2019	*175*	*260*	*315*	*200*	*950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.09	.52	1.40	.02	2.03
2016	d.14	.55	1.84	.14	2.39
2017	d.10	.89	1.47	.16	2.42
2018	*d.15*	*.75*	*1.70*	*.15*	*2.45*
2019	*d.10*	*.80*	*1.75*	*.15*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295	.31	.31	.31	1.23
2017	.31	.335	.335	.335	1.32
2018	.335				

BUSINESS: El Paso Electric Company (EPE) provides electric service to 417,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 49%; gas, 36%; purchased, 15%. Fuel costs: 27% of revenues. '17 reported depreciation rate: 2.3%. Has about 1,100 employees. Chairman: Charles A. Yamarone. President & CEO: Mary E. Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, TX 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

We estimate that El Paso Electric Company's earnings will advance slightly this year. The utility will have a full year's worth of the rate increase in Texas that took effect in July of 2017. EPE is also benefiting from above-average customer growth that stems from the healthy economy in El Paso and environs. On the other hand, the weather was favorable for the company in 2017, and we assume normal weather this year. Our 2018 earnings estimate, which we lowered by $0.20 a share, is within management's guidance of $2.30-$2.65 a share. Next year, the utility will benefit from rate relief in Texas through transmission and distribution regulatory mechanisms. However . . .

Earnings have become less predictable. The company owns a 15.8% share of the Palo Verde nuclear station in Arizona. Like any utility that owns nuclear assets, EPE invests in a trust to provide funds for nuclear decommissioning. The gains or losses on the nuclear decommissioning trust are now being reflected in the income statement, instead of through Accumulated Other Comprehensive Income on the balance sheet. This will make earnings more volatile.

The utility is required to file a general rate case in New Mexico by July of 2019. EPE may file sooner; we note that the portion of Units 3 and 4 of a new gas-fired generating station that is allocated to New Mexico is not reflected in rates. However, the regulatory climate in New Mexico is difficult (not just for EPE), so the company might well wait until it is required to file before it puts forth its rate application.

We expect a dividend hike at the board meeting in May. This has been the pattern since the directors initiated a common dividend several years ago. We estimate an increase of $0.10 a share (7.5%) in the annual disbursement. EPE's goal is a payout ratio in a range of 55%-65%.

This stock has a dividend yield that is below the industry mean. Like many utility issues, the recent quotation is within our 2021-2023 Target Price Range. Accordingly, total return potential over that time frame is unspectacular, despite good dividend growth prospects.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted earnings. Excl. nonrecurring gains (loss): '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. Next earnings report due early May. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '17: $96.0 mill., $2.37/sh. (D) In millions. (E) Rate allowed on common equity in TX in '17: 9.65%; in NM in '16: 9.48%; earned on avg. com. eq., '17: 8.9%. Regulatory Climate: TX, Average; NM, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	75

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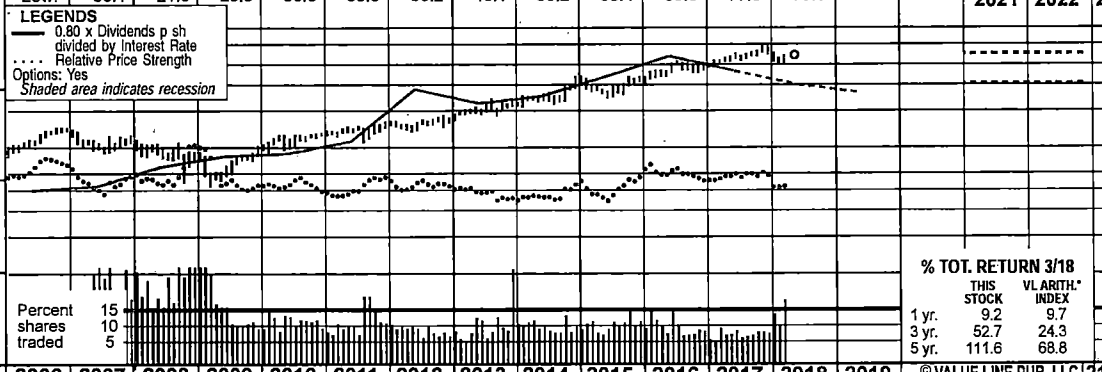
IDACORP, INC. NYSE-IDA

RECENT PRICE 88.84 | P/E RATIO 21.1 (Trailing: 21.1 Median: 14.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 2 Raised 12/22/17
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Lowered 2/23/18
BETA .70 (1.00 = Market)

High:	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	100.0	91.4
Low:	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(Nil)	3%
Low	65	(-25%)	-4%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	10
to Sell	2	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	139	116	127
to Sell	91	113	86
Hld's(000)	45985	45708	38200

Percent shares traded 15 10 5

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	9.7
3 yr.	52.7	24.3
5 yr.	111.6	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	26.60	27.00	Revenues per sh	28.75
4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.65	8.05	"Cash Flow" per sh	9.25
1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.15	4.35	Earnings per sh A	4.75
1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	Div'd Decl'd per sh B ■ †	3.05
3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	6.25	6.40	Cap'l Spending per sh	6.75
23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	46.40	48.15	Book Value per sh C	53.25
38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.40	50.40	Common Shs Outst'g D	50.40
18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	Bold figures are		Avg Ann'l P/E Ratio	16.0
1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	Value Line		Relative P/E Ratio	.90
6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1746.1 mill. Due in 5 Yrs $305.0 mill.
LT Debt $1746.1 mill. LT Interest $82.0 mill.
(LT interest earned: 3.9x)

Pension Assets-12/17 $697.7 mill. Oblig $999.3 mill.

Pfd Stock None

Common Stock 50,392,360 shs. as of 2/16/18

MARKET CAP: $4.5 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1340	1360	Revenues ($mill)	1450
98.4	124.4	142.5	166.9	168.9	182.4	193.5	194.7	198.3	212.4	210	220	Net Profit ($mill)	245
16.3%	15.2%	--	--	13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	10.5%	10.5%	Income Tax Rate	10.5%
10.2%	10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	14.0%	14.0%	AFUDC % to Net Profit	14.0%
47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	44.0%	42.0%	Long-Term Debt Ratio	44.0%
52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.0%	58.0%	Common Equity Ratio	56.0%
2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4180	4165	Total Capital ($mill)	4775
2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4425	4560	Net Plant ($mill)	4850
5.3%	5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.0%	6.5%	Return on Total Cap'l	6.0%
7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.0%	9.0%	Return on Shr. Equity	9.0%
7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.0%	9.0%	Return on Com Equity E	9.0%
3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.0%	4.0%	Retained to Com Eq	3.5%
55%	46%	41%	36%	41%	43%	46%	50%	53%	53%	57%	59%	All Div'ds to Net Prof	63%

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.2	-.5	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.70	5.63	5.83
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3402	3299	3422
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.8	+2.0
Fixed Charge Cov. (%)	307	295	329

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.5%	4.0%	2.0%
"Cash Flow"	5.5%	4.0%	4.5%
Earnings	7.5%	4.5%	3.5%
Dividends	5.5%	10.5%	6.5%
Book Value	5.5%	5.5%	3.5%

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	279.4	336.3	369.2	285.4	1270.3
2016	281.0	315.4	372.0	293.6	1262.0
2017	302.6	333.0	408.3	305.6	1349.5
2018	310	335	390	305	1340
2019	315	340	395	310	1360

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.47	1.31	1.46	.63	3.87
2016	.51	1.12	1.65	.66	3.94
2017	.66	.99	1.80	.77	4.21
2018	.60	1.00	1.85	.70	4.15
2019	.65	1.05	1.90	.75	4.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016	.51	.51	.51	.55	2.08
2017	.55	.55	.55	.59	2.24
2018	.59				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 545,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 41%; commercial, 24%; industrial, 14%; irrigation, 11%; other, 10%. Generating sources: hydro, 50%; coal, 18%; gas, 8%; purchased, 24%. Fuel costs: 33% of revenues. '17 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's 10-year streak of earnings growth might well come to an end in 2018. This is despite the performance of the company's utility subsidiary, Idaho Power, which is faring well, is financially sound, and has good growth prospects. A year ago, IDACORP's income benefited from some tax adjustments. Favorable weather conditions, helped, as well. Our earnings estimate of $4.15 a share, which we trimmed by a nickel, is within the company's targeted range of $4.10-$4.25. Given that IDACORP earned $4.21 a share in 2017, another year of profit growth is hardly out of the question, based on the company's guidance.

We expect dividend growth to continue, even if earnings growth is interrupted. Management anticipates recommending to the board annual increases of at least 5%. The company is targeting a payout ratio in a range of 50%-60%.

Idaho Power is performing well. The economy of the company's service area is healthy. Customer growth was 2.0% last year, which is more than double the industry norm. Kilowatt-hour sales generally aren't rising as fast (the 2.6% increase in 2017 was driven in part by weather) due to the effects of energy efficiency. The utility's cost control has been effective, too.

We forecast a resumption of profit growth in 2019. We think IDACORP will benefit from the growth of Idaho Power. Our $4.35-a-share estimate would produce an increase of 5%.

The utility has a regulatory mechanism to supplement its income, if necessary. If Idaho Power's earned return on equity falls below 9.5% through 2019, the utility may use up to $25 million of accumulated deferred investment tax credits annually to bring its ROE to that level. (A proposed regulatory settlement would extend this mechanism indefinitely beyond next year.) Note that the ROEs shown in the statistical array are for IDACORP as a whole, not just its utility subsidiary.

This stock is timely, but is priced expensively. The dividend yield is below average for a utility. The recent quotation is near the upper end of our 2021-2023 Target Price Range. Accordingly, total return potential is negligible.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '03, 26¢; '05, (24¢); '06, 17¢. '17 earnings don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '17: $21.49/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '11: 10% (imputed); earned on avg. com. eq., '17: 9.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	95

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NORTHWESTERN NYSE-NWE

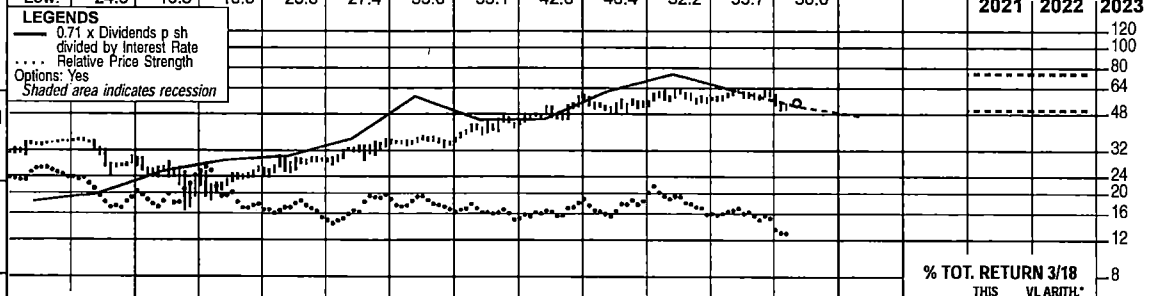
RECENT PRICE 54.59 | P/E RATIO 16.2 (Trailing: 16.3 / Median: 16.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 2/23/18
SAFETY 3 New 5/4/12
TECHNICAL 5 Lowered 4/6/18
BETA .65 (1.00 = Market)

High:	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	64.5	59.8
Low:	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+35%)	11%
Low	50	(-10%)	2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	1	0	0	1	0	2	15
to Sell	0	0	1	1	0	0	1	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	124	118	96
to Sell	101	100	97
Hld's(000)	56186	53930	45947

Percent shares traded 30 20 10

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.9	9.7
3 yr.	11.4	24.3
5 yr.	61.2	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	*26.25*	*27.00*	Revenues per sh	*29.50*
--	--	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	*6.95*	*7.30*	"Cash Flow" per sh	*8.25*
--	--	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	*3.45*	*3.55*	Earnings per sh A	*4.00*
--	--	--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	*2.20*	*2.30*	Div'd Decl'd per sh B ■ †	*2.60*
--	--	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	*5.70*	*6.70*	Cap'l Spending per sh	*6.25*
--	--	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	*37.95*	*39.10*	Book Value per sh C	*42.75*
--	--	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	*50.25*	*50.40*	Common Shs Outst'g D	*51.00*
--	--	--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
--	--	--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.89	*Value Line*		Relative P/E Ratio	*.90*
--	--	--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2137.3 mill. **Due in 5 Yrs** $332.0 mill.
LT Debt $1815.6 mill. **LT Interest** $83.5 mill.
Incl. $22.2 mill. capitalized leases.
(LT interest earned: 3.1x)

Pension Assets-12/17 $586.5 mill. **Oblig** $696.8 mill.

Pfd Stock None

Common Stock 49,397,196 shs. as of 2/9/18

MARKET CAP: $2.7 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	*1320*	*1360*	Revenues ($mill)	*1500*
67.6	73.4	77.4	92.6	83.7	94.0	120.7	138.4	164.2	162.7	*170*	*180*	Net Profit ($mill)	*205*
37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	--	13.7%	13.7%	7.6%	*2.5%*	*3.5%*	Income Tax Rate	*6.5%*
2.3%	4.4%	14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	*49.5%*	*48.5%*	Long-Term Debt Ratio	*46.0%*
53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	*50.5%*	*51.5%*	Common Equity Ratio	*54.0%*
1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	*3775*	*3840*	Total Capital ($mill)	*4050*
1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	*4465*	*4620*	Net Plant ($mill)	*4975*
7.0%	6.0%	5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
74%	66%	63%	56%	65%	61%	54%	65%	58%	62%	*64%*	*64%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	-.7	+3.8
Avg. Indust. Use (MWH)	30133	29784	30987
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2096	2138	2133
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.2	+1.3
Fixed Charge Cov. (%)	252	253	275

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.0%	-3.0%	*2.0%*
"Cash Flow"	5.5%	5.0%	*4.0%*
Earnings	8.0%	7.0%	*3.5%*
Dividends	5.5%	7.0%	*4.5%*
Book Value	5.5%	8.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	346.0	270.6	272.7	325.0	1214.3
2016	332.5	293.1	301.0	330.6	1257.2
2017	367.3	283.9	309.9	344.6	1305.7
2018	*365*	*300*	*315*	*340*	*1320*
2019	*375*	*310*	*325*	*350*	*1360*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.38	.51	.93	2.90
2016	.82	.73	.92	.92	3.39
2017	1.17	.44	.75	.98	3.34
2018	*1.15*	*.45*	*.80*	*1.05*	*3.45*
2019	*1.20*	*.45*	*.85*	*1.05*	*3.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.40	.40	.40	1.60
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525	.525	2.10
2018	.55				

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 433,000 electric customers in Montana and South Dakota and 286,000 gas customers in Montana (87% of gross margin), South Dakota (12%), and Nebraska (1%). Electric revenue breakdown: residential, 40%; commercial, 51%; industrial, 5%; other, 4%. Generating sources: hydro, 36%; coal, 29%; wind, 6%; other, 4%; purchased, 25%. Fuel costs: 31% of revenues. '17 reported deprec. rate: 3.0%. Has 1,600 employees. Chairman: Stephen P. Adik. President & CEO: Robert C. Rowe. Inc.: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

We estimate that NorthWestern's earnings will advance moderately this year. In 2018, the company will benefit from a full year's effect of a $5.1 million gas rate hike that took effect in Montana last September. The refinancing of debt in the fourth quarter of 2017 is another plus. However, there will be some dilution from the equity issued in 2017 and 2018 via its at-the-market program. Our 2018 share-earnings estimate, which we trimmed by $0.05 a share, is within NorthWestern's targeted range of $3.35-$3.50.

An electric rate case is upcoming in Montana. The utility expects to file an application by September, with an order due by mid-2019. NorthWestern has some assets that are not reflected in rates. However, regulation in Montana has worsened in recent years, which is a cause for concern. Still, a partial year of rate relief would benefit earnings in 2019.

NorthWestern had a setback in the U.S. Court of Appeals. The utility appealed an unfavorable ruling from the Federal Energy Regulatory Commission, which ruled that just 4% of the cost of a gas-fired plant could be allocated to wholesale customers (versus the company's request for a 20% allocation). This forced NorthWestern to take a $0.12-a-share charge in 2012. Management is deciding whether pursuing this matter further is worthwhile.

Another legal matter is pending. The Montana commission disallowed recovery of certain costs associated with a plant outage in 2013. This forced NorthWestern to take a $0.13-a-share charge in the 2016. The utility is seeking relief in the Montana District Court. It expects a decision within the next 12 months.

The board of directors raised the dividend in the first quarter. The hike was $0.10 a share (4.8%) annually, the same as a year earlier. NorthWestern is targeting a payout ratio in a range of 60%-70%.

This stock has a dividend yield and 3- to 5-year total return potential that are above the utility average. This follows a price decline of more than 10% since the start of 2018. This has been a bad year for utility equities, but the falloff has been greater than most in this industry. There isn't a clear reason why.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. gain (loss) on discont. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢. '15 EPS don't add due to rounding. Next earnings report due late July. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '17: $14.42/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '17: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	85

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OGE ENERGY CORP. NYSE-OGE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
34.32	16.7	(Trailing: 17.1 Median: 16.0)	0.91	4.3%	VALUE LINE

TIMELINESS **3** Raised 6/1/18
SAFETY **2** Lowered 12/18/15
TECHNICAL **4** Raised 6/15/18
BETA .95 (1.00 = Market)

High:	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4	35.4
Low:	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6

Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

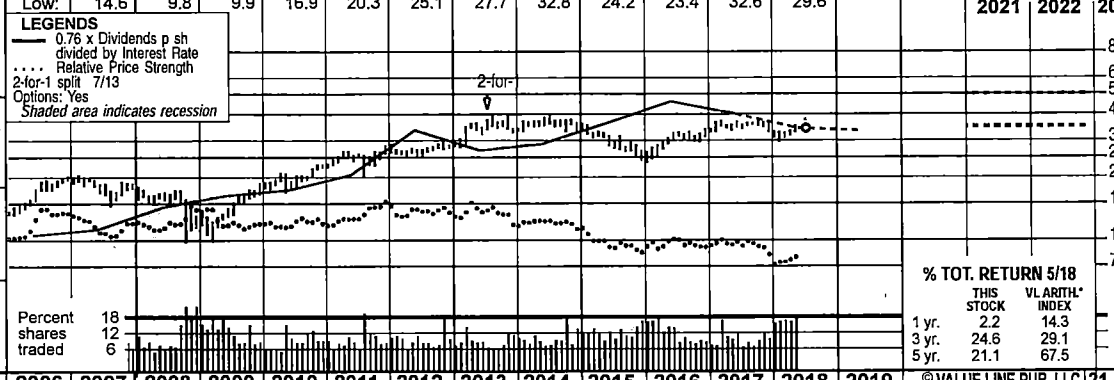
	Price	Gain	Ann'l Total Return
High	50	(+45%)	14%
Low	35	(Nil)	5%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	2	0	0
Options	0	0	0	0	0	0	11	0	0
to Sell	1	0	0	2	0	0	0	0	0

Institutional Decisions

	3Q2017	4Q2017	1Q2018
to Buy	151	155	188
to Sell	155	138	184
Hld's(000)	145781	124353	126569



% TOT. RETURN 5/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.2	14.3
3 yr.	24.6	29.1
5 yr.	21.1	67.5

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	12.25	13.00	Revenues per sh	15.25
1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.55	4.00	"Cash Flow" per sh	4.75
.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.05	2.15	Earnings per sh A	2.50
.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.54	Div'd Decl'd per sh B ■	1.85
1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	3.15	3.15	Cap'l Spending per sh	2.75
6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	19.90	20.50	Book Value per sh C	22.75
157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	199.70	Common Shs Outst'g D	199.70
14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	Bold figures are		Avg Ann'l P/E Ratio	17.0
.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.91	Value Line		Relative P/E Ratio	.95
6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	estimates		Avg Ann'l Div'd Yield	4.3%

CAPITAL STRUCTURE as of 3/31/18
Total Debt $3193.7 mill. **Due in 5 Yrs** $694.4 mill.
LT Debt $2500.1 mill. **LT Interest** $119.8 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $4.8 mill.

Pension Assets-12/17 $635.3 mill. **Oblig** $687.5 mill.

Pfd Stock None

Common Stock 199,731,036 shs.

MARKET CAP: $6.9 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2450	2600	Revenues ($mill)	3050
231.4	258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	405	425	Net Profit ($mill)	520
30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	15.5%	15.5%	Income Tax Rate	15.5%
1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.0%	7.0%	AFUDC % to Net Profit	3.0%
53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	43.0%	44.0%	Long-Term Debt Ratio	45.5%
46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	57.0%	56.0%	Common Equity Ratio	54.5%
4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6975	7345	Total Capital ($mill)	8275
5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8660	8910	Net Plant ($mill)	9450
7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.0%	7.0%	Return on Total Cap'l	7.5%
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.0%	10.5%	Return on Shr. Equity	11.5%
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.0%	10.5%	Return on Com Equity E	11.5%
5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.0%	3.0%	Retained to Com Eq	3.5%
55%	53%	48%	43%	44%	43%	47%	61%	67%	64%	69%	72%	All Div'ds to Net Prof	71%

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.9	-1.1	-2.2
Avg. Indust. Use (MWH)	754	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.05	5.17	5.30
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6537	6538	6456
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.1	+1.0
Fixed Charge Cov. (%)	314	336	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-8.0%	-10.0%	5.5%
"Cash Flow"	4.0%	-.5%	6.5%
Earnings	4.5%	1.0%	6.0%
Dividends	5.5%	8.5%	8.0%
Book Value	7.5%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	480.1	549.9	719.8	447.1	2196.9
2016	433.1	551.4	743.9	530.8	2259.2
2017	456.0	586.4	716.8	501.9	2261.1
2018	492.7	625	782.3	550	2450
2019	525	675	825	575	2600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.22	.44	.88	.15	1.69
2016	.13	.35	.92	.29	1.69
2017	.18	.52	.92	.30	1.92
2018	.27	.50	1.00	.28	2.05
2019	.20	.55	1.10	.30	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325	.3325			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 842,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.6% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 26%; industrial, 9%; oilfield, 7%; other, 18%. Generating sources: coal, 34%; gas, 25%; wind, 4%; purchased, 37%. Fuel costs: 40% of revenues. '17 reported depreciation rate (utility): 2.5%. Has 2,400 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary has a general rate case pending. Oklahoma Gas and Electric filed for a hike of $1.9 million, based on a 9.9% return on a 53% common-equity ratio. The requested amount is small because it reflects the effects of the new federal tax law; without tax reform, OG&E would have sought over $70 million. The company wants to place a $390 million project to modernize a gas-fired plant in rates; raise the depreciation rate; and boost its allowed ROE from the current 9.5%. The staff of the Oklahoma commission recommended a $43 million reduction, based on a 8.75% return on a 53% common-equity ratio, and the state attorney general proposed a $99 million cut, based on a return of 9.18% on a common-equity ratio of 50%. New rates are expected to take effect at the start of October.

Additional regulatory matters are upcoming. OG&E plans to file another rate application in December, with new tariffs taking effect in mid-2019. The main driver of this case will be a $542 million project to install pollution-control equipment at a coal-fired plant. In Arkansas, the utility will not have to file a general rate case to recover its major capital projects. Instead, OG&E will recover them through various regulatory mechanisms, such as a formula rate plan it will file in October.

We estimate respectable earnings growth this year and next. OG&E will benefit from rate relief, assuming reasonable regulatory treatment from the Oklahoma commission. The lower tax rate applied to OGE Energy's income from its stake in Enable Midstream Partners will add an estimated $0.08 to share net this year. Our 2018 estimate is at the upper end of the company's targeted range of $1.90-$2.05.

OGE Energy stock is attractive for income-oriented accounts. The dividend yield is above average, even by utility standards. In addition, management expects the board to raise the disbursement by 10% in each of 2018 and 2019, as the distributions OGE Energy receives from Enable are a good source of cash. Rapid dividend growth should continue beyond 2019, though not necessarily at the 10% level.

Paul E. Debbas, CFA *June 15, 2018*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '02, (20¢); '03, (7¢); '04, (3¢); '15, (33¢); '17, $1.18; gains on disc. ops.: '02, 6¢; '05, 25¢; '06, 20¢. Next earnings report due early Aug. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '17: $1.42/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '16: 9.5%; in AR in '11: 9.95%; earned on avg. com. eq., '17: 10.9%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	75

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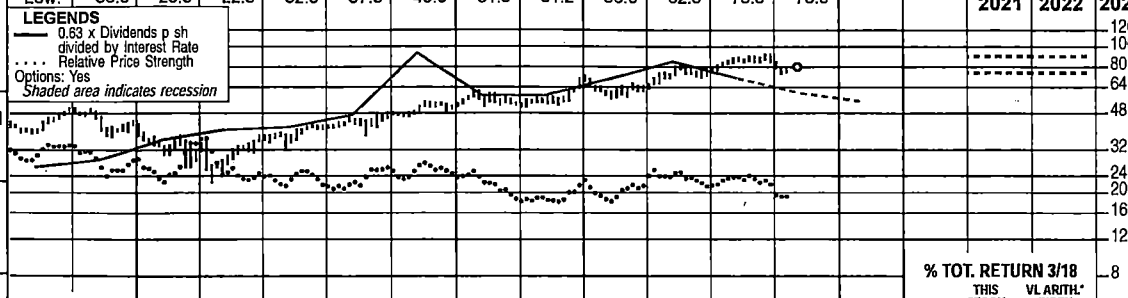
PINNACLE WEST NYSE-PNW

RECENT PRICE 80.15 | P/E RATIO 18.1 (Trailing: 18.1 Median: 15.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 3/30/18
SAFETY 1 Raised 5/3/13
TECHNICAL 5 Lowered 4/6/18
BETA .65 (1.00 = Market)

High:	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8	92.5	85.6
Low:	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.8

LEGENDS
— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+10%)	7%
Low	75	(-5%)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	12	0	0	1	12
to Sell	0	0	3	0	0	2	1	1	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	194	218	182
to Sell	224	185	183
Hld's(000)	107032	104825	94333

Percent shares traded 30 20 10

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.2	9.7
3 yr.	39.0	24.3
5 yr.	65.3	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	**32.80**	**34.30**	Revenues per sh	**39.75**
7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	**10.10**	**10.65**	"Cash Flow" per sh	**12.75**
2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	**4.50**	**4.70**	Earnings per sh A	**5.50**
1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	**2.86**	**3.02**	Div'd Decl'd per sh B ■	**3.50**
9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	**11.25**	**10.80**	Cap'l Spending per sh	**11.00**
29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	**46.35**	**48.00**	Book Value per sh C	**54.00**
91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	**112.00**	**112.25**	Common Shs Outst'g D	**113.00**
14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	**15.0**
.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	*Value Line*		Relative P/E Ratio	**.85**
4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	*estimates*		Avg Ann'l Div'd Yield	**4.2%**

CAPITAL STRUCTURE as of 12/31/17
Total Debt $4829.4 mill. **Due in 5 Yrs** $1188.4 mill.
LT Debt $4789.7 mill. **LT Interest** $213.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $13.4 mill.
Pension Assets-12/17 $3057.0 mill. **Oblig** $3394.2 mill.
Pfd Stock None

Common Stock 111,799,789 shs. as of 2/16/18
MARKET CAP: $9.0 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	**3675**	**3850**	Revenues ($mill)	**4500**
213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	442.0	497.8	**505**	**535**	Net Profit ($mill)	**630**
23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	**18.0%**	**18.0%**	Income Tax Rate	**18.0%**
17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	**13.0%**	**10.0%**	AFUDC % to Net Profit	**8.0%**
46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	**48.0%**	**48.5%**	Long-Term Debt Ratio	**45.5%**
53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	**52.0%**	**51.5%**	Common Equity Ratio	**54.5%**
6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	**9985**	**10480**	Total Capital ($mill)	**11175**
8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	12714	13445	**14075**	**14625**	Net Plant ($mill)	**16125**
4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.5%**
6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	**10.0%**	**10.0%**	Return on Com Equity E	**10.5%**
.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	**3.5%**	**3.5%**	Retained to Com Eq	**4.0%**
96%	89%	66%	68%	58%	58%	62%	59%	62%	58%	**63%**	**63%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.3	+.3	--
Avg. Indust. Use (MWH)	658	640	620
Avg. Indust. Revs. per KWH (¢)	8.17	8.37	8.34
Capacity at Peak (Mw)	9250	9192	8438
Peak Load, Summer (Mw)	7031	7051	7363
Annual Load Factor (%)	48.3	48.0	46.3
% Change Customers (yr-end)	+1.3	+1.3	+1.8
Fixed Charge Cov. (%)	438	416	425

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	1.0%	*4.0%*
"Cash Flow"	1.5%	5.0%	*5.0%*
Earnings	4.0%	5.0%	*5.0%*
Dividends	2.5%	2.5%	*5.5%*
Book Value	2.0%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	671.2	890.7	1199.1	734.4	3495.4
2016	677.2	915.4	1166.9	739.2	3498.7
2017	677.7	944.6	1183.3	759.7	3565.3
2018	***700***	***975***	***1225***	***775***	***3675***
2019	***725***	***1025***	***1300***	***800***	***3850***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.14	1.10	2.30	.37	3.92
2016	.04	1.08	2.35	.47	3.95
2017	.21	1.49	2.46	.27	4.43
2018	***.25***	***1.30***	***2.60***	***.35***	***4.50***
2019	***.25***	***1.35***	***2.70***	***.40***	***4.70***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.568	.568	.568	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017	.655	.655	.655	.695	2.66
2018	.695				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.2 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 50%; commercial, 40%; industrial, 5%; other, 5%. Generating sources: nuclear, 29%; gas & other, 26%; coal, 22%; purchased, 23%. Fuel costs: 28% of revenues. '17 reported deprec. rate: 2.8%. Has 6,300 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has asked the Arizona Corporation Commission for a rate increase. Although the rate order last year for Arizona Public Service froze base tariffs mid-2020, the ruling also allowed APS to file for recovery of an environmental project at the Four Corners coal-fired station through a rider (surcharge) on customers' bills. The utility is seeking an increase of $65 million (about 2%), and no change in the allowed return on equity of 10%. A decision is expected in time for the rider to take effect at the start of 2019. The project should be completed soon at a cost of $390 million. The costs that the company will incur this year will be deferred for recovery beginning next year under the rider.

Another large capital project is under construction. APS is building five gas-fired units and retiring two at an estimated cost of $500 million. This will increase the utility's generating capacity by 290 megawatts. Costs associated with this project will be deferred until APS recovers these in its next base rate increase, presumably in mid-2020.

We estimate a modest earnings increase this year. Pinnacle West raised its 2018 earnings guidance by a dime a share, to $4.35-$4.55, due largely because the company raised its expectation for the Allowance for Funds Used During Construction, a noncash credit to income. Additional expense-management initiatives are another factor. We raised our estimate by $0.10 a share, to $4.50.

We forecast higher profit growth in 2019. The aforementioned rate rider should help. In addition, the utility's strong (and rising) customer growth rate is stimulating modest kilowatt-hour sales growth, despite the effects of energy efficiency. Our $4.70-a-share earnings estimate would produce an increase of 4%.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards. Perhaps conservative investors will find this acceptable, given the equity's top-notch Safety rank and the company's high rating for Financial Strength. However, like most utility issues, the recent price is within our 2021-2023 Target Price Range.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (77¢); '09, ($1.45); '17, 8¢; gains (losses) from disc. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically pd. in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '17: $14.34/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '17: 10.0%; earned on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

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PORTLAND GENERAL NYSE-POR

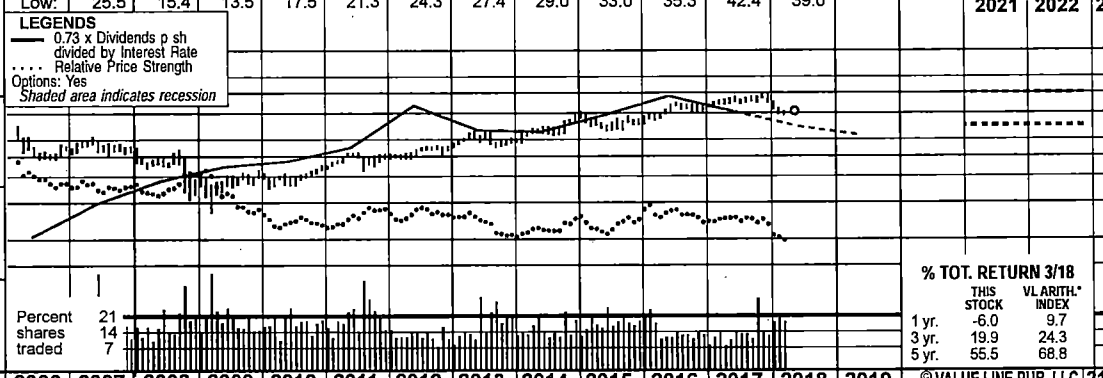
RECENT PRICE 40.92 | P/E RATIO 18.4 (Trailing: 17.9 Median: 16.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Lowered 3/23/18
SAFETY 2 Raised 5/4/12
TECHNICAL 5 Lowered 4/20/18
BETA .65 (1.00 = Market)

High:	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2	50.1	45.6
Low:	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	9%
Low	35	(-15%)	1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	10	0	0	10	0	0	0	0	5
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	147	122	136
to Sell	112	118	91
Hld's(000)	88988	88359	81125

Percent shares traded 21 14 7

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.0	9.7
3 yr.	19.9	24.3
5 yr.	55.5	68.8

2002	2003	2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	**22.70**	**23.50**	Revenues per sh	**25.75**
--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	**6.40**	**6.85**	"Cash Flow" per sh	**8.00**
--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	**2.20**	**2.35**	Earnings per sh A	**2.75**
--	--	--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	**1.42**	**1.50**	Div'd Decl'd per sh B ■ †	**1.80**
--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	**6.35**	**5.10**	Cap'l Spending per sh	**5.00**
--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	**27.85**	**28.70**	Book Value per sh C	**31.50**
--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	**89.25**	**89.40**	Common Shs Outst'g D	**90.00**
--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	*Bold figures are*		Avg Ann'l P/E Ratio	**15.5**
--	--	--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	*Value Line*		Relative P/E Ratio	**.85**
--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	*estimates*		Avg Ann'l Div'd Yield	**4.2%**

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2426 mill. **Due in 5 Yrs** $460 mill.
LT Debt $2426 mill. **LT Interest** $123 mill.
Incl. $49 mill. capitalized leases.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $9 mill.
Pension Assets-12/17 $629 mill. **Oblig** $869 mill.
Pfd Stock None

Common Stock 89,114,522 shs. as of 2/2/18

MARKET CAP: $3.6 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	**2025**	**2100**	Revenues ($mill)	**2325**
87.0	95.0	125.0	147.0	141.0	137.0	175.0	172.0	193.0	204.0	**195**	**210**	Net Profit ($mill)	**255**
28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	**12.5%**	**12.5%**	Income Tax Rate	**12.5%**
17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	**7.0%**	**5.0%**	AFUDC % to Net Profit	**4.0%**
46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	**47.0%**	**50.5%**	Long-Term Debt Ratio	**48.5%**
53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	**53.0%**	**49.5%**	Common Equity Ratio	**51.5%**
2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	**4710**	**5190**	Total Capital ($mill)	**5500**
3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	**6930**	**6985**	Net Plant ($mill)	**7000**
5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	**8.0%**	**8.5%**	Return on Shr. Equity	**9.0%**
6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	**8.0%**	**8.5%**	Return on Com Equity E	**9.0%**
2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	**3.0%**	**3.0%**	Retained to Com Eq	**3.5%**
69%	76%	62%	54%	57%	61%	50%	56%	57%	58%	**64%**	**63%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.6	-2.1	+3.9
Avg. Indust. Use (MWH)	17485	16146	16041
Avg. Indust. Revs. per KWH (¢)	5.01	4.99	4.94
Capacity at Peak (Mw)	4609	4730	4743
Peak Load, Summer (Mw)	3914	3726	3976
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.3
Fixed Charge Cov. (%)	243	271	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.5%	-2.0%	3.0%
"Cash Flow"	1.5%	3.0%	5.5%
Earnings	4.0%	3.5%	4.0%
Dividends	9.0%	3.5%	6.0%
Book Value	3.0%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	473.0	450.0	476.0	499.0	1898.0
2016	487.0	428.0	484.0	524.0	1923.0
2017	530.0	449.0	515.0	515.0	2009.0
2018	**530**	**455**	**515**	**525**	**2025**
2019	**555**	**470**	**530**	**545**	**2100**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.62	.44	.40	.57	2.04
2016	.68	.42	.38	.68	2.16
2017	.82	.36	.44	.67	2.29
2018	**.70**	**.42**	**.43**	**.65**	**2.20**
2019	**.75**	**.45**	**.45**	**.70**	**2.35**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30	.30	.32	.32	1.24
2017	.32	.32	.34	.34	1.32
2018	.34	.34			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 875,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 33%; industrial, 11%; other, 8%. Generating sources: gas, 28%; coal, 15%; wind, 8%; hydro, 8%; purchased, 41%. Fuel costs: 30% of revenues. '17 reported depreciation rate: 3.6%. Has 2,900 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has filed a rate case. The utility requested an increase of $89 million (4.8%), based on a return of 9.5% on a common-equity ratio of 50%. An order from the Oregon Public Utility Commission (OPUC) is expected in December, with new tariffs taking effect at the start of 2019.

Earnings are likely to decline this year. Favorable weather patterns helped the bottom line in 2017, but the weather in early 2018 turned the other way. In fact, the Portland area had its second-warmest January on record. We have lowered our earnings estimate by $0.20 a share, to $2.20. Our revised estimate is within PGE's guidance of $2.10-$2.25 a share.

There is a possible risk to earnings this year. PGE is going to ask the OPUC for permission to defer (for future recovery) costs in 2018 associated with the upgraded customer information system the company expects to complete soon. If the OPUC doesn't approve this request and the utility must incur these costs, this would reduce earnings by $0.10 a share this year.

Unrecovered costs associated with the Carty gas-fired plant continue to be a drag on earnings. The facility was completed in 2016, several months after PGE declared the contractor of the project in default of the construction agreement. However, $123 million of the plant's $637 million cost are not reflected in rates. PGE filed suit against the contractor's insurer, seeking to collect a $145.6 million performance bond, plus damages. The company expects resolution of this matter to take two to four years, but was citing the same time frame two years ago. Unrecovered costs and litigation expenses reduced earnings by $0.09 a share in 2017, and the loss will widen to an estimated $0.12 a share this year due to the lower tax shield from the reduced federal tax rate.

We forecast an earnings recovery in 2019. We assume normal weather conditions and reasonable treatment in the aforementioned rate case.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average for a utility.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring losses: '13, 42¢; '17, 19¢. '15 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '17: $4.92/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '18: 9.5%; earned on avg. com. eq., '17: 8.5%. Regulatory Climate: Average. (F) '05 per-share data are pro forma, based on shs. outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	80

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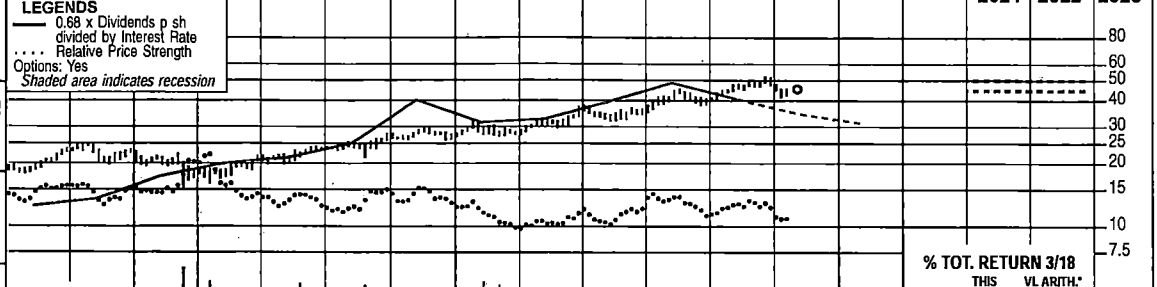
RECENT PRICE 45.61 | P/E RATIO 18.8 (Trailing: 19.7 / Median: 15.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 3/23/18
SAFETY 1 Raised 5/1/15
TECHNICAL 5 Lowered 4/27/18
BETA .60 (1.00 = Market)

High:	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	52.2	48.4					
Low:	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5					

LEGENDS
— 0.68 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	6%
Low	45	(Nil)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	12
to Sell	0	0	1	0	0	1	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	294	286	280
to Sell	242	246	216
Hld's(000)	416718	418292	379245

Percent shares traded 15 10 5

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.6	9.7
3 yr.	44.5	24.3
5 yr.	79.4	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	*22.55*	*22.90*	Revenues per sh	*25.25*
3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	*5.90*	*6.15*	"Cash Flow" per sh	*7.25*
.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	*2.45*	*2.55*	Earnings per sh A	*3.00*
1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	*1.52*	*1.60*	Div'd Decl'd per sh B ■	*1.90*
6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	*8.25*	*7.95*	Cap'l Spending per sh	*6.75*
11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	*23.55*	*24.85*	Book Value per sh C	*28.00*
398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	*509.50*	*518.00*	Common Shs Outst'g D	*522.50*
NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	*Value Line*		Relative P/E Ratio	*.90*
6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $15791 mill. **Due in 5 Yrs** $4262 mill.
LT Debt $14520 mill. **LT Interest** $646 mill.
Incl. $151 mill. capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $238 mill.
Pension Assets-12/17 $3088 mill.
Oblig $3828 mill.
Pfd Stock None

Common Stock 508,064,983 shs.
as of 2/19/18
MARKET CAP: $23 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
11203	9644.3	10311	10655	10128	10915	11686	11024	11107	11404	*11500*	*11850*	Revenues ($mill)	*13250*
645.7	685.5	727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	*1240*	*1320*	Net Profit ($mill)	*1575*
34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	*58.0%*	*57.0%*	Long-Term Debt Ratio	*58.0%*
47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	*42.0%*	*43.0%*	Common Equity Ratio	*42.0%*
14800	15277	17452	17331	19018	20477	21714	23092	25216	25975	*28450*	*29775*	Total Capital ($mill)	*34800*
17689	18508	20663	22353	23809	26122	28757	31206	32842	34329	*36775*	*39050*	Net Plant ($mill)	*42900*
6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*10.5%*
3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
59%	61%	59%	56%	54%	54%	55%	57%	61%	62%	*62%*	*62%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.6	+.3	-.7
Large C & I Use (MWH)	23521	22519	22642
Large C & I Revs. per KWH (¢)	6.10	6.17	6.36
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19583	20423	19591
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.9
Fixed Charge Cov. (%)	358	342	330

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.0%	.5%	*2.5%*
"Cash Flow"	4.0%	6.0%	*6.5%*
Earnings	5.5%	5.0%	*5.5%*
Dividends	4.5%	5.5%	*5.5%*
Book Value	4.5%	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2962	2515	2901	2646	11024
2016	2772	2500	3040	2795	11107
2017	2946	2645	3017	2796	11404
2018	*2900*	*2650*	*3050*	*2900*	*11500*
2019	*3000*	*2700*	*3150*	*3000*	*11850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.46	.39	.84	.41	2.10
2016	.47	.39	.90	.45	2.21
2017	.47	.45	.97	.42	2.30
2018	*.55*	*.45*	*1.00*	*.45*	*2.45*
2019	*.58*	*.47*	*1.03*	*.47*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.28	.30	.30	.30	1.18
2015	.30	.32	.32	.32	1.26
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.6 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 40% of revs. '17 reported depr. rate: 3.1%. Has 11,500 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy is awaiting orders on rate cases in three states. The largest ones are Public Service of Colorado's multiyear electric and gas applications. The utility requested electric hikes totaling $245 million from 2018 through 2020, and gas increases totaling $139 million over that span. Each filing is based on a 10% return on a 55.25% common-equity ratio. An interim gas increase of $63 million took effect at the start of 2018, and the company is asking for a $75 million interim gas raise at the start of June. Southwestern Public Service asked the regulators in Texas and New Mexico for a total of $97 million, based on a 10.25% return on a 58% common-equity ratio. Rulings are expected this summer in New Mexico and early in the fourth quarter (retroactive to January of 2018) in Texas.

Rate relief is boosting Xcel's earning power and enabling the company to reduce the gap between its earned and allowed returns on equity. Management's earnings guidance for 2018 is $2.37-$2.47 a share. Our estimate of $2.45 is near the upper end of this range. We forecast more-modest profit growth in 2019. Xcel's goal for long-term earnings growth is 5%-6% annually.

Xcel's utilities have some proposals pending involving renewable energy. The aim is to retire coal-fired units and replace them with renewables, gas, and storage — and to do this without raising rates for customers. SPS received approval in New Mexico, and awaits a decision in Texas, for a $1.6 billion project to add wind in the two states. P.S. of Colorado expects a ruling in July on its plan to spend up to $1.5 billion to add wind, solar, and gas.

The board of directors raised the common dividend, effective with the April payment. The increase was $0.02 a share (5.6%) quarterly, the same as in recent years. Xcel's goals for the dividend are growth of 5%-7% annually and a payout ratio of 60%-70%.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards. This might be acceptable for conservative accounts, given the issue's top rank for Safety.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '02, ($6.27); '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '17 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '17: $5.92/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '17: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

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Schedule AHG - 4
18-KCPE-480-RTS

Alliant Energy (LNT)

Date	High	Low	Close
7/3/2017	$ 40.36	$ 39.54	$ 39.71
7/10/2017	$ 40.21	$ 39.36	$ 39.97
7/17/2017	$ 41.39	$ 39.81	$ 41.38
7/24/2017	$ 41.66	$ 40.31	$ 40.47
7/31/2017	$ 41.40	$ 40.31	$ 41.09
8/7/2017	$ 41.75	$ 41.03	$ 41.37
8/14/2017	$ 42.32	$ 41.38	$ 42.24
8/21/2017	$ 43.09	$ 42.17	$ 42.87
8/28/2017	$ 43.23	$ 42.54	$ 42.57
9/4/2017	$ 43.24	$ 42.56	$ 43.19
9/11/2017	$ 43.69	$ 42.27	$ 42.90
9/18/2017	$ 42.91	$ 41.72	$ 41.73
9/25/2017	$ 42.32	$ 41.16	$ 41.57
10/2/2017	$ 42.14	$ 41.05	$ 41.92
10/9/2017	$ 43.46	$ 41.84	$ 43.05
10/16/2017	$ 43.97	$ 42.78	$ 43.87
10/23/2017	$ 43.95	$ 42.72	$ 43.75
10/30/2017	$ 44.39	$ 42.88	$ 43.83
11/6/2017	$ 44.29	$ 43.51	$ 43.68
11/13/2017	$ 45.55	$ 43.69	$ 44.40
11/20/2017	$ 44.49	$ 44.01	$ 44.22
11/27/2017	$ 45.38	$ 44.11	$ 44.83
12/4/2017	$ 45.22	$ 43.96	$ 44.94
12/11/2017	$ 45.10	$ 43.56	$ 44.43
12/18/2017	$ 44.37	$ 42.18	$ 42.50
12/25/2017	$ 42.97	$ 42.18	$ 42.61
1/1/2018	$ 42.72	$ 40.92	$ 41.08
1/8/2018	$ 41.58	$ 39.49	$ 39.53
1/15/2018	$ 40.17	$ 39.33	$ 39.41
1/22/2018	$ 40.54	$ 39.45	$ 40.30
1/29/2018	$ 40.18	$ 38.46	$ 38.91
2/5/2018	$ 39.34	$ 36.84	$ 38.42
2/12/2018	$ 39.81	$ 37.89	$ 39.75
2/19/2018	$ 39.70	$ 38.01	$ 39.42
2/26/2018	$ 39.82	$ 37.85	$ 38.22
3/5/2018	$ 38.99	$ 37.91	$ 38.71
3/12/2018	$ 40.22	$ 38.75	$ 40.13
3/19/2018	$ 40.58	$ 39.38	$ 39.45
3/26/2018	$ 41.04	$ 39.43	$ 40.86
4/2/2018	$ 41.45	$ 40.34	$ 41.02
4/9/2018	$ 41.36	$ 40.38	$ 41.11
4/16/2018	$ 42.30	$ 41.23	$ 41.54
4/23/2018	$ 43.13	$ 41.45	$ 43.06
4/30/2018	$ 43.47	$ 42.04	$ 43.27
5/7/2018	$ 43.29	$ 41.02	$ 41.66
5/14/2018	$ 41.78	$ 40.30	$ 40.57
5/21/2018	$ 40.94	$ 40.11	$ 40.79
5/28/2018	$ 41.81	$ 40.47	$ 40.63
6/4/2018	$ 40.76	$ 38.99	$ 39.23
6/11/2018	$ 40.08	$ 38.22	$ 39.96
6/18/2018	$ 41.28	$ 39.86	$ 41.09
6/25/2018	$ 42.78	$ 41.07	$ 42.32
7/2/2018	$ 43.42	$ 42.15	$ 43.41
Minimum		**$ 36.84**	$ 38.22
Maximum	**$ 45.55**		$ 44.94
Mean			**$ 41.56**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	LNT
Current Qtr.	7.30%
Next Qtr.	9.30%
Current Year	9.80%
Next Year	6.10%
Next 5 Years (per annum)	**5.85%**
Past 5 Years (per annum)	4.21%

Source: YahooFinance; July 18, 2018

Value-Line	EPS	DPS
Past 10 Years	5.00%	7.50%
Past 5 Years	6.50%	6.50%
Est '15-'17 to '21-'23	**6.50%**	**6.00%**

	2017	2018	**2019**	'21 to '23
$	1.26	$ 1.34	$ **1.42**	$ 1.66

Source: June 15, 2018; Value-Line

NYSE : LNT	**Mean**					
LT Growth (%)	**5.91**	6.00	6.00	5.73	0.13	3

Source: SNL/S&P Global

Schedule AHG - 4
18-KCPE-480-RTS

Allete, Inc. (ALE)

Date	High	Low	Close
7/3/2017	$ 72.20	$ 70.55	$ 71.26
7/10/2017	$ 71.67	$ 69.79	$ 70.29
7/17/2017	$ 73.53	$ 69.90	$ 73.45
7/24/2017	$ 73.76	$ 71.69	$ 72.57
7/31/2017	$ 75.12	$ 72.31	$ 73.98
8/7/2017	$ 75.17	$ 73.08	$ 73.30
8/14/2017	$ 75.26	$ 72.86	$ 75.07
8/21/2017	$ 77.02	$ 74.70	$ 76.81
8/28/2017	$ 77.73	$ 76.68	$ 77.52
9/4/2017	$ 79.27	$ 77.31	$ 79.14
9/11/2017	$ 79.61	$ 77.00	$ 78.41
9/18/2017	$ 78.35	$ 76.88	$ 76.91
9/25/2017	$ 78.16	$ 76.55	$ 77.29
10/2/2017	$ 78.85	$ 76.55	$ 78.31
10/9/2017	$ 79.69	$ 77.98	$ 78.38
10/16/2017	$ 79.54	$ 77.58	$ 78.93
10/23/2017	$ 79.85	$ 77.89	$ 79.69
10/30/2017	$ 80.00	$ 76.76	$ 76.93
11/6/2017	$ 77.74	$ 75.20	$ 76.34
11/13/2017	$ 78.59	$ 76.02	$ 77.50
11/20/2017	$ 78.69	$ 77.03	$ 78.18
11/27/2017	$ 80.93	$ 77.52	$ 80.21
12/4/2017	$ 81.24	$ 78.19	$ 79.33
12/11/2017	$ 79.50	$ 76.70	$ 77.90
12/18/2017	$ 78.53	$ 73.40	$ 73.45
12/25/2017	$ 74.97	$ 72.96	$ 74.36
1/1/2018	$ 74.42	$ 72.53	$ 73.55
1/8/2018	$ 74.13	$ 72.14	$ 73.00
1/15/2018	$ 74.04	$ 71.80	$ 71.98
1/22/2018	$ 73.97	$ 71.85	$ 72.84
1/29/2018	$ 72.63	$ 70.26	$ 70.42
2/5/2018	$ 70.64	$ 66.64	$ 69.89
2/12/2018	$ 69.97	$ 67.20	$ 69.34
2/19/2018	$ 69.98	$ 67.56	$ 69.98
2/26/2018	$ 70.06	$ 67.88	$ 68.58
3/5/2018	$ 68.72	$ 67.07	$ 68.08
3/12/2018	$ 71.20	$ 68.06	$ 71.07
3/19/2018	$ 72.61	$ 70.06	$ 70.12
3/26/2018	$ 72.80	$ 70.13	$ 72.25
4/2/2018	$ 72.66	$ 70.40	$ 71.72
4/9/2018	$ 72.65	$ 71.04	$ 71.67
4/16/2018	$ 74.78	$ 71.88	$ 73.10
4/23/2018	$ 77.44	$ 73.11	$ 77.08
4/30/2018	$ 79.86	$ 75.72	$ 79.62
5/7/2018	$ 79.40	$ 75.98	$ 77.78
5/14/2018	$ 77.50	$ 73.76	$ 74.49
5/21/2018	$ 76.15	$ 74.28	$ 76.00
5/28/2018	$ 78.12	$ 75.53	$ 76.12
6/4/2018	$ 76.56	$ 72.78	$ 73.11
6/11/2018	$ 73.28	$ 70.46	$ 73.11
6/18/2018	$ 76.65	$ 73.06	$ 76.31
6/25/2018	$ 78.62	$ 76.39	$ 77.41
7/2/2018	$ 79.50	$ 76.97	$ 79.45
Minimum		**$ 66.64**	$ 68.08
Maximum	**$ 81.24**		$ 80.21
Mean			**$ 74.78**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	ALE
Current Qtr.	1.40%
Next Qtr.	11.10%
Current Year	6.90%
Next Year	7.90%
Next 5 Years (per annum)	**6.00%**
Past 5 Years (per annum)	5.88%

Source: YahooFinance; July 18, 2018

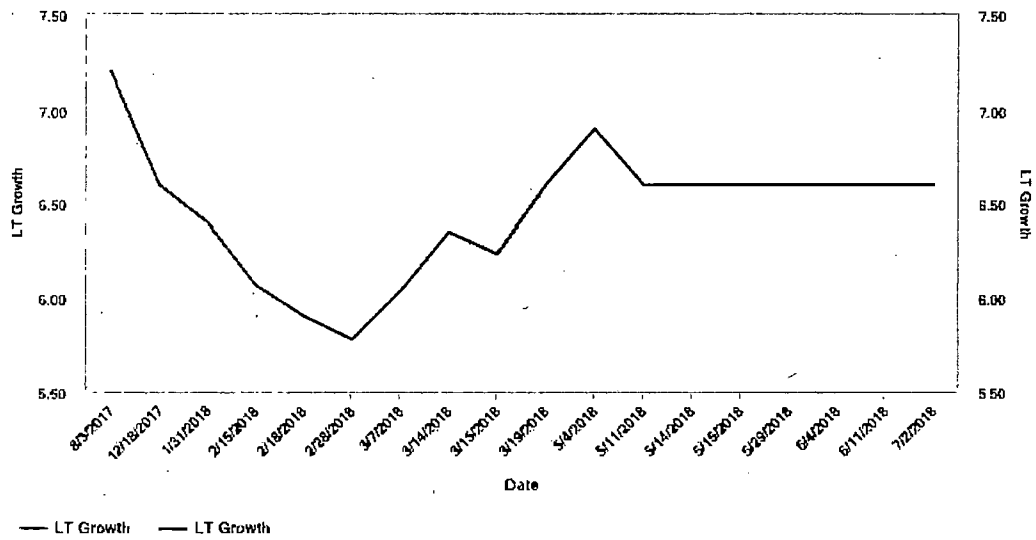
Value-Line	EPS	DPS
Past 10 Years	1.50%	3.50%
Past 5 Years	5.50%	3.00%
Est '15-'17 to '21-'23	**5.00%**	**4.50%**

	2017	2018	**2019**	'21 to '23
$	2.14	$ 2.24	**$ 2.34**	$ 2.70

Source: June 15, 2018; Value-Line

NYSE : ALE	**Mean**					
LT Growth (%)	**6.60**	6.00	7.80	6.00	0.85	3

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Ameren Corp. (AEE)

Date	High	Low	Close
7/3/2017	$ 54.92	$ 53.54	$ 54.14
7/10/2017	$ 54.63	$ 53.59	$ 54.43
7/17/2017	$ 56.58	$ 54.18	$ 56.53
7/24/2017	$ 56.67	$ 55.60	$ 56.16
7/31/2017	$ 57.65	$ 56.02	$ 57.50
8/7/2017	$ 58.75	$ 57.55	$ 57.95
8/14/2017	$ 59.75	$ 57.91	$ 59.21
8/21/2017	$ 60.58	$ 59.06	$ 60.37
8/28/2017	$ 60.79	$ 59.56	$ 59.80
9/4/2017	$ 60.28	$ 59.31	$ 60.09
9/11/2017	$ 60.91	$ 58.59	$ 59.81
9/18/2017	$ 59.85	$ 58.34	$ 58.51
9/25/2017	$ 59.78	$ 57.56	$ 57.84
10/2/2017	$ 58.90	$ 57.67	$ 58.78
10/9/2017	$ 60.74	$ 58.80	$ 60.41
10/16/2017	$ 61.74	$ 60.13	$ 61.56
10/23/2017	$ 61.96	$ 60.52	$ 61.80
10/30/2017	$ 62.83	$ 61.48	$ 62.19
11/6/2017	$ 63.15	$ 61.95	$ 62.48
11/13/2017	$ 64.89	$ 62.54	$ 63.30
11/20/2017	$ 63.66	$ 62.62	$ 62.98
11/27/2017	$ 64.36	$ 62.96	$ 63.75
12/4/2017	$ 64.02	$ 62.06	$ 63.19
12/11/2017	$ 63.71	$ 60.32	$ 60.94
12/18/2017	$ 61.22	$ 58.29	$ 58.69
12/25/2017	$ 59.44	$ 58.28	$ 58.99
1/1/2018	$ 59.03	$ 57.23	$ 57.39
1/8/2018	$ 58.09	$ 55.42	$ 55.52
1/15/2018	$ 55.94	$ 54.83	$ 55.16
1/22/2018	$ 57.09	$ 55.26	$ 56.92
1/29/2018	$ 56.74	$ 54.77	$ 54.89
2/5/2018	$ 55.72	$ 51.89	$ 55.42
2/12/2018	$ 56.85	$ 54.32	$ 56.32
2/19/2018	$ 56.39	$ 54.23	$ 56.35
2/26/2018	$ 56.46	$ 53.47	$ 54.03
3/5/2018	$ 55.32	$ 53.08	$ 53.99
3/12/2018	$ 55.64	$ 53.88	$ 55.49
3/19/2018	$ 55.96	$ 53.91	$ 54.01
3/26/2018	$ 56.79	$ 54.10	$ 56.63
4/2/2018	$ 57.92	$ 56.15	$ 57.13
4/9/2018	$ 57.55	$ 55.01	$ 55.51
4/16/2018	$ 57.49	$ 55.67	$ 56.27
4/23/2018	$ 58.72	$ 56.30	$ 58.60
4/30/2018	$ 59.18	$ 57.65	$ 58.90
5/7/2018	$ 58.98	$ 58.44	$ 58.54
5/14/2018	$ 57.06	$ 55.72	$ 56.26
5/21/2018	$ 59.23	$ 55.80	$ 58.87
5/28/2018	$ 59.79	$ 58.06	$ 58.11
6/4/2018	$ 58.59	$ 56.19	$ 56.69
6/11/2018	$ 57.02	$ 55.21	$ 56.97
6/18/2018	$ 58.82	$ 56.97	$ 58.68
6/25/2018	$ 61.25	$ 58.74	$ 60.85
Minimum		$ 51.89	$ 53.99
Maximum	**$ 64.89**		$ 63.75
Mean			**$ 58.17**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	AEE
Current Qtr.	-1.30%
Next Qtr.	2.40%
Current Year	7.40%
Next Year	6.20%
Next 5 Years (per annum)	**6.30%**
Past 5 Years (per annum)	7.79%

Source: YahooFinance; July 18, 2018

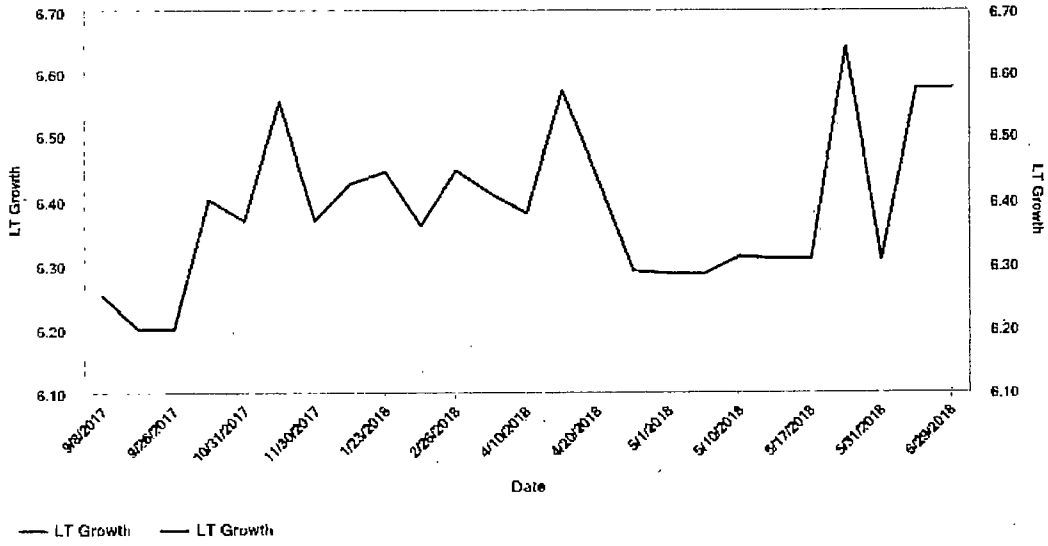
Value-Line	EPS	DPS
Past 10 Years	-1.00%	-4.00%
Past 5 Years	0.50%	2.00%
Est '15-'17 to '21-'23	**7.50%**	**5.50%**

2017	2018	**2019**	'21 to '23
$ 1.78	$ 1.85	$ **1.94**	$ 2.35

Source: June 15, 2018; Value-Line

NYSE : AEE	**Mean**					
LT Growth (%)	**6.57**	6.62	7.10	6.00	0.45	3

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

American Electric Power (AEP)

Date	High	Low	Close
7/3/2017	$ 69.69	$ 68.47	$ 69.15
7/10/2017	$ 69.53	$ 68.11	$ 68.17
7/17/2017	$ 69.99	$ 68.12	$ 69.98
7/24/2017	$ 70.81	$ 68.59	$ 70.43
7/31/2017	$ 71.20	$ 70.03	$ 70.88
8/7/2017	$ 71.61	$ 70.37	$ 70.56
8/14/2017	$ 72.63	$ 70.46	$ 72.16
8/21/2017	$ 73.77	$ 72.13	$ 73.57
8/28/2017	$ 74.29	$ 73.27	$ 73.54
9/4/2017	$ 74.37	$ 73.24	$ 74.19
9/11/2017	$ 74.59	$ 72.29	$ 73.03
9/18/2017	$ 73.11	$ 70.44	$ 70.57
9/25/2017	$ 71.21	$ 69.93	$ 70.24
10/2/2017	$ 71.63	$ 69.55	$ 71.53
10/9/2017	$ 73.91	$ 71.45	$ 73.16
10/16/2017	$ 73.99	$ 72.52	$ 73.98
10/23/2017	$ 74.90	$ 72.53	$ 74.02
10/30/2017	$ 74.92	$ 73.57	$ 74.08
11/6/2017	$ 75.84	$ 73.56	$ 74.78
11/13/2017	$ 77.93	$ 74.70	$ 76.38
11/20/2017	$ 77.06	$ 76.02	$ 76.47
11/27/2017	$ 77.97	$ 76.45	$ 77.24
12/4/2017	$ 78.07	$ 75.86	$ 76.93
12/11/2017	$ 77.22	$ 75.77	$ 76.54
12/18/2017	$ 76.91	$ 73.62	$ 73.65
12/25/2017	$ 74.00	$ 72.94	$ 73.57
1/1/2018	$ 73.42	$ 70.31	$ 70.80
1/8/2018	$ 71.53	$ 67.23	$ 67.46
1/15/2018	$ 68.59	$ 67.11	$ 67.76
1/22/2018	$ 69.80	$ 68.04	$ 68.75
1/29/2018	$ 68.98	$ 67.52	$ 67.75
2/5/2018	$ 68.42	$ 63.32	$ 64.72
2/12/2018	$ 67.52	$ 64.19	$ 67.26
2/19/2018	$ 67.50	$ 65.43	$ 67.37
2/26/2018	$ 67.76	$ 64.60	$ 65.18
3/5/2018	$ 66.72	$ 64.65	$ 65.65
3/12/2018	$ 67.92	$ 65.57	$ 67.81
3/19/2018	$ 68.34	$ 66.25	$ 66.39
3/26/2018	$ 69.24	$ 66.56	$ 68.59
4/2/2018	$ 69.42	$ 67.69	$ 68.53
4/9/2018	$ 69.14	$ 66.46	$ 67.34
4/16/2018	$ 69.67	$ 67.42	$ 68.46
4/23/2018	$ 70.98	$ 68.19	$ 70.55
4/30/2018	$ 70.81	$ 68.52	$ 69.39
5/7/2018	$ 69.45	$ 66.03	$ 67.16
5/14/2018	$ 67.40	$ 64.46	$ 64.93
5/21/2018	$ 67.40	$ 64.58	$ 67.22
5/28/2018	$ 68.43	$ 66.43	$ 66.68
6/4/2018	$ 67.12	$ 63.67	$ 64.11
6/11/2018	$ 65.13	$ 62.71	$ 65.05
6/18/2018	$ 67.82	$ 64.94	$ 67.35
6/25/2018	$ 70.30	$ 67.57	$ 69.25
7/2/2018	$ 71.16	$ 69.12	$ 71.13
Minimum		**$ 62.71**	$ 64.11
Maximum	**$ 78.07**		$ 77.24
Mean			**$ 70.22**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	AEP
Current Qtr.	13.30%
Next Qtr.	6.40%
Current Year	5.40%
Next Year	6.20%
Next 5 Years (per annum)	**5.79%**
Past 5 Years (per annum)	2.52%

Source: YahooFinance; July 18, 2018

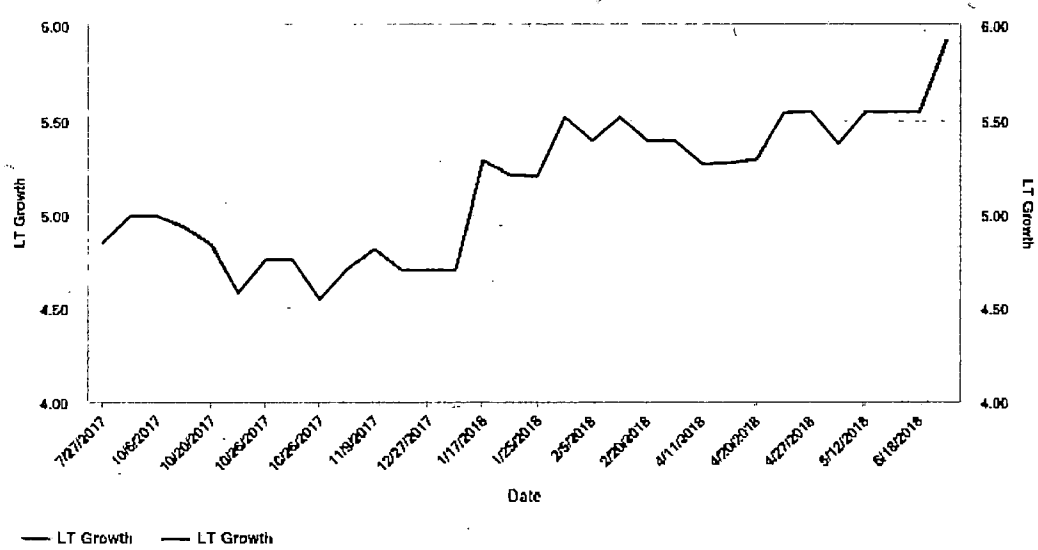
Value-Line	EPS	DPS
Past 10 Years	3.00%	4.00%
Past 5 Years	5.50%	4.50%
Est '15-'17 to '21-'23	**4.50%**	**5.00%**

2017	2018	**2019**	'21 to '23
$ 2.39	$ 2.51	**$ 2.63**	$ 3.05

Source: June 15, 2018; Value-Line

NYSE : AEP	**Mean**					
LT Growth (%)	**5.92**	6.00	6.00	5.76	0.11	8

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Consolidated Edison (ED)

Date	High	Low	Close
7/3/2017	$ 81.28	$ 80.04	$ 80.53
7/10/2017	$ 81.22	$ 80.04	$ 80.73
7/17/2017	$ 82.98	$ 80.49	$ 82.93
7/24/2017	$ 82.98	$ 81.24	$ 82.38
7/31/2017	$ 83.62	$ 82.15	$ 82.80
8/7/2017	$ 84.16	$ 82.51	$ 82.87
8/14/2017	$ 84.07	$ 82.04	$ 83.53
8/21/2017	$ 84.87	$ 83.31	$ 84.48
8/28/2017	$ 84.92	$ 83.76	$ 83.99
9/4/2017	$ 85.68	$ 83.82	$ 85.53
9/11/2017	$ 86.16	$ 83.44	$ 84.44
9/18/2017	$ 84.55	$ 81.58	$ 81.59
9/25/2017	$ 82.35	$ 80.02	$ 80.68
10/2/2017	$ 81.93	$ 80.26	$ 81.56
10/9/2017	$ 84.09	$ 81.40	$ 83.08
10/16/2017	$ 85.08	$ 82.28	$ 84.86
10/23/2017	$ 86.33	$ 84.24	$ 85.92
10/30/2017	$ 87.58	$ 85.27	$ 87.04
11/6/2017	$ 88.08	$ 86.12	$ 87.19
11/13/2017	$ 89.58	$ 86.22	$ 86.53
11/20/2017	$ 87.25	$ 85.86	$ 86.90
11/27/2017	$ 89.57	$ 86.82	$ 88.82
12/4/2017	$ 89.26	$ 87.30	$ 88.92
12/11/2017	$ 89.70	$ 86.93	$ 88.24
12/18/2017	$ 88.27	$ 84.35	$ 84.75
12/25/2017	$ 85.45	$ 84.18	$ 84.95
1/1/2018	$ 84.94	$ 81.03	$ 81.74
1/8/2018	$ 82.91	$ 79.18	$ 79.49
1/15/2018	$ 79.86	$ 77.77	$ 78.27
1/22/2018	$ 80.61	$ 78.37	$ 80.40
1/29/2018	$ 80.65	$ 77.89	$ 77.96
2/5/2018	$ 78.72	$ 74.57	$ 76.89
2/12/2018	$ 77.98	$ 75.66	$ 77.77
2/19/2018	$ 77.93	$ 75.46	$ 77.63
2/26/2018	$ 78.04	$ 73.73	$ 74.35
3/5/2018	$ 76.34	$ 73.98	$ 75.24
3/12/2018	$ 77.58	$ 75.18	$ 77.45
3/19/2018	$ 78.22	$ 75.41	$ 75.58
3/26/2018	$ 78.40	$ 75.62	$ 77.94
4/2/2018	$ 79.39	$ 76.67	$ 78.56
4/9/2018	$ 79.12	$ 76.07	$ 76.69
4/16/2018	$ 79.19	$ 76.95	$ 77.60
4/23/2018	$ 80.78	$ 77.40	$ 80.43
4/30/2018	$ 80.82	$ 78.01	$ 79.25
5/7/2018	$ 79.39	$ 74.88	$ 76.83
5/14/2018	$ 77.18	$ 73.35	$ 73.97
5/21/2018	$ 76.39	$ 73.38	$ 75.91
5/28/2018	$ 76.99	$ 75.22	$ 75.54
6/4/2018	$ 76.06	$ 72.01	$ 72.75
6/11/2018	$ 73.78	$ 71.12	$ 73.73
6/18/2018	$ 75.98	$ 73.41	$ 75.76
6/25/2018	$ 78.91	$ 75.97	$ 77.98
7/2/2018	$ 78.99	$ 77.55	$ 78.99
Minimum		**$ 71.12**	$ 72.75
Maximum	**$ 89.70**		$ 88.92
Mean			**$ 80.75**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	ED
Current Qtr.	-1.70%
Next Qtr.	0.70%
Current Year	3.60%
Next Year	4.20%
Next 5 Years (per annum)	**3.39%**
Past 5 Years (per annum)	2.66%

Source: YahooFinance; July 18, 2018

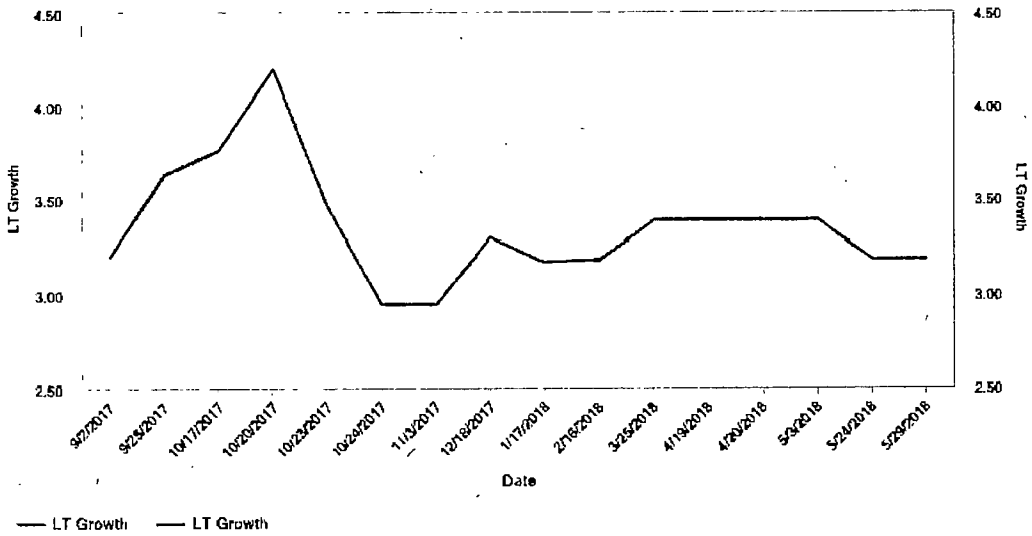
Value-Line	EPS	DPS
Past 10 Years	2.50%	1.50%
Past 5 Years	2.00%	2.00%
Est '15-'17 to '21-'23	**3.00%**	**3.50%**

	2017	2018	**2019**	'21 to '23
$	2.76	$ 2.86	**$ 2.96**	$ 3.30

Source: June 15, 2018; Value-Line

NYSE : ED	**Mean**					
LT Growth (%)	**3.18**	3.53	4.00	2.00	0.85	3

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Duke Energy (DUK)

Date	High	Low	Close
7/3/2017	$ 83.84	$ 82.72	$ 83.42
7/10/2017	$ 84.27	$ 82.80	$ 83.84
7/17/2017	$ 85.23	$ 83.60	$ 85.20
7/24/2017	$ 85.28	$ 83.60	$ 84.91
7/31/2017	$ 86.58	$ 84.65	$ 86.48
8/7/2017	$ 86.90	$ 85.16	$ 85.70
8/14/2017	$ 86.97	$ 85.61	$ 86.38
8/21/2017	$ 87.55	$ 86.11	$ 87.23
8/28/2017	$ 87.95	$ 86.73	$ 87.09
9/4/2017	$ 88.03	$ 86.79	$ 87.78
9/11/2017	$ 88.40	$ 86.53	$ 87.30
9/18/2017	$ 87.31	$ 84.22	$ 84.25
9/25/2017	$ 85.16	$ 83.40	$ 83.92
10/2/2017	$ 84.74	$ 83.52	$ 84.64
10/9/2017	$ 87.60	$ 84.69	$ 86.79
10/16/2017	$ 88.06	$ 86.42	$ 87.93
10/23/2017	$ 88.55	$ 86.71	$ 87.95
10/30/2017	$ 89.50	$ 87.56	$ 88.52
11/6/2017	$ 89.74	$ 87.61	$ 88.89
11/13/2017	$ 91.80	$ 88.45	$ 88.52
11/20/2017	$ 89.20	$ 88.29	$ 88.78
11/27/2017	$ 89.72	$ 88.19	$ 88.73
12/4/2017	$ 89.43	$ 87.45	$ 88.05
12/11/2017	$ 88.39	$ 86.72	$ 87.84
12/18/2017	$ 88.15	$ 83.75	$ 84.17
12/25/2017	$ 84.58	$ 83.56	$ 84.11
1/1/2018	$ 84.42	$ 81.35	$ 81.94
1/8/2018	$ 82.31	$ 78.55	$ 78.90
1/15/2018	$ 79.27	$ 76.64	$ 76.82
1/22/2018	$ 79.22	$ 76.85	$ 78.83
1/29/2018	$ 78.65	$ 76.43	$ 76.53
2/5/2018	$ 77.59	$ 72.93	$ 76.10
2/12/2018	$ 77.30	$ 74.66	$ 76.70
2/19/2018	$ 77.30	$ 74.82	$ 77.22
2/26/2018	$ 79.63	$ 74.58	$ 75.35
3/5/2018	$ 77.67	$ 74.87	$ 76.13
3/12/2018	$ 77.73	$ 76.06	$ 77.59
3/19/2018	$ 77.87	$ 75.03	$ 75.17
3/26/2018	$ 77.91	$ 75.23	$ 77.47
4/2/2018	$ 78.90	$ 76.57	$ 78.16
4/9/2018	$ 79.05	$ 75.96	$ 76.67
4/16/2018	$ 79.42	$ 76.80	$ 77.68
4/23/2018	$ 80.75	$ 77.57	$ 80.50
4/30/2018	$ 80.85	$ 78.82	$ 79.88
5/7/2018	$ 80.13	$ 76.88	$ 77.91
5/14/2018	$ 78.22	$ 73.13	$ 73.80
5/21/2018	$ 76.02	$ 73.35	$ 75.81
5/28/2018	$ 77.57	$ 75.49	$ 76.08
6/4/2018	$ 76.50	$ 72.83	$ 73.12
6/11/2018	$ 74.40	$ 71.96	$ 74.30
6/18/2018	$ 77.67	$ 74.04	$ 77.43
6/25/2018	$ 80.15	$ 77.47	$ 79.08
7/2/2018	$ 80.62	$ 78.90	$ 80.61
Minimum		**$ 71.96**	$ 73.12
Maximum	**$ 91.80**		$ 88.89
Mean			**$ 81.78**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	DUK
Current Qtr.	8.90%
Next Qtr.	N/A
Current Year	3.70%
Next Year	4.40%
Next 5 Years (per annum)	**4.22%**
Past 5 Years (per annum)	1.33%

Source: YahooFinance; July 18, 2018

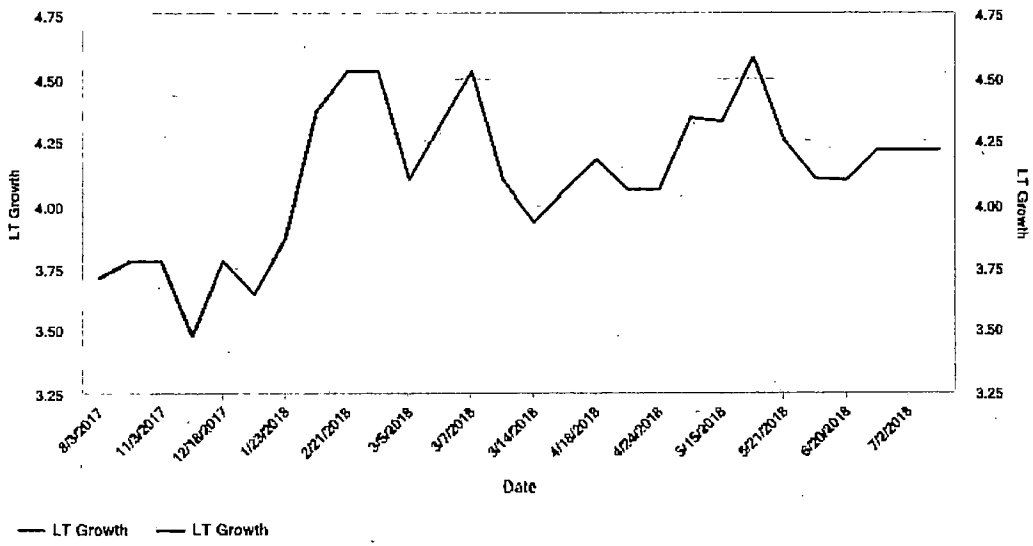
Value-Line	EPS	DPS
Past 10 Years	2.50%	10.00%
Past 5 Years	0.50%	2.50%
Est '15-'17 to '21-'23	**5.50%**	**4.50%**

	2017	2018	**2019**	'21 to '23
$	3.49	$ 3.64	**$ 3.80**	$ 4.40

Source: June 15, 2018; Value-Line

NYSE : DUK	**Mean**					
LT Growth (%)	**4.21**	4.50	5.00	3.00	0.80	5

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Edison International (EIX)

Date	High	Low	Close
7/3/2017	$ 78.46	$ 76.44	$ 76.83
7/10/2017	$ 78.47	$ 76.38	$ 77.45
7/17/2017	$ 79.01	$ 77.32	$ 78.98
7/24/2017	$ 79.35	$ 78.08	$ 78.25
7/31/2017	$ 79.44	$ 77.75	$ 79.29
8/7/2017	$ 80.26	$ 78.94	$ 79.53
8/14/2017	$ 81.33	$ 78.70	$ 78.94
8/21/2017	$ 81.26	$ 78.91	$ 80.75
8/28/2017	$ 81.32	$ 79.54	$ 79.96
9/4/2017	$ 80.78	$ 79.40	$ 80.74
9/11/2017	$ 81.58	$ 80.34	$ 81.20
9/18/2017	$ 81.41	$ 78.22	$ 78.28
9/25/2017	$ 79.45	$ 76.93	$ 77.17
10/2/2017	$ 77.88	$ 76.55	$ 77.62
10/9/2017	$ 79.88	$ 77.39	$ 77.99
10/16/2017	$ 79.83	$ 76.93	$ 79.60
10/23/2017	$ 80.20	$ 78.55	$ 79.47
10/30/2017	$ 80.64	$ 78.63	$ 79.52
11/6/2017	$ 80.43	$ 78.68	$ 80.06
11/13/2017	$ 83.38	$ 80.16	$ 80.89
11/20/2017	$ 81.14	$ 79.72	$ 80.55
11/27/2017	$ 81.96	$ 80.34	$ 80.76
12/4/2017	$ 81.19	$ 67.80	$ 71.80
12/11/2017	$ 73.23	$ 67.28	$ 69.71
12/18/2017	$ 71.11	$ 62.67	$ 65.23
12/25/2017	$ 65.30	$ 63.19	$ 63.24
1/1/2018	$ 63.73	$ 62.03	$ 62.98
1/8/2018	$ 64.34	$ 61.25	$ 61.42
1/15/2018	$ 62.64	$ 60.64	$ 62.12
1/22/2018	$ 62.84	$ 61.52	$ 62.46
1/29/2018	$ 67.56	$ 61.16	$ 61.60
2/5/2018	$ 61.96	$ 57.63	$ 58.94
2/12/2018	$ 61.37	$ 58.69	$ 61.05
2/19/2018	$ 62.56	$ 58.87	$ 62.17
2/26/2018	$ 62.62	$ 59.04	$ 59.59
3/5/2018	$ 60.84	$ 58.80	$ 59.38
3/12/2018	$ 65.15	$ 59.12	$ 65.15
3/19/2018	$ 65.27	$ 61.77	$ 62.16
3/26/2018	$ 63.78	$ 61.47	$ 63.66
4/2/2018	$ 64.11	$ 62.09	$ 63.38
4/9/2018	$ 63.86	$ 62.60	$ 63.44
4/16/2018	$ 65.82	$ 63.30	$ 64.12
4/23/2018	$ 66.60	$ 63.73	$ 65.79
4/30/2018	$ 66.10	$ 62.54	$ 63.69
5/7/2018	$ 63.74	$ 60.23	$ 62.29
5/14/2018	$ 62.51	$ 60.49	$ 61.25
5/21/2018	$ 63.37	$ 60.87	$ 62.98
5/28/2018	$ 62.95	$ 60.53	$ 60.84
6/4/2018	$ 61.61	$ 58.80	$ 59.61
6/11/2018	$ 60.54	$ 58.60	$ 60.44
6/18/2018	$ 61.78	$ 60.04	$ 61.70
6/25/2018	$ 63.72	$ 61.60	$ 63.27
7/2/2018	$ 65.30	$ 62.86	$ 65.28
Minimum		$ 57.63	$ 58.94
Maximum	$ 83.38		$ 81.20
Mean			$ 69.71

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	EIX
Current Qtr.	8.20%
Next Qtr.	-9.10%
Current Year	-8.90%
Next Year	10.20%
Next 5 Years (per annum)	**3.19%**
Past 5 Years (per annum)	2.53%

Source: YahooFinance; July 18, 2018

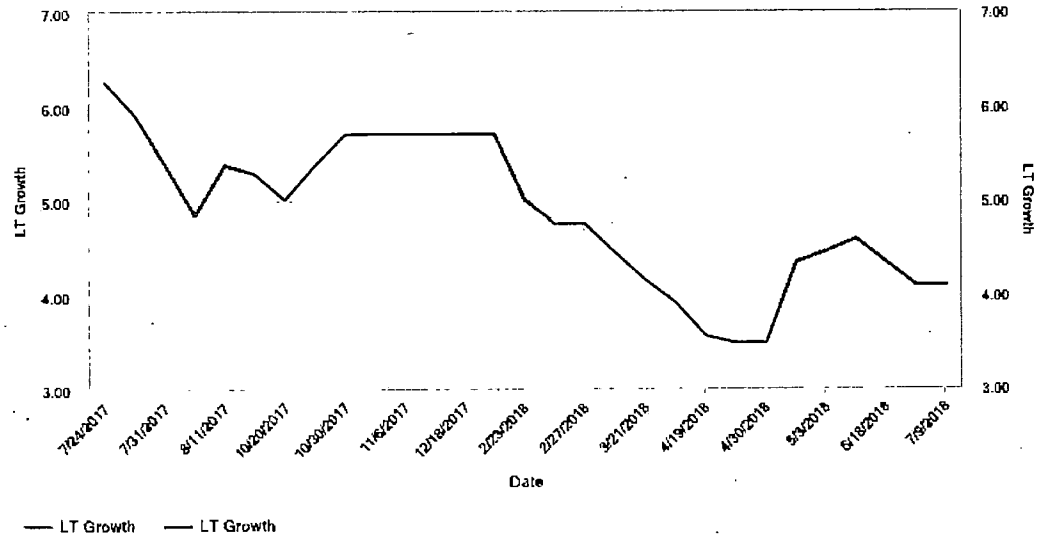
Value-Line	EPS	DPS
Past 10 Years	2.50%	6.00%
Past 5 Years	2.50%	9.00%
Est '15-'17 to '21-'23	**4.50%**	**8.00%**

	2017	2018	**2019**	'21 to '23
$	2.23	$ 2.45	**$ 2.57**	$ 3.10

Source: June 15, 2018; Value-Line

NYSE : EIX	**Mean**					
LT Growth (%)	**4.10**	3.93	7.00	2.48	1.55	5

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

El Paso Electric (EE)

Date	High	Low	Close
7/3/2017	$ 51.90	$ 50.30	$ 51.05
7/10/2017	$ 51.30	$ 50.25	$ 51.05
7/17/2017	$ 53.35	$ 50.85	$ 53.00
7/24/2017	$ 53.10	$ 51.45	$ 51.65
7/31/2017	$ 53.73	$ 51.55	$ 53.35
8/7/2017	$ 54.03	$ 52.83	$ 53.45
8/14/2017	$ 54.25	$ 53.00	$ 53.95
8/21/2017	$ 55.60	$ 53.65	$ 55.35
8/28/2017	$ 55.85	$ 54.85	$ 55.40
9/4/2017	$ 55.95	$ 54.95	$ 55.95
9/11/2017	$ 56.58	$ 54.35	$ 55.15
9/18/2017	$ 55.40	$ 54.30	$ 54.65
9/25/2017	$ 55.75	$ 54.58	$ 55.25
10/2/2017	$ 57.00	$ 55.30	$ 56.85
10/9/2017	$ 58.70	$ 56.85	$ 58.10
10/16/2017	$ 58.05	$ 56.00	$ 57.25
10/23/2017	$ 58.70	$ 56.75	$ 58.40
10/30/2017	$ 58.45	$ 55.45	$ 57.60
11/6/2017	$ 58.65	$ 57.25	$ 57.75
11/13/2017	$ 60.70	$ 57.50	$ 60.20
11/20/2017	$ 60.70	$ 59.15	$ 59.65
11/27/2017	$ 61.15	$ 59.30	$ 60.25
12/4/2017	$ 61.10	$ 58.55	$ 58.90
12/11/2017	$ 59.40	$ 57.98	$ 59.10
12/18/2017	$ 59.45	$ 54.75	$ 55.15
12/25/2017	$ 55.60	$ 54.60	$ 55.35
1/1/2018	$ 55.75	$ 53.65	$ 54.25
1/8/2018	$ 55.10	$ 50.70	$ 51.05
1/15/2018	$ 52.15	$ 50.70	$ 51.65
1/22/2018	$ 52.30	$ 51.15	$ 51.60
1/29/2018	$ 52.38	$ 50.95	$ 51.05
2/5/2018	$ 51.45	$ 48.15	$ 50.75
2/12/2018	$ 51.45	$ 49.70	$ 51.30
2/19/2018	$ 51.40	$ 49.65	$ 50.55
2/26/2018	$ 51.35	$ 48.05	$ 48.60
3/5/2018	$ 49.60	$ 48.05	$ 48.50
3/12/2018	$ 49.60	$ 48.25	$ 49.60
3/19/2018	$ 50.70	$ 48.85	$ 48.85
3/26/2018	$ 51.25	$ 48.80	$ 51.00
4/2/2018	$ 51.30	$ 49.60	$ 50.35
4/9/2018	$ 50.50	$ 48.50	$ 48.90
4/16/2018	$ 50.40	$ 48.90	$ 49.05
4/23/2018	$ 51.55	$ 49.05	$ 51.35
4/30/2018	$ 56.90	$ 49.45	$ 55.05
5/7/2018	$ 56.65	$ 54.50	$ 56.55
5/14/2018	$ 56.80	$ 54.33	$ 55.40
5/21/2018	$ 58.25	$ 55.20	$ 58.05
5/28/2018	$ 59.13	$ 57.65	$ 58.60
6/4/2018	$ 59.15	$ 55.60	$ 55.95
6/11/2018	$ 56.20	$ 54.75	$ 55.70
6/18/2018	$ 58.85	$ 55.80	$ 58.80
6/25/2018	$ 59.35	$ 57.70	$ 59.10
7/2/2018	$ 60.10	$ 58.25	$ 60.05
Minimum		**$ 48.05**	$ 48.50
Maximum	**$ 61.15**		$ 60.25
Mean			**$ 54.44**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	EE
Current Qtr.	-1.10%
Next Qtr.	10.20%
Current Year	5.00%
Next Year	5.10%
Next 5 Years (per annum)	**5.20%**
Past 5 Years (per annum)	14.71%

Source: YahooFinance; July 18, 2018

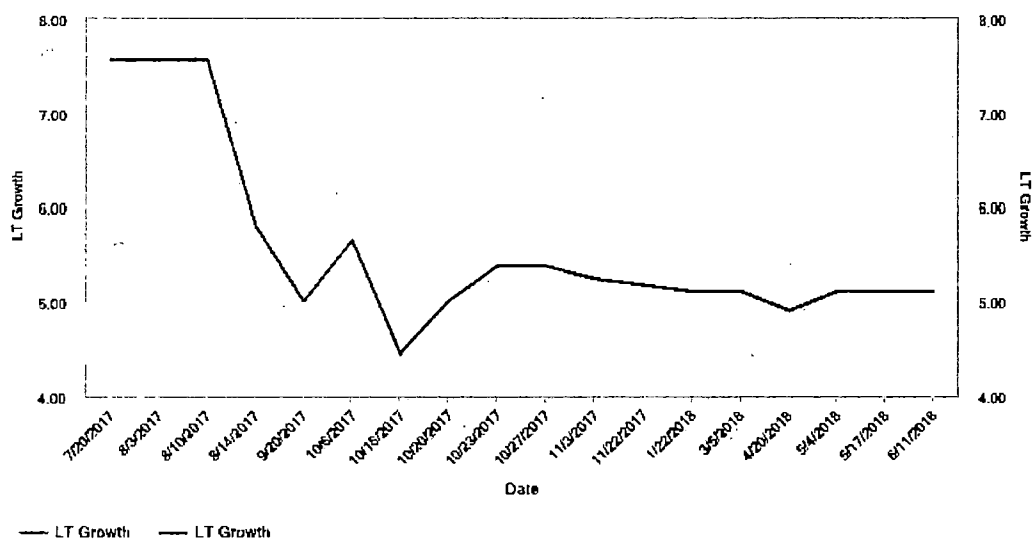
Value-Line	EPS	DPS
Past 10 Years	6.50%	
Past 5 Years		18.00%
Est '15-'17 to '21-'23	**4.50%**	**7.00%**

	2017	2018	**2019**	'21 to '23
$	1.32	$ 1.42	**$ 1.52**	$ 1.85

Source: June 15, 2018; Value-Line

NYSE : EE	**Mean**					
LT Growth (%)	**5.10**	5.10	5.20	5.00	0.10	2

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

IDACORP, Inc (IDA)

Date	High	Low	Close
7/3/2017	$ 85.73	$ 83.75	$ 84.64
7/10/2017	$ 85.15	$ 83.46	$ 84.07
7/17/2017	$ 87.90	$ 83.60	$ 87.84
7/24/2017	$ 87.83	$ 85.59	$ 86.00
7/31/2017	$ 87.63	$ 85.31	$ 86.56
8/7/2017	$ 88.23	$ 86.23	$ 86.78
8/14/2017	$ 87.90	$ 86.26	$ 87.15
8/21/2017	$ 89.75	$ 86.44	$ 89.54
8/28/2017	$ 89.94	$ 88.36	$ 89.32
9/4/2017	$ 91.60	$ 89.17	$ 91.40
9/11/2017	$ 91.98	$ 89.05	$ 90.06
9/18/2017	$ 90.06	$ 87.74	$ 87.75
9/25/2017	$ 89.06	$ 87.61	$ 87.93
10/2/2017	$ 89.25	$ 87.55	$ 88.44
10/9/2017	$ 91.61	$ 88.18	$ 90.34
10/16/2017	$ 92.26	$ 89.79	$ 91.68
10/23/2017	$ 93.22	$ 90.10	$ 93.18
10/30/2017	$ 93.79	$ 91.06	$ 92.71
11/6/2017	$ 95.57	$ 92.50	$ 95.17
11/13/2017	$ 98.43	$ 95.08	$ 97.23
11/20/2017	$ 97.98	$ 96.20	$ 96.55
11/27/2017	$ 100.04	$ 96.19	$ 98.23
12/4/2017	$ 99.03	$ 95.95	$ 97.16
12/11/2017	$ 97.26	$ 93.92	$ 95.51
12/18/2017	$ 96.13	$ 90.03	$ 90.66
12/25/2017	$ 92.43	$ 89.81	$ 91.36
1/1/2018	$ 91.40	$ 87.23	$ 87.69
1/8/2018	$ 88.31	$ 82.08	$ 83.32
1/15/2018	$ 84.70	$ 82.62	$ 83.86
1/22/2018	$ 86.74	$ 83.10	$ 86.07
1/29/2018	$ 86.57	$ 83.25	$ 83.39
2/5/2018	$ 84.32	$ 79.59	$ 83.57
2/12/2018	$ 85.53	$ 82.02	$ 85.27
2/19/2018	$ 85.05	$ 82.23	$ 84.98
2/26/2018	$ 85.25	$ 80.45	$ 81.61
3/5/2018	$ 83.00	$ 80.29	$ 81.95
3/12/2018	$ 86.22	$ 81.54	$ 86.10
3/19/2018	$ 87.95	$ 84.25	$ 84.34
3/26/2018	$ 88.60	$ 84.45	$ 88.27
4/2/2018	$ 88.77	$ 85.55	$ 87.25
4/9/2018	$ 87.86	$ 84.82	$ 85.74
4/16/2018	$ 89.83	$ 85.85	$ 89.08
4/23/2018	$ 94.16	$ 89.23	$ 93.63
4/30/2018	$ 96.01	$ 91.84	$ 94.04
5/7/2018	$ 94.34	$ 90.08	$ 91.24
5/14/2018	$ 91.71	$ 87.34	$ 87.90
5/21/2018	$ 91.23	$ 87.66	$ 90.58
5/28/2018	$ 93.56	$ 87.03	$ 91.51
6/4/2018	$ 91.43	$ 86.28	$ 87.01
6/11/2018	$ 88.56	$ 85.23	$ 88.34
6/18/2018	$ 91.63	$ 88.28	$ 91.26
6/25/2018	$ 93.28	$ 91.40	$ 92.24
7/2/2018	$ 93.95	$ 91.79	$ 93.90
Minimum		$ 79.59	$ 81.61
Maximum	$ 100.04		$ 98.23
Mean			$ 89.08

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	IDA
Current Qtr.	4.00%
Next Qtr.	-3.90%
Current Year	0.20%
Next Year	3.60%
Next 5 Years (per annum)	**3.55%**
Past 5 Years (per annum)	2.88%

Source: YahooFinance; July 18, 2018

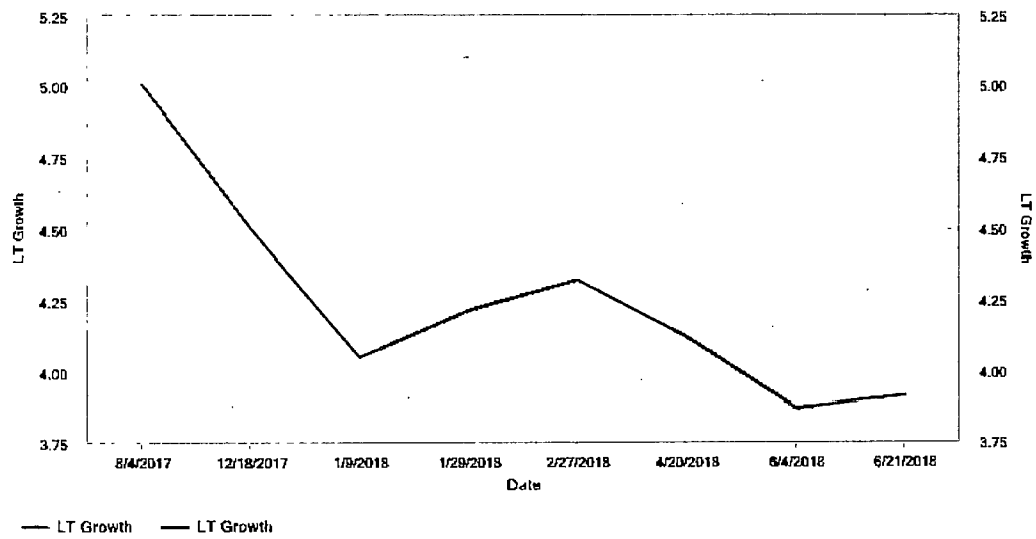
Value-Line	EPS	DPS
Past 10 Years	7.50%	5.50%
Past 5 Years	4.50%	10.50%
Est '15-'17 to '21-'23	**3.50%**	**6.50%**

	2017	2018	**2019**	'21 to '23
$	2.24	$ 2.40	**$ 2.56**	$ 3.05

Source: June 15, 2018; Value-Line

NYSE : IDA	**Mean**					
LT Growth (%)	**3.91**	4.00	5.00	2.74	0.93	3

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Northwestern Corp. (NWE)

Date	High	Low	Close
7/3/2017	$ 61.58	$ 59.85	$ 60.30
7/10/2017	$ 60.75	$ 59.09	$ 59.68
7/17/2017	$ 61.80	$ 58.99	$ 61.77
7/24/2017	$ 61.14	$ 58.42	$ 58.54
7/31/2017	$ 60.36	$ 57.58	$ 60.28
8/7/2017	$ 61.36	$ 59.77	$ 60.18
8/14/2017	$ 60.70	$ 58.63	$ 59.24
8/21/2017	$ 60.97	$ 59.16	$ 60.78
8/28/2017	$ 60.97	$ 59.78	$ 60.23
9/4/2017	$ 60.52	$ 59.56	$ 60.24
9/11/2017	$ 60.82	$ 58.21	$ 58.96
9/18/2017	$ 59.06	$ 57.74	$ 57.75
9/25/2017	$ 58.23	$ 56.87	$ 56.94
10/2/2017	$ 57.98	$ 56.44	$ 57.37
10/9/2017	$ 59.04	$ 57.29	$ 58.44
10/16/2017	$ 59.41	$ 58.24	$ 58.70
10/23/2017	$ 59.46	$ 57.50	$ 59.22
10/30/2017	$ 59.97	$ 58.46	$ 59.78
11/6/2017	$ 61.17	$ 59.28	$ 60.34
11/13/2017	$ 62.12	$ 60.11	$ 61.60
11/20/2017	$ 62.28	$ 61.32	$ 62.22
11/27/2017	$ 64.38	$ 62.02	$ 63.76
12/4/2017	$ 64.47	$ 62.46	$ 63.28
12/11/2017	$ 63.33	$ 60.82	$ 61.60
12/18/2017	$ 62.13	$ 58.48	$ 59.27
12/25/2017	$ 59.91	$ 58.66	$ 59.70
1/1/2018	$ 59.82	$ 57.00	$ 57.41
1/8/2018	$ 57.80	$ 55.33	$ 55.40
1/15/2018	$ 55.50	$ 53.01	$ 53.21
1/22/2018	$ 54.75	$ 53.13	$ 54.36
1/29/2018	$ 54.51	$ 52.71	$ 52.86
2/5/2018	$ 53.35	$ 50.01	$ 52.13
2/12/2018	$ 52.61	$ 50.64	$ 52.27
2/19/2018	$ 52.50	$ 50.89	$ 52.50
2/26/2018	$ 52.76	$ 50.54	$ 51.06
3/5/2018	$ 52.13	$ 50.46	$ 51.07
3/12/2018	$ 52.07	$ 50.65	$ 51.90
3/19/2018	$ 53.31	$ 51.47	$ 51.52
3/26/2018	$ 54.19	$ 51.63	$ 53.80
4/2/2018	$ 54.51	$ 52.43	$ 53.89
4/9/2018	$ 54.33	$ 52.74	$ 53.27
4/16/2018	$ 55.20	$ 53.45	$ 53.85
4/23/2018	$ 55.65	$ 53.72	$ 55.36
4/30/2018	$ 55.80	$ 54.15	$ 55.53
5/7/2018	$ 55.67	$ 52.95	$ 53.72
5/14/2018	$ 53.99	$ 52.77	$ 53.21
5/21/2018	$ 54.63	$ 52.88	$ 54.49
5/28/2018	$ 55.10	$ 52.98	$ 53.00
6/4/2018	$ 53.89	$ 51.53	$ 52.01
6/11/2018	$ 54.33	$ 51.53	$ 54.25
6/18/2018	$ 56.81	$ 54.16	$ 56.70
6/25/2018	$ 57.74	$ 56.64	$ 57.25
7/2/2018	$ 58.65	$ 56.84	$ 58.63
Minimum		**$ 50.01**	$ 51.06
Maximum	**$ 64.47**		$ 63.76
Mean			**$ 56.88**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	NWE	
Current Qtr.	N/A	
Next Qtr.	-1.40%	
Current Year	3.60%	
Next Year	-0.30%	
Next 5 Years (per annum)	**3.16%**	0.0241
Past 5 Years (per annum)	11.96%	

Source: YahooFinance; July 18, 2018

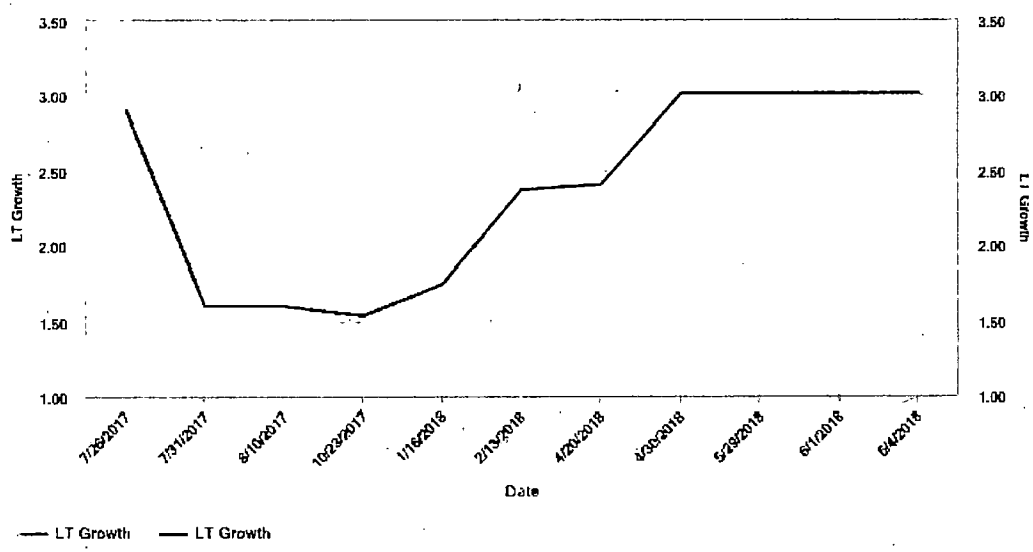
Value-Line	EPS	DPS
Past 10 Years	8.00%	5.50%
Past 5 Years	7.00%	7.00%
Est '15-'17 to '21-'23	**3.50%**	**4.50%**

	2017	2018	**2019**	'21 to '23
$	2.10	$ 2.20	**$ 2.30**	$ 2.60

Source: June 15, 2018; Value-Line

NYSE : NWE	**Mean**					
LT Growth (%)	**3.01**	3.01	3.02	3.00	0.01	2

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

OGE Energy (OGE)

Date	High	Low	Close
7/3/2017	$ 35.01	$ 34.09	$ 34.22
7/10/2017	$ 34.90	$ 33.95	$ 34.57
7/17/2017	$ 35.42	$ 34.26	$ 35.42
7/24/2017	$ 35.92	$ 35.33	$ 35.80
7/31/2017	$ 36.14	$ 35.35	$ 35.91
8/7/2017	$ 36.40	$ 35.27	$ 35.42
8/14/2017	$ 35.75	$ 35.25	$ 35.59
8/21/2017	$ 36.36	$ 35.53	$ 36.22
8/28/2017	$ 36.51	$ 35.67	$ 35.76
9/4/2017	$ 36.21	$ 35.55	$ 36.15
9/11/2017	$ 36.67	$ 35.77	$ 36.31
9/18/2017	$ 36.41	$ 35.69	$ 35.84
9/25/2017	$ 36.39	$ 35.70	$ 36.03
10/2/2017	$ 36.36	$ 35.00	$ 35.58
10/9/2017	$ 37.30	$ 35.65	$ 36.82
10/16/2017	$ 37.21	$ 36.62	$ 37.09
10/23/2017	$ 37.32	$ 36.35	$ 37.08
10/30/2017	$ 37.20	$ 35.60	$ 35.63
11/6/2017	$ 36.00	$ 34.93	$ 35.01
11/13/2017	$ 36.01	$ 34.89	$ 35.20
11/20/2017	$ 35.27	$ 34.72	$ 34.90
11/27/2017	$ 36.00	$ 34.81	$ 35.23
12/4/2017	$ 35.67	$ 33.97	$ 34.46
12/11/2017	$ 34.72	$ 33.47	$ 34.15
12/18/2017	$ 34.40	$ 32.65	$ 33.01
12/25/2017	$ 33.20	$ 32.60	$ 32.91
1/1/2018	$ 33.07	$ 32.47	$ 32.50
1/8/2018	$ 32.84	$ 30.70	$ 30.74
1/15/2018	$ 31.78	$ 30.76	$ 31.42
1/22/2018	$ 32.54	$ 31.47	$ 32.14
1/29/2018	$ 32.36	$ 31.31	$ 31.35
2/5/2018	$ 31.54	$ 29.59	$ 30.39
2/12/2018	$ 31.66	$ 30.34	$ 31.56
2/19/2018	$ 33.06	$ 30.74	$ 32.95
2/26/2018	$ 33.00	$ 30.85	$ 31.19
3/5/2018	$ 32.08	$ 30.76	$ 31.35
3/12/2018	$ 32.17	$ 31.14	$ 32.00
3/19/2018	$ 32.39	$ 31.38	$ 31.43
3/26/2018	$ 32.83	$ 31.43	$ 32.77
4/2/2018	$ 32.98	$ 31.94	$ 32.37
4/9/2018	$ 32.31	$ 31.49	$ 31.61
4/16/2018	$ 32.91	$ 31.69	$ 32.47
4/23/2018	$ 33.16	$ 32.38	$ 32.91
4/30/2018	$ 34.37	$ 32.70	$ 34.17
5/7/2018	$ 34.59	$ 33.46	$ 34.23
5/14/2018	$ 34.30	$ 33.22	$ 33.35
5/21/2018	$ 34.49	$ 33.29	$ 34.39
5/28/2018	$ 35.42	$ 34.17	$ 34.38
6/4/2018	$ 34.81	$ 33.48	$ 33.75
6/11/2018	$ 34.61	$ 33.19	$ 34.22
6/18/2018	$ 35.08	$ 34.11	$ 34.96
6/25/2018	$ 35.54	$ 34.77	$ 35.21
7/2/2018	$ 35.39	$ 34.94	$ 35.28
Minimum		**$ 29.59**	$ 30.39
Maximum	**$ 37.32**		$ 37.09
Mean			**$ 34.06**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	OGE
Current Qtr.	-1.90%
Next Qtr.	-6.50%
Current Year	4.70%
Next Year	4.50%
Next 5 Years (per annum)	**4.30%**
Past 5 Years (per annum)	0.60%

Source: YahooFinance; July 18, 2018

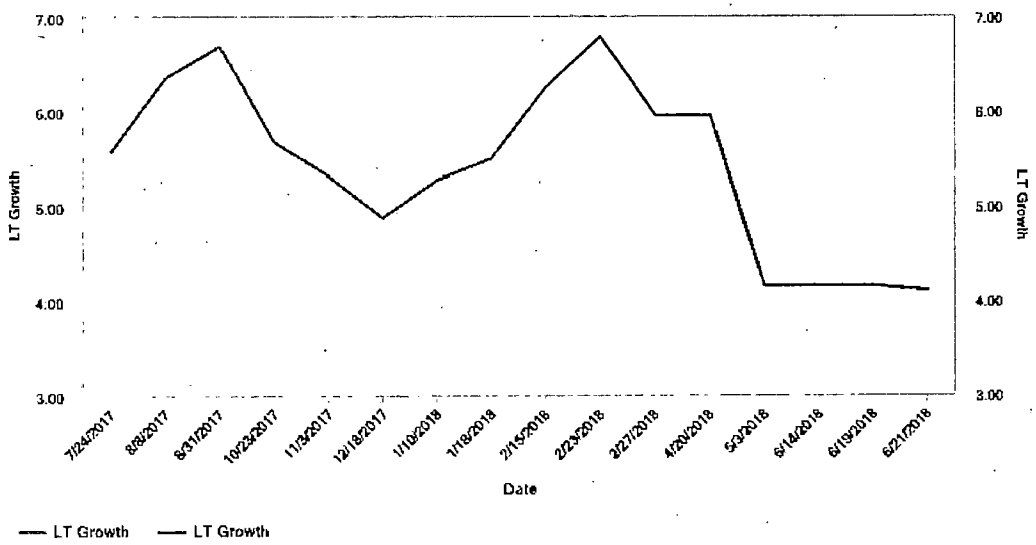
Value-Line	EPS	DPS
Past 10 Years	4.5%	5.5%
Past 5 Years	1.0%	8.5%
Est '15-'17 to '21-'23	**6.0%**	**8.0%**

	2017	2018	**2019**	'21 to '23
$	1.27	$ 1.40	**$ 1.54**	$ 1.85

Source: June 15, 2018; Value-Line

NYSE : OGE	**Mean**					
LT Growth (%)	**4.10**	4.10	4.30	3.90	0.20	2

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Pinnacle West (PNW)

Date	High	Low	Close
7/3/2017	$ 85.87	$ 84.14	$ 84.67
7/10/2017	$ 85.68	$ 83.95	$ 85.13
7/17/2017	$ 87.25	$ 84.95	$ 87.23
7/24/2017	$ 87.38	$ 85.75	$ 86.14
7/31/2017	$ 88.95	$ 85.35	$ 88.06
8/7/2017	$ 89.11	$ 87.95	$ 88.53
8/14/2017	$ 89.91	$ 88.41	$ 89.29
8/21/2017	$ 90.41	$ 88.63	$ 90.02
8/28/2017	$ 90.87	$ 89.46	$ 89.86
9/4/2017	$ 90.16	$ 88.94	$ 90.01
9/11/2017	$ 90.92	$ 87.79	$ 89.27
9/18/2017	$ 89.29	$ 86.14	$ 86.15
9/25/2017	$ 87.17	$ 83.95	$ 84.56
10/2/2017	$ 85.89	$ 84.14	$ 85.33
10/9/2017	$ 88.04	$ 85.17	$ 87.38
10/16/2017	$ 88.84	$ 86.79	$ 88.78
10/23/2017	$ 89.22	$ 87.04	$ 88.91
10/30/2017	$ 89.21	$ 86.23	$ 89.12
11/6/2017	$ 90.00	$ 88.14	$ 88.34
11/13/2017	$ 92.48	$ 88.28	$ 90.05
11/20/2017	$ 90.25	$ 88.93	$ 89.52
11/27/2017	$ 92.30	$ 89.23	$ 91.01
12/4/2017	$ 91.52	$ 88.66	$ 90.75
12/11/2017	$ 91.28	$ 88.20	$ 89.54
12/18/2017	$ 89.90	$ 84.81	$ 85.14
12/25/2017	$ 85.55	$ 84.26	$ 85.18
1/1/2018	$ 85.55	$ 82.02	$ 82.42
1/8/2018	$ 83.18	$ 79.11	$ 79.22
1/15/2018	$ 79.92	$ 78.55	$ 79.08
1/22/2018	$ 81.33	$ 78.81	$ 80.94
1/29/2018	$ 80.65	$ 77.69	$ 77.73
2/5/2018	$ 78.35	$ 73.81	$ 76.29
2/12/2018	$ 78.88	$ 75.61	$ 78.69
2/19/2018	$ 80.41	$ 75.92	$ 80.15
2/26/2018	$ 80.83	$ 76.06	$ 76.92
3/5/2018	$ 78.31	$ 75.21	$ 76.38
3/12/2018	$ 78.00	$ 75.96	$ 77.97
3/19/2018	$ 80.14	$ 77.40	$ 77.76
3/26/2018	$ 80.21	$ 77.73	$ 79.80
4/2/2018	$ 80.54	$ 78.32	$ 79.75
4/9/2018	$ 80.37	$ 77.14	$ 78.14
4/16/2018	$ 80.73	$ 77.55	$ 78.02
4/23/2018	$ 81.85	$ 77.95	$ 81.61
4/30/2018	$ 81.61	$ 78.24	$ 80.20
5/7/2018	$ 80.48	$ 76.96	$ 78.12
5/14/2018	$ 78.39	$ 75.97	$ 76.54
5/21/2018	$ 78.63	$ 75.82	$ 78.39
5/28/2018	$ 80.29	$ 77.48	$ 77.58
6/4/2018	$ 77.86	$ 73.90	$ 74.40
6/11/2018	$ 76.21	$ 73.41	$ 76.11
6/18/2018	$ 78.44	$ 75.69	$ 78.29
6/25/2018	$ 81.25	$ 78.24	$ 80.56
7/2/2018	$ 82.41	$ 80.57	$ 82.38
Minimum		**$ 73.41**	$ 74.40
Maximum	**$ 92.48**		$ 91.01
Mean			**$ 83.23**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	PNW
Current Qtr.	N/A
Next Qtr.	8.50%
Current Year	2.80%
Next Year	5.80%
Next 5 Years (per annum)	**3.78%**
Past 5 Years (per annum)	-8.83%

Source: YahooFinance; July 18, 2018

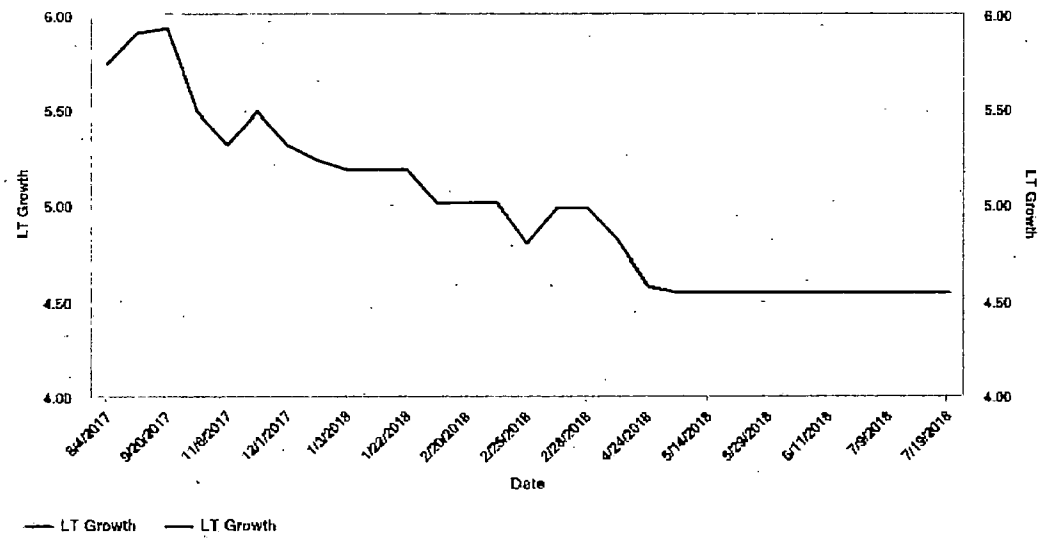
Value-Line	EPS	DPS
Past 10 Years	4.00%	2.50%
Past 5 Years	5.00%	2.50%
Est '15-'17 to '21-'23	**5.00%**	**5.50%**

	2017	2018	**2019**	'21 to '23
$	2.70	$ 2.86	**$ 3.02**	$ 3.50

Source: June 15, 2018; Value-Line

NYSE : PNW	**Mean**					
LT Growth (%)	**4.54**	4.85	5.00	3.46	0.64	4

Source: SNL/S&P Global



Schedule AHG - 4
18-KCPE-480-RTS

Portland General (POR)

Date	High	Low	Close
7/3/2017	$ 45.83	$ 44.55	$ 44.87
7/10/2017	$ 44.99	$ 44.20	$ 44.59
7/17/2017	$ 46.35	$ 44.41	$ 46.35
7/24/2017	$ 46.16	$ 44.27	$ 44.44
7/31/2017	$ 45.57	$ 44.45	$ 45.46
8/7/2017	$ 46.57	$ 45.24	$ 45.90
8/14/2017	$ 46.68	$ 45.61	$ 46.40
8/21/2017	$ 47.40	$ 46.27	$ 47.14
8/28/2017	$ 47.60	$ 47.02	$ 47.33
9/4/2017	$ 47.91	$ 47.10	$ 47.87
9/11/2017	$ 48.22	$ 46.60	$ 46.96
9/18/2017	$ 47.04	$ 45.48	$ 45.58
9/25/2017	$ 46.31	$ 45.53	$ 45.64
10/2/2017	$ 46.54	$ 45.52	$ 46.07
10/9/2017	$ 47.07	$ 45.95	$ 46.25
10/16/2017	$ 46.35	$ 44.70	$ 45.37
10/23/2017	$ 47.68	$ 45.25	$ 47.67
10/30/2017	$ 48.18	$ 47.10	$ 47.76
11/6/2017	$ 48.69	$ 47.48	$ 48.28
11/13/2017	$ 50.11	$ 48.35	$ 49.34
11/20/2017	$ 49.45	$ 48.38	$ 48.48
11/27/2017	$ 49.85	$ 48.23	$ 49.49
12/4/2017	$ 49.84	$ 48.23	$ 48.68
12/11/2017	$ 48.87	$ 47.00	$ 47.79
12/18/2017	$ 48.12	$ 45.36	$ 45.61
12/25/2017	$ 45.83	$ 45.00	$ 45.58
1/1/2018	$ 45.65	$ 43.63	$ 43.86
1/8/2018	$ 44.02	$ 42.38	$ 42.62
1/15/2018	$ 42.99	$ 42.25	$ 42.40
1/22/2018	$ 42.85	$ 41.89	$ 42.27
1/29/2018	$ 42.47	$ 41.00	$ 41.40
2/5/2018	$ 41.62	$ 39.40	$ 40.47
2/12/2018	$ 41.41	$ 39.77	$ 41.20
2/19/2018	$ 41.14	$ 39.86	$ 41.08
2/26/2018	$ 41.27	$ 39.41	$ 39.74
3/5/2018	$ 40.42	$ 39.02	$ 39.18
3/12/2018	$ 40.09	$ 39.07	$ 40.05
3/19/2018	$ 41.06	$ 39.09	$ 39.11
3/26/2018	$ 40.76	$ 39.27	$ 40.51
4/2/2018	$ 40.66	$ 39.56	$ 40.21
4/9/2018	$ 40.54	$ 39.18	$ 40.22
4/16/2018	$ 41.21	$ 40.07	$ 40.17
4/23/2018	$ 42.59	$ 40.15	$ 42.33
4/30/2018	$ 42.93	$ 41.63	$ 42.76
5/7/2018	$ 42.81	$ 40.56	$ 41.05
5/14/2018	$ 41.09	$ 39.66	$ 39.78
5/21/2018	$ 41.92	$ 39.66	$ 41.87
5/28/2018	$ 42.93	$ 41.46	$ 42.27
6/4/2018	$ 42.41	$ 39.99	$ 40.21
6/11/2018	$ 41.43	$ 39.60	$ 41.40
6/18/2018	$ 42.59	$ 41.12	$ 42.41
6/25/2018	$ 43.29	$ 42.39	$ 42.76
7/2/2018	$ 43.96	$ 42.47	$ 43.95
Minimum		**$ 39.02**	$ 39.11
Maximum	**$ 50.11**		$ 49.49
Mean			**$ 43.97**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	POR
Current Qtr.	8.30%
Next Qtr.	-2.30%
Current Year	-3.90%
Next Year	7.30%
Next 5 Years (per annum)	**2.65%**
Past 5 Years (per annum)	5.87%

Source: YahooFinance; July 18, 2018

0.023

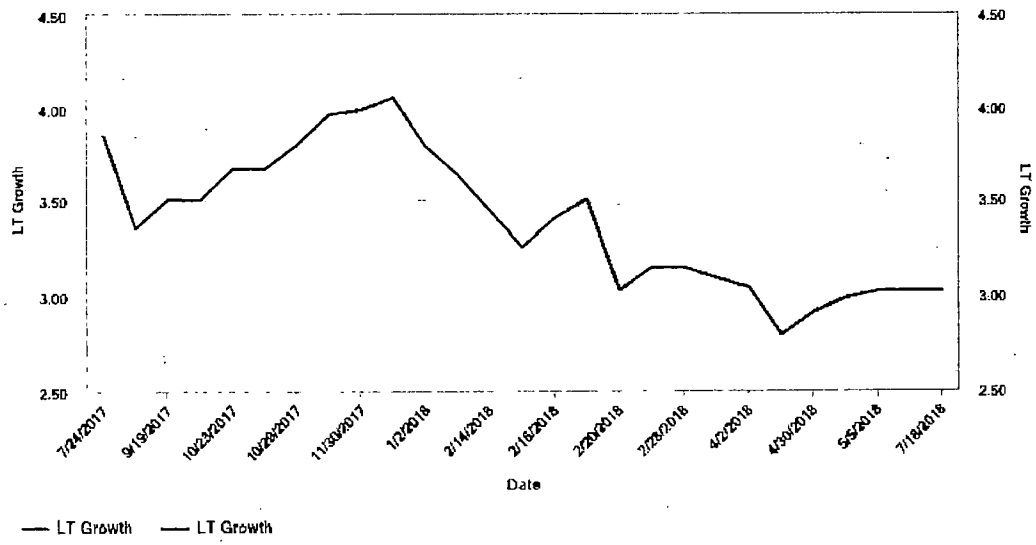
Value-Line	EPS	DPS
Past 10 Years	4.00%	9.00%
Past 5 Years	3.50%	3.50%
Est '15-'17 to '21-'23	**4.00%**	**6.00%**

2017	2018	**2019**	'21 to '23
$ 1.34	$ 1.42	**$ 1.50**	$ 1.80

Source: June 15, 2018; Value-Line

NYSE : POR	**Mean**					
LT Growth (%)	**3.02**	3.00	3.80	2.25	0.63	3

Source: SNL/S&P Global



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Xcel Energy (XEL)

Date	High	Low	Close
7/3/2017	$ 46.06	$ 45.18	$ 45.69
7/10/2017	$ 46.08	$ 45.41	$ 45.92
7/17/2017	$ 47.42	$ 45.85	$ 47.42
7/24/2017	$ 47.70	$ 46.55	$ 47.16
7/31/2017	$ 48.12	$ 46.96	$ 47.97
8/7/2017	$ 48.72	$ 47.79	$ 48.19
8/14/2017	$ 49.22	$ 48.19	$ 49.00
8/21/2017	$ 49.60	$ 48.93	$ 49.37
8/28/2017	$ 49.70	$ 49.19	$ 49.36
9/4/2017	$ 50.30	$ 49.17	$ 50.23
9/11/2017	$ 50.56	$ 48.59	$ 49.08
9/18/2017	$ 49.10	$ 47.29	$ 47.41
9/25/2017	$ 47.97	$ 46.69	$ 47.32
10/2/2017	$ 47.80	$ 46.86	$ 47.39
10/9/2017	$ 49.08	$ 47.37	$ 48.61
10/16/2017	$ 49.41	$ 48.26	$ 49.26
10/23/2017	$ 49.83	$ 48.56	$ 49.21
10/30/2017	$ 49.92	$ 48.93	$ 49.59
11/6/2017	$ 50.57	$ 49.29	$ 50.20
11/13/2017	$ 52.22	$ 50.13	$ 50.89
11/20/2017	$ 51.05	$ 50.35	$ 50.71
11/27/2017	$ 51.84	$ 50.61	$ 51.36
12/4/2017	$ 51.58	$ 50.40	$ 51.20
12/11/2017	$ 51.45	$ 50.16	$ 50.78
12/18/2017	$ 50.86	$ 48.12	$ 48.25
12/25/2017	$ 48.41	$ 47.53	$ 48.11
1/1/2018	$ 48.36	$ 46.63	$ 46.79
1/8/2018	$ 47.22	$ 45.06	$ 45.15
1/15/2018	$ 45.86	$ 44.89	$ 45.13
1/22/2018	$ 46.10	$ 45.12	$ 45.70
1/29/2018	$ 45.78	$ 44.45	$ 44.48
2/5/2018	$ 44.75	$ 41.51	$ 43.35
2/12/2018	$ 44.88	$ 43.04	$ 44.68
2/19/2018	$ 44.82	$ 43.50	$ 44.77
2/26/2018	$ 44.92	$ 42.65	$ 43.03
3/5/2018	$ 44.02	$ 42.57	$ 43.28
3/12/2018	$ 44.23	$ 43.23	$ 44.13
3/19/2018	$ 45.19	$ 43.66	$ 43.74
3/26/2018	$ 45.87	$ 43.81	$ 45.48
4/2/2018	$ 45.99	$ 44.68	$ 45.47
4/9/2018	$ 45.80	$ 43.93	$ 44.48
4/16/2018	$ 46.01	$ 44.49	$ 45.10
4/23/2018	$ 47.38	$ 45.12	$ 47.10
4/30/2018	$ 47.37	$ 45.93	$ 46.39
5/7/2018	$ 46.54	$ 44.58	$ 45.26
5/14/2018	$ 45.41	$ 43.44	$ 43.70
5/21/2018	$ 45.30	$ 43.28	$ 45.19
5/28/2018	$ 45.87	$ 44.63	$ 44.74
6/4/2018	$ 44.93	$ 42.27	$ 42.72
6/11/2018	$ 43.43	$ 41.99	$ 43.33
6/18/2018	$ 44.39	$ 43.25	$ 43.85
6/25/2018	$ 46.24	$ 43.90	$ 45.68
7/2/2018	$ 46.63	$ 45.70	$ 46.59
Minimum		**$ 41.51**	$ 42.72
Maximum	**$ 52.22**		$ 51.36
Mean			**$ 46.77**

Source: YahooFinance, July 18, 2018

I/B/E/S Growth Estimates	XEL
Current Qtr.	4.40%
Next Qtr.	2.10%
Current Year	5.70%
Next Year	6.60%
Next 5 Years (per annum)	**5.86%**
Past 5 Years (per annum)	4.18%

Source: YahooFinance; July 18, 2018

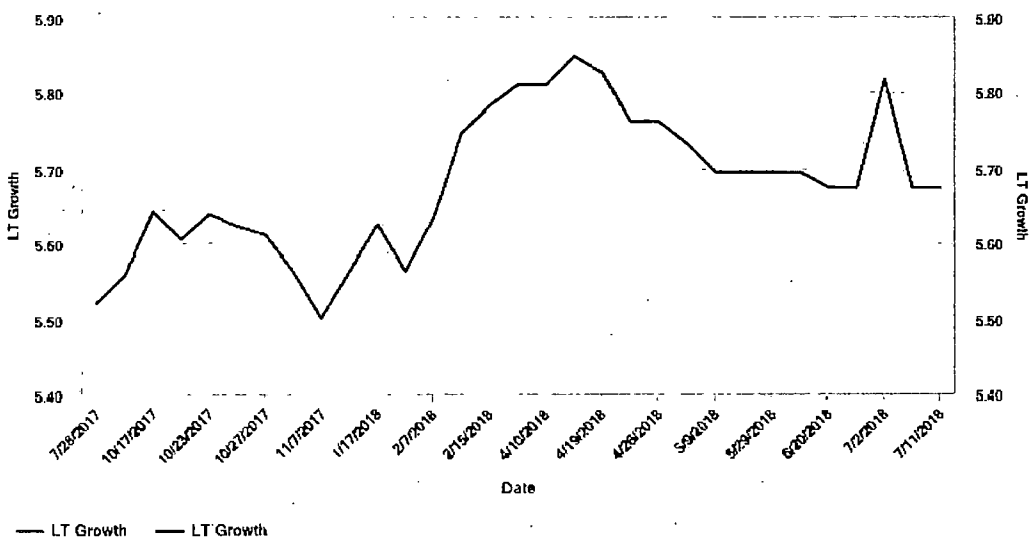
Value-Line	EPS	DPS
Past 10 Years	5.50%	4.50%
Past 5 Years	5.00%	5.50%
Est '15-'17 to '21-'23	**5.50%**	**5.50%**

	2017	2018	**2019**	'21 to '23
$	1.44	$ 1.52	**$ 1.60**	$ 1.90

Source: June 15, 2018; Value-Line

NASDAQ : XEL	**Mean**					
LT Growth (%)	**5.67**	5.60	6.30	5.00	0.40	7

Source: SNL/S&P Global



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Internal Rate of Return Analysis Summary

1	2	3	4	5	6	7	8	9	10	11	12	13	14
							Short-Term Growth EPS Growth				Long-Term Growth Years 5 Through 250		
	IRR	Average Price	ST Growth Estimate	LT Growth Estimate	2019 Dividends	2018 Year 0	2020 Year1	2021 Year2	2022 Year3	2023 Year4	2024 Year5	2025 Year6	2021 through 2264 Year 7 through Year 250
Allete Inc.	7.82%	$ 74.78	5.53%	4.30%	$ 2.34	$ (72.44)	$ 2.47	$ 2.61	$ 2.75	$ 2.90	$ 3.03	$ 3.16	$ 2,215,022
Alliant Energy Corp.	8.23%	$ 41.56	6.06%	4.30%	$ 1.42	$ (40.14)	$ 1.51	$ 1.60	$ 1.69	$ 1.80	$ 1.87	$ 1.95	$ 1,371,882
Ameren Corp.	8.19%	$ 58.17	6.47%	4.30%	$ 1.94	$ (56.23)	$ 2.07	$ 2.20	$ 2.34	$ 2.49	$ 2.60	$ 2.71	$ 1,902,961
American Electric Power Co.	8.51%	$ 70.22	5.30%	4.30%	$ 2.63	$ (67.59)	$ 2.77	$ 2.92	$ 3.07	$ 3.23	$ 3.37	$ 3.52	$ 2,468,566
Consolidated Edison Inc.	8.12%	$ 80.75	3.27%	4.30%	$ 2.96	$ (77.79)	$ 3.06	$ 3.16	$ 3.26	$ 3.37	$ 3.51	$ 3.66	$ 2,569,661
Duke Energy Corp.	9.44%	$ 81.78	4.61%	4.30%	$ 3.80	$ (77.98)	$ 3.98	$ 4.16	$ 4.35	$ 4.55	$ 4.75	$ 4.95	$ 3,473,721
Edison International	8.39%	$ 69.71	4.95%	4.30%	$ 2.57	$ (67.14)	$ 2.70	$ 2.83	$ 2.97	$ 3.12	$ 3.25	$ 3.39	$ 2,379,957
El Paso Electric Co.	7.42%	$ 54.44	5.45%	4.30%	$ 1.52	$ (52.92)	$ 1.60	$ 1.69	$ 1.78	$ 1.88	$ 1.96	$ 2.04	$ 1,434,756
IDACORP Inc.	7.39%	$ 89.08	4.37%	4.30%	$ 2.56	$ (86.52)	$ 2.67	$ 2.79	$ 2.91	$ 3.04	$ 3.17	$ 3.30	$ 2,318,531
NorthWestern Corp.	8.58%	$ 56.88	3.54%	4.30%	$ 2.30	$ (54.58)	$ 2.38	$ 2.47	$ 2.55	$ 2.64	$ 2.76	$ 2.88	$ 2,018,138
OGE Energy Corp.	9.47%	$ 34.06	5.60%	4.30%	$ 1.54	$ (32.52)	$ 1.63	$ 1.72	$ 1.81	$ 1.92	$ 2.00	$ 2.08	$ 1,461,907
Pinnacle West Capital Corp.	8.28%	$ 83.23	4.70%	4.30%	$ 3.02	$ (80.21)	$ 3.16	$ 3.31	$ 3.47	$ 3.63	$ 3.79	$ 3.95	$ 2,770,873
Portland General Electric Co.	7.93%	$ 43.97	3.92%	4.30%	$ 1.50	$ (42.47)	$ 1.56	$ 1.62	$ 1.68	$ 1.75	$ 1.82	$ 1.90	$ 1,335,299
Xcel Energy Inc.	8.18%	$ 46.77	5.63%	4.30%	$ 1.60	$ (45.17)	$ 1.69	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.17	$ 1,520,796
Mean	8.28%												
Min	7.39%												
Max	9.47%												

Column 1) Proxy group
2) Internal rate of return calcuation -- Investors' discount rate that equates the stock price to the stream of future dividends
3) Average stock price July 2, 2017 through July 3, 2018
4) Average of short-term growth rates used in first 5 years
5) Long-term nGDP growth rate used after 2024
6) 2019 dividends reported by Value-Line
7) Year 0 Cashflow; stock price less 2019 dividend
8 through 11) Annual cashflow growing at short-term growth rate
12 through 250) Annual cashflow growing at long-term growth rate

STATE OF KANSAS)
) ss.
COUNTY OF SHAWNEE)

VERIFICATION

Adam H. Gatewood, being duly sworn upon his oath deposes and says that he is the Managing Financial Analyst for the State Corporation Commission of the State of Kansas, that he has read and is familiar with the foregoing *Direct Testimony,* and that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Adam H. Gatewood
Senior Managing Financial Analyst
Utilities Division
State Corporation Commission of the
State of Kansas

Subscribed and sworn to before me this 12th day of September, 2018.

PAMELA J. GRIFFETH
Notary Public - State of Kansas
My Appt. Expires 08-17-2019

Notary Public

My Appointment Expires: August 17, 2019

CERTIFICATE OF SERVICE

18-KCPE-480-RTS

I, the undersigned, certify that a true and correct copy of the above and foregoing Direct Testimony was served by electronic service on this 12th day of September, 2018, to the following:

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18-KCPE-480-RTS

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Enclosure IV to WM 19-0008

Joint Motion to Approve Stipulation (Docket No. 15-WCNE-093-GIE)
(28 pages)

20150210140017
Filed Date: 02/10/2015
State Corporation Commission
of Kansas

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of the 2014Wolf Creek Decommissioning Cost Study as Provided by Wolf Creek Nuclear Operating Corporation on August 29, 2014 in Accordance with the Commission's Order in Docket Number 163,561-U on December 9, 1992 and the Commission's Order in Docket No. 13-WCNE-204-GIE on June 13, 2013.	)	Docket No. 15-WCNE-093-GIE

JOINT MOTION TO APPROVE STIPULATION AND AGREEMENT AND TO CONVERT THE EVIDENTIARY HEARING IN THIS DOCKET TO A SETTLEMENT HEARING OR CANCEL THE HEARING

COMES NOW the Staff of the State Corporation Commission of the State of Kansas ("Staff" and "Commission," respectively), Wolf Creek Nuclear Operating Corporation ("Wolf Creek"), Kansas Gas and Electric Company d/b/a Westar Energy ("Westar"), Kansas City Power & Light Company ("KCP&L"), and Kansas Electric Power Cooperative, Inc. ("KEPCo") (collectively referred to as the "Joint Movants") and respectfully move the Commission for an Order approving the Stipulation and Agreement ("S&A") filed contemporaneously with this Motion. The S&A is attached as Exhibit 1. The Parties also request the Commission convert the February 24, 2015 evidentiary hearing set out in the procedural schedule contained in the October 16, 2014 *Order Setting Procedural Schedule and Designating Prehearing Officer* in this docket to a settlement hearing.

I. INTRODUCTION

1. On August 29, 2014, Wolf Creek filed its 2014 Decommissioning Cost Analysis for the Wolf Creek Generating Station, in accordance with the Commission's December 9, 1992 Order in Docket No. 163,561-U and the Commission's Order in Docket No. 13-WCNE-204-GIE on June 13, 2013. The December 9, 1992 Order directed the filing of a decommissioning cost

study every three years after September 1, 1993. The June 13, 2013 Order directed Wolf Creek and the owning utilities to update the estimates of the total capital costs of the Independent Spent Fuel Storage Installation ("ISFSI") project at Wolf Creek as part of the triennial decommissioning cost study filings.[1]

2. Westar, KCP&L, KEPCo and CURB filed petitions to intervene, which were granted.

3. The Joint Movants and the Citizens' Utility Ratepayer Board ("CURB") held several conference calls and met on February 9, 2015 to discuss settlement of this docket. Following negotiations, the Joint Movants entered into an S&A (attached as Exhibit 1) for the purpose of determining a reasonable estimate of Wolf Creek decommissioning costs to be used in addressing accrual levels of the respective owner utilities' decommissioning trust accounts and the appropriate escalation factor (inflation rate). The Joint Movants and CURB also discussed a separate, future issue regarding the content of the 2017 triennial decommissioning cost study filing. Although CURB is not a signatory to the S&A, CURB has advised the Joint Movants that it does not oppose the S&A.

4. Further, the Joint Movants have submitted pre-filed testimony to support the S&A, no party to the docket opposes the S&A, and the Joint Movants have included sufficient information within the S&A to respond to the Commission's five threshold questions used in reviewing an S&A for reasonableness.

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[1] *See* Docket No. 13-WCNE-204-GIE, In the Matter of a Generic Proceeding Regarding Wolf Creek Nuclear Operating Corporation to Receive Information Concerning Spent Fuel, Pursuant to the Commission's May 12, 2012 Order in Docket No. 12-WCNE-136-GIE, *Order Closing Docket*, issued Jun. 13, 2013, Ordering ¶ A.

II. THE S&A MEETS THE LEGAL STANDARDS NECESSARY FOR COMMISSION APPROVAL OF SETTLEMENT AGREEMENTS AND SHOULD BE APPROVED.

5. An order of the Commission must afford parties their due process rights, be supported by substantial competent evidence, be in the public interest, conform with applicable law and if the order impacts rates those rates must be just and reasonable.

6. **All parties participated fully in the proceeding and no violation of due process claims has been raised.** The S&A is either supported or not opposed by all parties to the docket. As noted earlier, the following parties intervened in this docket: Staff, Wolf Creek, Westar, KEPCo, KCP&L and CURB. A procedural schedule was set on October 16, 2014 providing opportunity for Direct Testimony by the applicants, Wolf Creek, Westar, KEPCo and KCP&L, responsive Direct Testimony by Staff and CURB, Cross-Answering Testimony by Staff and CURB, and Rebuttal Testimony by the applicants. Additionally, all parties to the case participated on the January 30, 2015 conference call and in the Settlement Conference on February 9, 2015 wherein they discussed a joint motion and settlement agreement. Follow-up communication regarding the joint motion and settlement agreement included all parties to the case. Therefore, the Joint Movants to the S&A believe that appropriate and sufficient opportunity was provided for all parties to the docket to be heard on any reasons for opposing the S&A.

7. **The S&A is supported by substantial competent evidence.** A decision of the Commission is unsupported by substantial competent evidence "only when the evidence shows the [Commission's] determination 'is so wide of the mark as to be outside the realm of fair debate.' "[2] The Kansas Supreme Court has also stated that the Commission "is not obligated to

[2] *Zinke & Trumbo, Ltd. v. Kansas Corp. Comm'n*, 242 Kan. 470, 474 (1988) (quoting *Kansas-Nebraska Natural Gas Co. v. Kansas Corp. Comm'n*, 217 Kan. 604, 617).

render its finding of fact in minute detail ... [h]owever, we require its findings to be specific enough to allow judicial review of the reasonableness of the order."[3] As noted above, the Joint Movants have provided the decommissioning cost study as well as the testimony of three witnesses, all of which support the S&A. The cost for decommissioning funding of $765,060,000 and the escalation rate of 3.15% agreed to in the S&A are supported by substantial competent evidence. As part of the Application in this docket, Wolf Creek provided the decommissioning cost study supporting the decommissioning cost estimate. Staff witness Leo Haynos testified in support of the cost estimate provided in the Application. Haynos Direct, at p. 12. On behalf of the applicants, Gregg Clizer testified that 3.15% is the appropriate escalation rate. Clizer Direct, at pp. 3-7. Staff witness Adam Gatewood testified in support of the escalation rate. Gatewood Direct, at pp. 2-3.

8. **The S&A conforms with applicable law.** An Order is "lawful" if it is within the statutory authority of the commission, and if the prescribed statutory and procedural rules are followed in making the Order.[4] The S&A deals with the decommissioning cost estimate required to be submitted to the Commission by Kansas statute for utilities owning a nuclear facility. Thus, the subject matter of the S&A is clearly within the Commission's authority. It is also clear that the applicable statutory and procedural rules have been followed. The S&A is the result of negotiations among and is supported or not opposed by all of the parties to this proceeding. Commission approval of the S&A under these circumstances would clearly be in compliance with applicable law.

9. **The S&A results in just and reasonable rates.** Approval by the Commission of the S&A in this docket will not have an immediate effect on rates charged to Kansas customers. Rate impact will not occur until each owner company files its individual dockets wherein the

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[3] *Id.* at 475.

[4] *Central Kansas Power Co. v. State Corp. Comm'n*, 221 Kan. 505, Syl. 1 (1977).

new decommissioning accrual will be included in their revenue requirement. *See, e.g.,* Gatewood Direct, at pp. 1-2. However, because the decommissioning cost elements being stipulated to in this docket are fair, reasonable, and fully supported by the evidence, inclusion of the same in rates later should not cause such rates to become unjust or unreasonable.

10. **Whether the results of the Stipulation are in the public interest.** The Joint Movants agree the terms of this S&A are in the public interest and should be approved by the Commission. Each party to this proceeding has a duty to protect the interests of the party it represents. The companies have a duty to both their customers and shareholders. CURB represents the interests of residential and small commercial customers. The Staff is in the unique position of being required to weigh and balance the interests of the companies, the utility customers, and any other party to a proceeding. By signing or not opposing this S&A, these parties represent to the Commission that the total effect of the terms of the S&A represents an equitable balancing of the interests of all parties. It is also in the public interest to avoid the cost of litigation in this matter and the unanimous settlement promotes administrative efficiency and reduces related litigation costs. Thus, the S&A is in the public interest, and should be adopted by the Commission in its entirety.

11. As indicated above, the following testimony has been submitted in this docket in support of the S&A:

- Direct Testimony of Gregg Clizer for Wolf Creek, KCP&L, Westar and KEPCo.
- Direct Testimony and Testimony in Support of Settlement of Leo Haynos for Staff.
- Direct Testimony of Adam Gatewood for Staff.

- Testimony in Support of Settlement of Mary Britt Turner for Wolf Creek, KCP&L, Westar and KEPCo.

12. The Joint Movants ask that the testimony listed in paragraph 11 and the 2014 Decommissioning Cost Analysis performed by TLG Services, Inc. and submitted with the Application be admitted into the record. Because a settlement supported or unopposed by all parties is being presented and the terms of the S&A are supported by testimony in the record, the Parties do not believe that it is necessary for the Commission to hold an evidentiary hearing in this docket. The Parties believe that with the addition of testimony supporting the S&A to be filed on February 12, 2015, the record will allow the Commission to approve the S&A without the need for a settlement hearing. Thus, the Parties request the Commission either convert the February 24, 2015 evidentiary hearing set out in the procedural schedule contained in the October 16, 2014 *Order Setting Procedural Schedule and Designating Prehearing Officer* in this docket to a settlement hearing or cancel the hearing altogether if the Commission determines a hearing is unnecessary given the record.

WHEREFORE, the Joint Movants respectfully request that the Commission approve the S&A, convert the evidentiary hearing on this matter to a settlement hearing or cancel the hearing altogether, and for any further relief the Commission shall deem just and appropriate.

Respectfully submitted,

/s/ David Springe

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Exhibit 1

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the 2014Wolf Creek Decommissioning Cost Study as Provided by Wolf Creek Nuclear Operating Corporation on August 29, 2014 in Accordance with the Commission's Order in Docket Number 163,561-U on December 9, 1992 and the Commission's Order in Docket No. 13-WCNE-204-GIE on June 13, 2013.	)	Docket No. 15-WCNE-093-GIE

STIPULATION AND AGREEMENT

This Stipulation and Agreement ("S&A") is entered into by and between the Staff of the State Corporation Commission of the State of Kansas ("Staff" and "Commission," respectively), Wolf Creek Nuclear Operating Corporation ("Wolf Creek"), Kansas Gas and Electric Company d/b/a Westar Energy ("Westar"), Kansas City Power & Light Company ("KCP&L"), and Kansas Electric Power Cooperative, Inc. ("KEPCo") (collectively referred to as the "Parties").

1. On August 29, 2014, Wolf Creek filed its 2014 Decommissioning Cost Analysis for the Wolf Creek Generating Station, in accordance with the Commission's December 9, 1992 Order in Docket No. 163,561-U. The December 9, 1992 Order directed the filing of a decommissioning cost study every three years after September 1, 1993.

2. Westar, KCP&L, KEPCo and CURB filed petitions to intervene, which were granted.

3. On January 30, 2015, the Parties held a conference call to discuss settlement of the issues in this docket. The Parties also discussed settlement at the Settlement Conference held on February 9, 2015. The terms of the resulting S&A are set forth below.

I. TERMS OF THE STIPULATED SETTLEMENT AGREEMENT

4. This S&A is entered into for the purpose of determining a reasonable estimate of the Wolf Creek Generating Station decommissioning costs to be used in addressing accrual levels of the respective owner utilities' Decommissioning Trust Accounts.

5. The cost for decommissioning funding is agreed to be $765,060,000 in 2014 dollars as set forth in the Decommissioning Cost Analysis for the Wolf Creek Generating Station filed in this docket on August 29, 2014, which is hereby incorporated by reference. This number will be used by Westar, KCP&L and KEPCo in their respective proposals for setting an accrual level for each company's Decommissioning Trust Account. This will be done in individual company dockets, separate from the instant docket.

6. Westar, KCP&L and KEPCo agree to use an escalation rate of 3.15% per year to escalate the 2014 decommissioning cost estimate of $765,060,000 from 2014 dollars to the appropriate dollar amount in the year that the decommissioning costs will occur.

7. The Parties agree that Wolf Creek, KCP&L, Westar and KEPCo shall jointly file a new decommissioning financing plan that addresses each of the 11 requirements of K.S.A. 66-128m(b) by September 1, 2017; however, just as the review process is currently split into two phases – a joint phase for the decommissioning cost study and the escalation factor, and a utility-specific phase for the individual utility financing plans – the utilities may determine to file certain of the requirements separately at the time of the joint filing so long as all 11 requirements are covered.

8. The Parties agree that further discussion is necessary regarding the other issues raised by Staff[5] and will continue to discuss those issues in this docket. CURB, while not a

[5] *See* Direct Testimony of Leo M. Haynos, filed Jan. 5, 2015, p. 12, lines 8-23.

signatory, has indicated its support of such discussions. The Parties believe that a resolution can be achieved and suggest the following schedule be adopted by the Commission:

On or before February 15, 2016 – The Parties will report to the Commission as to the status of discussions to resolve the separate issues under this docket.

On or before September 1, 2016 – The Parties will file a resolution with the Commission for approval; or, in the event the Parties' reach an impasse after good faith efforts to reach consensus on a resolution to the separate issues, the Parties shall file a report with the Commission within 30 days of determining such impasse but no later than October 31, 2016.

9. In support of the S&A, the Parties pre-filed the testimony and schedules of the following witnesses:

- Direct Testimony of Gregg Clizer for Wolf Creek, KCP&L, Westar and KEPCo.
- Direct Testimony and Testimony in Support of Settlement of Leo Haynos for Staff.
- Direct Testimony of Adam Gatewood for Staff.
- Testimony in Support of Settlement of Mary Britt Turner for Wolf Creek, KCP&L, Westar and KEPCo.

The Application also included the 2014 Decommissioning Cost Analysis performed by TLG Services, Inc., which cost study is the primary subject of this docket.

II. RESERVATIONS

10. Except as specified in this S&A, none of the Parties to the agreement shall be deemed to have approved or acquiesced in any question of the Commission authority,

IN WITNESS HERETO, the Parties have executed and approved this S&A effective by subscribing their signatures below.

Respectfully submitted,

/s/ David Springe

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Enclosure V to WM 19-0008

Order Approving Unanimous Settlement Agreement (Docket No. 18-KCPE-480-RTS)
(34 pages)

**THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners: Shari Feist Albrecht, Chair
Jay Scott Emler
Dwight D. Keen

In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.	))))	Docket No. 18-KCPE-480-RTS

ORDER APPROVING UNANIMOUS SETTLEMENT AGREEMENT

This matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision. Having reviewed the pleadings and record, the Commission makes the following findings:

1. On May 1, 2018, Kansas City Power & Light Company (KCP&L) filed for a $32.9 million revenue increase, including property tax rebasing.[1] As a result of the Commission's approval of the merger of KCP&L's parent company, Great Plains Energy, Inc. with Westar Energy, Inc., on May 24, 2018 (the merger), KCP&L reduced its requested revenue increase to $22.6 million.[2] This Application was accompanied by the direct testimony from 14 witnesses.

2. On June 26, 2018, Darrin Ives, Vice President – Regulatory Affairs for KCP&L, filed supplemental direct testimony to reflect the Commission's approval of the merger and reduced. KCP&L's requested revenue requirement, including property tax rebasing, from $32,948,941 to $22,673,415.[3]

3. The Commission has jurisdiction to supervise and control electric public utilities, as defined in K.S.A. 66-101a, doing business in Kansas.[4] The Commission has the power to

[1] Application, May 1, 2018, ¶ 3.
[2] Supplemental Direct Testimony of Darrin R. Ives, June 26, 2018, p 2.
[3] *Id.*
[4] K.S.A. 66-101.

require all electric utilities governed by the Electric Public Utilities Act to establish and maintain just and reasonable rates.[5]

4. Notice of the proposed rate increase, public hearing, and evidentiary hearing was provided by mail for each customer in KCP&L's service territory as well as by publishing notice in the major newspapers in the region. The Commission received comments from the public at the August 23, 2018 public hearing in Overland Park. The Commission also received 876 public comments through its Office of Public Affairs and Consumer Protection.[6] The Commission issues this Order with due consideration of those comments.

5. The Citizens' Utility Ratepayer Board (CURB); Wal-Mart Stores, Inc. (Walmart); Midwest Division - OPRMC, LLC d/b/a Overland Park Regional Medical Center (OPRMC); Kansas Gas Service; American Fuel & Petrochemical Manufacturers (AFPM); Magellan Pipeline Company, L.P. (Magellan); Petroleum Marketers and Convenience Association of Kansas, Inc. (PMCA); Olathe Public Schools USD 233; Johnson County Community College; Spring Hill School District USD 230; and Blue Valley Schools – Unified School District No. 229 were granted intervention.

6. On September 12, 2018, David Banks filed direct testimony on behalf of Olathe Public Schools USD 233; Johnson County Community College; Spring Hill School District USD 230; and Blue Valley Schools – Unified School District No. 229 (the Schools). After opining that schools are paying inordinately high rates for electric service, Banks advocated for a separate schools tariff for educational institutions to take service as a separate customer class.[7]

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[5] K.S.A. 66-101b.
[6] The public comments were entered into the record by the Notice of Filing of Public Comments on October 23, 2018.
[7] Direct Testimony of David W. Banks, Sept. 12, 2018, p. 13.

7. Also, on September 12, 2018, Paul Raab filed direct testimony on behalf of Kansas Gas Service; Steve Chriss filed direct testimony on behalf of Walmart; Andrea C. Crane, Brian Kalcic, and Stacey Harden filed testimony on behalf of CURB; and Tim Stringer, Justin Grady, William Baldry, Adam Gatewood, Roxie McCullar, Justin Prentiss, Darren Prince, Brad Hutton, Joshua Frantz, Chad Unrein, Andria Jackson, and Dr. Robert Glass filed direct testimony on behalf of Commission Staff (Staff).

8. On September 19, 2018, Raab, Kalcic, and Chriss filed cross-answering testimony.

9. On October 3, 2018, Albert Bass, Jr., Charles Caisley, Brian File, Jeffrey Fleenor, Melissa Hardesty, Darrin Ives, Ronald Klote, Bradley Lutz, Marisol Miller, Linda Nunn, Tim Rush, Thomas Sullivan, Dane Watson, and Kimberly Winslow filed rebuttal testimony on behalf of KCP&L.

10. On October 15, 2018, Staff, CURB, KCP&L, Walmart, OPRMC, the Schools, AFPM, Magellan, PMCA, and Kansas Gas Service (the Signatories) filed a Joint Motion for Approval of Unanimous Settlement Agreement. The Unanimous Settlement Agreement (Unanimous Settlement Agreement), is attached as Attachment A and incorporated by reference.

11. The Signatories agree that the Unanimous Settlement Agreement resolves all revenue requirement issues in this Docket.[8] Under the terms of the Unanimous Settlement Agreement, KCP&L will experience an overall annual revenue requirement decrease of $10.7 million, before the Property Tax Surcharge (PTS) rebasing. The $10.7 million includes $7.5 million of merger savings, as required by the Settlement in the 18-KCPE-095-MER Docket. Including the PTS, under the Unanimous Settlement Agreement, KCP&L's revenue requirement decreases by $3,916,417.[9]

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[8] Unanimous Settlement Agreement, Oct. 15, 2018, ¶ 12.
[9] *Id.*, ¶ 7.

12. Other key terms included in the Unanimous Settlement Agreement are:

- KCP&L will distribute a one-time bill credit of $36,915,958 for tax savings related to the period of January 1, 2018, through December 27, 2018, to customers with the first billing cycle that starts 60 days after this Order;[10]
- KCP&L's approved ROE will be 9.3%, resulting in an overall rate of return of 7.07% and a capital structure with a 50.91%-49.09% debt-equity ratio.[11]
- KCP&L will create a regulatory liability to capture the Kansas jurisdictional amount of depreciation expense included in KCP&L's revenue requirement beginning with the retirement of the Montrose units to accumulate in the regulatory liability account until new customer rates are established in KCP&L's next KCP&L general rate case.[12]
- KCP&L's Kansas jurisdictional, non-transmission related property tax expense in base rates is $46,558,678.[13]
- The Residential Customer charge increases from $14.00 to $14.25.[14]
- The Signatories will ask the Commission to initiate a general investigation to evaluate whether KCP&L should implement a school tariff.[15]
- KCP&L will collaborate with Staff and Walmart to explore alternative rate designs for commercial customers, focusing on more transparent and simple demand/energy rates.[16]

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[10] *Id.*, ¶ 9.
[11] *Id.*, ¶ 8.
[12] *Id.*, ¶ 12.
[13] *Id.*, ¶ 19.
[14] *Id.*, ¶ 22; *see also* Direct Testimony of Robert H. Glass, Sept. 12, 2018, p. 14..
[15] Unanimous Settlement Agreement,¶ 34.
[16] *Id.*, ¶ 35.

- The Signatories agree that the Unanimous Settlement Agreement resolves all revenue allocation, class cost of service and rate design issues under this Docket.[17]

13. On October 15, 2018, Andrea Crane (CURB), Darrin Ives (KCP&L), David Banks (the Schools), and Justin Grady and Dr. Robert Glass (Staff) each filed testimony in support of the Unanimous Settlement Agreement.

14. On October 22, 2018, KCP&L filed an estimate of the rate case expense incurred and expected to be incurred in this Docket, indicating that it had originally anticipated $1,603,100 in total rate case expense. However, as a result of the Unanimous Settlement Agreement, KCP&L has lowered its expected total rate case expense to $632,272.[18]

15. On October 24, 2018, the Commission held a hearing on the Unanimous Settlement Agreement. KCP&L, Staff, CURB, Walmart, OPRMC, the Schools, Kansas Gas Service, and AFPM, Magellan, and PMCA appeared by counsel. KCP&L, Kansas Gas Service, the Schools, and Staff made opening statements. The Commission heard live testimony from 4 witnesses: Ives (KCP&L), Banks (the Schools), and Grady and Glass (Staff).

16. The law generally favors compromise and settlement of disputes between parties when they enter into an agreement knowingly and in good faith to settle the dispute.[19] When approving a settlement, the Commission must make an independent finding that the settlement is supported by substantial competent evidence in the record as a whole, establishes just and reasonable rates, and is in the public interest.[20]

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[17] *Id.*, ¶ 36.
[18] KCP&L Rate Case Expense Filing, Oct. 22, 2018, p. 2.
[19] *Krantz v. Univ. of Kansas*, 271 Kan. 234, 241-42 (2001).
[20] *Citizens' Util. Ratepayer Bd. v. Kansas Corp. Comm'n*, 28 Kan. App. 2d 313, 316 (2000), *rev denied* March 20, 2001.

17. The Unanimous Settlement Agreement is a "Unanimous settlement agreement" as defined by K.A.R. 82-1-230a. Therefore, there is no need to apply the five-factor test.[21]

18. Substantial competent evidence possesses something of substance and relevant consequence, which furnishes a substantial basis of fact to reasonably resolve the issues.[22] Whether another trier of fact could have reached a different conclusion given the same facts is irrelevant; a court can only find that a Commission decision is not supported by substantial competent evidence when the evidence shows "the [Commission's] determination is so wide of the mark as to be outside the realm of fair debate."[23] The Commission has reviewed the record in this Docket that consists of pre-filed testimony from a total of 34 witnesses, including 15 on behalf of KCP&L, live testimony of 4 witnesses, and the Joint Motion for Approval of Unanimous Settlement Agreement, supported by testimony from Andrea Crane (CURB), Darrin Ives (KCP&L), David Banks (the Schools), and Justin Grady and Dr. Robert Glass (Staff).

19. Having reviewed the record as a whole, the Commission finds and concludes that substantial competent evidence supports approval of the Unanimous Settlement Agreement in its entirety. Every electric public utility in Kansas is required to provide reasonably efficient and sufficient service and establish just and reasonable rates.[24] Under Kansas Supreme Court precedent, rates must fall within a "zone of reasonableness" which balances the interests of investors versus ratepayers, present versus future ratepayers, and the public interest.[25] The Signatories agree the Unanimous Settlement Agreement results in just and reasonable rates.[26] Accordingly, we find the

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[21] *See* Order Approving Contested Settlement Agreement, ¶¶ 9-10 (280 Order), Docket No. 08-ATMG-280-RTS (May 12, 2008).
[22] *Farmland Indus., Inc. v. Kansas Corp. Comm'n*, 25 Kan.App.2d 849, 852 (1999).
[23] *Id.* at 851.
[24] K.S.A. 66-101b.
[25] *Kansas Gas*, 239 Kan. 483, 488 (1986).
[26] Testimony in Support of Unanimous Settlement Agreement of Andrea C. Crane, Oct. 15, 2018, ¶ 12; Testimony in Support of Unanimous Settlement Agreement of Darrin R. Ives, Oct. 15, 2018, ¶ 12; Testimony in Support of Unanimous Settlement Agreement of Justin T. Grady, Oct. 15, 2018, ¶ 11.

Unanimous Settlement Agreement fairly represents a balance of the interests of the Signatories, reaches a reasonable result that is supported by the evidence, and is in the public interest.

20. The requirement of just and reasonable rates incorporates the "zone of reasonableness" test, and is used to determine whether the rate is within an elusive range of reasonableness in calculating a fair rate of return.[27] The Commission acts within its discretion in finding an "in-between point, where the rate is most fair to the utility and its customers."[28] The Commission considered the competing interests it must take into account in setting rates, and finds the agreed upon revenue requirement under the Unanimous Settlement Agreement falls within the "zone of reasonableness." There is substantial evidence in the record that the agreed-upon rates will provide KCP&L with sufficient revenues and cash flows to meet its financial obligations, yet will keep rates as low as possible while maintaining reliable service for its customers. Accordingly, the Commission finds and concludes that the approval of the Unanimous Settlement Agreement will result in just and reasonable rates for KCP&L and its customers.

21. The Commission finds that approval of the Unanimous Settlement Agreement is in the public interest. The Signatories agree the terms of the Unanimous Settlement Agreement are in the public interest and should be approved by the Commission.[29] The Signatories explain that the terms of the Unanimous Settlement Agreement represent an equitable balancing of the interests of all Signatories.[30] Furthermore, the public interest is served by minimizing the cost of litigation, and passing those cost savings on to ratepayers.[31]

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[27] *Kansas Gas*, 239 Kan. at 490.
[28] *Id.*
[29] Testimony in Support of Unanimous Settlement Agreement of Andrea C. Crane, ¶¶ 12-13; Testimony in Support of Unanimous Settlement Agreement of Darrin R. Ives, ¶ 13; Testimony in Support of Unanimous Settlement Agreement of Justin T. Grady, ¶ 13.
[30] Testimony in Support of Unanimous Settlement Agreement of Andrea C. Crane, ¶ 11; Testimony in Support of Unanimous Settlement Agreement of Darrin R. Ives, ¶ 13; Testimony in Support of Unanimous Settlement Agreement of Justin T. Grady, ¶¶ 13-14.
[31] *See* Testimony in Support of Unanimous Settlement Agreement of Justin T. Grady, ¶ 15.

22. The Commission finds that the agreed-upon rates under the Unanimous Settlement Agreement will provide KCP&L with sufficient revenue to meet its financial obligations and provide safe and reliable service at just and reasonable rates to its customers. After considering all of the terms of the Unanimous Settlement Agreement, the Commission finds and concludes that it is in the public interest. The Unanimous Settlement Agreement is a balanced agreement that is fair to all affected parties. Therefore, the Commission finds the proposed rate design is fair and reasonable, and is in the public interest.

23. After a careful review and consideration of the evidence in the record, the Commission finds that the attached Unanimous Settlement Agreement is supported by substantial competent evidence in the record as a whole, will result in just and reasonable rates, and is in the public interest. The Commission approves the Unanimous Settlement Agreement in its entirety.

24. The new rates and tariffs will be effective December 20, 2018.

25. As part of the Unanimous Settlement Agreement, the Signatories requested a general investigation docket to evaluate whether KCP&L should establish a separate tariff or tariffs for schools. The Signatories anticipated the initiation of this general investigation docket by July 1, 2019. The Commission agrees that such a general investigation is appropriate. Accordingly, the Commission directs KCP&L and the Schools to file comments in this docket delineating the scope of the general investigation into a possible school tariff by February 5, 2019. Those comments should be limited to 12 pages. Staff is directed to file a Report and Recommendation based on those comments by March 18, 2019.

THEREFORE, THE COMMISSION ORDERS:

A. The Unanimous Settlement Agreement is approved in its entirety. The terms of the attached Unanimous Settlement Agreement are incorporated into this Order.

B. KCP&L's Kansas jurisdictional, non-transmission related property tax expense in base rates is $46,558,678 and shall be the basis for property tax balance used for purposes of future PTS filings when the new rates take effect on December 20, 2018.

C. The $10.7 million overall revenue requirement decrease as provided under the Unanimous Settlement Agreement is approved. After rebasing amounts previously recovered through KCP&L's Property Tax Surcharge, the Commission approves a total revenue decrease of $3,916,417.

D. KCP&L and the Schools are each directed to file comments suggesting the scope of a general investigation into a possible school tariff. Those comments are due by February 5, 2019, and should be limited to 12 pages. Staff is directed to file a Report and Recommendation based on those comments by March 18, 2019.

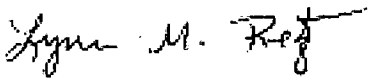
E. Any party may file and serve a petition for reconsideration pursuant to the requirements and time limits established by K.S.A. 77-529(a)(1).[32]

F. The Commission retains jurisdiction over the subject matter and parties to enter further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Albrecht, Chair; Emler, Commissioner; Keen, Commissioner

Dated: 12/13/2018



Lynn M. Retz
Secretary to the Commission

BGF

[32] K.S.A. 66-118b; K.S.A. 77-503(c); K.S.A. 77-531(b).

ATTACHMENT A

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in Its Charges for Electric Service.	))))	Docket No. 18-KCPE-480-RTS

UNANIMOUS SETTLEMENT AGREEMENT

As a result of discussions between the parties to this docket, the Staff of the State Corporation Commission of the State of Kansas ("Staff" and "Commission," respectively), Kansas City Power & Light Company ("KCP&L" or "the Company"), the Citizens' Utility Ratepayer Board ("CURB"), Walmart, Inc. ("Walmart"), Midwest Division – OPRMC, LLC d/b/a Overland Park Regional Medical Center ("OPRMC"), Olathe Unified School District 233 ("USD 233"), Spring Hill Unified School District 230 ("USD 230"), Blue Valley Unified School District 229 ("USD 229"), and Johnson County Community College ("JCCC"), (referred together as "Schools"),[1] Kansas Gas Service, Inc., a division of ONE Gas, Inc. ("KGS"), and American Fuel & Petrochemical Manufacturers ("AFPM"), Magellan Pipeline Company, L.P. ("Magellan"), and Petroleum Marketers and Convenience Association of Kansas, Inc. ("PMCA") (referred to collectively as the "Signatories" or the "Signatory Parties"), hereby submit to the Commission for its consideration and approval the following Unanimous Settlement Agreement ("Settlement"):

I. KCP&L'S APPLICATION

1. On May 1, 2018, KCP&L filed an Application with the Commission to make certain changes in its rates and charges for electric service, which was docketed as the above-

[1] USD 233, USD 230, and USD 229 sign this agreement subject to approval by their respective Boards of Education. These entitities commit to notify the Commission of board approvals as they occur through filings in this docket.

captioned proceeding. The filing was made in accordance with Kansas Statutes Annotated ("K.S.A.") § 66-117, and Kansas Administrative Regulations ("K.A.R.") § 82-1-231(b)(3).

2. The schedules filed with KCP&L's Application indicated a gross revenue requirement deficiency of $26.2 million, excluding the rebasing of property taxes, based upon normalized operating results for the test year ending September 30, 2017, adjusted for known and measurable changes in revenues, operating and maintenance expenses, cost of capital and taxes, and other adjustments explained in the testimony and schedules supporting this Application. The Company's requested increase was $32.9 million with the inclusion of the property tax rebasing.

3. On June 26, 2018, KCP&L filed supplemental testimony incorporating into its Application the terms of the agreement approved by the Commission in Docket No. 18-KCPE-095-MER[2] issued on May 24, 2018 ("18-095 Docket", 18-095 Settlement Agreement", and "18-095 Order").[3] With the 18-095 Settlement Agreement incorporated into KCP&L's position, the revenue requirement deficiency became $15.9 million, excluding property tax rebasing.

4. Staff filed its direct testimony on September 12, 2018, recommending a revenue decrease of approximately $1.2 million, excluding property tax rebasing. CURB filed its direct and cross-answering testimony on September 12, 2018 and September 19, 2018, respectively, recommending a revenue decrease of approximately $12.2 million, excluding property tax rebasing. Staff and CURB also addressed policy and rate design issues. Other intervenors filed direct and cross-answering testimony primarily addressing rate design issues.

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[2] *In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company and Westar energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.*

[3] On Aug. 10, 2018, KCP&L filed the *Corrected Supplemental Direct Testimony of Darrin Ives* to correct a transposed number contained in Mr. Ives' Supplemental Direct testimony.

5. Consistent with the Commission's Procedural Order, KCP&L filed rebuttal testimony on October 3, 2018. The parties held settlement discussions on October 9 - 10, 2018, and reached this Settlement, as described below.

II. TERMS OF SETTLEMENT AGREEMENT

6. The Signatory Parties have agreed to a total revenue requirement amount, revenue allocations, and rate design adjustments, without specifically addressing the underlying issues and disagreements regarding those issues, except as set forth herein. This Settlement resolves all issues in this matter, with such Settlement providing no precedent for future cases as to the underlying issues or positions of the parties on those issues. In the event the Commission either does not approve this Settlement in total, or materially changes the Settlement terms, then the Settlement shall be voidable by any Signatory negatively affected by such modification. The following set forth the terms of this Settlement:

A. Revenue Requirement

7. The Signatory Parties agree that KCP&L's overall annual revenue requirement decrease will be $10.7 million, not including the Property Tax Surcharge ("PTS") rebasing. This amount includes $7.5 million of merger savings, as required under the 18-095 Settlement Agreement. With the PTS included, the revenue requirement decrease is $3,916,417.

(1) ROE, Capital Structure, Cost of Debt

8. The Signatory Parties agree that KCP&L's revenue requirement is based on the cost of capital as follows:

Return on Rate Base				
		A	B	C
		Percent of Capitalization	Component Cost	Weighted Avg. Cost
1	Debt	50.91%	4.93%	2.51%
2	Common Equity	49.09%	9.30%	4.56%
3	**Totals**	**100.00%**		**7.07%**

(2) *Tax Cut and Jobs Act*

9. KCP&L will provide to customers a one-time bill credit of $36,915,958 for tax savings related to the period of January 1, 2018, through December 27, 2018. It will be distributed to customers with the first billing cycle that starts 60 days after the Commission issues its order in this case. KCP&L agrees to sync up the timing of these tax credits with the timing of the merger related up-front bill credits that will be provided pursuant to the Commission's Merger Order and to use the Merger Order processes to determine the tax credit amounts. If the effective date of new rates from this case is different than December 27, 2018, the amount refunded to customers shall be adjusted to reflect the number of days between January 1, 2018, and the effective date of rates from this case using the annual amount of $37,354,878 for such calculation.

10. Amortization expense associated with the excess accumulated deferred income taxes will be recorded by the Company using the following periods:

EXCESS DEFERRED INCOME TAXES ("EDIT") AMORTIZATIONS IN KCP&L-KS REVENUE REQUIREMENT - TOTAL COMPANY AMOUNTS		
EDIT Amount to Amortize	**Years/Amortize**	**Increase / (Decrease) to Tax Expense**
Plant-Protected ($403,638,981)	Average Rate Assumption Method ("ARAM")	$ (10,362,524)
Plant-Unprotected ($130,978,754)	5 yr	$ (26,195,751)
NOL $65,110,179	ARAM	$ 2,187,842

Miscellaneous ($1,205,360)	10 yr	$ (120,536)
	Total	$ (34,490,969)

11. The Signatory Parties agree that EDIT amortization from July 1, 2018 through the effective date of rates will be established in a regulatory liability and will not be recorded to the income statement until the Company addresses the amortization of this deferred regulatory liability in the next KCP&L general rate case filed after the KCP&L 2018 general rate case is completed.

(3) *Depreciation*

12. For settlement purposes only, Staff's depreciation rates will be adopted. Additionally, KCP&L will create a regulatory liability to capture the Kansas jurisdictional amount of depreciation expense included in KCP&L's revenue requirement beginning when the Montrose units are retired and depreciation expense is no longer recorded to the income statement associated with the Montrose units. The depreciation amounts will accumulate in the regulatory liability account until new customer rates are established in the next KCP&L general rate case filed after this 2018 general rate case is completed. At that time, the regulatory liability account will be closed into accumulated depreciation. Additionally, the closing of this regulatory liability into accumulated depreciation will be reflected in rates that are established in that rate case.

(4) *Revenue Adjustments*

13. The Signatories agree that KCP&L's sales revenues and unit sales will be utilized for purposes of setting rates.

14. KCP&L and Staff will work together to resolve normalization data requirement shortfalls noted by Staff in this case. Prior to the filing of the next rate case filing, the data issues will be resolved to the statisfaction of all parties..

(5) *Clean Charge Network*

15. The Signatories agree that the CCN tariff rate schedule proposed by the Company and the rates contained therein shall be adopted. The Settlement does not address inclusion or exclusion in rate base or cost of service of the plant, costs, or expenses related to the CCN. The Settlement does not address recovery of the CCN except for the tariffed rate and therefore any party can assert any position regarding CCN cost recovery in KCP&L's next general rate proceeding after the five year merger moratorium.

(6) *Accounting Adjustments*

16. There will be no change in the Wolf Creek NDT funding level from the amount currently in rates. This does not reflect agreement with any particular method in calculating the appropriate funding level.

17. KCP&L will continue the accounting for Asset Retirement Obligations ("ARO") as adopted in May 2018 for the KCP&L-KS jurisdiction. ARO settlements will reduce the ARO regulatory asset for settlement costs as they are incurred and are recorded to the reserve at the time of payment rather than waiting until the end of the life of the ARO.

18. The CIP/Cybersecurity Tracker as approved in Docket No. 15-KCPE-115-RTS will continue in this case. The base amount of the tracker is set at $4,592,958 (Total Company) for CIP and $933,304 (Total Company) for Cybersecurity.

(7) *Other Issues*

19. The Signatories agree that the Kansas jurisdictional, non-transmission related property tax expense in base rates is $46,558,678 and shall be the basis for property tax balance used for purposes of future PTS filings for the time period the new rates are applicable. This

includes the additional property tax rebase amount of $6,783,583 to be included in base rates in this case.

20. For the purposes of calculating KCP&L's pension tracker going forward, the Signatories agree that the base rates agreed to in this Settlement include the following expenses associated with KCP&L's pension and OPEB plans (amounts provided are total Company):

OPEB Expense:	$1,852,965
Amortization of Tracker 1:	($1,357,860)
Pension Expense:	$45,653,251
Amortization of Tracker 1:	$1,858,774

TRACKER BALANCES AS OF JUNE 30, 2018:

OPEB	Tracker 1	($6,789,299)
	Tracker 2	$0
Pension	Tracker 1	$9,293,870
	Tracker 2	($76,278,533)

21. A list of regulatory assets and liabilities and their associated amortization periods is attached hereto as **Attachment A.**

22. The Signatories agree this Settlement resolves all revenue requirement issues.

B. Allocation of Revenue Requirement Among Customer Classes and Rate Design Matters

(1) Revenue Allocation

23. The Signatories agree to the following revenue decrease allocation among the customer classes:

KANSAS RATE GROUP	Revenue from Existing Rates	Proposed Decrease $	Proposed Decrease %
LARGE GEN SVC TOTAL	$162,402,701	$(1,625,875)	-1.001%
MEDIUM GEN SVC TOTAL	$69,285,911	$(693,648)	-1.001%
SMALL GEN SVC TOTAL	$43,958,196	$(527,498)	-1.200%
RESIDENTIAL TOTAL	$295,423,478	$(1,001,043)	-0.339%
Metered TOTALS	$571,070,286	$(3,848,065)	
Lighting TOTAL:	$6,827,468	$(68,352)	-1.001%
TOTAL	**$577,897,754**	**$(3,916,417)**	**-0.678%**

24. In accepting the allocation of the revenue decrease and resulting rates, the Signatories agree that this Settlement does not indicate any specific class cost of service methodology or approach.

(2) Residential Rate Design

25. The Residential Customer charge shall increase to $14.25. The remaining residential class revenue requirement decrease will be allocated to the energy blocks. The residential rates are as follows:

	Present Rates	Proposed Rates
		-0.684%
CUSTOMER CHARGE (per month)		
One Meter - Rate Code (2RS1A; 2RSDA; 2RS6A; 2RW6A; 2RO1A):	14.00	14.25
Two Meter - Rate Code (2RS2A; 2RS3A; 2RW7A):	14.00	14.25
ENERGY CHARGE (per kWh)		
All rates less Other Use - SUMMER - Rate Code (All less 2RO1A):		
First 1000 kWh per month	0.10751	0.10677
Over 1000 kWh per month	0.10751	0.10677
Other Use - For all kWh - SUMMER - Rate Code (2RO1A):	0.12551	0.12465
General Use - WINTER - Rate Code (2RS1A; 2RSDA):		
First 1000 kWh per month	0.08300	0.08243
Over 1000 kWh per month	0.08300	0.08243
General Use and Space Heat - One Meter - WINTER - Rate Code (2RS6A; 2RW6A):		
First 1000 kWh per month	0.07474	0.07423
Over 1000 kWh per month	0.06524	0.06524
General Use and Space Heat - Two Meter - WINTER - Rate Code (2RS2A; 2RS3A; 2RW7A):		
First 1000 kWh per month	0.07474	0.07423
Over 1000 kWh per month	0.06527	0.06527
Other Use - For all kWh - WINTER - Rate Code (2RO1A):	0.09862	0.09795
Separately Metered Space Heat - Rate Code (2RS2A; 2RS3A; 2RW7A):		
For all kWh - SUMMER	0.10751	0.10677
For all kWh - WINTER	0.06524	0.06524
Time Of Day (Frozen) - Rate Code (2TE1A):		
Customer Charge	20.00	19.86
On-Peak - SUMMER	0.17621	0.17500
Off-Peak - SUMMER	0.07370	0.07320
For all kWh - WINTER	0.07705	0.07652

26. KCP&L will offer the following optional pilot rates as filed: Residential TOU rate and Residential Demand rate. With regard to those pilot rates the Signatories agree that:

a. KCP&L will be permitted to establish a regulatory asset or liability account to track the revenue impact of rate switching for customers switching to either the Residential TOU or Residential Demand rates. Further, customers will be allowed a one-year opt-out option consistent with the rebuttal testimony of KCP&L witness Kimberly Winslow.

b. Marketing and customer education costs associated with these tariffs and the Residential Distributed Generation tariff will be recorded in a regulatory asset account with a budget cap of $2.2 million (Kansas jurisdiction). KCP&L will track and may seek recovery of these costs

during KCP&L's next general rate case. KCP&L will collaborate with Staff with regard to marketing and education efforts, thereby providing Staff with the opportunity to provide input on the reasonableness of those efforts and expenditures in advance of proceeding. As part of this effort, KCP&L will provide detailed, line item budgets for expenses incurred in marketing and education efforts. Staff may request additional information related to these or any other expenses associated with marketing and customer education costs. In the event Staff disagrees with the level of expenditures, KCP&L shall have the right to argue the prudency of those expeditures during the next general rate proceeding.

27. With regard to Residential Distributed Generation, the Signatories agree to the following:

a. Adopt a three-part rate with modifications proposed by Staff witness Bob Glass:

(i) the summer and winter demand charges shall be $9.00/kW and $3.00/kW, respectively;

(ii) the customer charge shall be $14.25 (equal to Residential Customer Charge for general use);

(iii) the energy charge shall be $0.07688 energy charge per kWh; and

(iv) the demand measurement shall be a 60-minute interval.

(v) The demand billing period shall be the daily hours of 2:00 pm through 7:00 pm Central Time, except for weekends,

New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

b. The Company will report annually to Staff and CURB the following information for the Residential Distributed Generation rate:

(i) number of residential DG customers taking service from the rate,

(ii) the total demand and energy charges paid during the year,

(iii) annual energy consumption data by customer, and

(iv) annual total bill amounts (less riders) by customer.

This same information will be provided annually regarding the Residential TOU rate and the Residential Demand rates.

(3) *Non-Residential Rate Design*

28. The Signatories agree that the rate design for the Non-Residential decrease, established in the Revenue Requirement section above, will be applied in the following manner.

a. Small General Service

(i) Decrease all components equally based on class revenue allocation

b. Medium & Large General Service

(i) A reduction to all energy charges by 2%

(ii) Increase the remaining non-energy bill components on an equal percentage basis to achieve the class revenue reduction.

c. Lighting

(i) Decrease all components equally to all non-LED lighting rates based on class revenue allocation.

29. The Signatories agree to KCP&L's LGS Off-Peak rider as proposed with revisions as presented by KCP&L witness Miller in rebuttal testimony.

(4) *LED Lighting*

30. The Signatories accept Staff's recommendation to approve KCP&L's plan and related pricing for street and private area lighting with price modifications and regulatory accounting treatment for revenues and costs as proposed by Staff witness Ellis.

(5) Programs

31. With regard to the Solar Subscription Program the Signatories agree as follows:

a. KCP&L shall be authorized to pursue a build option or Power Purchase Agreement ("PPA") for solar resources.

b. KCP&L's selection of either a build option or PPA for solar resources will be based on least cost to customers.

c. The revenue requirement for inclusion in rates for a Company-owned solar built project will be levelized over the life of the project if the cost of the solar resource exceeds $10 million. For projects under this amount, parties reserve their ability to address the methodology for inclusion in KCP&L's revenue requirement at the time the solar resource is included in a future general rate proceeding.

d. KCP&L will not build or enter into a PPA for a solar project until the project is 75% subscribed, and the cost of any unsubscribed portion will

be borne 75% by KCP&L and 25% by customers. The 25% borne by customers will be reflected in the ECA.

32. With regard to the Renewable Energy Rider the Signatories agree as follows:

a. The Signatories agree to KCP&L's redesigned tariff and related provisions as described in the rebuttal testimony of KCP&L witness Brad Lutz, which provides for:

(i) Accommodation of the revisions below recommended by Walmart Witness Steve Chriss.

1. Revision of the process to first enroll customers for a resource tranche of the program to be apportioned on an allocation of the available resource based on expressed interest.

2. Inclusion of a renewal provision that gives the participating customer the option to renew its participation prior to offering that capacity to other customers.

3. Use of enrollment agreements with twenty-year terms. Lesser terms of five-year, ten-year, and fifteen-years will be allowed at a cost premium to the twenty-year rate.

4. Inclusion of more flexible transfer terms as noted in Paragraph 4 of the Definitions and Conditions

section of the exemplar tariff in the rebuttal testimony of Brad Lutz.

(ii) The redesigned tariff shall:

1. Be consistent with the Westar DRPS tariff.

2. Use separate Participation Agreements.

3. Allow for smaller participation limits.

a. Requiring a peak demand of 200 kW and subscription in 200 kW increments up to 1,000 kW and 500 kW increments thereafter.

b. Participation agreement will include provisions allowing Schools, municipalities, and goverments to aggregate accounts to meet participation limits.

4. Include a KCP&L commitment to make a subsequent tariff filing to establish the renewable resource, term, and price. KCP&L will also provide the price premium for shorter term enrollment. Staff and CURB agree to make all reasonable efforts to review and provide a recommendation concerning the filing within the time associated with the PPA offer terms.33.

The Signatories agree to KCP&L's Standby Service Rider as filed.

34. The Signatories agree to the following with regard to the Schools:

a. The Commission should initiate a general investigative docket on or before July 1, 2019, to evaluate whether KCP&L should implement one or more School tariffs and how such a tariff(s) should be designed and

implemented. If the investigation results in the implementation of School tariffs that are not revenue neutral to KCP&L, then a regulatory asset/liability will be created to allow KCP&L recovery of those revenues and associated deferred return at the weighted-average cost of capital at the time of the next general rate proceeding following the rate moratorium period resulting from the Merger.

b. While KCP&L has the ability to dedicate in-house personnel to the study of the school tariff issue, the Signatories understand that investigative proceedings often become more expansive than originally anticipated, resulting in the necessity for engagement of outside technical and legal consultants. As such, KCP&L shall be allowed the opportunity to seek a regulatory asset to recover those costs relating to the engagement of outside consultants resulting from the investigation, should such engagement become necessary.

c. If KCP&L implements one or more School tariffs, KCP&L agrees to separately identify Schools tariff customers in the class cost of service study filed in its next rate case. However, during the investigation contemplated in paragraph 33.a., the parties may explore alternative methods of providing transparency regarding School rates and may agree to modify or eliminate the requirement to identify School tariff customers in the Company's class cost of service study.

d. KCP&L agrees to assign key account representatives to assist the Schools in evalutating usage characteristics to determine the appropriate rate

schedules for each of the respective Schools' accounts and to discuss other rate opportunities such as the renewable energy rider. Key account representatives will be promptly assigned and will contact each of the Schools no later than 30 days following a final order approving this agreement.

35. KCP&L will collaborate with Walmart and Staff during the moratorium period on rate design issues for the purpose of exploring alternative rate designs for non-residential, non-lighting, rate classes. Specifically, KCP&L will review demand/energy rates and rates that may offer more transparency and simplicity.

36. The Signatories agree this Settlement resolves all revenue allocation, class cost of service and rate design issues.

C. <u>Modification to the Procedural Schedule.</u>

37. Due to the presentation of this Settlement that resolves all contested issues, the Signatories recommend to the Commission the following:

(1) The prehearing conference scheduled for October 15, 2018, the evidentiary hearings scheduled for October 23-26, 2018, and post-hearing briefing of this matter be cancelled.

(2) The prefiled testimony submitted in this case, including testimony filed in support of this Settlement Agreement on October 15, 2018, be entered into the record of this docket.

(3) The Commission issue its decision based upon the written record.

(4) If the Commission prefers to hold a hearing on this Settlement Agreement, the Commission convert the October 23, 2018 evidentiary hearing date to a hearing on the Settlement Agreement.

III. MISCELLANEOUS PROVISIONS

A. The Commission's Rights

38. Nothing in this Settlement is intended to impinge or restrict, in any manner, the exercise by the Commission of any statutory right, including the right of access to information, and any statutory obligation, including the obligation to ensure that KCP&L is providing efficient and sufficient service at just and reasonable rates.

B. Waiver of Cross-Examination

39. In the event the Commission conducts a hearing, the Signatory Parties waive cross-examination on all testimony filed prior to the filing of this Settlement Agreement.

C. Negotiated Settlement

40. This Settlement represents a negotiated settlement that fully resolves the issues raised in this proceeding. The Signatory Parties represent that the terms of this Settlement constitute a fair and reasonable resolution of the issues addressed herein. Except as specified herein, the Signatory Parties shall not be prejudiced, bound by, or in any way affected by the terms of this Settlement (a) in any future proceeding; (b) in any proceeding currently pending under a separate docket; and/or (c) in this proceeding should the Commission decide to not approve this Settlement in the instant proceeding. If the Commission accepts this Settlement Agreement in its entirety and incorporates the same into a formal order without material modification, the Signatory Parties shall be bound by its terms and the Commission's order

incorporating its terms as to all issues addressed herein and in accordance with the terms hereof, and will not appeal the Commission's order on these issues.

D. Interdependent Provisions

41. The provisions of this Settlement have resulted from negotiations among the Signatory Parties and are interdependent. In the event that the Commission does not approve and adopt the terms of this Settlement in total or materially changes the Settlement terms, the Settlement shall be voidable and no Signatory Party hereto shall be bound, prejudiced, or in any way affected by any of the agreements or provisions hereof. Further, in the event the Commission does not approve and adopt the terms of this Settlement in total, this Settlement shall be considered privileged and not admissible in evidence or made a part of the record in any proceeding. In the event of a termination pursuant to this Section, the Settlement shall be null and void and of no further effect, with all rights, duties, and obligations of the Signatory Parties thereafter restored as if this Settlement had never been executed; provided, that the Signatory Parties may, in the sole discretion of each Party, agree to attempt to modify the Settlement in a manner that would resolve the adverse effect of the material change of condition.

IN WITNESS THEREOF, the Signatory Parties have executed and approved this Settlement Agreement, effective as of the 12th day of October 2018, by subscribing their signatures below.

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KCPL-KS Regulatory Assets & Liabilities Amortization Schedule (Docket No. 18-KCPE-480-RTS)

Account	Description	Adjustment #	Vintage	Original Balance	Amortization Period	Amortization Begin	Amortization End	Annual Amortization Amount	Per Rate Case Unamortized Balance at 12/31/2018
182329	Iatan 1 and Common	RB-25, CS-111	1	2,855,631	47	Dec-10	Nov-57	60,758	2,364,503
			2	631,250	44.9	Jan-13	Nov-57	14,059	546,896
									2,911,399
182515	2011 Flood Expense	CS-110		924,928	10	Jan-13	Dec-22	92,493	369,971
182543	Customer Migration	CS-130		191,125	5	Dec-18	Nov-23	38,225	191,125
182546	La Cygne Depreciation Deferral	RB-27, CS-113		2,957,141	25	Oct-15	Sep-40	118,286	2,572,713
182556	Rate Case Expense	CS-80		203,212	5	Dec-18	Nov-23	40,642	203,212
TBD	Merger Transition Costs	CS-95		7,692,018	10	Dec-18	Nov-28	769,202	7,692,018
254000	Emission Allowance	RB-55		(36,987,232)	22	Dec-10	Nov-32	(1,681,238)	(23,375,664)
254555	Wolf Creek Budgeted Plant	CS-133		(83,350)	5	Dec-18	Nov-23	(16,670)	(83,350)
254556	LaCygne Budgeted Plant	CS-131		(1,985,865)	5	Dec-18	Nov-23	(397,173)	(1,985,865)
254556	LaCygne Depreciation Deferral	CS-132		(11,666)	5	Dec-18	Nov-23	(2,333)	(11,666)
254665	CIP - Cyber Tracker	CS-88	1	(2,182,363)	5	Dec-18	Nov-23	(436,473)	(2,182,363)

CERTIFICATE OF SERVICE

18-KCPE-480-RTS

I, the undersigned, certify that the true copy of the attached Order has been served to the following parties by means of electronic service on 12/13/2018.

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CERTIFICATE OF SERVICE

18-KCPE-480-RTS

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18-KCPE-480-RTS

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BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service.	)))))	Docket No. 15-WSEE-115-RTS

DIRECT TESTIMONY

PREPARED BY

Adam H. Gatewood

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION

JULY 9, 2015

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Introduction

Q Would you please state your name and business address?

A My name is Adam H. Gatewood. My business address is 1500 Southwest Arrowhead Road, Topeka, Kansas, 66604.

Q Who is your employer and what is your title?

A I am employed in the Utilities Division of the Kansas Corporation Commission as a Managing Financial Analyst.

Q What is your educational and professional background?

A I graduated from Washburn University with a B.A. in Economics and a Masters of Business Administration. I have filed testimony before the Commission in more than 100 proceedings. I have also filed testimony before the Federal Energy Regulatory Commission.

Q What is the purpose of your testimony?

A My testimony addresses the appropriate rate of return (ROR) for Westar Energy (Westar or WR). I also address Westar's annual funding level of its Wolf Creek

1 Decommissioning Trust Fund and the related testimony filed by Susan North.

2 **Executive Summary**

3 **Q Please Summarize Westar's requested ROR?**

4 A Westar is requesting a 7.99% rate of return that consists of the components in the

5 following table:

Westar Energy Rate of Return Proposed Rate of Return in Section 7 of Application Test Year Ended September 30, 2014 Updated to December 31, 2014			
	Weight	Cost	Weighted Cost
Long-term Debt	46.25%	5.69%	2.63%
Common Equity	53.12%	10.00%	5.31%
Post 1970 ITC	0.63%	7.99%	0.05%
			7.99%
Sources: Section 7			

6

7 **Q Please summarize your response to Westar's Application.**

8 A I do not agree with Westar's proposed return on equity capital. Westar is

9 requesting a 10.00% return for its shareholders; my analysis determined that a

10 9.25% return for shareholders is appropriate in the current capital markets.

11 Regarding the issue of Westar's annual funding of its Decommissioning Trust, I

12 recommend Westar increase its annual accrual from $3,150,000 to $5,772,700.

13 This change is accounted for in Adjustment IS-4 of Staff Schedules.

14 **Q. Please Summarize Staff's proposed range of return on equity (ROE) and rate**

15 **of return (ROR).**

16 A. As shown in the following table, Staff is proposing that the Commission set

17 Westar's ROE in a range of 9.00% to 9.50%. Staff has set a 50 basis point range

1 and recommends an ROR of 7.59% and an ROE of 9.25%, which is the mid-point
2 of Staff's range.

Range of Staff Proposed Rate of Return Assuming Staff's Proposed Capital Structure			
Return on Equity	9.00%	**9.25%**	9.50%
Rate of Return	7.46%	**7.59%**	7.72%

3

4 **Q Please summarize why you believe 9.25% is a reasonable ROE.**

5 A I have completed an analysis of Westar's capital costs using traditional financial
6 models and applying the Hope and Bluefield benchmarks. My analysis
7 demonstrates that capital costs have declined since the Commission set Westar's
8 allowed ROE at 10.00% by the Commission in Docket No. 05-WSEE-981-RTS.

9 As I discussed in Docket 15-KCPE-116-RTS (15-116 Docket), I am also applying
10 a degree of gradualism or moderation in that I do not recommend a reduction in
11 the ROE that reflects the full extent of the decline in capital costs. I apply a
12 degree gradualism by recommending Westar's ROE be set in the range of 9.00%
13 to 9.50%. I am setting only a 50 basis point range – as opposed to the 100 basis
14 point range that I typically use – primarily because I believe 9.00% is appropriate
15 as the low-end of my range.

16 **Q What is the dollar amount of the difference in ROE positions?**

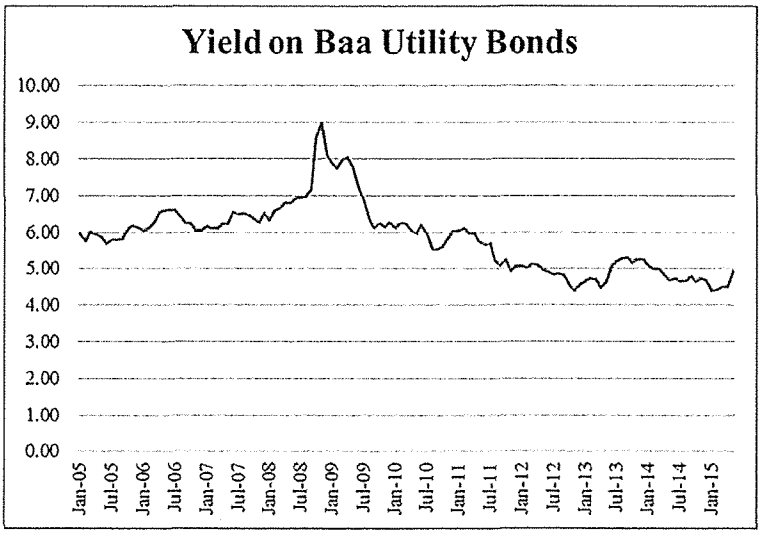
17 A Using Staff's capital structure and cost of debt, a 10 basis point change in the
18 allowed ROE results in about a $4.4 million change in Staff's revenue
19 requirement for Westar. This relationship is an approximation and assumes

1 Staff's proposed rate base shown in Staff Schedule REV REQ.

2 **Q. Why should gradualism be considered in this case.**

3 A. I am applying the same principle of gradualism to Westar as I did in my
4 recommendation for KCPL filed on May 11th in the 15-116 Docket. As I
5 discussed in that Docket, I have never recommended gradualism before and only
6 do in these two Dockets because I believe that a 9.00% lower bound for the ROE
7 is appropriate due to three factors. First, Westar's embedded debt costs have
8 declined from 6.25% to 5.69% since the Order in Docket 05-WSEE-981-RTS was
9 issued in December of 2005, Westar's last fully litigated rate case. Capital costs
10 measured by the yield on investment grade utility bonds have also declined. As
11 shown in the following table, the prevailing yield on public utility bonds declined
12 from the 5.80% - 6.00% range in 2005 to 4.50% - 4.91% range in 2015. Over this
13 time period, the yield on Baa utility bonds has declined by 135 basis points (5.93
14 – 4.58 = 1.35). A longer historical perspective of yields on public utility bonds is
15 shown in Schedule AHG-1 which contains a chart and the underlying data of
16 monthly observations of yields on "A" and "Baa" rated utility bonds from 1919
17 through 2015 reported by Moody's Investor Services.

Yield on Baa Utility Bonds	
Jan-05	5.95
Feb-05	5.76
Mar-05	6.00
Apr-05	5.95
May-05	5.88
Jun-05	5.70
Jul-05	5.80
Aug-05	5.80
Sep-05	5.83
Oct-05	6.08
Nov-05	6.19
Dec-05	6.14
Jan-06	6.06
Average	5.93
Nov-14	4.75
Dec-14	4.70
Jan-15	4.39
Feb-15	4.44
Mar-15	4.51
Apr-15	4.51
May-15	4.91
Average	4.58
Source: Moody's	



Second, a 9.25% ROE provides a 500 basis point spread over the current market cost of Westar's long-term debt. I observed recent trades of Westar bonds. Those

trades are in the range of 3.98% to 4.36% during the months of May and June of 2015.[1]

Third, and last of all, just as I stated in my 15-116 Docket testimony, authorized ROEs below 10.00% are a fairly recent development. Before recommending an ROE below 9.00%, I believe it is prudent to wait to see if the current capital market conditions continue.

Q Since 2005, the time of Westar's last litigated rate case, what has been the trend in allowed returns?

A For 2005, the average allowed ROE granted to electric utilities was 10.54%. For the first quarter of 2015, that average was 10.37%. It is important to note that the recent average includes four observations from Virginia that are "asset specific" determinations which appear to include some level of incentive or premium that distinguish them from the traditional rate case proceeding that we have before us. Without those four cases, the average for this time period is 9.67%. Attached as Schedule AHG-2 are Regulatory Research Reports: Major Rate Case Decisions publications for 2014 and the first quarter of 2015.

Q You recently filed testimony in the 15-116 Docket recommending a 9.25% ROE for Kansas City Power & Light (KCP&L). Is your recommendation for Westar based on your analysis of KCP&L in that Docket?

A No. My recommendation in this Docket is based on my analysis of Westar and the required return necessary for Westar to attract capital. The 15-116 Docket and

[1] Based on the lowest and highest yields to maturity reported by FINRA for Westar debt series 4.625% due 2043; 4.10% due 2043; and 4.125% due 2042 in the months of May and June of 2015.

this Docket are occurring at essentially the same time. These two electric utilities risk profiles are similar with nearly identical credit ratings by the major rating agencies. As a result of these Dockets occurring in the same capital markets environment and the fact that we are dealing with two electric utilities of nearly identical risk, it is expected that Staff's recommendations would (and should) be the same.

Credit Ratings			
Great Plains Energy	Moody's	S&P	Fitch Ratings
Long-term Rating	Baa2	BBB+	
Outlook	Stable	Stable	
Westar Energy			
Long-term Rating	Baa1	BBB+	BBB
Outlook	Stable	Stable	Positive
Source: SNL.com			

Q. Please summarize Staff's cost of equity estimates.

A. The mid-point of my recommended range of 9.25% recognizes that by most measures capital costs have declined since Westar's last fully litigated rate case in 2005.

Summary of Staff's Cost of Equity Estimates

Discounted Cash Flow Analysis		
Based on the Average of Short-Term Growth Forecasts & Long-Term nGDP Forecasts		
	Mean	8.65%
	Low	8.47%
	High	8.84%
Internal Rate of Return Analysis		
Using Short-Term Growth EPS & Long-Term nGDP Forecast		
	Mean	8.53%
	Low	7.18%
	High	10.01%
Capital Asset Pricing Model		
	Forecasted Data	6.64%
	Historic Data	9.40%
Changes in Bond Yields Since Order in 05-WSEE-981-RTS Docket		
Allowed Return on Equity Granted in 981 Docket		10.00%
Decrease in Yield on Moody's Baa Uility Bonds		1.35%
Staff Recommendation		**9.25%**
Indicated Range	9.00%	9.50%

As you can see from the table, the models, particularly the DCF model that regulators traditionally rely on, indicate that the cost of equity is less than 9.00%, even with the recent decline in the stock prices of electric utilities. At this time, I am not comfortable advocating for an allowed return below 9.00% for a retail electric utility as it has only been three years since allowed returns fell below the 10% threshold. If capital market conditions persist at the current level, I expect we will see challenges to that 9.00% threshold.

Q Please summarize your disagreement with Westar's cost of equity estimates.

A The primary disagreement is that of estimating growth. This is the same

disagreement that the Commission has heard in rate cases during the past three years. This disagreement is not confined to electric utilities; it has occurred—and will likely continue to occur—in electric utilities, natural gas distribution, telephony, electric transmission, and natural gas pipeline utilities as well. The table below summarizes the findings of Westar's cost of equity models and a synopsis of what I believe to be the short comings of each of Westar's models. I will elaborate on each model later in my testimony.

Summary of Westar's Cost of Equity Estimates & Growth Rates

Methodology	Range of Output		Discussion
Single Stage DCF	9.47%	9.52%	Mr. Somma's DCF analysis relies on a single stage DCF using 3 to 5 year forecasts of annual earnings growth rates. For his proxy group the average earnings growth rate is 5.86%.
CAPM	10.86%	11.76%	Mr. Somma's CAPM analysis is based on his assumption that the "market" or S&P500 Index will return 13.25% annually. His analysis assumes that the S&P500 will realize annual earnings growth greater than 11.00%
Risk Premium	10.33%	10.38%	Mr. Somma calculated a risk premium based on the difference between the returns granted by state commissions and the prevailing interest rates

Q. What support do utility executives and equity analysts usually provide when discussing why an ROE should not be lowered below ROE's set for other utilities?

A. Commissions and Commission Staff frequently hear from utility executives and equity analysts regarding their belief that Commissions should refrain from lowering allowed returns below those reported for other utilities because such a decision will impair the utility's access to additional capital. Those pleas are devoid of any statistical or factual support. Furthermore, no utility has ever provided Staff empirical evidence to support its contention that a Commission's decision has impaired its ability to access necessary capital. However, what I

have observed is that Kansas utilities continue to issue long-term debt at attractive rates.

Standards for a Reasonable Rate of Return

Q What is the role of rate of return in setting a revenue requirement for public utilities?

A The rate of return (ROR) earned on the utility's rate base is part of the revenue requirement equation. The ROR is a cost of providing the utility service.

Revenue Requirement = ROR (gross plant – accum. Depr.) + Operating Exp. + Income Taxes

In the revenue requirement formula, the ROR expresses the utility's return on its net plant investment. The utility's ROR is its weighted average cost of the capital. That is, the cost of each of the various forms of capital supplied by investors which includes debt, preferred equity, common equity and any hybrid securities multiplied by their respective weight in the utility's capital structure. The cost or return associated with each of these forms of capital is unique and it is a function of risks associated with that form of capital.

Components of an Allowed Rate of Return					
Debt Capital:	Weighted Average Interest Rate	x	Ratio of Debt Capital	=	Weighted Average Cost of Debt
Equity Capital:	Allowed Return on Equity	x	Ratio of Equity Capital	=	Weighted Average Cost of Equity
					Sum Equals Allowed Rate of Return for the Utility

The cost of debt generally relies on a contractual agreement with the investor,

1 making its cost relatively easy to determine because the cost is explicit within the
2 contract. Likewise, the ratios of the capital components are relatively easy to
3 determine because, under most circumstances, these ratios are traceable to the
4 utility's financial documents. It is the allowed ROE that requires the most time
5 and attention when setting the ROR because it is a cost that we cannot trace back
6 to a contractual agreement. It is best described as a forward looking discount rate
7 and equates to the rate that is necessary to induce equity investors to commit their
8 capital to the enterprise.

9 **Q What standards should commissions apply to making this decision?**

10 A The standards used to gauge the fairness and reasonableness of an allowed ROR
11 were announced by courts as the result of appeals of decisions issued by
12 regulatory agencies. Financial analysts and policy-makers rely on the courts'
13 decisions as a guide in estimating the appropriate cost of capital. The opinions do
14 not articulate precisely how to estimate or model a reasonable cost of capital.
15 Instead, the decisions provide critical questions for policy makers and analysts to
16 consider in determining a reasonable return for a regulated utility.

17 In general, United States Supreme Court decisions state that returns granted to
18 regulated public utilities should: 1) be commensurate with returns on investments
19 of similar risk; 2) be sufficient to assure the financial integrity of the utility under
20 economic management; and 3) change over time with changes in the money
21 market and business conditions.[2] An important take-away from these decisions is

[2] Smyth v. Ames 169 U.S. 466 (1898). Wilcox v. Consolidated Gas Co., 212 U.S. 19, 48-49 (1909).
Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-3 (1923).
Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

1 that the Court has afforded regulatory agencies a significant amount of latitude in
2 establishing what is an appropriate ROR for a utility. The Kansas Supreme Court
3 has recognized and generally follows this body of law.[3] This Commission has
4 noted that fact in Orders issued in previous Dockets.[4]

5 **Q Discuss how financial analysts apply the standards established by the Court.**

6 A For a ROR to meet the legal standards, the return should be as specific as possible
7 to the utility in question, in that the allowed return should consider the mix of debt
8 and equity capital the subject utility employs to finance its rate base and provide a
9 return for each of those components of its capitalization.

10 There are several court cases that, as a group, are viewed as the keystone to
11 measuring the adequacy of a utility's allowed return. The earliest of these
12 decisions go back to an era when it was not only the "rate of return" at issue but
13 also the fundamental measurement of the investment in the utility enterprise
14 commonly referred to as rate base. This is less of an issue today as regulators,
15 utility management, and investors readily accept actual historic-depreciated value
16 as a measure of investment to estimate the value of a utility's rate base, as
17 opposed to reproduction cost or market value. The Court's decision in *Bluefield*
18 addressed both rate base and ROR.[5] Treatises on rate of return for public utilities,
19 such as The Cost of Capital – A Practitioner's Guide, generally agree that
20 *Bluefield* lays out the four standards for a fair return.

[3] Kansas Gas & Elec. Co. v. State Corp. Comm'n, 239 Kan. 483, 491, 720 P.2d 1063, 1072 (1986).
[4] Order: 1) Addressing Prudence; 2) Approving Application, in Part; & 3) Ruling on Pending Requests, Docket No. 10-KCPE-415-RTS; November 22, 2010; 37-38.
[5] *Bluefield Water Works & Improvement Co. v. Pub. Svc. Comm'n of West Virginia*, 262 U.S. 679, 692-3 (1923).

1) *Comparable Earnings* – a utility is entitled to a return similar to that being earned by other enterprises with similar risks, but not as high as those earned by highly profitable or speculative ventures;
2) *Financial Integrity* – a utility is entitled to a return level reasonably sufficient to assure financial soundness;
3) *Capital Attraction* – a utility is entitled to a return sufficient to support its credit and raise capital; and
4) *Changing Level of Returns* – a fair return can change along with economic conditions and capital markets.[6]

As a financial analyst preparing rate of return analyses, I take from *Bluefield* that the Court requires that a rate order allow a utility an opportunity to earn a return that is consistent with the utility's risk profile and consistent with observations in the capital markets.

The Court's decision in *Hope,*[7] like that in *Bluefield,* dealt with both valuation of rate base as well as rate of return on that rate base. With respect to the rate of return, the Court in *Hope* affirmed the four standards set out in *Bluefield.*

Q Is a reasonable return necessarily equal to the return granted to other utilities in other jurisdictions?

A No. Relying on the allowed returns granted to other utilities in other jurisdictions

[6] The Cost of Capital – A Practitioner's Guide by David C. Parcell; Prepared for the Society of Utility and Regulatory Financial Analysts; 1997; pp. 3-13 to 3-14.

[7] *Federal Power Comm'n. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). *603 [8] [9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

1 runs the risk of overlooking: (1) changes in the capital markets; (2) differences in
2 other state Commissions' ratemaking policies; and (3) political pressures or other
3 state-specific factors. Commissions have to recognize that such a practice also
4 creates a degree of circular reasoning. Such a comparison also requires a
5 commission to place weight on a piece of data as evidence when they simply do
6 not have any specific facts from those reported cases to know how other state
7 commissions arrived at their decision or even what evidence was presented in
8 those Dockets. At best, returns authorized at other state commissions serve as a
9 rough benchmark of an average return on equity, as well as an indicator of a
10 downward or upward trend in returns. Simply put, the authorized returns of
11 separate utilities in other jurisdictions facing different risks are of limited
12 evidentiary value and are largely irrelevant to the *Hope* and *Bluefield* standards.

13 Q **Should the rate of return incorporate a return on equity that contains some**
14 **level of "cushion" to the cost of equity to compensate for potential future**
15 **changes in the capital markets?**

16 A No, it should not. Utilities seek rate adjustments on a regular basis as
17 demonstrated by the Kansas jurisdictional electric and gas utilities over the past
18 decade. Thus, there are periodic reviews of capital costs, that is, the allowed
19 return on equity and allowed return on debt is not set once and left at the level in
20 perpetuity. This provides protection to consumers and investors alike, in that the
21 periodic reviews eliminate the need for the Commission to inject any forecasting
22 of trends into their decision. As the cost of capital changes over time - and it will
23 change - the allowed return will be updated in future proceedings. In my view,

1 Court decisions do not require Commissions to speculate about the peaks and
2 troughs of our economy and capital markets; all of the directives from the Court
3 cases focus on the observations of the here and now.

4 **KCC Proxy Group**

5 **Q How did you estimate Westar's cost of equity?**

6 A To estimate Westar's cost of equity, I performed DCF and CAPM analyses on a
7 proxy group of similarly situated electric utility companies.

8 **Q Why is it necessary to select a proxy group to estimate the cost of equity for**
9 **Westar?**

10 A A proxy group aids us in meeting the standards set out in *Hope* and *Bluefield*, as it
11 focuses our analysis on a group of companies that are in the same industry and
12 exposed to similar risks. Financial theory tells us that investors require a return
13 that is commensurate with risk. Therefore, a proxy group similar in risk to Westar
14 provides us with a comprehensive picture of investors' expectations.

15 **Q Were you able to select a group of electric utilities similar in risk to Westar?**

16 A Yes, I found 22 proxy companies.

17 **Q How did you select a proxy group for your cost of equity analysis?**

18 A Using the following parameters, I was able to select a group of electric utilities
19 similar in risk to Westar (a table of the selection process is shown on Schedule
20 AHG-3):

- First, I began with the companies followed by Value Line Investment Survey and categorized as electric utilities. As a starting point, this parameter is important as it assures us the companies generally derive their earnings in the same industry as Westar by operating as ROR regulated electric utilities within the United States. Value-Line coverage also ensures that the common stock of these companies is publicly traded. There are 45 electric utilities followed by Value-Line.
- Second, from that group of 45 electric utilities, I selected those with credit ratings similar to Westar's credit rating. Westar's long-term credit rating is Baa1 by Moody's, BBB+ by Standard & Poors', and BBB by Fitch. The three ratings are relatively similar to each other.

Credit Ratings			
Great Plains Energy	Moody's	S&P	Fitch Ratings
Long-term Rating	Baa2	BBB+	
Outlook	Stable	Stable	
Westar Energy			
Long-term Rating	Baa1	BBB+	BBB
Outlook	Stable	Stable	Positive
Source: SNL.com			

I selected electric utilities with credit ratings one notch either side of Westar's rating. Credit ratings are a recognized broad indicator of a utility's financial health, financial risk, and business risk. Selecting those electric utilities with credit ratings very close to Westar's enables me to observe investors' required return for that level of risk. The following table shows the entire scope of credit ratings designations set by S&P and Moody's:

Credit Rating Range for Proxy Selection				
	S&P	Moody's		
	AAA	Aaa		
	AA+	Aa1		
	AA	Aa2		
	AA-	Aa3		
	A+	A1		
	A	A2		
Proxy	A-	A3		
Selection	BBB+	Baa1	Westar Long-term Rating	
Range	BBB	Baa2		
	BBB-	Baa3		
	BB+	Ba1		
	BB	Ba2		
	BB-	Ba3		
	B+	B1		
	B	B2		
	B-	B3		
	CCC+	Caa1		
	CCC	Caa2		
	CCC-	Caa3		
	CC	Ca		
	C			
	D	D		

The electric utilities followed by Value-Line fall in the range of AA-/Aa3 to BBB-/Baa3. Narrowing the range to one rating above and below that of Westar's rating reduced the proxy group to 35 companies.

- Third, I eliminated those companies with pending mergers or acquisitions (M&A). M&A transactions bring about added uncertainty and speculation regarding the financial projections for earnings and dividends, growth potential, and financial health of the surviving entity. This parameter eliminated four companies from my proxy group.
- Fourth, the proxy group companies had to exhibit a stable dividend policy both in the recent past and going forward. A stable dividend is an attribute of a financially sound utility company. By any measure, Westar is

financially sound; members of the proxy group must reflect that same attribute. This parameter did not eliminate any of the remaining 31 electric utilities.

The four parameters above have been adopted in recent cost of equity analyses filed at the Federal Energy Regulatory Commission (FERC) and I agree that these four parameters generally arrive at a group of companies with commensurate investment risk to that of Westar. For this group of 31 electric utilities, I gathered information on their sources of revenues and the focus of their asset base. The intent of this additional parameter is to increase the proxy groups' focus on the electric utility industry. Although each of the companies is categorized as electric utilities by Value-Line, most of them derive some revenues from other industries; some are combination natural gas distribution and electric utilities while others are more diverse with operations outside of the public utility industry. I set the threshold for electric utility revenues at 70%, which eliminated 9 of the 31 electric utilities. The remaining 22 companies derive 73% to 100% of their revenues from the electric utility business. It is these 22 companies that I analyzed to estimate Westar's cost of equity capital. The selection process is shown in Schedule AHG-3 and the Proxy Group is shown in Schedule AHG-4.

Discounted Cash Flow (DCF) Model

Q Does the DCF model meet the legal standards discussed earlier in your

testimony?

A Yes, a cost of equity estimate derived from the DCF model meets the legal standards discussed above if the model incorporates current information from the capital markets via current stock prices and accurate data that investors use to establish their discount rate. The market based information ensures the cost of equity estimates evaluate investors' required rate of return or discount rate that reflects the economic environment.

Q Has the DCF model been an accepted model for regulators to estimate the cost of equity?

A Yes. The DCF model is the most widely used model for regulatory bodies setting allowed returns. Regulatory agencies may incorporate more than one model to arrive at an estimate. If more than one is used, the DCF model is always one of the models. If only one model is used, it will be the DCF model. Regulatory agencies rely on the DCF analysis because, with reasonable inputs, it is a tool that meets the legal standards that investors have used to value all sorts of investments vehicles.

Q What is the underlying basis for the DCF model?

A The DCF model is an investment valuation model used to value different and diverse types of investments such as real estate, bonds, and common stocks. The DCF model is a useful tool to value any investment that involves regular, periodic cash flows. The notion of discounting a future receipt of cash back to the present so as to place a price or value on an investment goes back centuries. The formal

presentation of the DCF model as we use it today dates back to the 1930's in Irving Fisher's book The Theory of Interest and John Burr Williams' 1938 text The Theory of Investment Value. These two authors expressed the DCF model in modern economic terms.

The premise of the DCF model in the valuation of common stock is that investors determine the value of a company's common stock by discounting its future dividend payments back to the present. The cornerstone of the DCF model is the process of discounting those future cash flows back to the present at the investors' required ROR. An investor's required rate of return is risk sensitive and sensitive to the returns available on investments of comparable risk throughout the global capital markets. In other words, as the risk of the investment increases, so will the investors' required return. A higher required rate of return decreases the present value of the stream of dividends that equates to the price of the stock. So, all other variables being equal, investors price the riskier of two common stocks lower because the cash flows or dividends are discounted back to the present at a higher rate.

The form of the DCF model that regulatory agencies are accustomed to seeing is often referred to as the Gordon Growth Model, which is a model that values the present value of a stream of cash flows (dividends) growing at a constant rate into perpetuity. The basic form of this DCF equation is:

Stock Price = Annual Dividend / (Req'd Rate of Return – Dividend Growth Rate)

$$P_0 = \frac{D_0(1+g)}{(Ke-g)}$$

where:

P_0 = the value of the common stock or asset

D_0 = the current dividend of the stock or annual cash flow from the asset

g = the annual growth rate of the dividend or cash flow forever

Ke = cost of equity or required rate of return for the stockholders

This is the form of the equation commonly found in texts regarding finance, investments, and asset valuation. Such texts are inclusive of both theory and practical application.

Regulatory agencies responsible for setting rates and revenue requirements want to know the investors' required rate of return or Ke in the equation. So, we solve the equation for that variable. The equation below shows the algebraic isolation of the investors' required rate of return. By isolating investors' required rate of return in the equation, we can estimate it by knowing the stock's dividend yield and the annual dividend growth rate expected by investors. That form of the equation is:

$$Ke = \frac{D_0(1+g)}{P_0} + g$$

This equation is frequently written out as:

Req'd Rate of Return = (Current Annual Dividend/Current Stock Price) + Dividend Growth Rate

Req'd Rate of Return = Dividend Yield + Dividend Growth Rate

Or as commonly abbreviated by regulatory agencies

$$Ke = y + g$$

where: y = Dividend Yield

g = Expected Dividend Growth

Through a handful of inputs, the DCF model distills down to an equation, a complex cognitive process performed by investors. As with any equation that

attempts to model behavior, there are a host of assumptions that come along with it. Generally those assumptions are:

- Investors evaluate common stock in the classical economic framework.
- Investors discount the expected cash flows at the same rate (Ke) in every future period.
- Ke corresponds only to the specific stream of future dividends, rather than earnings, and constitutes the source of value.
- The discount rate (Ke) must exceed the growth rate (g).
- The constant growth rate will continue for an indefinite future.
- Investors require the same discount rate (Ke) each year.
- There is no external financing.

Q Why is it reasonable to accept these assumptions?

A A certain number of assumptions come along with any financial or economic model, especially ones that are attempting to emulate investors' behavior. The question becomes whether the assumptions are so contrary to investors' behavior in the real-world that the model output becomes meaningless or illogical. I do not believe the assumptions of the DCF model are contrary to investor behavior. Moreover, there are methods I use to evaluate whether an output falls outside of the realm of reality. For example, the output can be compared with the returns available on other investments such as long-term corporate bonds.

<u>Application of the DCF Model</u>

Q How did you calculate the dividend yield (y) component of the DCF model?

A The dividend yield (y) is the easiest of the two components to measure. It is calculated by dividing the stock's annual dividend payment per share by its market price per share. For example, a company paying an annual dividend of $2.00 per share with a market price of $76.00 has a dividend yield of 2.63%.

1 **Q What is the source of the dividend information?**

2 A Historic and current dividend information is easily obtained from public sources.
3 The DCF model requires a forward looking dividend payment which is often the
4 current year's dividend payment increased by the expected growth rate or the
5 forecasted growth rate for next year. I obtained the dividend per share
6 information from Value-Line Investment Survey. The Value-Line reports for
7 each of the proxy companies are attached as Schedule AHG-5. I obtained the
8 stock prices for the dividend yields from YahooFinance. The stock prices and
9 2015 annual dividend observed for each of the proxy companies appears on
10 Schedule AHG-6. The projected 2016 annual dividend rate and resulting
11 dividend yields appear on Schedule AHG-7. The dividend used to calculate the
12 dividend yield is the 2015 dividend rate multiplied by the projected growth rate so
13 as to reflect the expected 2016 dividend payment.

14 **Q Is it proper to use the dividend rate of a full year in the future?**

15 A Yes it is a proper application, although this method is likely a slightly higher
16 dividend rate than merely escalating the current quarterly dividend rate by the
17 projected growth estimate. This method ensures that the DCF analysis contains a
18 truly forward dividend rate, throughout the eight month process of setting
19 Westar's new revenue requirement.

20 **<u>Forecasted Growth Rates for the DCF Model</u>**

21 **Q Please discuss the importance of the second component, the growth rate (g)**
22 **in the DCF equation.**

1 A The "g" represents the anticipated annual growth rate in cash flows that investors
2 expect to receive through dividends from the stock. This is a difficult and
3 contentious issue in a DCF analysis for two reasons. First, it is a key element in
4 the DCF model because the growth rate has a one-for-one effect on the utility's
5 allowed return. All other factors being equal, a higher growth rate results in a
6 higher return on equity for the utility. Second, there is an element of subjectivity
7 to selecting the growth rate due to the uncertainty about future earnings and
8 dividends. It is difficult to uncover what growth rate estimates investors rely on
9 when they value a stock and where they obtain that information.

10 **Q How did you estimate the growth rate in the DCF model?**

11 A The appropriate growth estimate is that which is expected by the market and
12 factored into investors' analyses to estimate a stock prices. That is, it is the
13 growth estimate investors used to determine the stock price. Determining
14 precisely how investors estimate the growth rate used in evaluating common
15 stocks is difficult. Earnings per share growth forecasts are commonly
16 incorporated into the DCF model. Investment firms that publish growth forecasts
17 publish three to five-year annual earnings growth estimates and that is about as far
18 into the future as analysts forecast for a specific company. I discussed earlier that
19 the DCF model assumes the growth rate continues in perpetuity, well beyond the
20 three to five-year window of analysts' forecasts for earnings and dividends.

21 **Q How do investors estimate the dividend growth rate beyond the three to five**
22 **year horizon of the short-term growth forecasts?**

1 A For a long-term perspective of potential growth, investors rely on forecasts of the
2 broad economy. There are sources for long-term growth estimates of this
3 country's gross domestic product (GDP) that extend out more than 20 years.
4 Mathematically, a growth estimate rolled out over 20 years is for all practical
5 purposes a perpetuity in the world of discounting future cash flows. Academic
6 texts and investment professionals use these forecasts in DCF models as a forecast
7 of potential long-term growth. GDP refers to the market value of all final goods
8 and services produced within a country in a given period. Nominal GDP (nGDP)
9 is that measure of goods and services which *includes* effects of price changes -
10 better known as inflation. Inflation must be included because the DCF analysis is
11 interested in the nominal required return or cost of equity, and investors'
12 expectations of inflation are contained in their required return. Keep in mind that
13 the "head-line" GDP reported in the media is real GDP; GDP less the inflation
14 experienced over the measurement period.

15 **Q Is it accepted practice to use nGDP growth estimates in the DCF model?**

16 A Yes, in the federal regulatory arena, similar to the responsibilities of the KCC, the
17 FERC uses nGDP to estimate the cost of equity. FERC has reviewed the issue of
18 long-term growth estimates used in DCF models; it took comments from
19 concerned parties that included state commissions, customers, investment
20 bankers, and interstate pipeline companies.[8] Testimony from these parties made it
21 clear that long-term estimates of nGDP are a common component of valuation
22 analyses conducted by investment professionals. From that proceeding, FERC
23 concluded that long-term growth estimates of nGDP should be the estimate of

[8] Transcript from Technical Conference held on January 23, 2008, FERC Docket PL07-2-000.

long-term growth in the DCF models used to estimate required returns for interstate pipeline companies because that is consistent with investor behavior.[9] In June of 2014, FERC concluded that the same methodology should be used in setting the required returns for electric transmission companies.[10]

Q Is there academic support for this issue?

A Yes, valuation analysts have carefully considered the long-run growth rates used to value assets. Using an incorrect growth estimate will lead to incorrectly valuing an asset. Academic research supports has shown that nGDP growth forecasts are an important input to valuation studies because the analyst has to consider whether a company's annual earnings can grow faster than the broad economy. In two of his books devoted to the subject of asset valuation, Investment Valuation: Tools and Techniques for Determining the Value of Any Asset, 2nd Edition and Damodaran on Valuation: Security Analysis for Investment and Corporate Finance, 2nd Edition, Dr. Aswath Damodaran discusses the nature of a stable growth rate for DCF models. He argues for viewing nominal economic growth as the absolute maximum when using a stable-growth model, such as the DCF model we are using.

"The stable growth rate cannot exceed the growth rate of the economy in which a firm operates, but it can be lower. There is nothing that prevents us from assuming that mature firms will become a smaller part of the economy and it may, in fact, be the more reasonable assumption to make. Note that the growth rate of an economy reflects the contributions of both young, higher growth firms and mature, stable growth firms. If the former grow at a rate much higher than the growth rate of the economy, the latter have to grow at a rate that is lower." (Damodaran on Valuation: Security Analysis for Investment and Corporate Finance, 2nd edition; Aswath Damodaran; p.148.

[9] Policy Statement, FERC Docket PL07-2-000 (April 17, 2008); FERC Opinion No. 486, FERC Docket RP04-274 (Oct. 19, 2006).
[10] Opinion No. 531; June 19, 2014; 147 FERC 61,234; para 36.

1
2 *"The growth rate of a company cannot be greater than that of the economy but it*
3 *can be less. Firms can become smaller over time relative to the economy. Thus,*
4 *even though the cap on the growth rate may be the nominal growth rate of the*
5 *economy, analysts may use growth rates much lower than this value for individual*
6 *companies."* (Damodaran on Valuation: Security Analysis for Investment and
7 Corporate Finance, 2nd edition; Aswath Damodaran; p.159)
8
9 It is worth noting that Professor Damodaran cites the nGDP growth projection as
10 a *ceiling* for long-term growth in most valuation studies. Certainly there are
11 industries that will exceed the average for a period of time, but even for those
12 industries experiencing rapid growth, that would not continue forever. For
13 purposes of my analysis, it is not realistic to place a mature industry like electric
14 utility services in a group of companies that should experience rapid growth over
15 an extended period of years.
16 **Q In that discussion, your source states that nominal economic growth is a**
17 ***ceiling* for long-term earnings growth. Is the *ceiling* the appropriate number**
18 **for an investor to use when valuing a common stock?**
19 A There is research that casts doubt on using the forecasted nGDP as the growth
20 ceiling in valuation studies as nGDP may actually overstate the growth potential
21 for a company's earnings. Research by Bernstein and Arnott warns practitioners
22 that a portion of nGDP growth is created by new enterprises and that portion of
23 nGDP growth does not contribute to the earnings growth of existing enterprises.[11]

[11] Earnings Growth: The two Percent Dilution; William J. Bernstein and Robert D. Arnot; Financial Analysts Journal; September/October 2003, pp 47-55.

Two important concepts played a key role in the bull market of the 1990s. Both represent fundamental flaws in logic. Both are demonstrably untrue. First, many investors believed that earnings could grow faster than the macroeconomy. In fact, earnings must grow slower than GDP because the growth of existing enterprises contributes only part of GDP growth; the role of entrepreneurial capitalism, the creation of new enterprises, is a key driver of GDP growth, and it does not contribute to the growth in earnings and dividends of existing enterprises. During the 20th century, growth in stock prices and dividends was 2 percent less than underlying macroeconomic growth. Second, many investors believed that stock buybacks would permit earnings to grow faster than GDP. The important metric is not the volume of buybacks, however, but net buybacks—stock buybacks less new share issuance, whether in existing enterprises or through IPOs. We demonstrate, using two methodologies, that during the 20th century, new share issuance in many nations almost always exceeded stock buybacks by an average of 2 percent or more a year.

Q Does their view that nGDP growth is a ceiling on long-term earnings growth exist outside of academia?

A Yes, Bernstein and Arnott have both published in peer-reviewed academic journals, books on investment strategy, as well as building careers in the field of asset management and investment strategy. Furthermore, institutions directly involved in asset valuation and asset management that apply valuation models to analyze potential acquisition and merger transactions recognize that estimates of firm-specific growth are a driver to the value of an asset; overstating growth would cause a model to overestimate the value. These experts also warn of a ceiling to earnings growth rates as being no more than that of broad economic growth.

"Growth rate: Few companies can be expected to grow faster than the economy for long periods. The best estimate is probably the expected long-term rate of consumption growth for the industry's products, plus inflation." (Valuation: Measuring and Managing the Value of Companies; Tim Koller, Mark Goedhart, and David Wessels; McKinsey & Co; 4th ed; p275.)

The following quote from J.P. Morgan Asset Management (JPMAM) addresses the limits on earnings growth on a macro-level. This statement by JPMAM addresses the macro or economy-wide measures of profits and it is consistent with the firm-specific view expressed by asset valuation experts in that analysts must be aware of the forecasted growth rates applied in valuation models and how those growth forecasts comport with broad measures of forecasted economic growth.

"One common mistake is to assume that earnings and dividends received by investors can grow in line with—or even in excess of—overall economic growth (GDP) in perpetuity. Granted, it is almost a truism that aggregate earnings must grow at the same pace as the overall economy in the very long run; otherwise, profits would eventually outstrip the size of the entire economy or dwindle to an insignificant share of it. But not all of this earnings growth accrues to existing shareholders. On the contrary, a large portion of economic growth comes from the birth of new enterprises. Some commentators suggest (for example, Bernstein and Arnott, 2003; Cornell, 2010) that new enterprises account for more than half of GDP growth in the U.S., while in some rapidly developing economies new enterprises may account for the lion's share of overall economic growth." (Long-term Capital Market Return Assumptions: 2015 Estimates and Thinking Behind the Numbers; J.P. Morgan Asset Management; p.25 https://am.jpmorgan.com/lu/institutional/ltcmra)

Q Do you believe this information justifies incorporating long-run nGDP growth forecasts in cost of equity analyses of utility companies?

A Yes, in a general rate proceeding such as this, the Commission is attempting to ascertain the discount rate investors apply to the future cash flows from an investment in these utilities; therefore, the Commission should emulate investors' analytical practices as much as possible to determine their discount rate. As noted above, investment professionals include a long-run growth forecast for the general economy when applying valuation models like the DCF and capital asset pricing

1 model, and that measure of macro-economic growth serves as the upper bounds of
2 a firm-specific analysis. Therefore, the Commission should consider that same
3 information.

4 **DCF Results**

5 **A Please discuss the results of your DCF analysis.**

6 Q The results of my DCF analysis appear in the following table. As I have set out
7 the foundations for the DCF analysis in the previous pages, in this section I will
8 discuss the specific information that I relied on for the DCF model and interpret
9 the results.

Staff's Discounted Cash Flow Westar 15-WSEE-115-RTS

1		2	3	4	5	6
		Dividend Yield		Growth	Cost of Equity	
		Low	High	Rate	Low	High
Allete Inc	ALE	3.88%	4.45%	5.36%	9.23%	9.81%
Alliant Energy Corp	LNT	3.61%	3.90%	5.12%	8.72%	9.02%
Ameren Corp	AEE	4.03%	4.38%	5.20%	9.23%	9.58%
American Electric Pwr Co	AEP	3.86%	4.17%	4.79%	8.65%	8.96%
Avista Corp	AVA	4.03%	4.41%	5.19%	9.22%	9.60%
CMS Energy Corp	CMS	3.40%	3.74%	5.23%	8.63%	8.97%
Consolidated Edison Inc	ED	4.26%	4.59%	3.44%	7.70%	8.02%
Dominion Resources Inc	D	3.68%	4.00%	5.49%	9.16%	9.49%
Duke Energy Corp New	DUK	4.20%	4.56%	4.61%	8.81%	9.17%
Edison International	EIX	2.69%	3.03%	3.72%	6.41%	6.75%
El Paso Electric Co	EE	3.12%	3.56%	4.82%	7.94%	8.37%
Empire District Electric Co	EDE	4.29%	4.78%	4.36%	8.64%	9.14%
Great Plains Energy Inc	GXP	3.81%	4.16%	5.29%	9.10%	9.45%
IDACORP Inc	IDA	3.04%	3.36%	3.69%	6.73%	7.05%
NorthWestern Corp.	NWE	3.66%	4.01%	4.94%	8.60%	8.95%
OGE Energy Corp	OGE	3.29%	3.55%	4.19%	7.48%	7.74%
Pacific Gas and Electric Co.	PCG	3.50%	3.77%	5.26%	8.75%	9.03%
Pinnacle West Capital Corp	PNW	3.90%	4.37%	4.47%	8.37%	8.84%
Portland General Electric Co.	POR	3.26%	3.61%	4.88%	8.13%	8.48%
TECO Energy	TE	4.72%	5.24%	5.64%	10.36%	10.88%
Westar Energy Inc	WR	3.79%	4.24%	4.29%	8.08%	8.53%
Xcel Energy Inc	XEL	3.78%	4.09%	4.54%	8.32%	8.63%
	Average	3.72%	4.09%	4.75%	8.47%	8.84%
			Average of Low & High		8.65%	
				Range	6.41%	10.88%

Pricing March - May

1 KCC proxy group
2 2016 forecasted dividend / observed high stock price
3 2016 forecasted dividend / observed low stock price
4 growth rate, average of long-run and short-run forecasted growth
5 Min Dividend Yield + Growth Rate
6 Max Dividend Yield + Growth Rate

No observatios were eliminated as illogical or outliers. The test for low outliers is yield on Baa utility bonds plus 100 basis points (4.60% +1.00% = 5.60%)

To calculate the expected dividend, I multiplied the reported 2015 annual dividend by the forecasted growth rate to move the current 2015 dividend ahead one full year so as to reflect the expected dividend rate in year one. The data for each proxy company is shown on Schedule AHG-7. That 2016 annual dividend is divided by the pricing data gathered for each of the proxy companies from the time period of March 1, 2015, through May 31, 2015, on a weekly basis. The high and low prices for each week are shown on Schedule AHG-6. The low dividend yield is computed using the expected 2016 dividend divided by the

1 average of the weekly high prices while the high dividend yield is computed using
2 the weekly low prices.

3 **Q How did you arrive at a growth rate for each proxy company?**

4 A The growth rate is the average of the short-term growth rates[12] and the long-run
5 forecast of nGDP of 4.38%. Schedule AHG-8 summarizes all of the observed
6 growth forecasts; both historical and forecasted.

Summary of Growth Rates

15-WSEE-115-RTS		Value-Line Historic Data				Forecasted Earnings Growth Rates			
		DPS Growth		EPS Growth		Value Line			
		10 Year	5 Year	10 Year	5 Year	DPS	EPS	IBES	FactSet
Allete Inc	ALE	0.00%	2.00%	7.00%	1.00%	4.00%	7.00%	6.00%	6.00%
Alliant Energy Corp	LNT	3.50%	6.50%	8.00%	6.50%	4.50%	6.00%	5.45%	6.10%
Ameren Corp	AEE	-4.50%	-9.00%	-2.50%	-4.00%	2.00%	5.00%	5.85%	7.22%
American Electric Pwr Co.	AEP	-1.50%	4.00%	0.50%	1.50%	5.00%	5.50%	5.10%	5.00%
Avista Corp	AVA	9.50%	11.50%	7.50%	6.50%	4.00%	7.00%	5.00%	0.00%
CMS Energy Corp	CMS	0.00%	23.50%	0.00%	12.00%	6.50%	5.50%	6.73%	6.00%
Consolidated Edison Inc.	ED	1.00%	1.00%	3.50%	2.50%	2.50%	3.00%	2.48%	2.00%
Dominion Resources Inc	D	5.50%	7.00%	3.00%	2.50%	7.50%	8.00%	5.89%	5.90%
Duke Energy Corp	DUK	0.00%	2.50%	0.00%	3.50%	2.50%	5.00%	4.49%	5.00%
Edison International	EIX	0.00%	2.50%	10.00%	4.50%	10.00%	3.00%	0.70%	5.50%
El Paso Electric Co	EE	0.00%	0.00%	13.50%	6.50%	5.00%	3.50%	7.00%	0.00%
Empire Distr. Electric	EDE	-2.50%	-4.50%	2.50%	5.00%	3.00%	3.00%	5.00%	5.00%
Great Plains Energy Inc	GXP	-6.50%	-12.50%	-3.50%	-2.00%	5.50%	5.00%	6.80%	6.80%
IdaCorp, Inc	IDA	0.00%	5.50%	9.00%	10.00%	6.00%	1.00%	4.00%	4.00%
Northwestern Corp	NWE	0.00%	3.00%	0.00%	8.00%	6.50%	6.50%	5.00%	5.00%
OGE Energy Corp	OGE	2.00%	3.00%	9.50%	7.50%	10.00%	3.00%	4.00%	5.00%
Pacific Gas & Electric Co	PCG	0.00%	3.00%	14.50%	-5.00%	2.50%	8.50%	4.71%	5.20%
Pinnacle West Capital Corp	PNW	3.50%	3.00%	3.50%	8.00%	3.50%	4.00%	4.70%	5.00%
Portland General Electric Co	POR	0.00%	2.50%	0.00%	3.00%	6.00%	6.00%	4.72%	5.40%
TECO Energy	TE	-1.50%	2.00%	1.50%	0.00%	2.00%	6.00%	9.20%	5.50%
Westar Energy Inc	WR	3.50%	3.50%	6.50%	9.00%	3.00%	6.00%	3.40%	3.20%
Xcel Energy Inc	XEL	2.50%	3.50%	7.00%	6.00%	6.00%	4.50%	4.58%	5.00%
	Mean	1.12%	3.02%	5.61%	4.40%	4.89%	5.09%	5.04%	5.19%
	Min	-6.50%	-12.50%	-3.50%	-5.00%	2.00%	1.00%	0.70%	2.00%
	Max	9.50%	23.50%	14.50%	12.00%	10.00%	8.50%	9.20%	7.22%

7

8 **Q What are your observations of the short-run growth forecasts?**

9 A The average of the short-run growth forecasts for the proxy group is 5.12% with a

[12] For each proxy company, I gathered four short-run, three to five year growth forecasts - earnings and dividend growth projections from Value-Line Investment Survey, analysts' earnings growth projections reported by FactSet through SNL Financial, and earnings growth projections reported by Thomson Financial Network reported by YahooFinance. FactSet and Thomson Financial Network aggregate analysts' earnings forecasts and report the mean of those estimates. Value-Line produces its own growth forecasts and publishes on a quarterly basis. The Value-Line report for each company appears in Schedule AHG-5.

range of 2.50% to 6.90%.

Q How do the forecasts compare to historic growth rates realized by the proxy group?

A As you can see in the previous table, the averages from each forecast source fall under the ten year historic averages and are greater than the five year historic averages. All of the growth forecasts are positive although there are several individual observations of negative historic growth for both the five and 10 year periods.

Q How did you estimate long-run nominal GDP growth?

A I averaged the long-run nGDP forecasts of the Energy Information Agency (EIA) in its 2015 Annual Energy Outlook and the Social Security Administration (SSA). Both forecasts extend to 2090.

Nominal GDP Forecasts	
Energy Information Administration-- 2015 Annual Energy Outlook (2013 - 2090)	4.25%
Social Security Administration-- 2014 Annual Report to the Board of Trustees of OADSI (2014 - 2090)	4.50%
Average	4.38%

These two forecasts are consistent with the other long-run forecast for real GDP shown in the following table, as both the EIA and SSA forecasts of nominal GDP incorporate an inflation forecast of 1.8% to 2.0%, thus expecting real growth in the range of 2.4% to 2.6%. The following table is taken from EIA's 2014 Annual Energy Outlook. The first two lines contain EIA's forecasts from 2014 and 2013 respectively. Like the EIA and SSA, the Office of Management & Budget

1 (OMB) and Congressional Budget Office (CBO) are agencies of the U.S.
2 Government. ISH Global Insight and INFORUM (University of Maryland) are
3 subscription services and, of course, ExxonMobile is one of the largest
4 corporations in the world. From a diverse group of interests, there is some
5 consensus that long-run economic growth in real terms will be in the range of
6 2.5%. Applying the 1.8% to 2.0% inflation forecasts would result in a nominal
7 growth rate of 4.3% to 4.5%. This is in stark contrast to Mr. Somma's growth
8 forecast of 5.62% in his DCF analysis and 11.28% growth used in his CAPM;
9 both dramatically exceed the consensus forecasts from these seasoned,
10 professional services. Mr. Somma's 5.61% nGDP is built on his unsupportable
11 belief that real GDP will grow at an annual rate of 3.27%, which is about 100
12 basis points greater than any of these professional forecasts.

Table CP1. Comparisons of average annual economic growth projections, 2012–40

	Average annual percentage growth rates			
Projection	2012-2015	2012-2025	2025-2040	2012-2040
AEO2014 (Reference case)	2.8	2.5	2.4	2.4
AEO2013 (Reference case)	2.8	2.8	2.4	2.5
IHSGI (May 2013)	2.6	2.5	2.4	2.5
OMB (January 2014)[a]	2.7	2.6	--	--
CBO (February 2014)[a]	2.8	2.5	--	--
INFORUM (November 2013)	2.4	2.6	2.3	2.4
Social Security Administration (August 2013)	3.0	2.7	2.2	2.4
IEA (2013)[b]	2.6	2.8	--	2.4
ExxonMobil	--	2.5	2.2	2.4
OEG (January 2013)	2.7	2.7	2.5	2.8

-- = not reported or not applicable.
[a]OMB and CBO projections end in 2024, and growth rates cited are for 2012-24. AEO projections end in 2040.
[b]IEA publishes U.S. growth rates for certain intervals: 2011-15 growth is 2.6%, 2011-20 growth is 2.8%, and 2011-35 growth is 2.4%.

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14 This table was published in the 2014 edition of the Annual Energy Outlook. The
15 2015 did not contain a similar table. A check of ExxonMobil's 2015 Energy
16 Outlook indicates its forecasts for GDP growth are 10 basis points higher than
17 those published in 2014. I have not found any evidence that growth projections

shown in this 2014 table have changed significantly.

Q How is the long-run nGDP forecast applied in your DCF analysis?

A The long-run nGDP growth forecast of 4.38% is averaged with the short-run growth forecasts. The result is the sustainable growth estimate used in the DCF calculations for each of the proxy companies. In my analysis, I give equal weight to short-run and long-run growth forecasts. The weighting is certainly debatable. At FERC, in both natural gas pipeline and electric transmission rate cases, the short-run growth is afforded a two-thirds weighting. In the regulated electric utility industry, there is seldom a dramatic difference between a well-reasoned short-run growth estimate and a sound long-run forecast of nGDP, so the weighting is not going to cause a significant change in the results. Regardless of the small difference, a long-run nGDP estimate is one component of any sound DCF analysis, as it recognizes the upper-threshold of growth potential.

Internal Rate of Return Analysis

Q Please discuss the internal rate of return (IRR) analysis that you performed.

A An IRR analysis of an investment is a form of a discounted cash flow analysis, only with a more cumbersome equation than the Gordon Growth Model that we applied in the previous section. In the age of spreadsheets, the IRR equation is not that much harder to manage than the dividend yield plus growth DCF model, and as the IRR model allows us to apply the growth forecasts to their respective forecast periods, the IRR model provides important information to policy makers. In the IRR analysis, we are able to apply the five year growth forecasts to the

intended five years of dividends with the remaining years growing at the long-run nGDP forecasted growth rate.

The IRR calculations appear in Schedule AHG-9. The following table summarizes the results of the IRR. Recognizing that the short-term growth forecasts are given much less weight than in the DCF analysis, the average for the proxy group in the IRR analysis is about 20 basis points higher than the DCF results.

Internal Rate of Return	
Allete Inc	8.96%
Alliant Energy Corp	8.45%
Ameren Corp	8.98%
American Electric Pwr Co	8.66%
Avista Corp	8.99%
CMS Energy Corp	8.27%
Consolidated Edison Inc	8.73%
Dominion Resources Inc	8.64%
Duke Energy Corp New	9.01%
Edison International	7.18%
El Paso Electric Co	7.91%
Empire District Electric Co	9.10%
Great Plains Energy Inc	8.75%
IDACORP Inc	7.52%
NorthWestern Corp.	8.50%
OGE Energy Corp	7.87%
Pacific Gas and Electric Co.	8.35%
Pinnacle West Capital Corp	8.69%
Portland General Electric Co.	8.03%
TECO Energy	10.01%
Westar Energy Inc	8.52%
Xcel Energy Inc	8.50%
Mean	8.53%
Min	7.18%
Max	10.01%

Capital Asset Pricing Model Analysis

Q Please describe the capital asset pricing model (CAPM).

A The CAPM offers an explanation of the positive relationship between risk and

ROR required by investors.[13] It is appealing to regulators because it meets the legal standards I discussed as it incorporates current data from the financial markets and the unique risks of the utility in question.

Ke = Rf + Beta (Rm - Rf) or
Ke = Rf + Beta (Rp)

where:

Ke = required return on equity
Rf = return on the risk-free security
Rm = expected return from the market
Rp = risk premium required by investors to purchase common stocks instead of risk-free securities often calculated as Rm - Rf
Beta = volatility of the security's or portfolio's return relative to the volatility of the market's return

Rf

The Rf estimate is the interest rate investors believe represents a riskless return. Although it is a simple concept, the answer is not universally agreed upon. The 90-day U.S. Treasury Bill yields are used as the risk-free rate because they possess no default-risk and the time to maturity is short enough to minimize risks from inflation. The 30-year U.S. Treasury Bond is also used as a risk-free rate of return. This is not universally accepted because the value of U.S. Treasury Bonds fluctuates as interest rates change. An investment in U.S. Treasury Bonds is a risk-free investment if the investor plans to hold it until maturity. The risk-free instrument chosen will have an effect on the results of the CAPM analysis. Whichever instrument is selected, it should be used consistently in the equation.

Beta

The beta coefficient measures the volatility of return earned by the utility's stock relative to the volatility of the returns earned by the broader equity market. The

[13] The theoretical support for the CAPM is the work done by Harry Markowitz ("Portfolio Selection," Journal of Finance, March, 1952). W.F. Sharpe added the concept of a risk-free rate of return to the Markowitz model ("A Simplified Model of Portfolio Analysis," Management Science, January, 1963).

broad equity market is frequently measured using the S&P 500 Index. This measure provides a look at the risk and volatility of a stock relative to other investments. A stock with a beta of one is just as volatile as the market, .5 and the stock is half as volatile as the market, and 1.25 it is twenty-five percent more volatile than the market.

Rm

Rm is the expected return on the stock market as measured by a broad market index such as the S&P 500. This represents the total return consisting of the price change of the index plus dividends earned for the year.

Rp

The risk premium is the difference between investors' expected return from the stock market and their expected return from the risk-free investment over the same time period. The risk premium is written as Rm-Rf. The market return and the risk-free return should be taken from the same time period so as to accurately measure the additional return required by investors to take on the risk of common stocks over the risk-free investment. Rp is calculated using the historic market returns discussed above and the historic returns on U.S. Treasury Bills or Bonds from the same time period.

Q Please discuss your CAPM analysis.

A I took two distinct approaches to the CAPM analysis. I performed one analysis using historic measures of returns from the stock and bond markets and a second analysis using forecasted returns. The results using historic returns are drastically higher; 9.20% compared to 6.64%.

Both forms of my CAPM analysis incorporate the beta coefficients for the proxy

1 group. As you can see in the following table, the average for the group, as well as
2 Westar, is 0.75 meaning the total return of the proxy group on average is about
3 75% of the broad market. This is a clear indication that electric utilities like
4 Westar and the proxy group are less volatile than the broad stock market, and
5 investors expect a return lower than that expected of the market.

Beta Coefficients of Proxy Group		
Allete Inc	ALE	0.80
Alliant Energy Corp	LNT	0.80
Ameren Corp	AEE	0.75
American Electric Pwr Co	AEP	0.70
Avista Corp	AVA	0.80
CMS Energy Corp	CMS	0.75
Consolidated Edison Inc	ED	0.60
Dominion Resources Inc	D	0.70
Duke Energy Corp New	DUK	0.60
Edison International	EIX	0.75
El Paso Electric Co	EE	0.70
Empire District Electric Co	EDE	0.70
Great Plains Energy Inc	GXP	0.85
IDACORP Inc	IDA	0.80
NorthWestern Corp.	NWE	0.70
OGE Energy Corp	OGE	0.90
Pacific Gas and Electric Co.	PCG	0.65
Pinnacle West Capital Corp	PNW	0.70
Portland General Electric Co.	POR	0.80
TECO Energy	TE	0.85
Westar Energy Inc	WR	0.75
Xcel Energy Inc	XEL	0.65
		0.74
Source: Value-Line Investment Survey		

6

7 **Q Please describe the forecasted-CAPM analysis.**

8 A For the forecasted-CAPM, I relied on the expected returns published JPMAM in
9 its annual publication, Long-Term Capital Market Assumptions. JPMAM
10 publishes 10 to 15 year forecasts of expected returns on dozens of investment
11 asset classes. What is unique about this product is that JPMAM publishes not
12 only the forecasted return, but also an extensive discussion that explains how they

1 arrived at those forecasted returns.[14] JPMAM provides the following discussion
2 of how it uses the long term capital market return assumptions (LTCMRA) in its
3 own business as well as its intended audience. As you can see in the following
4 table, JPMAM forecasts an annual return on common stocks of 7.60%. The
5 Commission should compare this forecast to Mr. Somma's expectations for the
6 stock market; he expects annual returns of 13.25%. Mr. Somma's expectations
7 are far above the expected.

> How do investors use the LTCMRAs?
>
> The Long-Term Capital Market Return Assumptions are used widely by investment teams throughout J.P. Morgan Asset Management as well as by institutional investors–including pension plans, insurance companies, endowments and foundations–to ensure that investment policies and strategic asset allocations are developed based on a comprehensive and consistent set of "real world" views. In addition the LTCMRAs allow the resulting investment characteristics and return profiles to be tested and analysed, facilitating a more effective communication and underwriting of the implied risk and return profile.
>
> When used, as is most often the case, to review an existing strategic asset allocation, the LTCMRAs can help investors to better assess and quantify the trade-offs available to them across multiple dimensions. These trade-offs include: the relative risk premia between more and less volatile assets; the risk premia associated with investing outside of their own domestic asset classes; which opportunities exist to increase portfolio diversification; and which nominal or real return target is achievable with a given level of portfolio volatility and vice versa.

8

9 Following the calculations and inputs through the CAPM equation in line 2 of the
10 following table, the forecasted return on a risk-free investment, 10 Year U.S.
11 Treasury Bonds, is subtracted from the expected return on common stocks

[14] Long-term Capital Market Return Assumptions: 2015 Estimates and Thinking Behind the Numbers; J.P. Morgan Asset Management; p.7; https://am.jpmorgan.com/lu/institutional/ltcmra

1 resulting in a risk premium of 3.19%. This risk premium is essentially the
2 additional return necessary to induce investors to take on the added risk associated
3 with common stocks over the risk free investment. The beta coefficient is applied
4 to the risk premium to ascertain how much of a risk premium is necessary for
5 investors to, in this instance, take on risks of investing in electric utility stocks as
6 opposed to the risk free U.S. Treasury Bond. As the electric utilities like the
7 proxy group and Westar are less risky than common stock in general, their risk
8 premium is 2.39%.

Capital Asset Pricing Model -- Forecasted Risk Premium
Using Forecasted Market Returns & Treasury Bond Yields

			Proxy Group & Westar Beta
1)	Forecasted Returns on Common Stocks		7.60%
2)	Forecasted Total Return on 10 Year T-Bonds	-	4.41%
3)	Resulting Risk Premium		3.19%
4)	Beta Coefficient	x	0.75
5)	Risk Premium		2.39%
6)	Forecasted Yield on 10 Year T-Bonds	+	4.25%
7)	Forecasted Cost of Equity		6.64%

1) Forecasted 10 to 15 Year Annual Return Arithmetic return on stocks for large companies by J.P. Morgan Asset Management 2015 Edition.
2) Forecasted 10 to 15 Year Annual Return Arithmetic return on intermediate term U.S. Bonds by J.P. Morgan Asset Management 2015 Edition
3) Resulting risk premium (1-2)
4) Beta coefficient of 0.75 for the Proxy Group and Westar (Reported by Value-Line)
5) row 3 x row 4 = asset specific risk premium
6) Forecasted Yield on 10 year U.S. Treasury Bonds Forecasted by J.P. Morgan Asset Management 2015 Edition; Fixed Income Assumptions; Exhibit 2; p.56
7) Forecasted cost of equity capital row 5 + row 6

Sources:
J.P. Morgan Asset Management, Long-term Capital Market Return Assumptions, 2015 Edition; J.P. Morgan Asset Management.
www.jpmorganinstitutional.com/pages/jpmorgan/am/ia/research_and_publications/long-term_capital_market

9

1 The expected risk free yield of 4.25%[15] is added to the beta specific risk premium
2 to arrive at the cost of equity for the given beta coefficient of 6.64% 100 basis
3 points less than the returns JPMAM is forecasting for the broad stock market
4 indexes. These results appear low by historical measures, although in the current
5 capital markets investors in Westar, long-term bonds are purchasing bonds with
6 the expectation for returns or around 3.80% to 4.00% in March 2015 through May
7 of 2015.

8 **Q Please discuss the historical-CAPM analysis.**

9 A I performed a CAPM analysis incorporating historic data of returns earned from
10 1926 through 2014. The process is the same as that applied in the Forecasted
11 CAPM.

[15] JMAM is one source for forecasted data. Another source is the Survey of Professional Forecasters published by the Federal Reserve Bank of Philadelphia; https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2015/survq115.cfm
At page 17 in the February 13, 2015, edition the Survey, it is reported that for the next ten years, the mean expected annual return on the S&P 500 Index is 5.79% (20 forecasts) while the mean expected yield on 10 Year Treasury Bonds is 3.91% (25 forecasts). Forecasters project annual growth in real GDP over the next ten years of 2.51% and an annual inflation rate of 1.83% to 2.03%.

Capital Asset Pricing Model -- Historic Risk Premium
Based on Historic Risk Premiums from 1926 to 2014

			Proxy Group & Westar Beta
1)	Total Returns on Common Stocks		12.10%
2)	Total Return on Government Bonds	-	6.40%
3)	Resulting Risk Premium		5.70%
4)	Beta Coefficient	x	0.75
5)	Risk Premium		4.28%
6)	Yield on Government Bonds	+	5.12%
7)	Forecasted Cost of Equity		9.40%

1) Historic returns on common stocks 1926-2014
2) Historic returns on Long-term Government Bonds 1926-2014
3) Resulting risk premium (1-2)
4) Beta coefficient of 0.75 for the Proxy Group and Westar (Reported by Value-Line)
5) row 3 x row 4 = asset specific risk premium
6) Historic Year-End Yield on Long-term Government Bonds 1926-2014
7) Forecasted cost of equity capital row 5 + row 6

Sources:
Ibbotson SBBI: 2015 Classic Yearbook & Value-Line Investment Survey

Keep in mind that, in relying on historic data, we are assuming that certain trends observed in the past will continue in the future. Most notably, we would be assuming that the historic risk premium relationship observed in the returns on common stocks versus the returns on U.S. Treasury Bonds continues in the future. The historic risk premium is 5.70% which is drastically greater than the 3.19% risk premium expected by professional forecasters and institutional investors. That difference is an indication that institutional investors and professional forecasters do not expect the future nominal returns to be as great as those experienced in the past.

1 **Staff Response to Mr. Somma's Direct Testimony**

2 Q **What is the ROE Westar is requesting?**

3 A Westar is requesting an ROE of 10.00%.

4 Q **How did Westar arrive at a cost of equity estimate of 10%?**

5 A Westar witness Anthony Somma provided a cost of equity analysis. His findings

6 are summarized in this table which is from page 63 of his testimony.

Table 11

Adjusted ROE Recommendation					
	Range		Weight	Weighted Range	
DCF Results	9.47%	9.52%	50.0%	4.74%	4.76%
Forward CAPM Results	10.86%	11.76%	25.0%	2.72%	2.94%
Risk Premium Results	10.33%	10.38%	25.0%	2.58%	2.60%
				10.03%	10.30%
			Issuance Costs	0.12%	0.12%
			Adjusted ROE	**10.15%**	**10.42%**

7

8 His cost of capital study arrives at a range of 10.00% to 10.30%. As you can see

9 in the table, Mr. Somma places greatest weight, 50%, on the DCF analysis. He

10 weights the results of his CAPM and Risk Premium at 25% each.

11 Q **Generally, what are your criticisms of Mr. Somma's analysis?**

12 A Mr. Somma's DCF analysis assumes an unsustainably high growth rate, adjusting

13 that growth rate to a level that reflects the realities of the current and prospective

14 economy lowers the result closer to Staff's DCF analysis. Mr. Somma's CAPM

15 and Risk Premium analysis contain too many points of disagreement at both the

16 theoretical and application level, that I recommend the Commission place no

17 weight on them.

18 Q **Is it reasonable to expect corporate earnings and dividends to grow at a rate**

1 **that is so much greater than forecasted nGDP?**

2 A No, it is not a reasonable expectation. As I explained earlier, there is a
3 considerable amount of both academic research and professional application of
4 the DCF model that discuss the growth rate issue. The research from both realms
5 is very clear: the broad measure of economic growth, most always defined as
6 nGDP, is a necessary limit on dividends and earnings growth.

7 Q **Did you uncover any other evidence that Mr. Somma's CAPM analysis**
8 **overstates investors' required returns?**

9 A Yes, there are obvious indicators in Mr. Somma's CAPM. For instance, the
10 required return on the market is very high and well above reasonable
11 expectations. Mr. Somma's CAPM assumes that the annual average return on the
12 S&P 500 Index will be 13.25%. His forecasts for the equity market far exceed
13 historic return of 12.10%[16] and far exceed the expected returns for the future. As
14 a point of comparison, J.P. Morgan Asset Management forecasts an annual return
15 of 7.60 to 8.80% on common stocks over the next 10 to 15 years.[17]

16 Q **Does Mr. Somma's CAPM analysis provide the Commission with useful data**
17 **to estimate Westar's cost of equity?**

18 A No, it does not. The Commission should not place any weight on Mr. Somma's
19 CAPM analysis as I have demonstrated that the inputs are not representative of
20 the capital markets and would not be relied on by investors.

[16] Historic total return on the S&P 500 Index from 1926 through 2014 as reported in Ibbotson SBBI 2015 Classic Yearbook, Market Returns for Stocks, Bonds, Bills & Inflation; Morningstar.
[17] Long-Term Capital Market Return Assumptions: 2015 Estimates and the Thinking Behind the Numbers. https://am.jpmorgan.com/us/institutional/ltcmra

1 **Response to Westar Proxy Group**

2 Q **Do you agree with the proxy group Mr. Somma used in his cost of equity**
3 **analysis?**

4 A No. Mr. Somma incorporates a market capitalization selection parameter that I do
5 not use in my selection.

6 Q **Do you believe the proxy group is a cause of the difference in ROE estimates**
7 **between you and Mr. Somma?**

8 A No, it is unlikely the cause of the difference as all of Mr. Somma's proxy
9 companies are in my analysis and, generally, except for the market capitalization
10 parameter, his selection criteria is similar to those that I used. Given these
11 similarities, I will not spend time rebutting his proxy group.

12 Q **To be clear, are you using the same proxy group as Mr. Somma?**

13 A No. My proxy group is larger, consisting of 22 electric utilities, and it includes all
14 12 of the electric utilities in Mr. Somma's proxy group.

15 **Response to Westar DCF Analysis**

16 Q **On page 45 of his direct testimony, Mr. Somma states that his DCF analysis**
17 **results in a mean of 9.47% and a median of 9.52%. Why are his estimates so**
18 **much higher than your DCF analysis?**

19 A There are two reasons for the difference: 1) the growth rates he selects; and 2) his
20 exclusion of the results of one company. Mr. Somma shows the result of his DCF
21 analysis in Table 3 on page 45 of his testimony. Oddly enough, there are no
22 tables in his Direct Testimony that show his specific inputs for his DCF model;
23 that information only exists in his work papers.

1 **Q Why do you disagree with the growth rates in Mr. Somma's DCF analysis?**

2 A I disagree because he relies solely on three to five year earnings growth forecasts
3 for his estimate of growth in his DCF model. Throughout his testimony, he refers
4 to securities analysts' three to five year earnings growth forecasts as "long-term
5 forecasts." His methodology is contrary to the fundamentals of the DCF model
6 which views growth prospects well beyond Mr. Somma's three to five year
7 horizon.

8 I discuss growth rate selection for the DCF model earlier in my testimony.
9 Research demonstrates that securities valuation theory and its practical
10 application of the DCF model demands a long-term view of growth. Whether the
11 practitioner uses a two-stage DCF model, as I have or single stage DCF model as
12 Mr. Somma has done, the practitioner has to recognize that the DCF model
13 demands a long-term growth projection; a growth estimate that goes beyond the
14 three to five year window of analysts' earnings growth forecasts.

15 **Q What are the sources for Mr. Somma's growth estimates?**

16 A He obtains three to five year forecasts of earnings growth from Value-Line
17 Investment Survey, Thomson Reuters, and Bloomberg. I do not object to any of
18 these sources for earnings growth rate estimates. I only object to Mr. Somma's
19 position that market participants use a three to five year forecast as that which
20 continues far beyond that time period.[18]

21 **Q How do his growth forecasts compare to historic growth rates for electric**
22 **utilities?**

[18] His DCF calculations and the inputs to his DCF analysis appear only in his work papers (KCC #85).

1 A Mr. Somma does not provide any sort of review, analysis, or historical context for
2 his growth rates, nor does he even disclose the growth rates in his testimony.
3 Which is an odd presentation when he in fact acknowledges that the growth rate
4 in the DCF model is "...the most significant area of controversy among model
5 inputs."[19] Despite his acknowledgment that this is a critical input to a DCF
6 model, he never provides any historical context for this critical input.

7 **Q You stated earlier that a 4.38% annual growth in nGDP is forecasted for the**
8 **coming decades. How does that compare to the growth rates Mr. Somma**
9 **uses?**

10 A As you can see in the following table, the average three to five year annual
11 earnings growth forecast for Westar's proxy group is 5.86%; significantly greater
12 than the forecasted growth rate for the economy. Mr. Somma never attempts to
13 explain why it is reasonable for us to assume that his proxy group of electric
14 utilities will grow at a rate so much greater than the U.S. economy for many
15 decades into the future.

[19] Somma Direct 15-WSEE-115-RTS; p43; line 1.

Annual Growth Rates Contained in Mr. Somma's DCF Analysis	
	Growth
Westar Energy, Inc.	4.22%
Ameren Corp	7.08%
Allete Inc	6.00%
Avista Corp	4.75%
Great Plains Energy Inc	5.24%
IdaCorp Inc	excluded
Alliant Energy Corp	5.45%
NorthWestern Corp	6.87%
OGE Energy Corp	5.68%
PNM Resources Inc	8.14%
Pinnacle West Capital	4.48%
Portland General Electric Co	7.23%
TECO Energy	5.17%
Mean	5.86%
Median	5.56%
Source: Response to KCC DR #85	

Q You stated earlier that you disagree with the removal of IDACORP, Inc. from the DCF results. Why do you disagree?

A Mr. Somma concluded that the DCF outcomes for IdaCorp were too low to be logically representative of the capital markets, so he removed that result from the average. Mr. Somma stated that he removed IdaCorp from the average because its DCF results "...yielded a return on equity lower than the cost of debt that Westar is requesting."[20] While that statement is true, it is not a reason for removing that observation from the average. For an appropriate comparison, Mr. Somma should be looking to the *market cost* of debt in the current capital markets as opposed to the embedded or *historic cost* of debt. In the time period in which Mr. Somma gathered pricing data, the yield on Baa/BBB rated utility debt was about 4.30%. Thus, by a measure of current, market derived bond yields, the

[20] Somma Direct p44

1 estimates for IdaCorp should remain in the analysis. Leaving IdaCorp in the data
2 set lowers the average.
3 A test such as that applied by Mr. Somma is a common test used in cost of equity
4 studies as means to remove observations that are illogically low relative to other
5 investments. It is common place to assume to use observations on utility bond
6 yields as a benchmark. For instance, FERC has adopted a low-end limit of the
7 prevailing yield on utility bonds *plus* 100 basis points under the rationale that
8 investors would require a minimum risk premium of 100 basis points over the
9 available bond yield to induce them to purchase the common stock. As I pointed
10 out in the previous paragraph, the widely accepted benchmark is market yield; it
11 is not the historic or embedded yield as Mr. Somma relied on.
12 **Q If Mr. Somma had incorporated a long-run perspective in his growth**
13 **forecast and in IdaCorp, how much would that change the results of his DCF**
14 **analysis?**
15 A Giving the nGDP and his earnings growth rate forecast equal weighting would
16 lower the average of his DCF results 62 basis points. Shown in Table 3 on page
17 45 of Mr. Somma's Testimony, the average of 9.47% would decrease to 8.85%
18 which is comparable to the cost of equity estimates in Staff's DCF analysis.
19 **Response to Westar's Capital Asset Pricing Model**
20 **Q Do you agree with the results of Mr. Somma's CAPM analysis?**
21 A No, I do not. His CAPM analysis does not provide an accurate picture of
22 Westar's capital costs because of overly optimistic long-run growth rates.
23 **Q What is the result of Mr. Somma's CAPM analysis?**

A Mr. Somma's CAPM analysis indicates a cost of equity in the range of 10.86% to 11.76%.

Q Where is the growth rate applied in the CAPM?

A In Mr. Somma's CAPM analysis, the three to five year annual earnings growth rate estimate is used to calculate the market return (Rm) used in the CAPM. Thus, the growth rate is a couple layers deep into the CAPM equation, but nonetheless it has a tremendous impact on the end result of the CAPM. The growth rate is used to estimate the expected return on the S&P 500 stock index. The expected return on the market index becomes the foundation for the calculation of the individual company. If the foundation or Rm does not comport with capital market theory and realistic valuation practices, then the CAPM analysis on the individual company will be inaccurate.

Q What is the Rm supposed to represent?

A In the CAPM the Rm is the return expected by investors through an index of the stock market such as the S&P 500.

Q What does Mr. Somma claim the S&P 500 will return in the future?

A Mr. Somma estimated that the S&P 500 will return 13.25% annually for many, many years into the future; a dizzyingly high return that is even higher than the often cited historic return on common stocks of 12.10% for 1926 through 2014.[21] Economic growth for the foreseeable future is forecast to be significantly lower than that experienced in those 88 years. This forecast for the S&P 500 is solely his own. He does not provide any support for this estimate or provide any

[21] Ibbotson SBBI 2015 Classic Yearbood: Market Results for Stocks, Bonds, Bills, and Inflation 1926-2014; Mornningstar; p.40.

1 corroborating studies indicating that market participants factor estimates similar
2 to his into their decisions. I have not come across any analytical work that could
3 support such a high return on common stocks in the coming decades.

4 Q **How does Mr. Somma arrive at his forecast of a 13.25% annual return from**
5 **the S&P 500?**

6 A He performs a DCF analysis on each of the 500 companies in the S&P 500 Index.
7 The calculation requires a dividend yield and a long-run growth rate estimate to
8 apply to each company's dividends. Just as with the DCF estimates for his proxy
9 group, the calculation of the dividend yield is relatively uncontroversial. It is his
10 growth rate estimates that cause an extraordinarily high cost of equity estimate.

11 Q **What growth does he apply to each of the 500 companies?**

12 A Mr. Somma uses the annual earnings growth rate estimate obtained from
13 Bloomberg, a source he also uses in his DCF analysis of his proxy group.
14 Bloomberg reports the consensus or average of analysts' growth forecasts. These
15 are three to five year earnings growth rate projections. Consensus estimates are
16 an average of growth estimates made by analysts.

17 Q **How does he apply the growth forecasts?**

18 A Mr. Somma's calculations assume that the three to five year earnings growth for
19 each company continues in perpetuity, forever. For any company with a negative
20 three to five year earnings growth forecast, he applied a growth rate of *zero*. That
21 is to say, he has biased his growth estimate by assuming that no company in the
22 S&P 500 will ever experience negative earnings growth. He did not provide any
23 support or evidence that market participants share his level of optimism. I have

1 not evaluated the effect of Mr. Somma zeroing out the negative growth
2 projections; I find that to be an unusual methodology to use in evaluating the
3 expected return for the market.

4 **Q With that unique methodology that Mr. Somma applies, what is the growth**
5 **rate that Mr. Somma assumes for the S&P 500?**

6 A Mr. Somma expects earnings of the S&P 500 Index to grow at annual rate of
7 11.28%; more than two and a half times the expected growth rate of the nation's
8 economy. Mr. Somma's CAPM is highly dependent on this extraordinarily high
9 earnings growth forecast. Incorporating a growth forecast that is more in line
10 with expected long-run growth will lower the results of his CAPM analysis
11 proportionally to the change in forecasted growth. A growth rate estimate that is
12 more in line with expectations will result in a CAPM result that is closer to my
13 CAPM results.

14 **Q Are there any notable data points in Mr. Somma's S&P 500 index?**

15 A In Mr. Somma's analysis the forecasted growth rate for ExxonMobile is negative
16 for the next three to five years. That is not surprising given the sudden drop in
17 energy prices; it is conceivable that the company could experience a contraction
18 in earnings for a period of time. Mr. Somma's CAPM analysis assumes
19 ExxonMobile, the second largest publicly traded corporation in the world, will
20 forever have a growth rate of zero. Mr. Somma does not attempt to reconcile his
21 application of the CAPM with the reality of the financial markets. Under Mr.
22 Somma's analysis, we would expect the price of ExxonMobile to collapse; it has

not collapsed, it has declined in value as have most energy companies, but it has not collapsed.

Q If Mr. Somma is projecting zero growth, in lieu of the negative growth rate reported by Bloomberg, why would ExxonMobile continue to have value and continue to be the second largest investment vehicle in the world?

A I would surmise that it is because investors do not apply growth forecasts in the same manner as Mr. Somma has done throughout his analysis. Rather than believing that analysts' three to five year earnings growth forecasts are the sole forecasts for valuation analysis, market participants likely recognize that ExxonMobile's three to five year growth forecast should not be used as an estimate of growth in to perpetuity. That is why the stock has not collapsed and it continues to be one of the largest corporations in the world. ExxonMobile is not the only data point that exhibits a negative growth rate that was zeroed out by Mr. Somma, there are several more examples in his analysis.

Response to Westar's Risk Premium Study

Q Do you agree with the results of the Risk Premium study that begins on page 50 of Mr. Somma's Testimony?

A I disagree with using this type analysis in setting Westar's allowed return because this type of analysis has several shortcomings that cast doubt on the applicability of the results. Although the data provides an interesting view of regulatory and financial history, I recommend the Commission disregard it in setting Westar's allowed return.

1 **Q How is the risk premium study constructed?**

2 A Mr. Somma's risk premium analysis is based on observations of allowed returns
3 granted by state regulatory commissions to electric utilities in litigated cases and
4 the yield on 10 Year U.S. Treasury Bonds prevailing at the time of the rate case.
5 From these observations, he established a relationship between the risk premium
6 (the allowed ROE granted by commissions minus the prevailing yield on 10 Year
7 U.S. Treasury Bond) and the yield on the 10 Year U.S. Treasury Bond.

8 **Q Is this a new type of analysis for estimating the cost of equity?**

9 A Mr. Somma's Risk Premium analysis is similar to that filed by several different
10 Kansas jurisdictional utilities in recent gas and electric rate cases. My criticism of
11 Westar's risk premium analysis is the same as in those recent dockets.

12 **Q Is the reasonable return on equity for Westar equal to the return granted to**
13 **other utilities in other jurisdictions many years ago?**

14 A No, relying on the allowed returns granted to other utilities in other jurisdictions
15 runs the risk of overlooking data in the present day capital markets, setting an
16 allowed return on what could be outdated information. At a minimum, such a
17 practice creates a degree of circular reasoning that could preclude a Commission
18 from setting an allowed return at any level other than some historic average when
19 current economic conditions call for something different. *Hope* and *Bluefield*
20 emphasize that an allowed return changes with changes in the capital markets.

21 **Q What are your observations of Mr. Somma's risk premium study?**

22 A The Commission needs to be cautious in using Mr. Somma's risk premium study
23 because it does not comport with the framework set out in the *Hope* and *Bluefield*

1 decisions, as there is no comparison of the risk of the electric utilities in the
2 historic data to the risk of Westar today. The *Hope* and *Bluefield* decisions state
3 that an allowed return must be commensurate with risks on similar investments;
4 Mr. Somma's risk premium study does not speak to that standard. It would be
5 comparable to merely performing a DCF analysis on all of the electric utilities,
6 without attempting to select a proxy group of comparable risk. Both I and Mr.
7 Somma recognize that electric utility companies are different from one another.
8 That is why both of us culled through many publicly traded electric utilities to
9 arrive at our respective proxy groups that we believe are similar in risk to Westar.
10 Keep in mind that research publications such as Value-Line cover about 45
11 companies in the electric utility industry, from which Mr. Somma selected 12 as
12 being of comparable risk to Westar; an indication that he believes that electric
13 utilities are not of equal risk.

14 **Q Have the electric utility industry and regulatory policies evolved and changed**
15 **over this period of time since 1980 that alters its risk profile?**

16 A Yes, I believe it has changed over this 35 year time period and Mr. Somma's risk
17 premium analysis fails to recognize any changes to the industry as merely
18 plugging in a recent interest rate does not measure changes in risk. For instance,
19 rate design, and trackers/riders/pass-through mechanisms have evolved over the
20 past two decades; these mechanisms lower the risk of utilities by shifting risk to
21 the consumer. Mr. Somma fails to account for such changes in the industry.
22 Equally important as those formal mechanisms used in Kansas is this Staff's
23 willingness to update Westar's rate base well beyond the test-year balances which

is a tremendous benefit to Westar. Mr. Somma does not offer his thoughts on whether the Kansas regulatory mechanisms and post-test-year updates are the norm for the industry either now or over history. Thus, based on Mr. Somma's Testimony we cannot know whether those observations in the 1980's and 1990's provide us with a risk premium measure that is applicable today.

Risk premium studies such as these provide some historical perspective of the changes in capital costs that occurred in the past three decades and, for that reason alone, a review of the data is interesting. The findings in this risk premium analysis are not compelling evidence because there is no distinction of risk among the observations in the data.

Response to Westar's Request for Flotation Costs

Q Has Westar requested recovery of flotation costs as part of its cost of equity?

A Yes, Mr. Somma has requested an additional 12 basis points to recover the flotation costs associated with issuing equity capital.

Q Does Staff support the recovery of such expenses added to the allowed return on equity?

A No. Staff does not support inclusion of flotation costs in its cost of equity because Westar has not attempted to quantify the amount, if any, of unrecovered costs associated with it issuing common equity.

Q How much does Westar's adjustment collect in flotation costs?

A In the following table, I calculate the annual revenue requirement of Westar's proposed 12 basis point adjustment to recover flotation costs.

Quantification of Westar's Proposed Flotation Cost Adjustment		
Total Rate Base (Application Section 3)		$ 5,062,804,912
Equity Ratio of Capital Structure		53%
Equity Financed Rate Base		$ 2,683,286,603
Flotation Cost	0.12%	
Tax Gross Up Factor	0.6667	
Pretax Flotation Cost Collected in Rev Req	0.18%	
Annual Flotation Cost Charged to Westar Consumers		$ 4,829,674

Westar does not quantify the dollar amount of this element on the revenue requirement, nor does it explain why recovering this expense through the cost of equity is efficient. I contend that it is not efficient because the cost of equity has to be grossed up to recover the associated income taxes.

Q Is there a more efficient way to recover those costs?

A Yes, simply track the actual costs, and include a pro forma adjustment to the test year operations to include those costs as an expense in the rate case. We could certainly spread recovery of those costs over a several decades.

Q If the Commission follows past practices and allows Westar an allowance for flotation costs, does Mr. Somma's estimate of 12 basis points comport that practice?

A Yes, it does, as he has applied the flotation cost adjustment to common equity less the retained earnings portion of common equity. Historically, flotation cost adjustments calculated in this manor are in the range of 10 to 12 basis points.

<u>Response to Westar's Claim of Needing a Premium on its ROE</u>

Q Did you evaluate Mr. Somma's claim that Westar could justify a higher return due to its "small size"?

1 A Yes, the issue of higher return or a premium to the allowed return related to
2 "small size" is not new to the Commission, although I believe this is the first time
3 it has been made by one of our major utilities. The Commission is faced with this
4 argument from time to time in testimony from rural telephone companies in
5 Kansas Universal Service Fund audits.

6 **Q Has the Commission explicitly agreed that small utilities require a premium**
7 **on their allowed return?**

8 A My recollection of the past decade is that the Commission has not explicitly
9 agreed with the concept of small utilities requiring a premium or higher allowed
10 return solely due to their relative size. Those decisions have almost exclusively
11 been in telecommunications cases dealing with regulated entities that are much,
12 much smaller than Westar. If the Commission is unwilling to accept the notion of
13 a small-size premium on those companies, there would be good reason not to
14 adopt such a premium for a much larger entity like Westar.

15 **Q What is your position on the small-size premium?**

16 A I have consistently opposed this type of adjustment because it is not a widely
17 accepted premise in public utility finance (or even finance generally) that size as
18 measured by capitalization is a determinant of risk. The data used to support the
19 notion of a small company risk premium has shown that there is a survivorship
20 bias. The survivorship bias stems from the fact that a larger proportion of small
21 companies cease to exist than larger companies. The studies supporting a small
22 company premium frequently fail to measure the full extent of the loss incurred
23 by investors in those small companies that disappear. Accurately measuring those

1 losses has been shown to eliminate measured small company premium.
2 There is a tremendous amount of data mining that has taken place on this very
3 topic and similar beliefs of market inefficiencies some believe create
4 opportunities for investors. Professor Burton Malkiel author of A Random Walk
5 Down Wall Street, addresses the measurement of a size premium along with
6 several other alleged measures of market inefficiencies in a 2003 journal article.
7 His conclusion is that if investors cannot replicate or exploit the alleged market
8 inefficiency, it likely does not exist. As this passage discusses, professionals have
9 attempted to profit from these alleged market conditions and it is not profitable.[22]

> Many of the predictable patterns that have been discovered may simply be the result of data mining. The ease of experimenting with financial databanks of almost every conceivable dimension makes it quite likely that investigators will find some seemingly significant but wholly spurious correlation between financial variables or among financial and nonfinancial data sets. Given enough time and massaging of data series, it is possible to tease almost any pattern out of most data sets. Moreover, the published literature is likely to be biased in favor of reporting such results. Significant effects are likely to be published in professional journals while negative results, or boring confirmations of previous findings, are relegated to the file drawer or discarded. Data-mining problems are unique to nonexperimental sciences, such as economics, which rely on statistical analysis for their insights and cannot test hypotheses by running repeated controlled experiments.
>
> An exchange at a symposium about a decade ago between Robert Shiller, an economist who is sympathetic to the argument that stock prices are partially predictable and skeptical about market efficiency, and Richard Roll, an academic financial economist who also is a portfolio manager, is quite revealing (Roll and Shiller, 1992). After Shiller stressed the importance of inefficiencies in the pricing of stocks, Roll responded as follows:
>
>> I have personally tried to invest money, my client's money and my own, in every single anomaly and predictive device that academics have dreamed up. . . . I have attempted to exploit the so-called year-end anomalies and a whole variety of strategies supposedly documented by academic research. *And I have yet to make a nickel on any of these supposed market inefficiencies* . . . a true market *inefficiency* ought to be an exploitable opportunity. If there's nothing investors can exploit in a systematic way, time in and time out, then it's very hard to say that information is not being properly incorporated into stock prices.

10

[22] The Efficient Market Hypothesis and Its Critics; Burton G. Malkiel; Journal of Economic Perspectives; Volume 17, Number 1, Winter 2003; pp 59-82.

It is clear from the research on this issue that it is possible to dredge the data banks and find instances where there was some measure of a premium, but investors establish their required return based on risk and there are more reliable measures of the risk in an investment than the size of the company.

Response to Proposed ROE Adjustment Mechanism

Q At page 71 of his Direct Testimony, Mr. Somma describes an ROE adjustment mechanism. Do you believe the Commission should adopt such a mechanism?

A No. I have reviewed Mr. Somma's proposal. Staff's objection to this mechanism is not based on the nuances of Mr. Somma's proposal; it is based on the conceptual notion of an annual adjustment to a utility's allowed return. Staff does not support such a mechanism for Westar because it would set one critical element of the revenue requirement for annual adjustment while there is no annual adjustment for other key drivers of the revenue requirement. Additionally, Westar's allowed return is evaluated in each general rate case and, given the current climate of heavy capital expenditures there have been and will likely continue to be, regularly filed general rate cases. I want to emphasize that Staff is opposed to such a mechanism. If the Commission has an interest in it, Staff recommends that it be considered through a generic proceeding where record is developed for the Commission to assess how this policy change would affect the diverse group of stake-holders in Kansas.

Capital Structure

Q Have you reviewed the capital structure proposed by Westar?

A Yes, I reviewed the capital structure Westar proposed in Section 7 and addressed in the Direct Testimony of Susan M. North. Westar calculated its ROR using a capital structure based on the test year ending September 30, 2014, applying adjustments to reflect projected balances to December 31, 2014, and then pro forma adjustments so that the capital structure reflects what it believes is a picture of its capitalization beyond the test year. Staff is accepting of post-test year adjustments to capital accounts as these are relatively easy to verify.

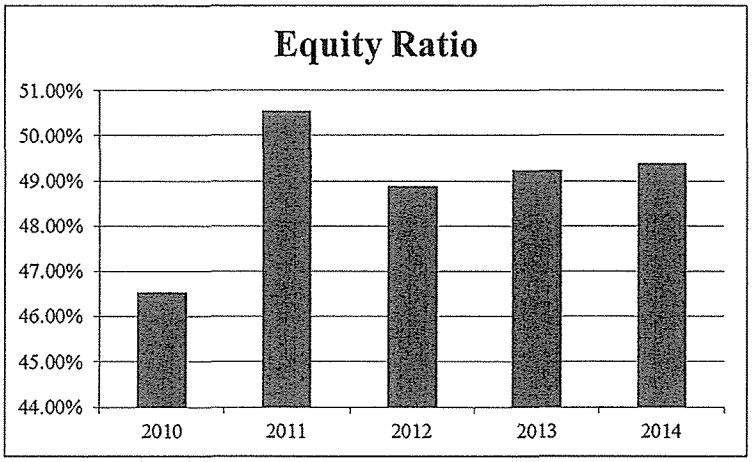
Pro Forma Capital Structure
Test Year Ended September 30, 2014

	September 30, 2014 Totals		December 31, 2014 Adjustments	Pro Forma Adjustments	Used in the ROR Pro Forma December 31, 2014	Ratio
Long-term Debt	$ 3,215,356,038	49.29%	$ 183,066	$ (125,000,000)	$ 3,090,539,104	46.25%
Common Equity	$ 3,264,878,394	50.05%	$ 29,977,610	$ 254,489,857	$ 3,549,345,861	53.12%
Post 1970 ITC	$ 42,801,587	0.66%	$ (782,217)	$ -	$ 42,019,370	0.63%
	$ 6,523,036,019		$ 29,378,459	$ 129,489,857	$ 6,681,904,335	

Source: Section 7

Q Do you agree with the capital structure proposed by Westar?

A Generally, yes. I would only note that the proposed equity ratio is high relative to Westar's equity ratio reported in the past. It is not outlandishly high, but it is higher than that seen for more than a decade. As the difference is merely a couple percentage points difference than the historic observations, I am not proposing any adjustment to the capital structure. Staff is using Westar's capital structure as shown in Section 7 of Westar's Application.



	2010	2011	2012	2013	2014
Debt Ratio	53.46%	49.46%	51.11%	50.76%	50.60%
Equity Ratio	46.54%	50.54%	48.89%	49.24%	49.40%

Cost of Debt

Q What is Westar asking to recover as its cost of debt capital?

A In Section 7, Schedule 7-C Westar calculates an embedded cost of long-term debt of 5.687%.

Q Do you agree with Westar's cost of debt?

A Yes, that is the value that Staff will use to calculate the ROR.

Wolf Creek Decommissioning Trust Annual Accrual

Q Please discuss the Wolf Creek Decommissioning issues in this Docket?

A In this Docket, we are dealing with what is referred to as Phase-Two of the triennial review of the Wolf Creek decommissioning cost estimate. In Phase-One

of the review, the Wolf Creek Owners[23] submitted a decommissioning cost estimate and a forecasted cost-inflation rate. Those two variables are used in Phase-Two for each of the owners to calculate their annual accrual payment to its decommissioning trust fund. The annual accrual payment is part of the operating expenses recovered through their respective revenue requirements. Susan North presents Westar's proposal for Phase-Two.

Q What is Westar's proposal for its annual accrual?

A Westar has calculated an annual accrual of $3,150,070 to fund its portion of the decommissioning costs. I disagree with Westar's proposal.

Q Please describe the analysis.

A The goal of the calculations shown in Exhibit SMN-1 of Susan North's Direct Testimony is to estimate how much Westar must deposit each year in a trust account so as to have sufficient funds in the future to pay its share of decommissioning Wolf Creek at the end of its operations. Westar's analysis incorporates ten variables to arrive at an estimate for the annual accrual.

- Decommissioning cost estimate set in Phase-One (15-WCNE-093-GIE)
- Decommissioning timing set in Phase-One (15-WCNE-093-GIE)
- Remaining life of fund
- Westar's 47% ownership percentage
- Kansas jurisdictional allocation factor
- Trust fund investment mix
- Trust fund management fees
- Taxes on fund earnings
- Earnings on fund investments
- Current trust fund balance

[23] Westar Energy owns 47% of Wolf Creek Nuclear Operating Corporation; Great Plains Energy owns 47%; and Kansas Electric Power Cooperative, Inc. owns the remaining 6%.

1 Now that the Commission has adopted a Decommissioning Plan in Phase-One, all
2 but two of the variables are readily discernable. That is to say, for most of the
3 inputs there is not much latitude in what constitutes a realistic input. The two
4 variables, the *trust fund investment mix* and the *earnings on fund investments*, are
5 difficult and somewhat speculative to forecast. Fortunately, these forecasts are
6 reviewed every three years; they are not set once and for all. Future Commissions
7 will have the opportunity to make adjustments in the future as new information
8 comes to light.

9 **Q Is the proposed investment asset mix reasonable?**

10 A The investment mix in Westar's analysis is a reasonable approximation because it
11 presents estimated asset allocation parameters that are likely to apply over the life
12 of the trust. Just as Westar modeled in Exhibit SMN-1, the investment mix
13 should change over time. The trust does not exist into perpetuity; it has a
14 definitive liquidation date and, at the end of its life, it is expected to achieve a
15 specific goal. Thus, as it nears the end-date, the portfolio managers should
16 increase the use of less volatile, fixed income investments so as to protect the
17 value. With the lower volatility investment vehicles comes a lower return.
18 Exhibit SMN-1 correctly models that facet of the investment strategy.

19 **Q Are the forecasted returns reasonable?**

20 A I disagree with the forecasted returns that Westar used in Exhibit SMN-1.
21 Westar's forecasted returns are built largely from historic returns from 1985-2013
22 for the equity investments or historic risk premiums for this time period coupled
23 with the current interest rate on the 30 Year Treasury Bonds for the fixed income

1 securities. My concern with a reliance on historic returns is that historic returns
2 embody a level of annual economic growth that is considerably higher than what
3 is likely in the future. It is generally the case that long-run *projected* returns on
4 both debt and equity investments are lower than those experienced in the recent
5 past. This trend is attributed to expectations for lower inflation relative to historic
6 averages and expectations for slower growth in GDP.

7 **Q What data did you rely on to review the forecasted returns in SMN-1 and the**
8 **adequacy of Westar's proposed annual accrual?**

9 A I relied on the 10 to 15 year returns forecasted by J.P. Morgan Asset
10 Management. As you can see in the following table, J.P. Morgan's forecasts for
11 equity returns are much lower than Westar's forecasts, and its forecasts for returns
12 on cash or short-term fixed income securities are higher than Westar's forecast.

Comparison of Forecasted Returns

	Westar*	J.P. Morgan Forecasted**
Large Capitalization Equities	11.40%	7.60%
Small Capitalization Equities	10.27%	8.81%
International Equities	7.65%	8.10%
Core Bonds (Corporates)	4.89%	4.95%
High Yield Bonds	7.63%	6.40%
Real Estate	7.73%	8.17%
Cash & Equivalents	0.98%	2.00%

*As filed in the testimony of Susan North (SMN-1)

**Asset class forecasts of 10 to 15 year annual returns; Long-term Capital Market Return Assumptions, 2015 Edition (U.S.); J.P. Morgan Asset Management.

13

14 **Q Why do you believe it is reasonable to use the forecasts from J.P. Morgan to**

1 **estimate the annual accrual?**

2 A This information was prepared by JPMAM who manages investments globally.
3 As such, these forecasts represent the expectations of an important market
4 participant that directly manages $1.7 trillion. As an asset manager, JPMAM
5 does not have an incentive to skew the forecasts, as doing so could harm its ability
6 to effectively manage client money. In its 2015 publication, it provides the
7 following discussion of how investors can make use of these forecasts.[24] Our
8 evaluation of the decommissioning trust and capital costs fall within JPMAM
9 intended use.

> How do investors use the LTCMRAs?
>
> The Long-Term Capital Market Return Assumptions are used widely by investment teams throughout J.P. Morgan Asset Management as well as by institutional investors—including pension plans, insurance companies, endowments and foundations—to ensure that investment policies and strategic asset allocations are developed based on a comprehensive and consistent set of "real world" views. In addition the LTCMRAs allow the resulting investment characteristics and return profiles to be tested and analysed, facilitating a more effective communication and underwriting of the implied risk and return profile.
>
> When used, as is most often the case, to review an existing strategic asset allocation, the LTCMRAs can help investors to better assess and quantify the trade-offs available to them across multiple dimensions. These trade-offs include: the relative risk premia between more and less volatile assets; the risk premia associated with investing outside of their own domestic asset classes; which opportunities exist to increase portfolio diversification; and which nominal or real return target is achievable with a given level of portfolio volatility and vice versa.

10

11 Q **Precisely what changes do you propose making to Exhibit SMN-1?**

12 A My recommendation is to change the expected returns on the various asset classes

[24] Long-term Capital Market Return Assumptions: 2015 Estimates & Thinking Behind the Numbers; J.P. Morgan Asset Management; p.7; https://am.jpmorgan.com/lu/institutional/ltcmra

1 from those proposed by Westar to the expected returns presented in the JPMAM
2 study shown in the previous table. The market balance of Westar's trust fund
3 needs to recognize income taxes that must be paid on the net amount of the trust
4 fund's unrealized gains as those taxes will have to be paid sometime in the future.
5 Recognizing the tax liability reduces the balance of the trust fund.[25]

6 **Q What is the effect of those changes to the trust balance and expected returns?**

7 A Changing the returns increases the annual accrual from $3,150,070 proposed by
8 Westar to $5,772,700.

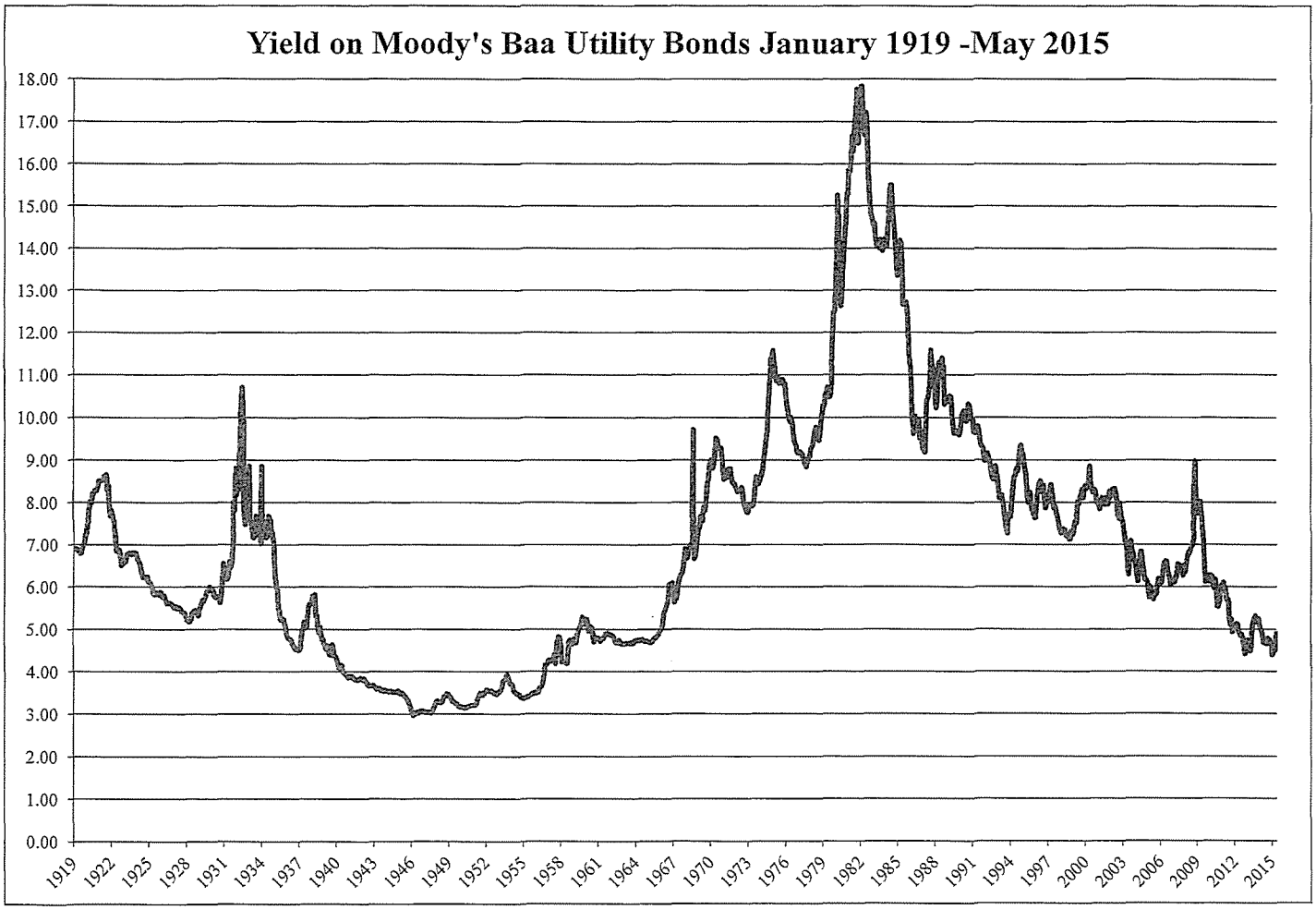
9 **Q How has the trust performed?**

10 A Westar's Decommissioning Trust, accounting for the annual contributions, the
11 accumulated tax liability, and the market value at December 31, 2014,
12 experienced an annual return of 5.40% for the period of 1985 through 2014. My
13 calculations are shown in Schedule AHG-10. Westar projected returns shown in
14 Exhibit SMN-1 are substantially higher than its experience since 1985.

15 **Q Does this conclude your testimony?**

16 A Yes.

[25] In response to KCC DR #334, Westar reported that the December 31, 2014, a fair value $185,015,632 that includes net unrealized gains of $20,929,450. At a 20% tax rate, the trust fund has a tax liability of $4,185,890.


Yield on Moody's Baa Utility Bonds January 1919 -May 2015
18.00
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2015

Schedule AHG-1
15-WSEE-115-RTS

Moody's Public Utility Bond Data		
	Baa	A
Jan-19	6.89	6.35
Feb-19	6.91	6.39
Mar-19	6.91	6.41
Apr-19	6.88	6.18
May-19	6.84	6.27
Jun-19	6.84	6.19
Jul-19	6.79	6.16
Aug-19	6.80	6.26
Sep-19	6.94	6.44
Oct-19	7.01	6.41
Nov-19	7.08	6.67
Dec-19	7.25	6.79
Jan-20	7.30	6.85
Feb-20	7.48	7.03
Mar-20	7.59	7.04
Apr-20	7.88	7.36
May-20	8.03	7.72
Jun-20	7.99	7.73
Jul-20	8.21	7.82
Aug-20	8.21	7.96
Sep-20	8.29	7.83
Oct-20	8.27	7.75
Nov-20	8.28	7.73
Dec-20	8.36	7.96
Jan-21	8.51	7.74
Feb-21	8.50	7.65
Mar-21	8.51	7.61
Apr-21	8.52	7.61
May-21	8.54	7.66
Jun-21	8.62	7.64
Jul-21	8.64	7.72
Aug-21	8.66	7.67
Sep-21	8.30	7.32
Oct-21	8.40	7.04
Nov-21	7.92	6.55
Dec-21	7.68	6.32
Jan-22	7.83	6.41
Feb-22	7.74	6.32
Mar-22	7.55	6.22
Apr-22	7.29	6.06
May-22	6.86	5.93
Jun-22	6.92	5.91
Jul-22	6.83	5.89
Aug-22	6.88	5.86
Sep-22	6.77	5.69
Oct-22	6.51	5.83
Nov-22	6.56	5.87
Dec-22	6.56	5.95
Jan-23	6.59	5.85
Feb-23	6.60	5.83
Mar-23	6.73	6.06
Apr-23	6.78	6.04
May-23	6.78	6.00
Jun-23	6.80	6.06
Jul-23	6.79	6.02
Aug-23	6.77	5.77
Sep-23	6.81	5.95
Oct-23	6.79	5.98
Nov-23	6.78	6.00
Dec-23	6.80	6.05

Moody's Public Utility Bond Data		
	Baa	A
Jan-24	6.73	6.02
Feb-24	6.64	6.00
Mar-24	6.60	5.97
Apr-24	6.55	5.94
May-24	6.42	5.91
Jun-24	6.32	5.79
Jul-24	6.23	5.68
Aug-24	6.24	5.70
Sep-24	6.24	5.71
Oct-24	6.21	5.65
Nov-24	6.24	5.62
Dec-24	6.13	5.63
Jan-25	6.12	5.61
Feb-25	6.08	5.52
Mar-25	6.02	5.53
Apr-25	5.99	5.52
May-25	5.85	5.25
Jun-25	5.82	5.25
Jul-25	5.83	5.37
Aug-25	5.87	5.42
Sep-25	5.85	5.40
Oct-25	5.83	5.39
Nov-25	5.81	5.43
Dec-25	5.88	5.36
Jan-26	5.81	5.29
Feb-26	5.76	5.21
Mar-26	5.80	5.23
Apr-26	5.75	5.20
May-26	5.67	5.15
Jun-26	5.61	5.11
Jul-26	5.61	5.13
Aug-26	5.62	5.15
Sep-26	5.62	5.17
Oct-26	5.61	5.18
Nov-26	5.58	5.15
Dec-26	5.54	5.12
Jan-27	5.51	5.10
Feb-27	5.54	5.13
Mar-27	5.54	5.13
Apr-27	5.49	5.04
May-27	5.50	5.04
Jun-27	5.51	5.05
Jul-27	5.48	5.05
Aug-27	5.43	5.02
Sep-27	5.41	4.98
Oct-27	5.39	4.95
Nov-27	5.38	4.92
Dec-27	5.32	4.88
Jan-28	5.24	4.85
Feb-28	5.20	4.85
Mar-28	5.18	4.82
Apr-28	5.18	4.82
May-28	5.23	4.87
Jun-28	5.38	4.99
Jul-28	5.38	5.04
Aug-28	5.43	5.08
Sep-28	5.45	5.05
Oct-28	5.43	4.99
Nov-28	5.38	4.98
Dec-28	5.32	5.05

Moody's Public Utility Bond Data		
	Baa	A
Jan-29	5.48	5.05
Feb-29	5.52	5.10
Mar-29	5.62	5.14
Apr-29	5.69	5.14
May-29	5.66	5.14
Jun-29	5.72	5.23
Jul-29	5.79	5.24
Aug-29	5.89	5.30
Sep-29	5.92	5.38
Oct-29	5.91	5.34
Nov-29	6.00	5.29
Dec-29	5.96	5.23
Jan-30	5.92	5.26
Feb-30	5.93	5.29
Mar-30	5.80	5.18
Apr-30	5.77	5.15
May-30	5.76	5.04
Jun-30	5.78	5.01
Jul-30	5.78	4.99
Aug-30	5.70	4.95
Sep-30	5.63	4.86
Oct-30	5.82	4.88
Nov-30	6.15	4.96
Dec-30	6.56	5.11
Jan-31	6.36	5.01
Feb-31	6.37	5.01
Mar-31	6.18	4.98
Apr-31	6.19	4.86
May-31	6.36	4.84
Jun-31	6.60	4.87
Jul-31	6.47	4.83
Aug-31	6.60	4.81
Sep-31	7.04	5.05
Oct-31	8.01	5.54
Nov-31	7.80	5.51
Dec-31	8.81	6.24
Jan-32	8.18	6.17
Feb-32	8.33	6.41
Mar-32	8.31	6.06
Apr-32	9.56	6.83
May-32	10.21	7.36
Jun-32	10.70	7.57
Jul-32	10.11	7.28
Aug-32	7.92	6.35
Sep-32	7.48	5.91
Oct-32	7.87	5.81
Nov-32	8.32	5.88
Dec-32	8.41	5.85
Jan-33	8.86	5.39
Feb-33	7.58	5.77
Mar-33	7.58	6.34
Apr-33	7.18	6.89
May-33	7.17	6.50
Jun-33	7.20	6.11
Jul-33	7.36	5.91
Aug-33	7.68	5.98
Sep-33	7.62	6.36
Oct-33	7.38	6.36
Nov-33	7.21	7.06
Dec-33	7.03	7.22

Moody's Public Utility Bond Data		
	Baa	A
Jan-34	8.86	6.56
Feb-34	7.58	5.78
Mar-34	7.58	5.66
Apr-34	7.18	5.44
May-34	7.17	5.39
Jun-34	7.20	5.40
Jul-34	7.36	5.29
Aug-34	7.68	5.43
Sep-34	7.62	5.56
Oct-34	7.38	5.40
Nov-34	7.21	5.38
Dec-34	7.03	5.36
Jan-35	6.60	5.18
Feb-35	6.20	4.96
Mar-35	5.99	4.88
Apr-35	5.94	4.79
May-35	5.51	4.61
Jun-35	5.41	4.53
Jul-35	5.22	4.42
Aug-35	5.22	4.44
Sep-35	5.25	4.43
Oct-35	5.24	4.40
Nov-35	5.12	4.35
Dec-35	5.07	4.29
Jan-36	4.88	4.21
Feb-36	4.80	4.17
Mar-36	4.78	4.17
Apr-36	4.77	4.17
May-36	4.76	4.14
Jun-36	4.72	4.12
Jul-36	4.62	4.07
Aug-36	4.59	4.06
Sep-36	4.54	4.05
Oct-36	4.53	4.04
Nov-36	4.53	3.95
Dec-36	4.53	3.83
Jan-37	4.50	3.82
Feb-37	4.55	3.89
Mar-37	4.76	4.00
Apr-37	4.98	4.07
May-37	5.02	4.00
Jun-37	5.17	3.99
Jul-37	5.08	3.94
Aug-37	5.04	3.89
Sep-37	5.25	3.96
Oct-37	5.53	4.09
Nov-37	5.59	4.08
Dec-37	5.60	4.03
Jan-38	5.59	4.01
Feb-38	5.79	4.03
Mar-38	5.80	3.99
Apr-38	5.82	4.08
May-38	5.32	3.95
Jun-38	5.33	3.95
Jul-38	5.01	3.86
Aug-38	4.93	3.84
Sep-38	5.05	3.88
Oct-38	4.90	3.79
Nov-38	4.77	3.73
Dec-38	4.77	3.74

Moody's Public Utility Bond Data		
	Baa	A
Jan-39	4.66	3.68
Feb-39	4.59	3.59
Mar-39	4.53	3.54
Apr-39	4.62	3.55
May-39	4.50	3.50
Jun-39	4.41	3.47
Jul-39	4.39	3.43
Aug-39	4.39	3.41
Sep-39	4.64	3.71
Oct-39	4.48	3.58
Nov-39	4.38	3.41
Dec-39	4.36	3.38
Jan-40	4.30	3.34
Feb-40	4.23	3.35
Mar-40	4.14	3.34
Apr-40	4.06	3.25
May-40	4.10	3.30
Jun-40	4.15	3.34
Jul-40	3.99	3.23
Aug-40	3.98	3.21
Sep-40	3.94	3.18
Oct-40	3.92	3.15
Nov-40	3.88	3.11
Dec-40	3.86	3.10
Jan-41	3.87	3.15
Feb-41	3.90	3.20
Mar-41	3.90	3.16
Apr-41	3.86	3.14
May-41	3.85	3.08
Jun-41	3.83	3.03
Jul-41	3.82	3.00
Aug-41	3.80	2.98
Sep-41	3.80	3.00
Oct-41	3.82	3.00
Nov-41	3.82	2.98
Dec-41	3.85	3.06
Jan-42	3.83	3.09
Feb-42	3.81	3.09
Mar-42	3.84	3.12
Apr-42	3.79	3.09
May-42	3.76	3.10
Jun-42	3.73	3.12
Jul-42	3.68	3.10
Aug-42	3.67	3.10
Sep-42	3.66	3.08
Oct-42	3.66	3.08
Nov-42	3.67	3.07
Dec-42	3.68	3.06
Jan-43	3.65	3.05
Feb-43	3.61	3.02
Mar-43	3.58	3.01
Apr-43	3.60	3.00
May-43	3.60	3.00
Jun-43	3.60	2.98
Jul-43	3.55	2.96
Aug-43	3.55	2.96
Sep-43	3.55	2.96
Oct-43	3.53	2.97
Nov-43	3.55	2.98
Dec-43	3.55	2.99

Moody's Public Utility Bond Data		
	Baa	A
Jan-44	3.54	2.99
Feb-44	3.53	2.99
Mar-44	3.52	2.97
Apr-44	3.53	2.99
May-44	3.53	2.99
Jun-44	3.53	2.99
Jul-44	3.51	2.96
Aug-44	3.51	2.94
Sep-44	3.51	2.93
Oct-44	3.51	2.94
Nov-44	3.53	2.96
Dec-44	3.54	2.97
Jan-45	3.50	2.99
Feb-45	3.48	2.98
Mar-45	3.48	2.97
Apr-45	3.49	2.95
May-45	3.47	2.92
Jun-45	3.43	2.87
Jul-45	3.40	2.83
Aug-45	3.37	2.80
Sep-45	3.34	2.79
Oct-45	3.29	2.79
Nov-45	3.22	2.77
Dec-45	3.15	2.75
Jan-46	3.07	2.69
Feb-46	3.00	2.67
Mar-46	2.96	2.66
Apr-46	2.98	2.65
May-46	3.02	2.69
Jun-46	3.04	2.70
Jul-46	3.03	2.69
Aug-46	3.02	2.71
Sep-46	3.06	2.75
Oct-46	3.06	2.76
Nov-46	3.07	2.76
Dec-46	3.07	2.76
Jan-47	3.05	2.72
Feb-47	3.03	2.72
Mar-47	3.04	2.72
Apr-47	3.04	2.70
May-47	3.03	2.70
Jun-47	3.04	2.71
Jul-47	3.03	2.73
Aug-47	3.02	2.73
Sep-47	3.06	2.80
Oct-47	3.13	2.88
Nov-47	3.18	2.93
Dec-47	3.25	3.05
Jan-48	3.30	3.05
Feb-48	3.31	3.05
Mar-48	3.29	3.02
Apr-48	3.28	2.97
May-48	3.27	2.94
Jun-48	3.29	2.94
Jul-48	3.34	2.99
Aug-48	3.40	3.03
Sep-48	3.42	3.05
Oct-48	3.44	3.03
Nov-48	3.48	3.07
Dec-48	3.47	3.06

Moody's Public Utility Bond Data		
	Baa	A
Jan-49	3.42	2.99
Feb-49	3.40	2.99
Mar-49	3.36	2.97
Apr-49	3.31	2.96
May-49	3.30	2.95
Jun-49	3.28	2.94
Jul-49	3.25	2.90
Aug-49	3.25	2.86
Sep-49	3.22	2.85
Oct-49	3.19	2.83
Nov-49	3.17	2.81
Dec-49	3.16	2.78
Jan-50	3.18	2.76
Feb-50	3.17	2.76
Mar-50	3.16	2.76
Apr-50	3.15	2.77
May-50	3.15	2.79
Jun-50	3.15	2.79
Jul-50	3.18	2.79
Aug-50	3.18	2.76
Sep-50	3.19	2.80
Oct-50	3.20	2.83
Nov-50	3.21	2.86
Dec-50	3.21	2.86
Jan-51	3.21	2.83
Feb-51	3.21	2.84
Mar-51	3.23	2.95
Apr-51	3.31	3.09
May-51	3.38	3.13
Jun-51	3.45	3.21
Jul-51	3.49	3.26
Aug-51	3.48	3.19
Sep-51	3.44	3.14
Oct-51	3.49	3.17
Nov-51	3.49	3.24
Dec-51	3.53	3.29
Jan-52	3.57	3.29
Feb-52	3.55	3.23
Mar-52	3.55	3.25
Apr-52	3.54	3.23
May-52	3.54	3.22
Jun-52	3.55	3.22
Jul-52	3.53	3.22
Aug-52	3.50	3.24
Sep-52	3.50	3.24
Oct-52	3.50	3.26
Nov-52	3.47	3.24
Dec-52	3.50	3.22
Jan-53	3.51	3.25
Feb-53	3.53	3.30
Mar-53	3.56	3.36
Apr-53	3.62	3.47
May-53	3.76	3.63
Jun-53	3.80	3.71
Jul-53	3.83	3.66
Aug-53	3.88	3.61
Sep-53	3.93	3.62
Oct-53	3.86	3.49
Nov-53	3.78	3.40
Dec-53	3.72	3.38

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Moody's Public Utility Bond Data		
	Baa	A
Jan-54	3.72	3.32
Feb-54	3.69	3.23
Mar-54	3.58	3.16
Apr-54	3.53	3.16
May-54	3.51	3.14
Jun-54	3.50	3.16
Jul-54	3.48	3.14
Aug-54	3.47	3.13
Sep-54	3.44	3.12
Oct-54	3.41	3.12
Nov-54	3.39	3.11
Dec-54	3.38	3.11
Jan-55	3.37	3.13
Feb-55	3.38	3.14
Mar-55	3.38	3.15
Apr-55	3.40	3.15
May-55	3.40	3.19
Jun-55	3.41	3.21
Jul-55	3.43	3.21
Aug-55	3.46	3.24
Sep-55	3.48	3.27
Oct-55	3.47	3.30
Nov-55	3.48	3.32
Dec-55	3.50	3.35
Jan-56	3.50	3.31
Feb-56	3.50	3.29
Mar-56	3.51	3.29
Apr-56	3.59	3.40
May-56	3.62	3.48
Jun-56	3.65	3.49
Jul-56	3.70	3.55
Aug-56	3.84	3.63
Sep-56	4.02	3.72
Oct-56	4.15	3.79
Nov-56	4.15	3.82
Dec-56	4.18	3.91
Jan-57	4.26	3.96
Feb-57	4.26	4.05
Mar-57	4.25	4.05
Apr-57	4.24	4.01
May-57	4.28	4.01
Jun-57	4.33	4.09
Jul-57	4.41	4.20
Aug-57	4.19	4.37
Sep-57	4.66	4.55
Oct-57	4.73	4.61
Nov-57	4.82	4.62
Dec-57	4.81	4.36
Jan-58	4.60	3.93
Feb-58	4.23	3.96
Mar-58	4.25	4.13
Apr-58	4.25	3.95
May-58	4.23	4.01
Jun-58	4.20	3.99
Jul-58	4.19	4.04
Aug-58	4.44	4.29
Sep-58	4.69	4.55
Oct-58	4.74	4.56
Nov-58	4.67	4.47
Dec-58	4.65	4.49

Moody's Public Utility Bond Data		
	Baa	A
Jan-59	4.71	4.52
Feb-59	4.77	4.50
Mar-59	4.69	4.47
Apr-59	4.68	4.56
May-59	4.87	4.77
Jun-59	4.97	4.86
Jul-59	5.03	4.88
Aug-59	5.04	4.89
Sep-59	5.17	5.03
Oct-59	5.29	4.96
Nov-59	5.20	4.90
Dec-59	5.13	4.96
Jan-60	5.20	5.02
Feb-60	5.23	5.00
Mar-60	5.11	4.91
Apr-60	4.96	4.79
May-60	5.08	4.86
Jun-60	5.05	4.84
Jul-60	5.03	4.79
Aug-60	4.81	4.64
Sep-60	4.71	4.57
Oct-60	4.82	4.61
Nov-60	4.80	4.62
Dec-60	4.78	4.65
Jan-61	4.79	4.64
Feb-61	4.76	4.59
Mar-61	4.72	4.48
Apr-61	4.74	4.48
May-61	4.77	4.52
Jun-61	4.78	4.57
Jul-61	4.84	4.65
Aug-61	4.90	4.73
Sep-61	4.91	4.73
Oct-61	4.92	4.71
Nov-61	4.89	4.68
Dec-61	4.88	4.65
Jan-62	4.86	4.65
Feb-62	4.86	4.66
Mar-62	4.85	4.64
Apr-62	4.81	4.59
May-62	4.74	4.51
Jun-62	4.68	4.48
Jul-62	4.68	4.50
Aug-62	4.72	4.53
Sep-62	4.74	4.51
Oct-62	4.71	4.49
Nov-62	4.65	4.45
Dec-62	4.66	4.44
Jan-63	4.65	4.39
Feb-63	4.65	4.37
Mar-63	4.66	4.37
Apr-63	4.67	4.37
May-63	4.67	4.37
Jun-63	4.67	4.37
Jul-63	4.67	4.39
Aug-63	4.66	4.38
Sep-63	4.69	4.40
Oct-63	4.66	4.41
Nov-63	4.68	4.42
Dec-63	4.73	4.46

Moody's Public Utility Bond Data		
	Baa	A
Jan-64	4.74	4.49
Feb-64	4.74	4.50
Mar-64	4.73	4.51
Apr-64	4.75	4.52
May-64	4.73	4.53
Jun-64	4.74	4.55
Jul-64	4.75	4.54
Aug-64	4.75	4.54
Sep-64	4.73	4.53
Oct-64	4.72	4.51
Nov-64	4.72	4.53
Dec-64	4.72	4.54
Jan-65	4.71	4.53
Feb-65	4.69	4.51
Mar-65	4.68	4.50
Apr-65	4.69	4.49
May-65	4.71	4.50
Jun-65	4.77	4.52
Jul-65	4.78	4.54
Aug-65	4.79	4.58
Sep-65	4.82	4.63
Oct-65	4.85	4.66
Nov-65	4.89	4.71
Dec-65	4.97	4.83
Jan-66	4.99	4.86
Feb-66	5.02	4.92
Mar-66	5.19	5.14
Apr-66	5.39	5.25
May-66	5.44	5.25
Jun-66	5.52	5.40
Jul-66	5.61	5.45
Aug-66	5.79	5.58
Sep-66	6.06	5.81
Oct-66	6.07	5.74
Nov-66	6.06	5.63
Dec-66	6.09	5.67
Jan-67	5.83	5.46
Feb-67	5.63	5.28
Mar-67	5.69	5.44
Apr-67	5.74	5.42
May-67	5.93	5.66
Jun-67	6.14	5.84
Jul-67	6.23	5.94
Aug-67	6.29	5.96
Sep-67	6.32	6.05
Oct-67	6.42	6.18
Nov-67	6.63	6.48
Dec-67	6.91	6.67
Jan-68	6.76	6.54
Feb-68	6.68	6.37
Mar-68	6.75	6.41
Apr-68	6.94	6.58
May-68	6.99	6.62
Jun-68	7.01	6.62
Jul-68	6.92	6.53
Aug-68	9.72	6.27
Sep-68	6.67	6.27
Oct-68	6.74	6.40
Nov-68	7.01	6.59
Dec-68	7.23	6.87

Moody's Public Utility Bond Data		
	Baa	A
Jan-69	7.42	7.04
Feb-69	7.39	7.13
Mar-69	7.61	7.27
Apr-69	7.68	7.30
May-69	7.56	7.16
Jun-69	7.77	7.41
Jul-69	7.92	7.52
Aug-69	7.82	7.44
Sep-69	8.11	7.63
Oct-69	8.47	8.02
Nov-69	8.53	8.00
Dec-69	8.89	8.59
Jan-70	9.00	8.69
Feb-70	8.96	8.51
Mar-70	8.81	8.31
Apr-70	8.94	8.31
May-70	9.20	8.67
Jun-70	9.52	9.04
Jul-70	9.48	9.06
Aug-70	9.34	8.88
Sep-70	9.32	8.82
Oct-70	9.27	8.76
Nov-70	9.29	8.79
Dec-70	9.04	8.48
Jan-71	8.76	8.15
Feb-71	8.55	7.89
Mar-71	8.63	8.05
Apr-71	8.58	8.07
May-71	8.68	8.34
Jun-71	8.79	8.45
Jul-71	8.78	8.45
Aug-71	8.80	8.40
Sep-71	8.59	8.18
Oct-71	8.48	8.10
Nov-71	8.47	7.96
Dec-71	8.44	7.90
Jan-72	8.37	7.79
Feb-72	8.32	7.78
Mar-72	8.26	7.77
Apr-72	8.30	7.82
May-72	8.30	7.84
Jun-72	8.31	7.77
Jul-72	8.36	7.82
Aug-72	8.22	7.64
Sep-72	8.01	7.61
Oct-72	7.94	7.66
Nov-72	7.86	7.60
Dec-72	7.78	7.48
Jan-73	7.77	7.52
Feb-73	7.88	7.62
Mar-73	7.95	7.66
Apr-73	7.96	7.63
May-73	7.91	7.63
Jun-73	7.94	7.71
Jul-73	8.10	7.82
Aug-73	8.47	8.04
Sep-73	8.61	8.04
Oct-73	8.44	8.02
Nov-73	8.44	8.15
Dec-73	8.51	8.24

Moody's Public Utility Bond Data		
	Baa	A
Jan-74	8.58	8.36
Feb-74	8.68	8.42
Mar-74	8.81	8.46
Apr-74	9.04	8.77
May-74	9.23	9.00
Jun-74	9.48	9.32
Jul-74	9.72	9.66
Aug-74	10.14	10.03
Sep-74	10.59	10.45
Oct-74	11.03	10.78
Nov-74	11.38	10.46
Dec-74	11.40	10.27
Jan-75	11.57	10.37
Feb-75	11.32	9.99
Mar-75	10.94	9.72
Apr-75	10.86	10.06
May-75	10.95	10.23
Jun-75	10.85	10.10
Jul-75	10.80	10.01
Aug-75	10.87	10.12
Sep-75	10.89	10.19
Oct-75	10.89	10.16
Nov-75	10.78	10.04
Dec-75	10.79	10.11
Jan-76	10.55	9.90
Feb-76	10.31	9.71
Mar-76	10.17	9.67
Apr-76	9.95	9.53
May-76	9.91	9.55
Jun-76	10.01	9.54
Jul-76	9.88	9.37
Aug-76	9.67	9.13
Sep-76	9.47	8.90
Oct-76	9.41	8.79
Nov-76	9.34	8.76
Dec-76	9.21	8.62
Jan-77	9.17	8.61
Feb-77	9.19	8.65
Mar-77	9.20	8.70
Apr-77	9.17	8.71
May-77	9.13	8.71
Jun-77	9.02	8.58
Jul-77	8.97	8.51
Aug-77	8.91	8.49
Sep-77	8.85	8.46
Oct-77	9.01	8.61
Nov-77	9.06	8.64
Dec-77	9.08	8.64
Jan-78	9.27	8.92
Feb-78	9.29	8.97
Mar-78	9.37	8.98
Apr-78	9.54	9.09
May-78	9.70	9.22
Jun-78	9.78	9.40
Jul-78	9.73	9.51
Aug-78	9.53	9.32
Sep-78	9.47	9.28
Oct-78	9.69	9.46
Nov-78	9.99	9.68
Dec-78	10.08	9.70

Moody's Public Utility Bond Data		
	Baa	A
Jan-79	10.29	9.90
Feb-79	10.27	9.84
Mar-79	10.53	10.04
Apr-79	10.56	10.10
May-79	10.70	10.30
Jun-79	10.56	10.14
Jul-79	10.48	9.98
Aug-79	10.50	10.14
Sep-79	10.78	10.36
Oct-79	11.89	11.40
Nov-79	12.48	11.89
Dec-79	12.51	11.79
Jan-80	12.92	12.27
Feb-80	14.42	13.55
Mar-80	15.26	14.65
Apr-80	14.35	13.87
May-80	12.93	12.53
Jun-80	12.63	12.21
Jul-80	12.75	12.26
Aug-80	13.50	12.96
Sep-80	14.07	13.43
Oct-80	14.43	13.58
Nov-80	14.79	14.12
Dec-80	15.29	14.63
Jan-81	15.30	14.26
Feb-81	15.86	14.91
Mar-81	15.83	15.14
Apr-81	16.14	15.48
May-81	16.66	16.25
Jun-81	16.30	15.74
Jul-81	16.98	16.21
Aug-81	17.19	16.58
Sep-81	17.76	17.16
Oct-81	17.71	17.21
Nov-81	16.49	16.20
Dec-81	17.02	16.29
Jan-82	17.83	16.83
Feb-82	17.83	16.84
Mar-82	17.16	16.50
Apr-82	17.00	16.31
May-82	16.68	16.04
Jun-82	17.21	16.42
Jul-82	17.09	16.42
Aug-82	16.37	15.83
Sep-82	15.68	15.40
Oct-82	15.10	14.79
Nov-82	14.81	14.46
Dec-82	14.69	14.43
Jan-83	14.56	14.24
Feb-83	14.61	14.26
Mar-83	14.33	13.94
Apr-83	14.07	13.61
May-83	14.05	13.50
Jun-83	14.16	13.64
Jul-83	14.01	13.58
Aug-83	14.21	13.57
Sep-83	14.10	13.42
Oct-83	13.95	13.25
Nov-83	14.12	13.38
Dec-83	14.23	13.52

Moody's Public Utility Bond Data		
	Baa	A
Jan-84	14.05	13.39
Feb-84	14.05	13.41
Mar-84	14.56	13.87
Apr-84	14.82	14.16
May-84	15.28	14.90
Jun-84	15.50	15.09
Jul-84	15.50	14.82
Aug-84	14.79	14.43
Sep-84	14.51	14.17
Oct-84	14.17	13.80
Nov-84	13.72	13.23
Dec-84	13.46	13.11
Jan-85	13.36	12.99
Feb-85	13.44	13.08
Mar-85	14.19	13.87
Apr-85	14.11	13.61
May-85	13.62	13.12
Jun-85	12.66	12.13
Jul-85	12.70	12.07
Aug-85	12.73	12.13
Sep-85	12.72	12.13
Oct-85	12.52	12.01
Nov-85	12.04	11.49
Dec-85	11.48	10.97
Jan-86	11.24	10.79
Feb-86	10.74	10.26
Mar-86	9.91	9.48
Apr-86	9.63	9.14
May-86	10.02	9.59
Jun-86	10.03	9.62
Jul-86	9.69	9.37
Aug-86	9.70	9.29
Sep-86	9.96	9.52
Oct-86	9.52	9.52
Nov-86	9.69	9.28
Dec-86	9.49	9.12
Jan-87	9.27	8.95
Feb-87	9.24	9.00
Mar-87	9.19	8.93
Apr-87	9.85	9.38
May-87	10.40	9.91
Jun-87	10.46	10.02
Jul-87	10.62	10.15
Aug-87	10.90	10.45
Sep-87	11.58	11.22
Oct-87	11.29	10.75
Nov-87	11.18	10.61
Dec-87	11.09	10.54
Jan-88	10.50	9.96
Feb-88	10.23	9.70
Mar-88	10.43	9.84
Apr-88	11.08	10.40
May-88	11.28	10.72
Jun-88	11.00	10.53
Jul-88	11.22	10.75
Aug-88	11.39	10.89
Sep-88	10.92	10.41
Oct-88	10.31	10.01
Nov-88	10.35	9.90
Dec-88	10.44	10.06

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Moody's Public Utility Bond Data		
	Baa	A
Jan-89	10.38	10.08
Feb-89	10.38	10.07
Mar-89	10.50	10.23
Apr-89	10.49	10.18
May-89	10.29	9.99
Jun-89	9.80	9.64
Jul-89	9.64	9.50
Aug-89	9.64	9.52
Sep-89	9.70	9.58
Oct-89	9.64	9.54
Nov-89	9.64	9.51
Dec-89	9.60	9.44
Jan-90	9.74	9.56
Feb-90	9.96	9.76
Mar-90	10.06	9.85
Apr-90	10.13	9.92
May-90	10.16	10.00
Jun-90	9.96	9.80
Jul-90	9.92	9.75
Aug-90	10.12	9.92
Sep-90	10.32	10.12
Oct-90	10.28	10.05
Nov-90	10.12	9.90
Dec-90	9.96	9.73
Jan-91	9.96	9.71
Feb-91	9.68	9.47
Mar-91	9.74	9.55
Apr-91	9.64	9.46
May-91	9.64	9.44
Jun-91	9.79	9.59
Jul-91	9.69	9.55
Aug-91	9.47	9.29
Sep-91	9.35	9.15
Oct-91	9.32	9.12
Nov-91	9.28	9.05
Dec-91	9.07	8.88
Jan-92	8.98	8.84
Feb-92	9.09	8.93
Mar-92	9.16	8.97
Apr-92	9.11	8.93
May-92	9.01	8.87
Jun-92	8.90	8.78
Jul-92	8.69	8.57
Aug-92	8.58	8.44
Sep-92	8.54	8.40
Oct-92	8.76	8.54
Nov-92	8.86	8.63
Dec-92	8.69	8.43
Jan-93	8.57	8.27
Feb-93	8.31	8.04
Mar-93	8.10	7.90
Apr-93	8.11	7.81
May-93	8.18	7.86
Jun-93	8.05	7.75
Jul-93	7.93	7.54
Aug-93	7.59	7.25
Sep-93	7.35	7.04
Oct-93	7.27	7.03
Nov-93	7.69	7.30
Dec-93	7.73	7.34

Moody's Public Utility Bond Data		
	Baa	A
Jan-94	7.66	7.33
Feb-94	7.76	7.47
Mar-94	8.11	7.85
Apr-94	8.47	8.22
May-94	8.61	8.33
Jun-94	8.64	8.31
Jul-94	8.80	8.47
Aug-94	8.74	8.41
Sep-94	8.98	8.64
Oct-94	9.24	8.86
Nov-94	9.35	8.98
Dec-94	9.16	8.76
Jan-95	9.15	8.73
Feb-95	8.93	8.52
Mar-95	8.78	8.37
Apr-95	8.67	8.27
May-95	8.30	7.91
Jun-95	8.01	7.60
Jul-95	8.11	7.70
Aug-95	8.24	7.83
Sep-95	7.98	7.62
Oct-95	7.82	7.46
Nov-95	7.81	7.43
Dec-95	7.63	7.23
Jan-96	7.64	7.22
Feb-96	7.78	7.37
Mar-96	8.15	7.73
Apr-96	8.32	7.89
May-96	8.45	7.98
Jun-96	8.51	8.06
Jul-96	8.44	8.02
Aug-96	8.25	7.84
Sep-96	8.41	8.01
Oct-96	8.15	7.77
Nov-96	7.87	7.49
Dec-96	7.98	7.59
Jan-97	8.18	7.77
Feb-97	8.02	7.64
Mar-97	8.26	7.87
Apr-97	8.42	8.03
May-97	8.28	7.89
Jun-97	8.12	7.72
Jul-97	7.87	7.48
Aug-97	7.93	7.51
Sep-97	7.84	7.58
Oct-97	7.67	7.35
Nov-97	7.49	7.25
Dec-97	7.41	7.16
Jan-98	7.28	7.04
Feb-98	7.36	7.12
Mar-98	7.37	7.16
Apr-98	7.37	7.16
May-98	7.34	7.16
Jun-98	7.21	7.03
Jul-98	7.24	7.03
Aug-98	7.20	7.00
Sep-98	7.13	6.93
Oct-98	7.13	6.96
Nov-98	7.31	7.03
Dec-98	7.24	6.91

Moody's Public Utility Bond Data		
	Baa	A
Jan-99	7.30	6.97
Feb-99	7.41	7.09
Mar-99	7.55	7.26
Apr-99	7.51	7.22
May-99	7.74	7.47
Jun-99	8.03	7.74
Jul-99	7.97	7.71
Aug-99	8.16	7.91
Sep-99	8.19	7.93
Oct-99	8.32	8.06
Nov-99	8.12	7.94
Dec-99	8.28	8.14
Jan-00	8.40	8.35
Feb-00	8.33	8.25
Mar-00	8.40	8.28
Apr-00	8.40	8.29
May-00	8.86	8.70
Jun-00	8.47	8.36
Jul-00	8.33	8.25
Aug-00	8.25	8.13
Sep-00	8.32	8.23
Oct-00	8.29	8.14
Nov-00	8.25	8.11
Dec-00	8.01	7.84
Jan-01	7.99	7.80
Feb-01	7.94	7.74
Mar-01	7.85	7.68
Apr-01	8.06	7.93
May-01	8.11	7.99
Jun-01	8.02	7.85
Jul-01	8.05	7.78
Aug-01	7.95	7.59
Sep-01	8.12	7.75
Oct-01	8.02	7.63
Nov-01	7.96	7.57
Dec-01	8.27	7.83
Jan-02	8.13	7.66
Feb-02	8.18	7.54
Mar-02	8.31	7.76
Apr-02	8.25	7.57
May-02	8.33	7.52
Jun-02	8.25	7.41
Jul-02	8.08	7.31
Aug-02	7.74	7.17
Sep-02	7.62	7.08
Oct-02	7.99	7.23
Nov-02	7.75	7.14
Dec-02	7.60	7.06
Jan-03	7.47	7.06
Feb-03	7.17	6.93
Mar-03	7.05	6.79
Apr-03	6.93	6.64
May-03	6.47	6.36
Jun-03	6.29	6.21
Jul-03	6.65	6.56
Aug-03	7.09	6.79
Sep-03	6.87	6.56
Oct-03	6.78	6.42
Nov-03	6.69	6.37
Dec-03	6.61	6.27

Moody's Public Utility Bond Data		
	Baa	A
Jan-04	6.47	6.16
Feb-04	6.28	6.15
Mar-04	6.13	5.97
Apr-04	6.46	6.35
May-04	6.75	6.62
Jun-04	6.84	6.46
Jul-04	6.67	6.27
Aug-04	6.45	6.14
Sep-04	6.27	5.98
Oct-04	6.17	5.94
Nov-04	6.16	5.96
Dec-04	6.10	5.92
Jan-05	5.95	5.78
Feb-05	5.76	5.61
Mar-05	6.00	5.83
Apr-05	5.95	5.64
May-05	5.88	5.53
Jun-05	5.70	5.40
Jul-05	5.80	5.51
Aug-05	5.80	5.50
Sep-05	5.83	5.52
Oct-05	6.08	5.79
Nov-05	6.19	5.88
Dec-05	6.14	5.79
Jan-06	6.06	5.74
Feb-06	6.11	5.82
Mar-06	6.26	5.98
Apr-06	6.54	6.29
May-06	6.59	6.41
Jun-06	6.61	6.40
Jul-06	6.61	6.37
Aug-06	6.43	6.20
Sep-06	6.26	6.00
Oct-06	6.24	5.98
Nov-06	6.04	5.80
Dec-06	6.05	5.81
Jan-07	6.16	5.96
Feb-07	6.10	5.90
Mar-07	6.10	5.85
Apr-07	6.24	5.97
May-07	6.23	5.99
Jun-07	6.54	6.30
Jul-07	6.49	6.25
Aug-07	6.51	6.24
Sep-07	6.45	6.18
Oct-07	6.36	6.11
Nov-07	6.27	5.97
Dec-07	6.51	6.16
Jan-08	6.35	6.02
Feb-08	6.60	6.21
Mar-08	6.68	6.21
Apr-08	6.81	6.29
May-08	6.79	6.28
Jun-08	6.93	6.38
Jul-08	6.97	6.40
Aug-08	6.98	6.37
Sep-08	7.15	6.49
Oct-08	8.58	7.56
Nov-08	8.98	7.60
Dec-08	8.11	6.52

Moody's Public Utility Bond Data		
	Baa	A
Jan-09	7.90	6.39
Feb-09	7.74	6.30
Mar-09	8.00	6.42
Apr-09	8.03	6.48
May-09	7.76	6.49
Jun-09	7.30	6.19
Jul-09	6.87	5.97
Aug-09	6.36	5.71
Sep-09	6.12	5.53
Oct-09	6.22	5.64
Nov-09	6.16	5.64
Dec-09	6.27	5.83
Jan-10	6.13	5.77
Feb-10	6.27	5.88
Mar-10	6.24	5.88
Apr-10	6.06	5.66
May-10	5.97	5.44
Jun-10	6.18	5.46
Jul-10	5.98	5.26
Aug-10	5.55	5.01
Sep-10	5.53	5.01
Oct-10	5.62	5.10
Nov-10	5.85	5.37
Dec-10	6.04	5.56
Jan-11	6.06	5.57
Feb-11	6.10	5.68
Mar-11	5.97	5.56
Apr-11	5.98	5.55
May-11	5.74	5.32
Jun-11	5.67	5.26
Jul-11	5.70	5.27
Aug-11	5.22	4.69
Sep-11	5.11	4.48
Oct-11	5.24	4.52
Nov-11	4.93	4.25
Dec-11	5.07	4.33
Jan-12	5.06	4.34
Feb-12	5.02	4.36
Mar-12	5.13	4.48
Apr-12	5.11	4.40
May-12	4.97	4.20
Jun-12	4.91	4.08
Jul-12	4.85	3.93
Aug-12	4.88	4.00
Sep-12	4.81	4.02
Oct-12	4.54	3.91
Nov-12	4.42	3.84
Dec-12	4.55	4.00
Jan-13	4.66	4.15
Feb-13	4.74	4.18
Mar-13	4.72	4.20
Apr-13	4.49	4.00
May-13	4.65	4.17
Jun-13	5.08	4.53
Jul-13	5.21	4.68
Aug-13	5.28	4.73
Sep-13	5.31	4.80
Oct-13	5.17	4.70
Nov-13	5.24	4.77
Dec-13	5.25	4.81

Moody's Public Utility Bond Data		
	Baa	A
Jan-14	5.09	4.63
Feb-14	5.01	4.53
Mar-14	5.00	4.51
Apr-14	4.85	4.41
May-14	4.69	4.26
Jun-14	4.73	4.29
Jul-14	4.66	4.23
Aug-14	4.65	4.13
Sep-14	4.79	4.24
Oct-14	4.67	4.06
Nov-14	4.75	4.09
Dec-14	4.70	3.95
Jan-15	4.39	3.58
Feb-15	4.44	3.67
Mar-15	4.51	3.74
Apr-15	4.51	3.75
May-15	4.91	4.17

WOLF CREEK DECOMMISSIONING COSTS
EXTERNAL TRUST FUND
Review of 2014 Cost Estimate
*****ADJUSTED TO REFLECT KCC STAFF INPUTS*****

		in 2014 $	In 2045 $
TOTAL COST DECON method		$765,060,000	$1,939,869,279
KGE'S SHARE OF TOTAL COST		$359,578,200	$911,738,561
CURRENT VALUE OF TRUST (12/31/14)	$	180,829,742	**Adjusted to Reflect Taxes on Unrealiz**

EQUIVALENT BEFORE TAX RETURN: THE EXPECTED INVESTMENT RETURNS ARE SHOWN ON PAGE 2 OF 2

PAYMENT GROWTH AMOUNT	$0
GROWTH RATE FOR COSTS (INFLATION)	3.15%
# OF PERIODS FOR ANALYSIS	30
# OF PERIODS - 1	29
PERIOD OF PAYMENTS	MID YEAR
DECOMMISSIONING PERIOD IN YEARS	9
FUND MANAGER FEES	0.576%

LINE	YEAR	BEGIN YR. BALANCE	DECOM EXPENSE	ANNUAL CONTRIB.	EARNINGS AFTER FEES AND TAXES	END YR. BALANCE
	2012					
	2013					
	2014					
1	2015	$180,829,742		$2,762,483	$9,161,452	$192,753,677
2	2016	192,753,677		5,772,700	9,844,745	$208,371,122
3	2017	208,371,122		5,772,700	10,629,297	$224,773,119
4	2018	224,773,119		5,772,700	11,453,263	$241,999,082
5	2019	241,999,082		5,772,700	12,318,620	$260,090,402
6	2020	260,090,402		5,772,700	13,227,450	$279,090,552
7	2021	279,090,552		5,772,700	14,181,935	$299,045,187
8	2022	299,045,187		5,772,700	15,184,369	$320,002,257
9	2023	320,002,257		5,772,700	16,237,162	$342,012,118
10	2024	342,012,118		5,772,700	17,342,842	$365,127,660
11	2025	365,127,660		5,772,700	18,504,066	$389,404,427
12	2026	389,404,427		5,772,700	16,702,987	$411,880,114
13	2027	411,880,114		5,772,700	17,659,005	$435,311,819
14	2028	435,311,819		5,772,700	18,655,688	$459,740,207
15	2029	459,740,207		5,772,700	19,694,766	$485,207,673
16	2030	485,207,673		5,772,700	20,778,042	$511,758,415
17	2031	511,758,415		5,772,700	21,907,395	$539,438,510
18	2032	539,438,510		5,772,700	23,084,786	$568,295,997
19	2033	568,295,997		5,772,700	24,312,259	$598,380,956
20	2034	598,380,956		5,772,700	25,591,943	$629,745,598
21	2035	629,745,598		5,772,700	26,926,059	$662,444,357
22	2036	662,444,357		5,772,700	21,663,615	$689,880,672
23	2037	689,880,672		5,772,700	22,556,274	$718,209,645
24	2038	718,209,645		5,772,700	23,477,976	$747,460,321
25	2039	747,460,321		5,772,700	24,429,666	$777,662,687
26	2040	777,662,687		5,772,700	25,412,320	$808,847,707
27	2041	808,847,707		5,772,700	26,426,945	$841,047,352
28	2042	841,047,352		5,772,700	27,474,582	$874,294,634
29	2043	874,294,634		5,772,700	28,556,305	$908,623,638
30	2044	908,623,638		5,772,700	29,673,222	$944,069,560
31	2045	944,069,560	76,742,107	1,443,175	15,496,371	$884,266,999
32	2046	884,266,999	170,390,309		13,361,348	$727,238,039
33	2047	727,238,039	209,293,207		10,189,818	$528,134,650
34	2048	528,134,650	156,404,173		7,349,097	$379,079,574
35	2049	379,079,574	127,253,390		5,101,820	$256,928,004
36	2050	256,928,004	114,089,268		3,136,287	$145,975,022
37	2051	145,975,022	58,558,037		1,854,229	$89,271,213
38	2052	89,271,213	54,764,209		915,049	$35,422,054
39	2053	35,422,054	35,623,101		202,618	$1,571

KCC Adjustments to Expected Returns

FEDERAL TAX RATE 20.00%

FOR THE YEARS 2012 THROUGH 2025				
INVESTMENT MIX	EXPECTED RETURNS	RATIO	WEIGHTED RETURN	AFTER TAX
Large Cap	7.60%	30%	2.28%	1.82%
Small Cap	8.81%	8%	0.70%	0.56%
International Equities	8.14%	16%	1.30%	1.04%
Core Fixed Income	4.95%	21%	1.04%	0.83%
High Yield Bonds	6.40%	20%	1.28%	1.02%
Real Estate	8.17%	5%	0.41%	0.33%
Cash and equivalents	2.00%	0%	0.00%	0.00%
		100%	7.01%	5.60%

FOR THE YEARS 2026 THROUGH 2035				
INVESTMENT MIX	EXPECTED RETURNS	RATIO	WEIGHTED RETURN	AFTER TAX
Large Cap	7.60%	20%	1.52%	1.22%
Small Cap	8.81%	5%	0.44%	0.35%
International Equities	8.14%	12%	0.98%	0.78%
Core Fixed Income	4.95%	44%	2.18%	1.74%
High Yield Bonds	6.40%	8%	0.51%	0.41%
Real Estate	8.17%	3%	0.25%	0.20%
Cash and equivalents	2.00%	8%	0.16%	0.13%
		100%	6.04%	4.83%

FOR THE YEARS 2036 THROUGH 2044				
INVESTMENT MIX	EXPECTED RETURNS	RATIO	WEIGHTED RETURN	AFTER TAX
Large Cap	7.60%	10%	0.76%	0.61%
Small Cap	8.81%	2%	0.18%	0.14%
International Equities	8.14%	3%	0.24%	0.19%
Core Fixed Income	4.95%	65%	3.22%	2.58%
High Yield Bonds	6.40%	0%	0.00%	0.00%
Real Estate	8.17%	0%	0.00%	0.00%
Cash and equivalents	2.00%	20%	0.39%	0.31%
		100%	4.79%	3.83%

FOR THE YEARS 2045 THROUGH COMPLETION OF DECOMMISSIONING				
INVESTMENT MIX	EXPECTED RETURNS	RATIO	WEIGHTED RETURN	AFTER TAX
Large Cap	7.60%	0%	0.00%	0.00%
Small Cap	8.81%	0%	0.00%	0.00%
International Equities	8.14%	0%	0.00%	0.00%
Core Fixed Income	4.95%	30%	1.49%	1.19%
High Yield Bonds	6.40%	0%	0.00%	0.00%
Real Estate	8.17%	0%	0.00%	0.00%
Cash and equivalents	2.00%	70%	1.40%	1.12%
		100%	2.89%	2.31%

CERTIFICATE OF SERVICE

15-WSEE-115-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Direct Testimony was served by electronic service on this 9th day of July, 2015, to the following parties who have waived receipt of follow-up hard copies.

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Order Approving Stipulation and Agreement (Docket No. 15-WSEE-115-RTS)
(51 pages)

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Kansas Corporation Commission

THE STATE CORPORATION COMMISSION OF THE STATE OF KANSAS

Before Commissioners: Shari Feist Albrecht, Chair
Jay Scott Emler
Pat Apple

In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service	))))	Docket No. 15-WSEE-115-RTS

ORDER APPROVING STIPULATION AND AGREEMENT

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This matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision. Having reviewed the pleadings and record, the Commission makes the following findings and conclusions:

I. Introduction

A. Procedural History and Entries of Appearance

1. On July 21, 2014, in Docket No. 15-GIME-025-MIS (15-025 Docket), Westar Energy, Inc. and Kansas Gas and Electric Company (jointly referred to as "Westar") filed a Joint Application with Kansas City Power & Light Company to approve the timing and accounting treatment for their respective rate cases regarding the inclusion of the La Cygne Environmental Project into rate base. The Joint Application also included proposed schedules for the pending Westar rate case.

2. On September 9, 2014, in the 15-025 Docket, the Commission issued an Order Approving Joint Application, establishing the accounting treatment and procedural schedule for Westar's general rate case.[1]

3. On March 4, 2015, the Commission took administrative notice of the procedural schedule set forth in the 15-025 Docket and incorporated it into Westar's instant general rate case, Docket No. 15-WSEE-115-RTS.

4. The Commission modified the procedural schedule on three separate occasions to conduct an additional public hearing, amend settlement procedures, and divide the scheduled evidentiary hearing into two distinct phases.[2]

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[1] A Petition Initiating Docket filed by Westar on September 15, 2014, gave rise to the present docket, Docket No. 15-WSEE-115-RTS.

[2] *See* Order Modifying Procedural Schedule (Apr. 14, 2015); Order Modifying Procedural Schedule and Substituting Prehearing Officers (Jul. 14, 2015); Order On: Interventions, Petition For Leave To Issue Discovery, Motion To

5. When the Commission modified the procedural schedule to bifurcate the evidentiary hearing into two distinct phases, the Commission separated out certain issues and limited the participation of certain intervenors to certain issues. The Commission placed issues related to Westar's proposed Residential Demand Plan and Residential Stability Plan, Community Solar proposal, and solar block subscription proposal into "Phase II" of the evidentiary hearing.[3] All other issues to be decided would be heard during "Phase I" of the evidentiary hearing.[4] The Commission granted The Alliance for Solar Choice (TASC), Cromwell Environmental Inc. (CEI), Brightergy, LLC (Brightergy), Climate and Energy Project (CEP) and the Environmental Defense Fund (EDF),[5] collectively referred to as the "Solar Parties," limited intervention in this proceeding.[6]

6. On August 6, 2015, parties who had been granted full intervention status, and were thus able to participate in both Phase I and Phase II of the evidentiary hearing, submitted a Stipulation and Agreement (S&A) that resolved all outstanding issues in the matter.[7] Subsequent to the filing of the S&A, Westar engaged in additional settlement talks with the Solar Parties.[8] Upon amending certain language in the S&A, the Solar Parties agreed to not oppose the S&A.[9] Westar filed an Unopposed Motion for Leave to File Addendum to Stipulation and Agreement

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Accept Pre-Filed Direct Testimony Out Of Time And Modifying Procedural Schedule (Jul. 23, 2015) [hereinafter Final Procedural Order].

[3] Final Procedural Order at 30.

[4] *Id.*

[5] The Commission prohibited CEP from participating in the evidentiary hearing. *See* Final Procedural Order at 25.

[6] Final Procedural Order at 14, 18-19, 21-22, 25, 27. The Commission limited TASC, CEI, Brightergy and EDF to only the Phase II issues. *See id.* The Commission excluded CEP from participation in the hearing but allowed CEP to brief on the fixed rate charge. *See id.* at 25.

[7] *See* Joint Motion To Approve Stipulation And Agreement at 2. (Aug. 6, 2014) [hereinafter S&A]. Note: The Joint Motion to Approve Stipulation and Agreement also contained the Stipulation and Agreement as a separate document with separate pagination. For purposes of this order, all references to S&A are to the Stipulation and Agreement attached to the Joint Motion unless otherwise noted.

[8] Unopposed Motion For Leave To File Addendum To Stipulation And Agreement Out Of Time at 2 (Aug. 12, 2015) [hereinafter Unopposed Addendum].

[9] *Id.* at 3.

Out of Time (Unopposed Addendum) on August 12, 2015. The disposition of the S&A is discussed in greater detail below.

B. Jurisdiction, Authority and Legal Standards

7. The Commission has full power, authority and jurisdiction to supervise and control electric public utilities, as defined in K.S.A. 66-101a, doing business in Kansas, and is empowered to do all things necessary and convenient for the exercise of such power, authority and jurisdiction.[10] "Electric public utility" means any public utility, as defined in K.S.A. 66-104, which generates or sells electricity.[11] K.S.A. 66-104 defines "public utility" in part as "all companies for the production, transmission, delivery or furnishing of heat, light, water, or power."[12]

8. Electric public utilities subject to the Commission's jurisdiction are "required to furnish reasonably efficient and sufficient service and facilities for the use of any and all products or services rendered, furnished, supplied or produced by such electric public utility, to establish just and reasonable rates, charges and exactions and to make just and reasonable rules, classifications and regulations."[13] The Commission thus has the power to require utilities to establish just and reasonable rates and maintain reasonably sufficient and efficient service.[14]

9. The authority of the Commission is liberally construed, and in the exercise of the Commission's power, authority, and jurisdiction, all incidental powers necessary to carry into

[10] K.S.A. 66-101; K.S.A. 66-101a; K.S.A. 66-104.
[11] K.S.A. 66-101a.
[12] K.S.A. 66-104(a).
[13] K.S.A. 66-101b.
[14] K.S.A. 66-101b.

effect the provisions of the Electric Public Utilities Act, K.S.A. 66-101 *et seq.*, are expressly granted to and conferred upon the Commission.[15]

10. Pursuant to K.S.A. 66-117, a public utility over which the Commission has jurisdiction cannot make effective any changed rate, joint rate, toll, charge or classification or schedule of charges, or any rule or regulation or practice pertaining to the service of a public utility except by filing with the Commission.

11. On March 2, 2015, Westar filed its Application to make changes to its charges for electric service pursuant to K.S.A. 66-117 and K.A.R. 82-1-231.[16] Accordingly, the Commission has jurisdiction to exercise control and jurisdiction over Westar for, among other things, this particular rate request.

C. Prefiled Testimony and Other Documents

12. Commission regulations address filing requirements for rate proceedings, and require utilities such as Westar to provide appropriate schedules and competent testimony when filing a rate change application.[17]

13. Throughout the course of this proceeding, parties submitted direct testimony, rebuttal testimony, and cross-answering testimony, exhibits and evidence. With its Application of March 2, 2015, Westar filed direct testimony from twenty-two witnesses in addition to two volumes of data that numbered over 700 pages. On July 9, 2015, multiple parties to this docket submitted direct testimony in accordance with the procedural schedule. Shortly thereafter, on July 24, 2015, eight witnesses submitted cross-answering testimony. On July 29, 2015, Westar submitted rebuttal testimony from eighteen witnesses and the U.S. Department of Defense and

[15] K.S.A. 66-101g.
[16] Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company (Mar. 2, 2015) [hereinafter Application].
[17] *See* K.A.R. 82-1-231.

all Federal Executive Agencies submitted rebuttal testimony from one witness. The following table identifies and outlines these filings:

Party	Direct Testimony Witnesses	Cross-Answering Testimony Witnesses	Rebuttal Testimony Witnesses
Westar	1. Mark Ruelle 2. John Bridson 3. Bruce Akin 4. Jeff Cummings 5. Jerl Banning 6. Tony Somma 7. Susan North 8. Geoff Greene 9. Cindy Wilson 10. Kevin Kongs 11. Mike Heim 12. Rebecca Fowler 13. Mike Rinehart 14. Eric Devin 15. Julie Lux 16. Jeanette Bouzianis 17. Ed Overcast 18. John Wolfram 19. Ahmad Faruqui 20. Chad Luce 21. Terry Wilson 22. Hal Jensen		1. Bruce Akin 2. Jerl Banning 3. Jeanette Bouzianis 4. Eric Devin 5. Ahmad Faruqui 6. Rebecca Fowler 7. Mike Heim 8. Hal Jensen 9. Kevin Kongs 10. Chad Luce 11. Susan North 12. Ed Overcast 13. Mike Rinehart 14. Mark Ruelle 15. Terry Wilson 16. John Wolfram 17. John Bridson 18. Tony Somma
Staff	1. Leo Haynos 2. Adam Gatewood 3. William E. Baldry 4. Timothy Rehagen 5. Luis M. Solorio 6. Tyler J. Page 7. Dorothy J. Myrick 8. Katie L. Figgs 9. Kristina Luke-Fry 10. Andy Fry 11. Robert Glass 12. Justin Grady	1. Robert Glass 2. Justin Grady	

Citizens' Utility Ratepayer Board	1. Andrea C. Crane 2. Brian Kalcic 3. J. Randall Woolridge	1. Brian Kalcic	
Kanas Industrial Consumers Group	1. Stephen M. Rackers 2. Brian C. Andrews 3. Michael P. Gorman 4. Christopher C. Walters	1. Brian C. Andrews 2. Michael P. Gorman	
Environmental Defense Fund	1. Diane Munns 2. Paul Alvarez		
Climate & Energy Project	1. Ashok Guptaon		
Occidental Chemical Corporation	1. Jeffry Pollock	1. Jeffry Pollock	
U.S. Department of Defense and all Federal Executive Agencies	1. Jeff Hoppe	1. Jeff Hoppe	1. Jeff Hoppe
Kroger, Co.	1. Kevin Higgins		
Wal-Mart Stores, Inc.	1. Steve Chriss		
Kansas Association of School Boards	1. Mark Tallman		
Unified School District # 259	1. John Allison		
Frontier El Dorado Refining, LLC	1. Robert R. Stephens	1. Robert R. Stephens	

14. In summation, by July 29, 2015, fifty-one witnesses from thirteen separate parties had placed into the administrative record for this docket seventy-eight iterations of direct, cross-answering, or rebuttal testimony that established and defended the basis and rationale for their respective initial positions. Parties and witnesses further supplemented the testimony with additional schedules and exhibits.

D. Public Hearings and Comments

15. The Commission, though not required by statute, has established a history of directly reaching out to and receiving comments from individual members of the public. Public hearings provide the citizens of Kansas an opportunity to address the Commission directly.

16. The procedural schedule set a public hearing for July 21, 2015, at Farley Elementary School, Topeka, Kansas, with video conferencing available at satellite locations in Emporia, Kansas, and Salina, Kansas. The Commission scheduled a second public hearing later in the proceeding for July 23, 2015, at Wichita State University, Wichita, Kansas,[18] with video conferencing available at satellite locations in Hutchinson, Kansas, and Pittsburg, Kansas.

17. Westar customers and the general public received notification by way of multiple newspapers throughout the state, as well as mailers included in every Westar customer's bill.[19]

18. The Commission took comments from the public regarding Westar's Application from the commencement of Westar's general rate case up through August 11, 2015, as directed by the procedural schedule. The Commission received comments via telephone, traditional mail, and electronic mail. These comments were in addition to any comments received at the public hearings.

19. On August 13, 2015, the Commission's Public Affairs and Consumer Protection Division (PACP) caused to be filed in the record a report summarizing the public comments received.[20]

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[18] Order Modifying Procedural Schedule, 2 (Apr. 14, 2015).
[19] *See* Affidavit of Publication (Jul. 8, 2015); *See also* Affidavit of Cindy Wilson Regarding Customer Notice, 1 (Jul. 8, 2015).
[20] Notice of Filing of Public Comment (Aug. 13, 2015).

20. On August 14 and 25, 2015, PACP caused to be filed in the record an Addendum and a subsequent Supplement, respectively, to its initial report.[21] Fifteen additional comments were received via regular mail that had been postmarked by the August 11, 2015, cutoff date,[22] and four comments were received via electronic mail after 5:00 p.m. on August 11, 2015, but before midnight.[23]

21. To summarize, the Commission received 1,458 comments from March 2, 2015, through August 11, 2015. Additionally, the Commission received thirty-two comments during the July 21, 2015, Topeka public hearing, and forty-three comments during the July 23, 2015, Wichita public hearing. The overwhelming public response received in this docket indicated general opposition to Westar's initial Application.

E. Evidentiary Hearings and Administrative Notice

22. On August 3, 2015, the Prehearing Officers filed and served notice of the prehearing conference upon counsel of record.[24] On August 12, 2015, the Prehearing Officers held a prehearing conference to discuss preliminary matters prior to the Commission convening the scheduled evidentiary hearing.

23. On August 17, 2015, in accordance with the procedural schedule set forth in this docket, the Commission convened an evidentiary hearing to receive testimony in support of the S&A. In total, twenty-three parties participated in the evidentiary hearing. Entries of appearance for counsel were as follows:

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[21] Notice of Filing Addendum to Public Comment (Aug. 14, 2015); Notice of filing Supplement to Addendum to Public Comment, 2 (Aug. 25, 2015).
[22] Notice of Filing Addendum to Public Comment at 2.
[23] Notice of filing Supplement to Addendum to Public Comment at 2.
[24] Notice of Prehearing Conference (Aug. 3, 2015).

Party	Entry of Appearance at Evidentiary Hearing
Westar Energy, Inc.	1. Cathryn Dinges 2. Martin Bregman
Commission Staff	1. Amber Smith 2. Michael Neeley
Citizens' Utility Ratepayer Board	1. David Springe 2. Niki Christopher
The Alliance for Solar Choice	1. Jacob Schlesinger 2. Anne Callenbach
Tallgrass Pony Express Pipeline, LLC	1. Terri Pemberton
Kansas Industrial Consumer Group and its Member Companies: Occidental Chemical Corporation, CCPS Transportation, LLC, Spirt AeroSystems, Inc., Coffeyville Resources Refining & Marketing, LLC, The Goodyear Tire & Rubber Company	1. James P. Zakoura
Occidental Chemical Corporation	1. Phillip Oldham
Frontier El Dorado Refining, LLC	1. James Flaherty
Cromwell Environmental, Inc.	1. C. Edward Peterson
Wal-Mart Stores, Inc., Tyson Foods, Cargill, Inc.	1. David Woodsmall
International Brotherhood of Electrical Workers, Local Union 304	1. William R. Lawrence, IV
Environmental Defense Fund	1. Robert Eye
Unified School District # 259, Kansas Association of School Boards	1. Timothy McKee 2. Samuel Ritchie
Kroger Co.	1. John Wine
U.S. Department of Defense and all other Federal Executive Agencies	1. Matthew Dunne 2. Kevin LaChance
Brightergy, LLC	1. Andrew Zellers

24. Counsel for all parties to this docket appeared at the evidentiary hearing. After inquiring with Commission Staff (Staff) Counsel and hearing no objections, the Commission found that notice of the evidentiary hearing was proper.[25]

25. Upon the finding that notice was proper, the Commission took up certain preliminary matters. The Commission approved Mr. Jacob Schlesinger's Verified Application for admission *pro hac vice* on behalf of TASC.[26] The Kansas Industrial Consumers Group, Occidental Chemical Corporation, and the U.S. Department of Defense and all Federal Executive Agencies withdrew their motion to strike the testimony of the Citizen's Utility Ratepayer Board (CURB) witness Brian Kalcic.[27] The Commission denied the International Brotherhood of Electric Workers, Local 304's (IBEW's) motion to file testimony out of time.[28] Due to the settlement of all issues, the Commission waived the previously ordered bifurcation of the evidentiary hearing.[29]

26. Following the preliminary matters and opening statements, Westar called Greg Greenwood to testify in support of the S&A[30] and moved for admission into the record the prefiled testimony of Westar's remaining witnesses.[31] No party opposed the motion and the Commission admitted the testimony.[32]

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[25] Transcript of Evid. Hearing at 9-10.
[26] *Id.* at 10.
[27] *Id.* at 10-11.
[28] *Id.* at 11-12.
[29] *Id.* at 12-13.
[30] Transcript of Evid. Hearing at 47-55.
[31] *Id.* at 55-56.
[32] *Id.* at 56.

27. Staff called Justin T. Grady and Dr. Robert Glass to testify in support of the S&A[33] and moved for admission into the record the prefiled testimony of Staff's remaining witnesses.[34] No party opposed the motion and the Commission admitted the testimony.[35]

28. CURB called Andrea C. Crane to testify in support of the S&A[36] and moved for admission into the record the prefiled testimony of CURB's remaining witnesses.[37] No party objected to this motion and the Commission admitted the testimony.[38]

29. All remaining parties who had previously filed direct, cross-answering, and rebuttal testimony in this proceeding, as described above, moved to have their respective witnesses' testimonies entered into the record.[39] No party objected to the admittance of the testimony into the record and the Commission admitted the same.[40]

II. Stipulation and Agreement

A. Agreement and Addendum

30. On August 6, 2015, Staff, Westar, CURB, Kansas Industrial Consumers on its own behalf and behalf of its member companies, Unified School District No. 259, the Kansas Association of School Boards, Kroger Co., the U.S. Department of Defense and all other Federal Executive Agencies, Frontier El Dorado Refining LLC, Occidental Chemical Corporation, Wal-Mart Stores, Inc., Tallgrass Pony Express Pipeline, LLC., Cargill, Inc., and Tyson Foods,

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[33] *Id.* at 57-65.
[34] *Id.* at 65-66.
[35] *Id.* at 66.
[36] Transcript of Evid. Hearing at 66-68.
[37] *Id.* at 68.
[38] *Id.*
[39] *Id.* at 68-72.
[40] *Id.*

collectively referred to as the "Joint Movants" filed a Joint Motion to Approve Stipulation and Agreement.[41]

31. Upon the filing of the S&A, Westar reached out to the Solar Parties.[42] The Solar Parties indicated that although they could file formal comments indicating their disagreement with certain provisions of the S&A, if certain changes were made to paragraph 39 of the S&A, the Solar Parties would agree not to oppose the S&A.[43] As a result of this, Westar proposed these changes in the Unopposed Addendum.[44] Westar received confirmation that no party to the docket objected to the filing of the Unopposed Addendum.[45]

B. Provisions of the Stipulation and Agreement

32. The S&A begins with a recitation of the Joint Movant's initial positions.[46] As described above, the entirety of the terms contained within the S&A, described below, have been unanimously subscribed to by the Joint Movants to the S&A.[47] Additionally, the terms of the S&A are not opposed by any of the Solar Parties.[48]

33. Stipulated Revenue Requirement: The Joint Movants propose that Westar's net overall annual revenue increase should be set at $78,000,000.[49] This revenue requirement does not include costs recoverable through Commission-approved riders.[50]

34. Rebasing: The Joint Movants propose that Westar roll into base rates the existing balance in the Environmental Cost Recovery Rider (ECRR), including the amount updated in

[41] *See* S&A.
[42] Unopposed Addendum at 2.
[43] *Id.*
[44] *See id.* at 2-3.
[45] *See id.* at 3.
[46] S&A at 2-3.
[47] *See id.*
[48] Unopposed Addendum at 3.
[49] S&A at ¶ 12.
[50] *Id.*

June, 2015, and the existing balance in the property tax surcharge and allocate the discount provided to Interruptible Service Rider (ISR) customers to the other customer classes.[51] By including the roll-in of the ECRR, property tax surcharge, and allocation of the ISR discount, the total base revenue requirement increase is $185,100,000.[52] These rebasing amounts to be rolled into base rates are reflected in Appendix A to the S&A.[53]

35. Rate case expense: The Joint Movants propose that rate case expense in excess of the actual amount included in Staff's filed revenue requirement should be trued up at the end of the case to the actual amount of rate case expense incurred and be added to the agreed-upon revenue requirement.[54] Westar agreed to submit these expenses to Staff for review within 14 days of the close of the record in this case.[55] Staff reports that Westar's total rate case expense is $1,536,649. Of that amount, Staff and CURB costs account for $493,631. This adjustment for rate case expense causes an increase in the revenue requirement of $225,264.

36. Bad debt expense: The Joint Movants propose that bad debt expense in excess of that included in Staff's filed revenue requirement recommendation be calculated as .43% of the net increase in revenue requirement and be added to the stated net increase in revenue requirement.[56] When the Joint Movants drafted the S&A using the agreed-upon revenue requirement increase described above, before accounting for the increase in rate case expenses the bad debt expense amounted to $86,700.[57] Using the revised rate case expense indicated by Staff, the bad debt expense now totals $87,658.

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[51] *Id.* at ¶ 13.
[52] *Id.* at ¶ 13.
[53] *Id.* at ¶ 13; S&A at Appendix A.
[54] S&A at ¶ 14.
[55] *Id.*
[56] *Id.* at ¶ 15.
[57] *Id.* at ¶ 15.

37. Inclusion of Pension and Other Post Employment Benefit (OPEB) Expense: The Joint Movants propose that the $78,000,000 net increase in the annual revenue requirement include a $5,000,000 increase in Pension and OPEB expense from Staff's filed position as stated in the Direct Testimony of Bill Baldry.[58]

38. Nuclear Decommissioning Trust Fund: The Joint Movants propose that Westar utilize Staff's recommendation as stated in the Direct Testimony of Staff Witness Adam Gatewood regarding the appropriate funding level for Westar's nuclear decommissioning trust fund, e.g. $5,772,700.[59]

39. Analog Meter Regulatory Asset: As Westar retires analog meters between October 28, 2015, and the effective date of rate changes in Westar's *next* general rate case, the Joint Movants proposed that Westar place the unrecovered investment in a retired analog meter regulatory asset.[60] The Joint Movants propose Westar be permitted to amortize the balance of the regulatory asset account over five years and recover that amortization amount in the base rates established in Westar's next general rate case.[61] No return on the regulatory asset will be allowed.[62] The Joint Movants agree that this particular ratemaking treatment should have no precedential value.[63]

40. Discontinuance of Environmental Cost Recovery Rider: The Joint Movant's propose that Westar's ECRR should be discontinued.[64] The Joint Movants agree that Westar would do a final update of environmental costs for 2015 that would have been recovered through

[58] *Id.* at ¶ 16.
[59] Direct Testimony of Adam Gatewood Direct on Behalf of Commission Staff at 70 (Jul. 9, 2015); S&A at ¶ 17.
[60] S&A at ¶ 18.
[61] *Id.* at ¶ 18.
[62] *Id.* at ¶ 18.
[63] *Id.* at ¶ 18.
[64] *Id.* at ¶ 19.

the ECRR previously noticed to the Commission, and roll them into base rates established in a proposed abbreviated rate case discussed below.[65]

41. Grid Resiliency: The Joint Movants propose that Westar be permitted to recover up to $50,000,000 of capital investment in grid resiliency improvements completed between October 28, 2015, and March 1, 2017, consistent with improvements proposed as part of the Electric Distribution Grid Resiliency (EDGR) program discussed in the Direct Testimony of Westar witness Bruce Akin and the report sponsored in Westar witness Jeffrey Cummings' Direct Testimony.[66] Plant in-service, less the associated accumulated depreciation and deferred income taxes, would be reflected in rates as a result of the abbreviated rate case discussed below. Westar will work with Staff to develop a process for periodic reporting regarding the investments being made and periodic meetings to provide updates and discussion on such investments.[67]

42. RENEW Tariff: The Joint Movants propose the Commission approve Westar's proposal as discussed in the Direct Testimony of Westar witness Chad Luce to change the pricing of the RENEW tariff to $0.25 per 100 KWh block,[68] a reduction to 1/4 of the current rate.[69]

43. Wind Capacity Programs: The Joint Movants propose the Commission approve Westar's Wind Energy and Wind Capacity Programs discussed in the Direct Testimony of Westar Witness Chad Luce with the modification to the calculation of avoided cost agreed to in the Rebuttal Testimony of Westar Witness John Wolfram.[70] Specifically, the avoided cost for customers participating in these programs shall be Westar's Retail Energy Cost Adjustment

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[65] *Id.* at ¶ 19.
[66] S&A at ¶ 20; *See* Direct Testimony of Jeffrey W. Cummings on Behalf of Westar Energy, exhibit JC-1, as amended (Jun. 10, 2015).
[67] S&A at ¶ 20.
[68] *Id.* at ¶ 21.
[69] Direct Testimony of Chad Luce on Behalf of Westar Energy, 13 (Mar. 2, 2015).
[70] S&A at ¶ 22.

(RECA) rate increased by 5% of the [Medium General Service] base energy charge. The Joint Movants agree to add language to the RECA tariff to allow the revenues and costs from the program to be included in the RECA calculation.[71]

44. Solar Energy & Capacity Tariff: The Joint Movants propose the Commission approve Westar's solar energy and solar capacity tariff as described in the Direct Testimony of Chad Luce with the following conditions: (1) Westar will require the initial subscription of a solar project to equal 100% of the capacity of the project before beginning construction; (2) the minimum size for Westar's solar projects under this program shall be 1 MW; and, (3) the rates charged to initial participants will cover 100% of the direct costs of the project.[72]

45. Residential Stability Plan and Residential Demand Plan: The Joint Movants agree that Westar will not implement these proposed tariffs at this time.[73]

46. Community Solar: The Joint Movants agree that Westar will not implement the Community Solar program discussed in the Direct Testimony of Hal Jensen at this time.[74]

47. Subdivision Policy: The Joint Movants propose that the Commission approve the subdivision policy changes in the Direct Testimony of Westar witness Mike Heim (increasing the allowance given to developers for residential subdivisions for the overhead distribution system from $30,000 to $40,000).[75]

48. Street Lighting (SL), Private Area Lighting (PAL), Restricted Institution Time of Day (RITODS): The Joint Movants propose the Commission approve the changes in the Direct

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[71] *Id.* at ¶ 22.
[72] *Id.* at ¶ 23.
[73] *Id.* at ¶ 24.
[74] *Id.* at ¶ 25.
[75] Direct Testimony of Mike Heim on Behalf of Westar Energy, 21 (Mar. 2, 2015) [hereinafter Heim Direct]; S&A at ¶ 26.

Testimony of Westar witness Mike Heim to the SL, PAL and RITODS tariffs as filed.[76] These changes will allow for the implementation of LED lighting options and expand the types of organizations that could take service under Westar's current RITODS tariff.[77]

49. Economic Discount Sharing: The Joint Movants propose that customers and shareholders share the costs equally (50-50) associated with any discount awarded in the future, as long as that discount affects future test year revenues in a rate case pursuant to Westar's Economic Development Rider (EDR).[78] The Joint Movants propose that the EDR tracker described in the Direct and Rebuttal Testimony of Westar witness Terrance D. Wilson not be adopted at this time.[79]

50. Security Tracker: The Joint Movants propose that Westar be permitted to implement a Security Tracker as discussed in Staff witness Justin Grady's Direct Testimony, the Rebuttal Testimony of Westar Witness John Wolfram, and as specifically described in Appendix C to the S&A.[80]

51. Return on Equity: There is no stated return on equity included in the S&A. The Joint Movants propose that until Westar's next general rate proceeding, Westar be authorized to use 10.926% as its overall pretax rate of return for regulatory accounting purposes, including the calculation of the equity component of Allowance for Funds Used During Construction (AFUDC), and for the abbreviated rate case discussed below.[81] This pre-tax rate of return assumes Westar's filed capital structure to be 46.3% Long-Term Debt, 53.1% Common Equity,

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[76] S&A at ¶ 27.
[77] Heim Direct at 19-21. Note: Under Westar's current RITODS tariff, the "R" is an abbreviation for "Religious." Westar's proposed changes also change this abbreviation to "Restricted" to make the tariff available to other customers with similar usage patterns of religious institutions. *See* Heim Direct at 20.
[78] S&A at ¶ 28.
[79] *Id.* at ¶ 28.
[80] *Id.* at ¶ 29.
[81] *Id.* at ¶ 30.

and .6% Post 1970 [Investment Tax Credit] as discussed in the Direct Testimony of Westar Witness Susan North.[82] The Joint Movants agreed to the use of the indicated overall pretax rate of return for settlement purposes only, and do not view such return on equity as precedential.[83]

52. Jurisdictional Non-Transmission Related Retail Property Tax Expense: The Joint Movants propose upon approval of the agreed-upon rate increase, that the Kansas jurisdictional, non-transmission related, retail property tax expense in base rates be $106,671,011. This amount would be the basis for determining property tax balance used in future property tax surcharge filings for the time-period when the proposed new rates would be applicable.[84] In order to calculate future property tax surcharges, the property tax surcharge expense assumed to be collected in base rates will begin with the effective date of the rate increase resulting from this docket, until the amount is reset in a Commission order.[85]

53. Cost-of-Service Deferred Income Tax Expense: The Joint Movants propose that Westar's cost-of-service deferred income tax expense and amortization of investment tax credits comply with the tax normalization requirements of the Internal Revenue Code of 1986 as amended.[86]

54. Amortization Periods: The Joint Movants propose the following amortization periods:

a. Westar's actual rate case expense - three years;

b. Regulatory asset associated with SmartStar Lawrence - three years;

c. Regulatory asset associated with SCR Catalyst – fifty-four months;

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[82] *Id.* at ¶ 30.
[83] *Id.* at ¶ 30.
[84] S&A at ¶ 31.
[85] *Id.* at ¶ 31.
[86] *Id.* at ¶ 32.

d. Regulatory asset associated with Baghouse - six years;

e. Regulatory liability associated with Stateline purchased power – three years;

f. Pension tracker authorized by Docket No. 10-WSEE-135-ACT in the annual amount of $3,423,867- five years.[87]

55. Going Forward Pension Tracking: The Joint Movants propose that base rates agreed to in the S&A include the following expenses associated with Westar's pension plan:

a. Westar Pension Expense - $33,403,818

b. Westar FAS 106 Expense - $841,864

c. Westar FAS 112 Expense - $431,737

d. WCNOC Pension Expense - $9,934,193[88]

56. Abbreviated Rate Proceeding: The Joint Movants propose that Westar be allowed to use the abbreviated rate setting process contained in K.A.R. 82-1-231(b)(3) to update rates to include capital costs related to the environmental projects at LaCygne Energy Center that were preapproved by the Commission in Docket No. 11-KCPE-581-PRE, up to the amount of costs approved by the Commission in said docket, but not included in rates set as a result of this proceeding.[89] The Joint Movants also propose that Westar use the abbreviated rate setting process to update rates to include capital costs related to projects at the Wolf Creek Generating Station described in the Direct Testimony of Westar witness John Bridson.[90] The Joint Movants request the Commission expressly grant Westar prior approval to file this abbreviated rate case

[87] *Id.* at ¶ 33.
[88] *Id.* at ¶ 34.
[89] *Id.* at ¶ 35.
[90] S&A at ¶ 35.

pursuant to K.A.R. 82-1-231(b)(3). The cost of capital to be used for purposes of such proceeding is to be the overall rate of return stated in paragraph 30 of the S&A.[91]

57. Inclusion of Grid Resiliency Projects & Final Roll-in of Environmental Cost Recovery Rider Costs: The Joint Movants propose that Westar use the abbreviated rate setting process contained in K.A.R. 82-1-231(b)(3) to include in Westar's rates the costs associated with investments in grid resiliency projects discussed in paragraph 20 of the S&A,[92] and the final roll-in of ECRR costs discussed in paragraph 19 of the S&A.[93]

58. Allocation Among Classes: The Joint Movants propose that the rate increase be allocated among the respective classes of customers according to the amounts indicated for each class as shown in Appendix A of the S&A, and that rates should be adjusted as shown in Appendix B of the S&A.[94]

59. Creation of Standard Residential Distributed Generation Tariff: The Joint Movants propose that Westar be allowed to create a Standard Residential Distributed Generation Tariff.[95] Residential customers who install distributed generation after October 28, 2015, would be required to take service pursuant to the terms of this new tariff.[96] The initial rates and rate structure for the Standard Residential Distributed Generation Tariff would be identical to Westar's Standard Residential Tariff, as determined in this rate case.[97] Residential customers who install distributed generation after October 28, 2015, and are placed on the Standard Residential Distributed Generation Tariff, will not be considered grandfathered or exempt from future changes in rates or rate structures for distributed generation customers approved by the

[91] *Id.* at ¶ 35.
[92] *Id.* at ¶ 36.
[93] *Id.* at ¶ 36.
[94] *Id.* at ¶ 37.
[95] *Id.* at ¶ 38.
[96] S&A at ¶ 38.
[97] *Id.* at ¶ 38.

Commission in either a generic docket proposed in paragraph 39 of the S&A (as amended), or in any other Commission proceeding.[98] Westar would provide notice to all customers applying for service under the Standard Residential Distributed Generation Tariff that the rates and rate structures contained therein are subject to change, and that any such future rate or rate structure change could impact the economics of the customer's distributed generation.[99]

60. Generic Docket Proposal as Amended by Addendum: The Joint Movants and Solar Parties agree that the issue of whether a separate Residential Standard Distributed Generation Tariff is necessary, and, if so, how to structure the Residential Standard Distributed Generation Tariff in order to properly recover just and reasonable costs from customers with distributed generation should be deferred to a generic docket.[100] Westar and Staff proposed working together to develop a procedural schedule for a generic docket in order to ensure timely resolution of distributed generation issues to be addressed.[101] The Joint Movants agree that they will not oppose or seek to limit the participation of the Solar Parties in the generic proceeding.[102]

61. Residential Customer Charge: The Joint Movants propose that the monthly basic service fee be $14.50 for all residential classes except for the Peak Management.[103] The Joint Movants proposed the monthly basic service fee for the Peak Management Rate be $16.50.[104] These basic service fees would not be adjusted in the abbreviated rate case discussed in paragraphs 35-36 of the S&A.

62. Elimination of High Load Factor (HLF) schedule and creation of new schedules: The Joint Movants propose that the HLF rate schedule be eliminated and two new rate classes be

[98] *Id.* at ¶ 38.
[99] *Id.* at ¶ 38.
[100] Unopposed Addendum, Addendum to Stipulation and Agreement.
[101] *Id.*
[102] *Id.*
[103] S&A at ¶ 40.
[104] *Id.* at ¶ 40.

created as proposed in the Direct Testimony of Westar witness John Wolfram.[105] Customers with billing demands greater than 1,000 kW and up to 25,000 kW would qualify for the Large General Service (LGS) class and customers with billing demands greater than 25,000 kW would qualify for the Industrial & Large Power (ILP) class.[106] As proposed, customers moving to a new class as a result of this change would be moved at the beginning of the first complete billing cycle following the issuance of the Commission's order in this docket.[107] This provision was further clarified at the evidentiary hearing to mean the first billing cycle occurring after the effective date of the final order in this docket.[108] In order to minimize the impact on customers that are required to move to the LGS class as a result of the Joint Movant's S&A proposed changes, the Joint Movants proposed that Westar's next Transmission Delivery Charge (TDC) filing use the recalculated 12 Coincidental Peak (CP) which takes into account CP data from these customers being moved to the appropriate class.[109]

63. Small General Service Basic Service Fee: The Joint Movants propose that the monthly basic service fee for the small general service customer class be set at $22.50.[110]

64. Separation of Grid Resiliency Costs: The Joint Movants propose that no part of the increase in revenue requirement in the abbreviated rate case associated with investments in grid resiliency be allocated to the LGS, ILP, large tire manufacturer (LTM), interruptible service (IS) classes, or special contract customers.[111] Grid Resiliency Costs would be allocated to the remaining customer classes in the abbreviated rate case based on the same percentages reflected

[105] *Id.* at ¶ 41.
[106] *Id.* at ¶ 41.
[107] *Id.* at ¶ 41.
[108] Transcript of Evid. Hearing at 50.
[109] S&A at ¶ 41(a).
[110] *Id.* at ¶ 42.
[111] *Id.* at ¶ 43.

in Appendix A of the S&A but adjusted proportionally to reflect the exclusion of the LGS, ILP, LTM, IS, and special contract customers from the allocation.[112]

65. Remainder of Revenue Increase: The Joint Movants propose that the remainder of the increase in revenue requirement in the abbreviated rate case will be allocated based on the same percentages reflected in Appendix A of the S&A.[113]

66. Continuing Discussions: The Joint Movants propose that Westar agree to continue discussions regarding a potential multi-site rate for medium general service customers, and, if appropriate, propose such a rate structure in the abbreviated rate case.[114]

67. Study Delivery Voltage Cost: The Joint Movants propose that Westar agree to study the potential of making further changes to the delivery voltage cost differences and, if appropriate, make any changes in the next general rate case.[115] If Westar determines no additional changes are appropriate, Westar will present evidence explaining the reason for that determination.[116]

68. Miscellaneous Provisions: The Joint Movants propose several miscellaneous provisions to the S&A that indicate nothing in the S&A is intended to impinge or restrict in any manner the exercise by the Commission of any statutory right, including the right of access to information, or any statutory obligation, including the obligation to ensure that Westar is providing efficient and sufficient service at just and reasonable rates. The S&A also detailed a number of privileges regarding the filing of testimony to support positions, the cross-examination of witnesses, and standard language typically included in S&As.[117]

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[112] *Id.*
[113] *Id.* at ¶ 44.
[114] *Id.* at ¶ 45.
[115] S&A at ¶ 46.
[116] *Id.*
[117] *Id.* at ¶¶ 47-51.

C. Standard of Review

69. Rates, fares, tolls, and charges imposed by a public utility upon its customers are required to be just and reasonable, not unjustly or unreasonably discriminatory and not unduly preferential.[118]

70. The Commission, in setting rates for an electrical utility, must fix rates within a "zone of reasonableness" after balancing interests of the utility's investors, ratepayers, and public.[119]

71. The Kansas Supreme Court mandates the Commission consider and balance the interests of the utility's investors vs. the ratepayers, the present ratepayers vs. the future ratepayers, and the public interest.[120] "[C]ases in this area clearly indicate that the goal should be a rate fixed within the zone of reasonableness after the application of a balancing test in which the interests of all concerned parties are considered."[121]

> "There is an elusive zone of reasonableness Kansas courts have recognized when reviewing utility rate decisions. [A] court can only concern itself with the question as to whether a rate is so unreasonably low or so unreasonably high as to be unlawful. The in-between point, where the rate is most fair to both the utility and its customers, is a matter for the Commission's determination."[122]

72. In addition to Kansas' own statutes and case law on the subject, the U.S. Supreme Court has established certain principles for the Commission to follow when reviewing rate change applications. *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923), and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), provide what

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[118] *Grindsted Products, Inc. v. Kansas Corp. Com'n*, 262 Kan. 294, 309 (1997); K.S.A. 66-101d.
[119] *Kansas Gas and Elec. Co. v. State Corp. Com'n*, 239 Kan. 483, 488 (1986).
[120] *Id.* at 488.
[121] *See id.* (internal quotation omitted)
[122] *Aquila, Inc. v. State Corp. Comm'n of State*, No. 94,326, 2005 WL 1719705 at *2 (Kan. App. Jul. 22, 2005).

this Commission has referred to as the "capital attraction standard."[123] "The return [on investment] should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, *to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties*."[124] "That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[125] The court has also stated however, "a rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[126] Also in *Hope Natural Gas,* the U.S. Supreme Court promulgated what this Commission refers to as the "comparable earnings standard."[127] "By that standard the return to the equity owner *should be commensurate with returns on investments in other enterprises having corresponding risks*" which would include not only service on a utility's debt but also dividends on the stock.[128] This, as Westar noted in its Application, does not guarantee it will actually earn its authorized return.[129] "[R]egulation does not insure that the business shall produce net revenues, nor does the Constitution require that the losses of the business in one year shall be restored from future earnings by the device of capitalizing the losses and adding them to the rate base on which a fair return and depreciation allowance is to be earned."[130] These standards taken together stand for the general idea that the return provided to a

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[123] Order Approving Nonunanimous Stipulation and Agreement with Modification at 3, *Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Co. for Approval to Make Certain Changes in Their Charges for Electric Service*, Docket No. 12-WSEE-112-RTS (Apr. 18, 2012) [hereinafter 12-112 Docket].
[124] *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 693 (1923) (emphasis added).
[125] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[126] *Bluefield Waterworks*, 262 U.S. at 693.
[127] 12-112 Docket at 3.
[128] *Hope Natural Gas*, 320 U.S. at 603.
[129] Application at 10.
[130] *Fed. Power Comm'n v. Natural Gas Pipeline Co. of Am.*, 315 U.S. 575, 590 (1942).

utility's investors should (1) be consistent with other businesses having similar risks and (2) the adequacy of the return for servicing debt and paying dividends be able to support a utility's credit quality, access to capital, and financial integrity. "The KCC is required to balance the public need for adequate, efficient, and reasonable service with the public utility's need for sufficient revenue to meet the cost of furnishing service and to earn a reasonable profit."[131]

73. The Commission may accept a settlement agreement provided an independent finding is made, supported by substantial evidence in the record as a whole, that the settlement will establish just and reasonable rates.[132] The Commission may utilize a five-element test to aid in the review of settlement agreements.[133]

1. Was there an opportunity for the opposing party to be heard on the reasons for opposition to the Stipulation and Agreement?

74. For a variety of reasons discussed in previous Commission Orders in this docket, not every party to this proceeding was able to participate in initial settlement discussions.[134] Notwithstanding the fact that the S&A is unanimously supported by the Joint Movants, it would be premature for the Commission to conclude from this fact alone that there were no opposing parties. The Commission must also turn to the parties who were not permitted to engage in settlement discussions to gauge their support or opposition to such agreement. Westar in the Unopposed Addendum established the first instance that all parties were either: (1) in support of the S&A or,[135] (2) unopposed to the S&A's approval.[136]

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[131] *Danisco Ingredients USA, Inc. v. Kansas City Power & Light Co.*, 267 Kan. 760, 773 (1999).
[132] *Citizens' Util. Ratepayer Bd. v. State Corp. Comm'n of State of Kansas*, 28 Kan. App. 2d 313, 316 (2000).
[133] Order Approving Contested Settlement Agreement at 5-6, Application of Atmos Energy for Adjustment of Its Natural Gas Rates in the State of Kansas, Docket No. 08-ATMG-280-RTS (May 12, 2008).
[134] *See e.g.* Final Procedural Order.
[135] *See* S&A at 14-19.
[136] Unopposed Addendum at 3.

75. The majority of the parties who were unable to participate in the creation of the S&A were the Solar Parties. However, as noted in Westar's Unopposed Addendum, the Solar Parties agreed not to oppose the S&A, and not to cross-examine any witnesses who may have testified in support of the S&A at the evidentiary hearing.[137] These were rights that the Commission had expressly granted to TASC, CEI, Brightergy, and EDF.[138] CEP was not allowed to participate at the evidentiary hearing and was thus not conferred these rights.[139] However, CEP also concurred with the other Solar Parties that it did not oppose the S&A.[140] Westar's Unopposed Addendum makes it clear to the Commission that the Solar Parties are not opposed to the S&A.

76. Settlement agreements revolve around compromise to reach reasonable outcomes. The S&A presented by the Joint Movants is a global settlement. It resolves all outstanding issues between the Joint Movants.[141] A careful review of the S&A, and the detail to which it discusses dozens of separate items, makes it clear to the Commission that the Joint Movants to the S&A intended to resolve all disputes between them, and had ample opportunity to advocate their respective interests. Every signatory to the S&A is in favor of the agreement. There are no parties opposed to the S&A who were allowed to participate in either its creation, or the subsequent filing of an addendum as Westar noted in its Unopposed Addendum.[142] Additionally, no party to this proceeding has logged an objection to the S&A as required by K.A.R. 82-1-230a.

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[137] *Id.*
[138] Final Procedural Order at 14, 18-19, 22, 27.
[139] *Id.* at 25.
[140] Unopposed Addendum at 3.
[141] S&A at 12.
[142] Unopposed Addendum at 3.

77. The only remaining party who did not participate in settlement discussions is the IBEW. IBEW had previously indicated it had no position regarding Westar's Application,[143] and when granted intervention, they were prohibited from participating at the evidentiary hearing.[144] IBEW did not petition the Commission for reconsideration of its intervenor status, and made no motion or argument despite being present at the evidentiary hearing through counsel that would otherwise indicate IBEW's opposition to the S&A.

78. No party has offered any formal objection to any term contained within the S&A. Pursuant to K.A.R. 82-1-230a(c), a party objecting to a settlement agreement must file a written objection within 10 days after the filing of the settlement agreement unless a shorter time-period is ordered by the Commission. Failure to do so constitutes a waiver of a party's right to object to a settlement agreement.[145]

79. Therefore, after examining all of the parties' respective roles and degrees of participation in this proceeding, the Commission finds that all parties had an opportunity to be heard on any opposition to the S&A, and that no parties are opposed to the adoption and approval of the S&A.

2. Is the Stipulation and Agreement supported by substantial competent evidence in the record as a whole?

80. The record to this proceeding is extensive and comprehensive. The Commission will not attempt to summarize the entire record as established in this proceeding. As discussed above, dozens of witnesses have filed testimony outlaying and defending positions while criticizing others. The Commission has reviewed the direct, cross-answering and rebuttal testimony as supplied by the parties. Further, the Commission has taken into consideration over

[143] Petition to Intervene at 3 (Jul. 16, 2015).
[144] Order Granting Limited Intervention at 2-3 (Aug. 11, 2015).
[145] *See* K.A.R. 82-1-230a(c).

1,500 public comments submitted in this proceeding. Because all parties to this docket are either in support of or unopposed to the adoption and approval of the S&A as amended, the Commission will undertake a more comprehensive review of the four witnesses who testified in support of the S&A.

81. Mr. Greenwood testified that the S&A is supported by substantial competent evidence when viewing the record as a whole.[146] Mr. Greenwood detailed the initial position of Westar, and how accounting adjustments proposed by other parties later became reflected in Westar's rebuttal testimony.[147] Mr. Greenwood detailed how the S&A in terms of the net revenue requirement incorporates pieces from and is supported or agreed to by a number of parties.[148] Mr. Greenwood expanded upon individual terms contained within the S&A, and provided ample evidence indicating multiple witnesses from diverse parties supported the variety of positions.[149]

82. Mr. Grady submitted testimony in support of the S&A. Mr. Grady noted the S&A "resolves all contested issues related to the revenue requirement [class cost of service] and rate design in this docket."[150] Specifically, Mr. Grady testified to: Westar's net overall annual revenue increase, the rebasing of rates, rate case expense true-up, bad debt expense, Pension and OPEB Expenses, the Nuclear Decommissioning Trust Fund, the analog retirement and regulatory asset, the discontinuance of the ECRR, grid resiliency projects and ratemaking treatment, the proposed security tracker, return on equity and capital structure, Kansas-jurisdictional non-transmission related retail property tax expense, deferred income tax expense and amortization of

[146] Testimony of Greg A. Greenwood in Support of Stipulation and Agreement at 11-14 (Aug. 11, 2015) [hereinafter Greenwood S&A Testimony].
[147] *Id.* at 11-12.
[148] *Id.* at 12.
[149] *See id.* at 12-14.
[150] Testimony in Support of Stipulation and Agreement Prepared by Justin T. Grady at 3 (Aug. 11, 2015) [hereinafter Grady S&A Testimony].

investment tax credits, amortization periods, pension trackers, and abbreviated rate case procedures and issues.[151]

83. Mr. Grady detailed that Westar's initial Application, and the rigorous scrutiny that it was subject to from not only Staff, but also CURB and other intervenors created a body of evidence for the Commission to consider.[152] The Joint Movants accordingly relied on this body of evidence when they negotiated the terms of the S&A.[153] Mr. Grady noted that the terms contained in the S&A are comparable with an outcome that could be expected if the case were to be fully litigated.[154]

84. Mr. Grady concluded that the S&A represents a reasonable resolution of the issues and matters contained within this docket, is in the public interest, is supported by substantial competent evidence in the record, and falls within the realm of reasonable debate and the zone of reasonableness.[155]

85. Dr. Glass submitted testimony in support of the S&A. Specifically, Dr. Glass testified to numerous rate design issues such as: class revenue allocation, rate consolidation for High Load Factor North & South customers, structural problems between Medium General Service and High Load Factor classes, secondary primary and transmission service for High Load Factor Customers, renewable resource tariffs, customer charges, distributed generation issues, the Economic Development Rider, revenue requirement allocation in the proposed abbreviated rate case, and miscellaneous non-controversial issues.

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[151] *Id.* at 3-9.
[152] *Id.* at 10-11.
[153] *Id.* at 11.
[154] *Id.*
[155] *Id.* at 16.

86. Dr. Glass concluded in his testimony that the S&A represents a realistic resolution of rate design issues, and that the proposed rate design in the S&A will result in just and reasonable rates.[156] Ultimately, Dr. Glass states that the S&A is in the public interest, is supported by substantial competent evidence in the record, and should be approved by the Commission in total.[157]

87. Ms. Crane, on behalf of CURB, testified that the S&A is supported by substantial competent evidence when viewed from the record as a whole.[158] Ms. Crane first testified to the parties' initial positions.[159] Ms. Crane explained that using the capital structure and cost of debt as provided by Westar that was adopted by CURB, and utilizing a 9.35% cost of equity, would increase CURB's net revenue requirement from $50.80 million to $72.31 million.[160] Ms. Crane expanded on this by saying it was difficult to provide an item-by-item settlement on issues contained within the S&A as some issues increased the net revenue requirement while some issues decreased the net revenue requirement.[161] Taking into account the pre-tax return of 10.926% as contained within the S&A, Ms. Crane stated the net revenue increase was close to CURB's recommended increase, and fell within the range provided by other parties to the proceeding.[162] Ms. Crane then undertook a review of how the net revenue increase would be allocated amongst the classes as well as the monthly service charges for residential and small commercial customers.[163] Ms. Crane indicated that the revenue allocations contained within the

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[156] Testimony in Support of Stipulation and Agreement Prepared by Robert H. Glass, PhD at 3 (Aug. 11, 2015) [hereinafter Glass S&A Testimony].
[157] *Id.* at 3.
[158] Testimony in Support of Stipulation and Agreement Andrea C. Crane on Behalf of CURB at 9-11 (Aug. 11, 2015) [hereinafter Crane S&A Testimony].
[159] *Id.* at 2-3.
[160] *Id.* at 10
[161] *Id.*
[162] *Id.* at 10-11.
[163] *Id.* at 11.

S&A appear to be reasonable, and that the proposed customer charges fall within ranges provided by the parties.[164]

88. The Commission finds that the record established prior to settlement discussions, and supplemented with testimony and evidence in support of the S&A, establishes a thorough and complete record to fully and adequately prepare an S&A. Parties to this proceeding relied on data provided either by their individual institutions, or by others. As parties to this proceeding engaged in attentive settlement discussions, they relied on the information contained within this docket to strike a realistic compromise that could be supported or defended with information contained in the record. To supplement the parties' respective positions in support of the terms of the S&A, the parties to this proceeding submitted additional testimony.

89. The testimony and evidence submitted throughout the entirety of this proceeding provided a substantive body of evidence on which to base compromises struck within the S&A. The witnesses who testified and submitted evidence are experts in their respective fields. As such, they provided competent information not only for parties to use when negotiating, but also for the Commission to review when determining the reasonableness of the S&A and its terms. Therefore, the Commission concludes that substantial competent evidence supports the S&A as amended when viewed through the record as a whole.

3. Does the Stipulation and Agreement conform with applicable law?

90. At the outset, it is important to note that no party to this proceeding has raised the slightest concern that the proposed S&A may be unlawful. Regardless, the Commission is required to undertake its own independent review.[165] Determining whether an S&A conforms with applicable law requires the Commission to assume that the S&A would be approved and be

[164] Crane S&A Testimony at 11.
[165] *See Citizens' Util. Ratepayer Bd. v. State Corp. Comm'n of State of Kansas*, 28 Kan. App. 2d 313, 316 (2000).

subject to judicial scrutiny the same as any other order of the Commission. In other words, would the S&A conform to applicable law and survive judicial review if the Commission had established the terms of the S&A under its own judgment? Such an inquiry requires the Commission to examine the reasonableness and lawfulness of the order.

91. An order of the Commission is lawful if it is within the statutory authority of the Commission, and if the prescribed statutory and procedural rules are followed in the making of the order.[166] The Commission has wide discretion from the legislature regarding rates for public utilities.[167] Specifically, K.S.A. 66-117 requires public utilities, such as Westar, seek Commission approval prior to changing any rate for which it charges customers for the use of electricity. After reviewing the testimony, it is undeniable that parties to this proceeding had disputes among their respective initial positions. However, "the law favors the amicable settlement of disputes."[168] It follows that if parties come to such a resolution, their resolution could seek to adjust rates for a public utility. The adjustment of rates agreed to via compromise between parties is still subject to Commission approval. Therefore, it is well within the lawful authority and jurisdiction of the Commission to consider this S&A as amended as it adjusts rates for a public utility subject to the Commission's jurisdiction and oversight.

92. Rates established by the Commission must be just and reasonable.[169] In developing five questions to review settlement agreements, the Commission dedicated one question to examine the "just and reasonable" standard alone. As such, the Commission defers discussion of that item to a separate part of this order.

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[166] *Cent. Kansas Power Co. v. State Corp. Comm'n*, 221 Kan. 505, 511 (1977).
[167] *Id.*
[168] *Int'l Motor Rebuilding Co. v. United Motor Exch., Inc.*, 193 Kan. 497, 499 (1964).
[169] K.S.A. 66-101b.

93. The Parties and the Commission complied with all procedural rules within this docket. The Parties and the Commission complied with the procedural schedules, the issuance of orders and the disposition of preliminary matters in accordance with the Kansas Administrative Procedure Act, K.S.A. 77-501 *et seq.*, which K.S.A. 66-117 requires the Commission to follow when reviewing a public utility's application to change rates. The Commission may therefore find that the prescribed statutory and procedural rules for reviewing the S&A and issuing this order have been followed.

94. Orders issued by the Commission are considered reasonable if they are based upon substantial competent evidence.[170] Applying the same standard to the S&A that is applied to orders issued by the Commission, it is clear to see that the S&A is based upon substantial competent evidence. The Commission's standard has been to review settlement agreements in light of the record as a whole. This allows the Commission to determine where such an agreement and its terms lie in relation to the terms of the previously articulated positions of the parties. Upon examining the record as a whole, it is clear that there is ample evidence used to support the parties' initial positions, and ample evidence to support how the parties were able to reach a negotiated settlement. The proceedings established the scope and breadth of the record in this case as discussed above.[171] The Commission finds that such a thorough record, and supplementary filings used to support the S&A as amended, establishes that substantial competent evidence necessary to support such an S&A as amended.

95. The Commission therefore finds that the S&A as amended complies with applicable law.

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[170] *Cent. Kansas Power Co.*, 221 Kan. at 511.
[171] *See supra* Part I.C.

4. Does the Stipulation and Agreement result in just and reasonable rates?

96. Electric Public Utilities, such as Westar, are required to provide reasonably efficient and sufficient service at just and reasonable rates.[172] In determining what constitutes a just and reasonable rate, the Commission has broad discretion.[173] As promulgated by the U.S. Supreme Court and adopted by the Kansas Court of Appeals, just and reasonable rates must fall within a "zone of reasonableness"[174] As Dr. Glass testified, the initial filed positions from all of the signatories to the S&A represents the "zone of reasonableness" for the Commission to consider.[175]

97. Westar Witness Mr. Greenwood testified in support of the S&A.[176] Ultimately, Mr. Greenwood testified that the rates proposed in Appendix B to the S&A would either remain in-line or below 2014 national averages.[177] Mr. Greenwood testified that he expected national electric rates to rise in the future, which in turn would mean Westar's electric rates (as proposed by the Joint Movants) would be even lower than national averages.[178] Mr. Greenwood states he believed the rates proposed in Appendix B to the S&A were just and reasonable, and requested this Commission approved them.[179] The Commission concurs with Mr. Greenwood's summation and rationale.

98. Dr. Glass testified on the "Balancing Test" that Kansas courts have developed when reviewing the zone of reasonableness standard.[180] Specifically, Dr. Glass conducted a

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[172] K.S.A. 66-101b.
[173] *Citizens' Util. Ratepayer Bd. v. State Corp. Comm'n of State*, 47 Kan. App. 2d 1112, 1131 (2012).
[174] *Kansas Gas and Elec. Co.*, 239 Kan. at 488.
[175] Glass S&A Testimony at 15.
[176] Greenwood S&A Testimony at 2.
[177] *Id.* at 16.
[178] *Id.*
[179] *Id.*
[180] Glass S&A Testimony at 14.

review of the interests of: investors vs. ratepayers, present ratepayers vs. future ratepayers, and the public interest.[181] Dr. Glass' testimony in support of the proposed S&A compels a finding favorable on these specific items.[182]

99. Ultimately, Dr. Glass concluded that the S&A was a realistic resolution of rate design issues outlined in this proceeding, that the proposed rate design is just and reasonable, that the agreement is supported by substantial competent evidence, and should be approved.[183] The Commission concurs with Dr. Glass' summation and rationale.

100. Mr. Grady testified that he believed the rates established in the S&A would result in rates that fall within the "zone of reasonableness."[184] Mr. Grady testified that the agreed-to revenue requirement increase struck the appropriate balance between Westar's desire to have assurance that it could earn sufficient revenue and cash flow to meet its financial obligations, and the desire of the ratepayer to keep rates low while maintaining reliable electric service.[185] Mr. Grady further theorized that if any particular party to settlement negotiations took issue with an unfavorable term related to their respective interest, they would not have joined or conceded to the S&A.[186] Therefore, because multiple rate classes with widely different interests were represented and later joined together to become signatories to the S&A, Mr. Grady concluded that the proposed terms of the S&A, specifically the revenue increase, could be viewed as reasonable from the viewpoint of the signatories.[187] As Mr. Grady postulates, if the terms were

[181] *Id.* at 14-16.
[182] *Id.*
[183] *Id.* at 16.
[184] Grady S&A Testimony at 13.
[185] *Id.* at 13-14.
[186] *Id.* at 14.
[187] *Id.*

not just or reasonable, then a unanimous S&A could not have been reached.[188] The Commission concurs with this summation.

101. Ms. Crane testified in support of the S&A on behalf of CURB. Like Mr. Greenwood, Dr. Glass, and Mr. Grady, Ms. Crane testified that approval of the S&A would result in just and reasonable rates.[189] Ms. Crane spoke specifically to the terms of the S&A, and how Westar's net revenue increase in the S&A was approximately 51% of what Westar had initially proposed in its Application, and only 8% above CURB's net revenue increase as adjusted.[190]

102. Ms. Crane also testified positively in support of the elimination of the ECRR, reduced customer charges, grid resiliency, retired analog meters, and the EDR.[191] Taken together, Ms. Crane testified as to how these terms as outlined in the S&A are beneficial to Kansas ratepayers, and ultimately concluded that the S&A would result in just and reasonable rates.[192]

103. The requirement that just and reasonable rates fall within a zone of reasonableness is used to determine whether a particular rate is contained within an "elusive range of reasonableness in calculating a fair rate of return."[193] The Commission acts within the discretion granted to it when it searches for and finds an in-between point "where the rate is most fair to the utility and the customers."[194] The Commission has reviewed the filed positions of the parties. The Commission has also examined in detail the impact to individual customer classes as outlined to the various appendices to the S&A. The Joint Movants are unanimously in support of

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[188] *Id.*
[189] Crane S&A Testimony at 13.
[190] *Id.*
[191] *Id.* at 13-14.
[192] *Id.* at 14.
[193] *Kansas Gas and Elec. Co.*, 239 Kan. at 490.
[194] *Id.*

the S&A as amended and neither the Solar Parties nor the IBEW are opposed to the amended S&A's approval. No evidence has been presented to the Commission suggesting that approval of the rates as described by the S&A would in any way be unjust or unreasonable, or make service unaffordable to customers. Therefore, the terms of the S&A as amended will result in rates that are not unduly burdensome, unduly preferential, or unreasonably discriminatory.

104. The Commission has also reviewed the terms of the S&A and its impact on the relationship between the utility's investors, the present ratepayer's and future ratepayers, and the public interest. The Commission has set aside as a separate question whether the S&A is in the public interest and will defer discussion on that item until the next section of this order.

105. The Commission finds the terms contained within the S&A fall within a zone of reasonableness and appropriately balance the interests of the Westar's investors with ratepayers, and with present ratepayers vs. future ratepayers. The evidence submitted in this proceeding has compelled the Commission to find that the S&A as amended will allow the utility to continue to meet its financial obligations while earning a return on investment that is commiserate with businesses of similar risks. The Commission further finds that ratepayers will benefit from the S&A as amended as they will continue to have access to affordable electricity at or below national average costs with the confidence that Westar will continue to be able to provide such service. Moreover, the Commission finds the S&A as amended protects and balances the interests of current and future ratepayers. Terms contained within the S&A as amended are designed to maintain or improve service quality while maintaining low costs. Additionally, the S&A takes proactive steps to ensure cross-subsidization is mitigated (e.g. grid resiliency cost allocation and the deferment of unique distributed generation terms until the completion of a generic docket).

106. The Commission has taken into consideration the competing interests as described by the Court when the Commission exercises its power in the setting of rates. The Commission finds that the agreed-upon net revenue increase and terms of the S&A as amended fall within the zone of reasonableness to which the Commission must adhere. The S&A as amended represents a series of compromises set and agreed to by the Joint Movants, and upon further concession, unopposed by the Solar Parties and IBEW. The rates established by the S&A will allow Westar to continue to meet its financial obligations, as well as its statutory obligation to provide efficient and sufficient service at just and reasonable rates. Therefore, the Commission finds the S&A, the rates and rate structures contained within, and specific terms of the S&A will result in just and reasonable rates for Westar's customers.

5. Are the results of the Stipulation and Agreement in the public interest, including the interest of customers represented by any party not consenting to the agreement?

107. Mr. Greenwood testified that the rates Westar customers would pay if the S&A were to be approved included approximately 96% of the expected La Cygne investments.[195] Mr. Greenwood also testified that the rate specific classes customers would pay, as proposed by the S&A is supported by the numerous class cost of service studies that had been provided in this docket, and that the increased customer charge helped better align customer rates with Westar's costs.[196]

108. Mr. Greenwood testified that Westar's customers would see benefits from additional investments in grid resiliency programs, digital meters, approval of certain solar

[195] Greenwood S&A Testimony at 17.
[196] *Id.* at 17-18.

programs and reductions in prices for renewable investment options.[197] Regarding specific tariffs, Mr. Greenwood testified in support of a generic docket to study distributed generation issues, and also explained how changes to industrial and commercial rate structures would better reflect the principles of cost causation in rate designs for larger customers.[198] Mr. Greenwood concluded that the approval of the S&A and the rates identified in Appendix A to the S&A would be in the public interest.[199] The Commission concurs with Mr. Greenwood's assessment.

109. Dr. Glass testified that the public interest is served when the utility remains a "healthy, viable business able to provide reliable service."[200] Dr. Glass stated that under the proposed rate plan, ratepayers would be protected from unrealistic price increases, undue discrimination, and unreliable service while at the same time allowing Westar to recover the revenues necessary to comply with environmental mandates.[201] While the end result of distributed generation has not been settled within the S&A, Dr. Glass noted that the generic docket outlined in the S&A provides a path forward to reach potentially better decisions.[202] Ultimately, Dr. Glass concluded that the S&A is in the public interest.[203] The Commission concurs with Dr. Glass' assessment.

110. Mr. Grady testified that the public interest is served "when ratepayers are protected from unnecessarily high prices, discriminatory prices and/or unreliable service."[204] According to Mr. Grady, because varied interests were able to collaborate and present a

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[197] *Id.*
[198] *Id.* at 19.
[199] *Id.*
[200] Glass S&A Testimony at 16.
[201] *Id.*
[202] *Id.*
[203] *Id.*
[204] Grady S&A Testimony at 15.

unanimous resolution of the issues in this case, the public interest standard has been met.[205] Mr. Grady then detailed five examples on how the public interest would be satisfied.[206] For example, Westar's requested revenue is reduced to a level that Westar still finds reasonable while at the same time decreasing the proposed cost customers would bear. The public will not have to potentially absorb the cost of a fully-litigated hearing, and the utility will continue to meet its financial obligations while providing sufficient and efficient service.[207] The Commission concurs with Mr. Grady's assessment.

111. Ms. Crane also testified that approval of the S&A is in the public interest.[208] Ms. Crane described how the S&A was a significant reduction from Westar's initial request, and how the customer charge would be set much lower than Westar's initial request and remain at that level until Westar's next general rate case.[209] Ms. Crane further expanded on the importance of rate stability, how the S&A withdraws certain proposals CURB took particular opposition to, how the S&A authorizes a return on investment that is significantly lower than Westar's present authorized return, the elimination of riders and how Westar's grid resiliency program costs would be recovered.[210] Ms. Crane concluded her remarks by stating "while the S&A represents a compromise of the positions put forth by the parties in this case, on balance I believe the S&A is in the public interest."[211] The Commission concurs with Ms. Crane's assessment.

112. To support a finding that the S&A is in the public interest the Commission must examine the information as filed in this docket and conclude that the interests of the ratepayers and Kansans will continue to be promoted if the S&A were to be approved. Westar, Staff

[205] *Id.*
[206] *Id.*
[207] *Id.* at 16.
[208] Crane S&A Testimony at 14.
[209] *Id.* at 14-15.
[210] *Id.* at 14-16.
[211] *Id.* at 16.

(submitting testimony for multiple signatories), and CURB have all testified regarding dozens of provisions contained within the S&A and detailed how those terms are in the public's interest. The Commission's focus for this inquiry turns on the result or total effect of the S&A as amended. The manner in which the terms of the S&A were constructed evidences the S&A is in the public interest. Multiple parties from a diverse set of interests encompassing large ranges of industrial, commercial, residential and specialty customers have all concluded that the terms of the S&A will allow them to continue to take service from Westar in a manner acceptable to them. The S&A as amended will allow multiple entities to undertake a review of distributed generation concerns before any changes in service are proposed. The S&A allows Westar to recover costs from prudently incurred expenses and continue to make reliability enhancements to Kansas' electric grid. Based upon the wide ranging support and lack of opposition to the S&A, as well as how the S&A will affect ratepayers if approved, the Commission is confident in finding that approval of the S&A is in the public interest.

III. Abbreviated Rate Case

113. The Joint Movants request Westar be granted preapproval to file an abbreviated rate case. Pursuant to K.A.R. 82-1-231(b)(3), a utility proposing to change rates within 12 months after a Commission order is issued in a general rate proceeding may do so without submitting duplicative information provided certain conditions are met.

114. First, the utility must be willing to adopt all regulatory procedures, principles, and rate of return established by the Commission in the order setting rates from the general rate

case.[212] Second, the utility must receive prior approval from the Commission before filing such an abbreviated rate case.[213]

115. Consistent with the terms contained within the S&A, the Commission grants Westar's request to file an abbreviated rate case no later than one year from the effective date of this order.

116. The Commission hereby limits matters to be addressed during Westar's abbreviated rate case to items specifically listed and identified in the S&A as being subject to the abbreviated rate proceeding.

IV. Generic Docket

117. As contemplated by the S&A, the parties to this proceeding wish to conduct a general investigation to research and evaluate specific issues related to distributed generation (particularly solar distributed generation). The Commission concurs that a generic docket is the appropriate method of identifying and discussing issues related to distributed generation before a public utility implements distributed generation-specific rates in the public utility's service territory. The Commission hereby directs Staff to file a Report and Recommendation outlining specific issues to discuss, research and evaluate in a manner consistent with the terms of the S&A as amended. The Commission directs Staff to coordinate with the parties to this proceeding and other Kansas-jurisdictional public utilities on the initial outlaying of issues. The Commission understands that such an evaluation will take considerable time, and therefore directs Staff begin such an undertaking with all due haste.

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[212] *See* K.A.R. 82-1-231(b)(3)(A).
[213] K.A.R. 82-1-231(b)(3)(B).

V. Findings and Conclusions

118. The Commission has examined the statutory and legal standards the Commission must consider when reviewing a request for rate changes, and has examined the voluminous record as a whole developed in this proceeding.

119. Upon reviewing the terms contained within the S&A, the Commission accepts the terms detailed within the S&A and as amended by the Unopposed Addendum.

120. The Commission finds that approval of the S&A as amended by Addendum would result in just and reasonable rates that would enable Westar to continue to provide sufficient and efficient service. The Commission finds that the rates established by the S&A conform and fall within the zone of reasonableness that properly balances the interests of the parties to this proceeding, the ratepayers, and the public.

121. The Commission finds that there was ample opportunity for parties to this proceeding to voice opposition to such agreement, and that the end result of unanimous support, or agreement not to oppose, provides evidence for such a conclusion. Therefore, the Commission concludes that all parties have had the opportunity to fully examine and critique the S&A as amended.

122. The Commission finds that the S&A is supported by substantial competent evidence from not only witnesses who testified in support of the S&A, but also how the terms of the S&A were constructed as a compromise from each party's respective initial position. Therefore, the Commission concludes that the S&A is supported by substantial competent evidence as filed in this proceeding.

123. The Commission finds that approval of the S&A as amended is in the public interest.

124. Upon reviewing the S&A, its terms individually, the parties' filed positions in this proceeding, testimony and evidence in support of the S&A, and amendments to the S&A as late filed by Westar, the Commission finds that the Joint Motion to Approve Stipulation and Agreement and amendments thereto should be granted.

125. The procedural schedule set October 28, 2015, as the effective date of the proposed rate change to take effect.[214] Pursuant to K.S.A. 66-117(b), the Commission may elect to hold a hearing on a public utility's proposed rate change. Pursuant to K.S.A. 66-117(c), the Commission cannot delay the effective date of a proposed rate change beyond 240 days from the date of the filing unless certain exemptions exist. The Commission finds that, having concluded approval of the S&A as amended is appropriate, the Commission must now set an effective date for such proposed changes. The Commission finds that given the date suggested in the notice of proposed rate changes that Westar sent to its customers, the effective date of any proposed rate change must remain October 28, 2015. This date complies with K.S.A. 66-117(c) in terms of suspension periods, is permitted by K.S.A. 66-117(b) as Westar would have to submit new rate schedules subject to a Commission-set effective date, and is consistent with the proposed effective date as detailed in the 15-025 Docket. Westar may file schedules necessary to implement the terms of the S&A as amended at any time. However, no schedule filed in accordance with the S&A as amended will become effective until October 28, 2015.

[214] Prehearing Officer Order Taking Administrative Notice of Procedural Schedule Adopted in Docket No. 15-GIME-025-MIS at 3 (Mar. 4, 2015).

IT IS, THEREFORE, BY THE COMMISSION ORDERED THAT:

A. The Joint Motion to Approve Stipulation and Agreement as amended is hereby granted. The terms, conditions, rates and schedules contained within the Stipulation and Agreement as filed on August 6, 2015, and as amended by Westar's Unopposed Motion For Leave to File Addendum to Stipulation and Agreement Out of Time filed on August 12, 2015, is hereby approved. Accounting for revised final rate case expense and bad debt expense figures, Westar's net overall annual revenue increase shall be set at $78,312,992.

B. The effective date of this order shall be October 28, 2015.

C. The parties have 15 days, plus three days if service of this Order is by mail, to petition the Commission for reconsideration of any issue or issues decided herein.[215]

D. The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Albrecht, Chair; Emler, Commissioner; Apple, Commissioner

Dated: SEP 2 4 2015

Amy L. Gilbert
Secretary to the Commission

REV/DLK

EMAILED

SEP 2 4 2015

[215] K.S.A. 66-118b; K.S.A. 77-529(a)(1).

CERTIFICATE OF SERVICE

15-WSEE-115-RTS

I, the undersigned, certify that the true copy of the attached Order has been served to the following parties by means of Electronic Service on SEP 24 2015.

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EMAILED

SEP 24 2015

CERTIFICATE OF SERVICE

SEP 24 2015

15-WSEE-115-RTS

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15-WSEE-115-RTS

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Order Approving Unopposed Stipulation and Agreement (15-WCNE-093-GIE)
(10 pages)

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Kansas Corporation Commission

**THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners: Shari Feist Albrecht, Chair
Jay Scott Emler
Pat Apple

In the Matter of the 2014 Wolf Creek Decommissioning Cost Study as Provided by Wolf Creek Nuclear Operating Corporation in Accordance with the Commission's Order in Docket Number 163,561-U on December 9, 1992, and the Commission's Order in Docket 13-WCNE-204-GIE on June 13, 2013.	)	Docket No. 15-WCNE-093-GIE

ORDER APPROVING UNOPPOSED STIPULATION AND AGREEMENT

The above-captioned matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision. Having reviewed the files and records, and being duly advised in the premises, the Commission makes the following findings and conclusions:

1. On August 29, 2014, Wolf Creek Nuclear Operating Corporation (Wolf Creek) filed its 2014 Decommissioning Cost Analysis for the Wolf Creek Generating Station in accordance with the Commission's December 9, 1992 Order in Docket No. 163,561-U and the Commission's Order in Docket No. 13-WCNE-204-GIE on June 13, 2013. The December 9, 1992 Order directed the filing of a decommissioning cost study every three years after September 1, 1993. The June 13, 2013 Order directed Wolf Creek and the owning utilities to update the estimates of the total capital costs of the Independent Spent Fuel Storage Installation (ISFSI) project at Wolf Creek as part of the triennial decommissioning cost study filings.[1]

[1] See Docket No. 13-WCNE-204-GIE, Order Closing Docket, Ordering ¶ A (June 13, 2013).

2. Kansas Gas and Electric Company d/b/a Westar Energy (Westar), Kansas City Power & Light Company (KCP&L), Kansas Electric Power Cooperative, Inc. (KEPCo), and the Citizens' Utility Ratepayer Board (CURB) filed petitions to intervene, which the Commission granted.

I. Proceedings in the Docket

3. The following witnesses submitted pre-filed testimony according to deadlines adopted in the procedural schedule. KCP&L, Westar, and KEPCo filed the direct testimony of Gregg N. Clizer on October 3, 2014. Staff witnesses pre-filed direct testimony on January 5, 2015, as follows: Adam H. Gatewood (Gatewood) and Leo M. Haynos (Haynos).

4. The parties met on February 9, 2015 to discuss settlement of this docket. Following negotiations, all parties except CURB entered into a Stipulation and Agreement (Stipulation) for the purpose of determining a reasonable estimate of Wolf Creek decommissioning costs to be used in addressing accrual levels of the respective owner utilities' decommissioning trust accounts and the appropriate escalation factor (inflation rate). The parties also discussed a separate, future issue regarding the content of the 2017 triennial decommissioning cost study filing.

5. On February 10, 2015, the parties filed a *Joint Motion to Approve Stipulation and Agreement and to Convert the Evidentiary Hearing in this Docket to a Settlement Hearing or Cancel the Hearing* (Joint Motion), advising the Commission that an unopposed settlement had been reached in this docket.[2] Although CURB is not a signatory to the Stipulation, CURB has advised the other parties that it does not oppose the Stipulation.[3] The Prehearing Officer

[2] Joint Motion to Approve Stipulation and Agreement and to Convert the Evidentiary Hearing in this Docket to a Settlement Hearing or Cancel the Hearing (Feb. 10, 2015) (Joint Motion).
[3] Joint Motion, p.2.

approved the motion to convert the evidentiary hearing to a settlement hearing on February 11, 2015.[4]

6. The following witnesses filed testimony in support of the Stipulation on February 12, 2015: Mary Britt Turner on behalf of the companies, and Haynos on behalf of Staff.

7. The settlement hearing was held before the Commission on February 24, 2015.

8. In deciding whether to grant the parties' Joint Motion, the Commission has reviewed and considered the entire record, including all pre-filed testimony of witnesses. The Commission's decision, as reflected in this Order, is based upon a review of all issues raised in this case, taking into account the issues upon which the parties have agreed.

II. Provisions of the Stipulation

9. The Stipulation resulted from discussions among the Joint Movants and CURB. The terms of the Stipulation are briefly summarized as follows:

a. The Stipulation is entered into for the purpose of determining a reasonable estimate of the Wolf Creek Generating Station decommissioning costs to be used in addressing accrual levels of the respective owner utilities' Decommissioning Trust Accounts.

b. The cost for decommissioning funding is agreed to be $765,060,000 in 2014 dollars as set forth in the Decommissioning Cost Analysis for the Wolf Creek Generating Station filed in this docket on August 29, 2014. This number will be used by Westar, KCP&L and KEPCo in their respective proposals for setting an accrual level for each company's Decommissioning Trust Account. This will be done in separate, individual company dockets.

[4] Prehearing Officer Order Granting Joint Motion to Convert Evidentiary Hearing to Settlement Hearing (Feb. 11, 2015).

c. Westar, KCP&L, and KEPCo agree to use an escalation rate of 3.15% per year to escalate the 2014 decommissioning cost estimate of $765,060,000 from 2014 dollars to the appropriate dollar amount in the year that the decommissioning costs will occur.

d. The Parties agree that Wolf Creek, KCP&L, Westar, and KEPCo shall jointly file a new decommissioning financing plan that addresses each of the 11 requirements of K.S.A. 66-128m(b) by September 1, 2017. The utilities may determine to file certain of the requirements separately at the time of the joint filing so long as all 11 requirements are covered.

e. The Parties agree that further discussion is necessary regarding the other issues raised by Staff[5] and will continue to discuss those issues in this docket. The Parties believe that a resolution of these issues can be achieved and suggest the Commission adopt the following schedule:

   i. On or before February 15, 2016: The Parties will report to the Commission as to the status of discussions to resolve the separate issues under this docket.

   ii. On or before September 1, 2016: The Parties will file a resolution with the Commission for approval; or, in the event the Parties reach an impasse after good faith efforts to reach consensus on a resolution to the separate issues, the Parties shall file a report with the Commission within 30 days of determining such impasse but no later than October 31, 2016.

[5] Direct Testimony of Leo M. Haynos, p. 12, lines 8-23 (Jan. 5, 2015).

III. Findings and Conclusions

10. The Commission must separately state findings of fact, conclusions of law, and policy reasons for its decision if it is an exercise of its discretion.[6] Any findings of fact must be based exclusively upon the evidence of record in the adjudicative proceeding and on matters officially noticed in the proceeding.[7] Agency action must be based upon evidence that is substantial when viewed in light of the record as a whole.[8]

A. Standard of Review

11. The Commission evaluates the evidence in the record as a whole regarding the proposed Stipulation in light of the following standards of review. Generally, the law favors compromise and settlement of disputes when parties enter into agreement settling and adjusting a dispute.[9]

12. Pursuant to K.A.R. 82-1-230a(b), the Commission has authority to approve, reject or modify a settlement agreement. In approving, rejecting or modifying a settlement, the Commission must make an independent finding that its decision regarding the settlement is supported by substantial competent evidence in the record as a whole and that the settlement will establish just and reasonable rates.[10]

B. Evaluation of the Stipulation

13. The Commission will consider the Stipulation by reviewing the criteria identified for evaluating whether a specific unanimous settlement reached by the parties should be approved. Each criterion will be considered separately.

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[6] K.S.A. 77-526(c).
[7] K.S.A. 77-526(d).
[8] K.S.A. 77-621(c)(7), (d).
[9] *Krantz v. Univ. of Kan.*, 271 Kan. 234, 241-42 (2001).
[10] *Citizens' Utility Ratepayer Board v. State Corp. Comm'n*, 28 Kan.App.2d 313, 316 (2000).

1. Is the Stipulation supported by substantial evidence in the record as a whole?

14. This Order has listed names of witnesses submitting pre-filed direct testimony, as set forth above in paragraph 3, as well as two witnesses presenting pre-filed testimony to support approval of the Stipulation. After reviewing the record as a whole, the Commission finds the evidence supports approval of the Stipulation reached by the parties. The Commission will briefly summarize evidence that supports finding substantial evidence exists to approve the Stipulation in its entirety.

15. The Joint Movants have provided the decommissioning cost study as well as the testimony of four witnesses, all of which support the Stipulation. The cost for decommissioning funding of $765,060,000 and the escalation rate of 3.15% agreed to in the Stipulation are supported by substantial competent evidence in the record.

16. Having reviewed the evidence in the record, the Commission concludes that substantial evidence is present in the record as a whole to support approval of the Stipulation. The Commission finds evidence in the record as a whole establishes the Stipulation is reasonable and should be approved in its entirety.

2. Will the Stipulation result in just and reasonable rates?

17. Every electric public utility in Kansas is required to provide reasonably efficient and sufficient service and establish just and reasonable rates.[11]

18. The Joint Movants state that Commission approval of the Stipulation will not have an immediate effect on rates charged to Kansas customers.[12] Rather, rate impact will not occur until each owner company files its individual dockets wherein the new decommissioning accrual will be included in their revenue requirement.[13] Nonetheless, the Joint Movants state

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[11] K.S.A. 66-101b.
[12] Joint Motion, p. 4-5.
[13] *Id.*

because the decommissioning cost elements being stipulated to in this docket are fair, reasonable, and fully supported by the evidence, inclusion of the same in rates later should not cause such rates to become unjust or unreasonable.[14]

19. The Commission agrees with the Joint Movants' statements that the Stipulation will not have an immediate impact on rates, and any effect they may have on rates in the future will be just and reasonable because they are based on a reasonable settlement of the decommissioning cost elements in this docket.

3. Are the results of the Stipulation in the public interest, including the interest of the customers represented by any party not consenting to the agreement?

20. The Joint Movants agree the terms of the Stipulation are in the public interest and should be approved by the Commission.[15] Each party has a duty to protect its interests: the companies have a duty to both their customers and shareholders; CURB represents the interests of residential and small commercial customers; and Staff has a duty to weigh and balance the interests of the public generally. The fact that these varied interests were able to collaborate and present an unopposed resolution of the issues in this case is a strong indication that the public interest standard has been met. The Joint Movants stated that the Stipulation reflects a reasonable compromise among the parties and eliminates the need for further costly and time-consuming proceedings.[16]

21. In reviewing the Stipulation presented by the parties, the Commission has considered that the agreed-upon and stipulated decommissioning cost elements are fair, reasonable, and in the public interest. The Commission therefore finds that approval of the Stipulation is in the public interest.

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[14] *Id.*
[15] *Id.*, p. 5.
[16] *Id.*

C. *Conclusion*

22. The Commission approves of the Stipulation in its entirety, including the portions proposing a procedural schedule for the unresolved issues. The Commission finds that the Stipulation is supported by substantial competent evidence, is in the public interest, and will result in just and reasonable rates.

IT IS, THEREFORE, BY THE COMMISSION ORDERED THAT:

A. The Commission grants the Joint Motion and approves the Stipulation in its entirety, for reasons discussed in this Order. By attaching the Stipulation to this Order, the terms are incorporated into this Order.

B. This Order shall be electronically served on all parties of record. Parties have 15 days from the date of electronic service of this Order in which to petition the Commission for reconsideration.[17]

C. The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further order or orders as it may deem necessary.

BY THE COMMISSION IT IS ORDERED.

Albrecht, Chair; Emler, Commissioner; Apple, Commissioner

Date: MAR 24 2015

Neysa Thomas
Acting Secretary

EMAILED

MAR 24 2015

JV

[17] K.S.A. 66-118b; K.S.A. 2014 Supp. 77-529(a)(1).

MAR 24 2015

CERTIFICATE OF SERVICE

15-WCNE-093-GIE

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Order Approving Unopposed Stipulation and Agreement was served by electronic mail this 24th day of March, 2015, to the following parties who have waived receipt of follow-up hard copies:

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Order Approving Stipulation and Agreement (File No. EO-2018-0062)
(4 pages)

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 23rd day of January, 2018.

In the Matter of Application of Kansas City Power & Light Company for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels.	))))	**File No. EO-2018-0062**

ORDER APPROVING STIPULATION AND AGREEMENT

Issue Date: January 23, 2018 Effective Date: February 22, 2018

This order approves the stipulation and agreement between Kansas City Power & Light Company (KCP&L) and the Staff of the Commission regarding KCP&L's funding for the decommissioning of its Wolf Creek Generating Station.

Commission rule 4 CSR 240-3.185 (3) states, in part:

> On or before September 1, 1990, and every three years after that, utilities with decommissioning trust funds shall perform and file with the commission cost studies detailing the utilities' latest cost estimates for decommissioning their nuclear generating unit(s) along with the funding levels necessary to defray these decommissioning costs. These studies shall be filed along with appropriate tariff(s) effectuating the change in rates necessary to accomplish the funding required.

On September 1, 2017, KCP&L filed an application pertaining to Wolf Creek asking the Commission to: (a) find that the 2017 cost study and 2017 funding analysis satisfies the requirements of 4 CSR 240-3.185(3); and (b) approve the continuation of the annual accrual at the current level of $1,281,264.[1]

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[1] In filing its application, KCP&L did not comply with the 60-day notice provision of 4 CSR 240-4.017(4), which requires advance notice of an intent to file a new case before the Commission. In the stipulation and

Staff and KCP&L filed a non-unanimous stipulation and agreement on January 5, 2018. Commission rule 4 CSR 240-2.115 provides that if no party objects to a non-unanimous stipulation and agreement within seven days of its filing, the Commission will treat the stipulation and agreement as unanimous. The Office of the Public Counsel, the only other party, did not sign the stipulation and agreement, but has not opposed the agreement. Therefore, the Commission will treat the stipulation and agreement as unanimous.

The stipulation and agreement asks the Commission to:

- Approve the stipulation and agreement;
- Receive into evidence the stipulation and agreement, the 2017 Cost Study, and the Funding Analysis;
- Find that KCP&L's 2017 Cost Study and Funding Analysis satisfies the requirements of 4 CSR 240-3.185(3);
- Find that KCP&L's Missouri retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264;
- Find, in order for the decommissioning fund to retain its qualified tax status, that the annual decommissioning costs for Wolf Creek, inclusive of the Independent Spent Fuel Storage Installation (ISFSI), are included in KCP&L's current Missouri cost of service and are reflected in its current Missouri retail rates for ratemaking purposes; and
- Authorize KCP&L to continue to record and preserve Wolf Creek asset retirement obligation costs, as agreed to by the Staff, Public Counsel, and KCP&L, and authorized by the Commission in Case No. EU-2004-0294.

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agreement, KCP&L requests a waiver of that requirement, presenting a verified statement that it had no communication with the Office of the Commission within the 150 days before it filed the application, thus providing good cause for the requested waiver. The Commission will grant the requested waiver.

Having considered the 2017 decommissioning cost study for the Wolf Creek Generating Station and the stipulation and agreement, both of which will be received into evidence, the Commission determines that the stipulation and agreement should be approved. In doing so, the Commission finds that KCP&L's 2017 cost study satisfies the requirements of 4 CSR 240-3.185(3). In addition, the Commission finds that KCP&L's Missouri retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264. The Commission also finds that the current decommissioning costs for Wolf Creek are included in KCP&L's current Missouri cost of service and are reflected in its current Missouri retail rates for ratemaking purposes.

THE COMMISSION ORDERS THAT:

1. The stipulation and agreement filed by the Kansas City Power & Light Company and the Staff of the Missouri Public Service Commission on January 5, 2018, is approved.

2. The signatories shall comply with the terms of the stipulation and agreement.

3. The stipulation and agreement and Kansas City Power & Light Company's 2017 Cost Study and Funding Analysis are admitted into evidence.

4. Kansas City Power & Light Company's retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264.

5. Kansas City Power & Light Company is authorized to continue to record and preserve Wolf Creek asset retirement obligation costs, as agreed by the Commission Staff, the Office of the Public Counsel, and KCP&L and authorized by the Commission in Case No. EU-2004-0294.

6. Kansas City Power & Light Company's request for waiver of the 60-day notice requirement of 4 CSR 240-4.017(1) is granted.

7. This order shall become effective on February 22, 2018.

8. This file shall be closed on February 23, 2018.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Hall, Chm., Kenney, Rupp, Coleman, and
Silvey, CC., concur.

Woodruff, Chief Regulatory Law Judge

Enclosure X to WM 19-0008

Non-Unanimous Stipulation and Agreement (File No. EO-2018-0062)
(17 pages)

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels	))))	**File No. EO-2018-0062**

NON-UNANIMOUS STIPULATION AND AGREEMENT

Kansas City Power & Light Company ("KCP&L") and the Staff of the Missouri Public Service Commission ("Staff") (collectively, the "Signatories," and individually "Signatory") hereby submit this Non-Unanimous Stipulation and Agreement ("Agreement") to the Missouri Public Service Commission ("Commission"). The Office of the Public Counsel ("Public Counsel") has advised the Signatories that it will not oppose this Agreement.

INTRODUCTION

The Legislature provided, in Section 393.292 RSMo 2000,[1] that the Commission may authorize changes to the rates and charges of an electrical corporation as a result, of a change in the level or annual accrual of funding necessary for its nuclear power plant decommissioning trust fund. This statute creates a narrow exception to the general requirement that the Commission must consider "all relevant factors," prior to changing any rate charged by a utility under its jurisdiction. See *State ex. rel. Utility Consumers Council of Missouri, Inc. v. Public Serv. Comm'n.*, 585 S.W.2d 41 (Mo. banc 1979). Under Section 393.292, the Commission may limit its review in nuclear decommissioning trust fund cases to only those factors relevant to the funding level or accrual rate of the trust fund when deciding matters related to the rates and charges associated with that fund.

[1] All statutory references are to Revised Statutes of Missouri 2016, unless otherwise noted. Section 393.292 was enacted by the Missouri Legislature in Laws 1989 and has not been amended.

Further, Section 393.292 gives the Commission authority to adopt rules and regulations governing the procedures associated with these tariff changes as well as to ensure that the amounts contained in the trust funds will be neither "greater nor lesser than the amounts necessary to carry out the purposes of the trust." In Case No. EX-90-110, the Commission adopted the original decommissioning rule, 4 CSR 240-20.070.

Rule 4 CSR 240-3.185(3) states, in part: "On or before September 1, 1990 and every three (3) years after that, utilities with decommissioning trust funds shall perform and file with the commission cost studies detailing the utilities' latest cost estimates for decommissioning their nuclear generating unit(s) along with the funding levels necessary to defray these decommissioning costs."

KCP&L established an external nuclear decommissioning trust fund[2] as a result of its ownership interest in the Wolf Creek Generating Station ("Wolf Creek") and the Commission's Report and Order in the rate case authorizing KCP&L to commence recovery of the costs of Wolf Creek. Kansas City Power & Light Co., Case Nos. EO-85-185 and EO-85-224, 28 Mo.P.S.C. (N.S.) 228 (1986). KCP&L owns 47% of Wolf Creek and approximately 56% of KCP&L's 47% ownership share is currently allocated to KCP&L's Missouri retail operations.

On August 30, 2005, KCP&L filed an Application (Case No. EO-2006-0094) with the Commission for approval of its then-current decommissioning cost estimate and

[2] If decommissioning financial assurance is provided by an external sinking fund, 10 CFR 50.75(e)(1)(ii) requires that "the total amount of funds would be sufficient to pay decommissioning costs at the time termination of operation is expected." The operating license for Wolf Creek was initially for 40-years, but the Nuclear Regulatory Commission ("NRC") subsequently extended Wolf Creek's operating license 20-years. Because KCP&L does not contemplate shutting down Wolf Creek prior to the end of its operating license life, the shutdown date used in the 2011 and 2014 Studies is 2045, the year in which Wolf Creek's operating license now expires.

continuation of the then-current authorized funding level for its nuclear decommissioning trust fund for Wolf Creek. A Unanimous Stipulation and Agreement, settling all issues pertaining to Case No. EO-2006-0094 was filed on December 20, 2005. Among other things, said Unanimous Stipulation and Agreement maintained the annual decommissioning expense accrual and trust fund payment at $2,303,856 (Missouri jurisdictional amount). The parties to that agreement further agreed that KCP&L's authorized annual funding level would be addressed in the Company's Rate Filing #1, as contemplated pursuant to the terms of the Stipulation and Agreement approved by the Commission in Case No. EO-2005-0329 ("Regulatory Plan Agreement"). In Rate Filing #1 (Case No. ER-2006-0314), the Commission reduced KCP&L's authorized annual decommissioning expense accrual and trust fund payment to $1,281,264 (Missouri jurisdictional amount). That reduction was primarily caused by recognizing the 20-year life extension of Wolf Creek.

On August 29, 2008, KCP&L filed an Application (Case No. EO-2009-0072) with the Commission for approval of its then-current decommissioning cost estimate and continuation of the then-current authorized funding level for its nuclear decommissioning trust fund for Wolf Creek. A Unanimous Stipulation and Agreement, settling all issues pertaining to Case No. EO-2009-0072 was filed on April 7, 2009. Among other things, said Unanimous Stipulation and Agreement maintained the annual decommissioning expense accrual and trust fund payment at $1,281,264 (Missouri jurisdictional amount), with the understanding that any proposed change in the annual Wolf Creek decommissioning cost accrual would be addressed in the context of the then upcoming rate case (now known as File No. ER-2010-0355).

KCP&L filed to generally increase its rates in File No. ER-2010-0355. As part of the overall rate increase request, KCP&L proposed to decrease the Missouri jurisdictional annual Wolf Creek decommissioning expense accrual and trust fund payment to $1,158,417 from $1,281,264. In Staff's Cost of Service Report in File No. ER-2010-0355, Staff recommended no change in the decommissioning expense accrual and trust fund payment because Great Plains Energy, Inc. had recently reduced its return expectations for its pension plan assets. Ultimately the annual contribution amount remained at $1,281,264 (Missouri jurisdictional amount) at the conclusion of the rate case.

On August 31, 2011, KCP&L filed in File No. EO-2012-0068 an Application for Approval of the Accrual and Funding of Wolf Creek Decommissioning Costs at Current Levels. Attached to KCP&L's Application was the required cost study detailing the latest estimate for the cost to decommission Wolf Creek. For the purposes of the 2011 Study, the final shutdown date of Wolf Creek was projected to occur in 2045. The calculations set forth in the 2011 Study were performed in a manner consistent with previous filings. KCP&L's 2011 analysis confirmed the adequacy of the annual funding level of $1,281,264 (Missouri jurisdictional amount), given the 2011 Study's then current prediction of decommissioning costs of $630.135 million for the DECON decommissioning option under what KCP&L believed were a reasonable set of economic, financial, and investment assumptions. Consequently, KCP&L did not seek any changes to its funding level. KCP&L and the Staff entered into a Non-Unanimous Stipulation And Agreement, which Public Counsel did not oppose. As part of the Non-Unanimous Stipulation And Agreement in File No. EO-2012-0068, KCP&L and the Staff agreed as follows:

> 5. The Parties agree that it is reasonable to use capital market return expectation information provided by Great Plains Energy's pension plan consultant for purposes of developing expected portfolio returns

> for KCP&L's nuclear decommissioning trust fund. The Parties agree that any proposed changes to the annual contribution to KCP&L's nuclear decommissioning trust fund shall be based on capital market return expectation information provided by Great Plains Energy's pension plan consultant, unless the Parties agree to use a different source and/or methodology for capital market return expectations or the Commission finds in a contested case that different source and/or methodology for capital market return expectation are more appropriate.

The Commission on May 1, 2012 issued an Order Approving Stipulation And Agreement and directing that the signatories comply with the terms of the stipulation and agreement.

On August 29, 2014, KCP&L filed in File No. EO-2015-0056 an Application for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels. Attached to KCP&L's Application was the required cost study detailing the latest estimate for the cost to decommission Wolf Creek. For the purposes of the 2014 Study, the final shutdown date of Wolf Creek was projected to occur in 2045. The calculations set forth in the 2014 Study were performed in a manner consistent with previous filings. KCP&L's 2014 analysis confirmed the adequacy of the annual funding level of $1,281,264 (Missouri jurisdictional amount), given the 2014 Study's then current prediction of decommissioning costs of $765.060 million for the DECON decommissioning option under what KCP&L believed were a reasonable set of economic, financial, and investment assumptions. Consequently, KCP&L did not seek any changes to its funding level. KCP&L and the Staff entered into a Non-Unanimous Stipulation And Agreement, which Public Counsel did not oppose.

As part of the Non-Unanimous Stipulation And Agreement in File No. EO-2015-0056, KCP&L and the Staff agreed as follows:

> 5. The Signatories agree that it is reasonable to use capital market return expectation information provided by Great Plains Energy's pension plan consultant for purposes of developing expected

portfolio returns for KCP&L's nuclear decommissioning trust fund. The Signatories agree that any proposed changes to the annual contribution to KCP&L's nuclear decommissioning trust fund shall be based on capital market return expectation information provided by Great Plains Energy's pension plan consultant, unless the Signatories agree to use a different source and/or methodology for capital market return expectations or the Commission finds in a contested case that different source and/or methodology for capital market return expectation are more appropriate.

THE 2017 STUDY

Pursuant to 4 CSR 240-3.185(3), on September 1, 2017, KCP&L filed its Application for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels ("Application"). KCP&L filed as Schedule A the Wolf Creek Generating Station Decommissioning Cost Estimate Update for September 1, 2017 ("2017 Study"). The 2017 Study, with the date August 2017 on its cover, was prepared for the Wolf Creek Nuclear Operating Corporation ("WCNOC") by TLG Services, Inc. ("TLG"), a consulting engineering firm based in Bridgewater, Connecticut.[3] The TLG analysis relies upon site-specific, technical information from a TLG evaluation prepared in 2014, updated to reflect current assumptions pertaining to the disposition of the nuclear station and relevant industry experience in undertaking such projects. Costs are represented in 2017 Dollars.

For the purposes of the 2017 Study, the final shutdown date of Wolf Creek is projected to occur in 2045. The 2017 Study shows the decommissioning cost estimate to be $813,733,000 million in 2017 Dollars for the DECON decommissioning option. TLG

[3] Since 1982, TLG has provided engineering and field services for contaminated facilities including estimates of decommissioning costs for nuclear generating units. TLG also prepared the decommissioning cost estimate for Wolf Creek that was filed with and approved by the Commission in previous KCP&L and Union Electric Company decommissioning cost studies.

examined two decommissioning options: (a) DECON,[4] and (b) SAFSTOR.[5] Both alternatives are acceptable to the NRC. KCP&L's Schedule B ("2017 Funding Analysis") to the Application indicates that under current assumptions the present annual trust fund contribution of $1,281,264 is sufficient to meet the estimated DECON decommissioning option within $263,000 which is less than 0.40% of the Missouri jurisdictional share of future estimated total decommissioning costs. Based on its analysis KCP&L has concluded that its funding level should result in a final decommissioning trust amount which is sufficient to cover the costs estimated in the 2017 Study under what KCP&L believes are a reasonable set of economic, financial, and investment assumptions. KCP&L believes it is reasonable and prudent to continue the annual accruals at the current level of $1,281,264.

The 2017 Study by TLG includes KCP&L's share of the cost for decommissioning the Independent Spent Fuel Storage Installation ("ISFSI") at Wolf Creek. KCP&L's 47% share of the $6.69 million is $3.14 million (MO and KS) identified in the current decommissioning cost analysis [Document WII-1741-001, Rev. 0, Table C, cost element 2d.2.4] prepared by TLG Services, Inc., dated August 2017.[6] The ISFSI will be constructed on the Wolf Creek site to hold the spent nuclear fuel assemblies (high-level

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[4] DECON assumes decontaminating and decommissioning immediately following conclusion of power operations in 2045. Work is anticipated to be completed by 2053. DECON consists of removal of fuel assemblies, source material, radioactive fission and corrosion products, and other radioactive materials immediately after cessation of power operations. Total estimated cost to decommission in 2017 Dollars is $813,733,000.

[5] SAFSTOR places the facility in protective storage for deferred decontamination to levels that permit release for unrestricted use. Delayed decontamination and dismantling activities are initiated once spent fuel and source material are removed, such that license termination is accomplished within the 60-year time period set by the NRC. This process is anticipated to be completed by 2106. Total estimated cost to decommission in 2017 Dollars is $1,093,117,000.

[6] Since the design for decommissioning has not been selected, the $6.69 million amount should be considered a representative decommissioning cost included within the DECON and SAFSTOR estimates. (*See* page 50 of 139 of TLG Services 2017 Study.)

radioactive waste). The Department of Energy ("DOE") has partially breached a contract with KCP&L, under which KCP&L customers had, until recently, been paying fees in rates, to remove, transport, and dispose of at the Nevada – Yucca Mountain repository site. Until the DOE performs under that contract, the spent nuclear fuel assemblies will need to be stored onsite in the ISFSI with a portion stored in the spent fuel pool until decommissioning.

Among other things, the 2017 Funding Analysis is based on capital market assumptions dated July 1, 2017 from KCP&L's pension consultants, Willis Towers Watson as agreed in the Non-Unanimous Stipulation And Agreement approved in File No. EO-2012-0068, and a decommissioning cost escalation rate based on inflation assumptions also from Willis Towers Watson dated July 1, 2017 in order to provide consistency with the capital market assumptions.

In its Application, KCP&L requests the Commission: (i) find that the 2017 Study and Funding Analysis satisfy the requirements of 4 CSR 240-3.185(3); and (ii) approve the continuation of the annual decommissioning expense accrual and trust fund contribution amount at the current funding level of $1,281,264 (Missouri jurisdictional amount). Because KCP&L is not proposing a change in the funding level, KCP&L has not filed new tariff sheets regarding its funding of decommissioning, is not requesting a hearing, and does not believe that a hearing is required respecting its decommissioning cost study filing.

STIPULATIONS AND AGREEMENTS

The Signatories to this case have reached certain understandings so that the Staff and KCP&L stipulate and agree as follows:

1. KCP&L's Missouri retail jurisdictional operations annual decommissioning expense accrual and trust fund payment was initially set by the Commission at $2,303,856, first in Case No. EO-91-84, Kansas City Power & Light Co., 1 Mo.P.S.C.3d 353 (1992), again in Case No. EO-94-80, Kansas City Power & Light Co., 3 Mo.P.S.C.3d 60 (1994), again in Case No. EO-97-84, Kansas City Power & Light Co., 7 Mo.P.S.C.3d 124 (1998), again in Case No. EO-2000-210, Kansas City Power & Light Co., 8 Mo.P.S.C.3d 516 (2000), again in Case No. EO-2003-0081, and again in Case No. EO-2006-0094. As part of Rate Filing #1 of the KCPL Experimental Regulatory Plan, the Commission approved in Case No. EO-2005-0329 (Case No. ER-2006-0314) KCP&L's Missouri retail jurisdictional authorized annual decommissioning expense accrual and trust fund payment was reduced to $1,281,264. The authorized Missouri retail jurisdictional annual decommissioning expense accrual and trust fund payment has remained the same in each subsequent triennial decommissioning filing and rate case filed subsequent to Rate Filing # 1.[7]

2. On September 1, 2017, KCP&L filed its Application along with the 2017 Study. The Signatories request that the Commission recognize in its Report and Order for this case that KCP&L's Application and the 2017 Study meet the requirements of 4 CSR 240-3.185(3).

[7] Case/File Nos. ER-2007-0291, ER-2009-0089, EO-2009-0072, ER-2010-0355, ER-2012-0174, and ER-2016-0285.

3. The 2017 Study estimates the decommissioning cost for the DECON alternative to be $813,733,000 in 2017 Dollars, which is 6.36% higher than the 2014 estimate of $765,060,000 which represents approximately a 2.08% annualized escalation rate over the 3-year period. The 2017 Study includes KCP&L's share of the estimated cost for decommissioning the ISFSI under the specific assumptions in the TLG Services 2017 Study.

4. ISFSI funds recovered from the DOE in connection with decommissioning of the ISFSI will be used to offset the costs of decommissioning the ISFSI.

5. Pursuant to 4 CSR 240-20.070(12), excess trust funds from the costs of decommissioning the Wolf Creek Generating Station and the ISFSI are to be reimbursed to the ratepayers through the ratemaking process.

6. The current annual contribution of $1,281,264 (Missouri jurisdictional amount) to KCP&L's nuclear decommissioning trust fund is reasonable given the uncertainties in the numerous forecasted assumptions used to determine the contribution level. The forecasted assumptions include, but are not limited to, capital market expectations, projected decommissioning inflation rates and the costs to decommission Wolf Creek and the ISFSI.

7. The Signatories agree that it is reasonable to use capital market return expectation information provided by Great Plains Energy's pension plan consultant for purposes of developing expected portfolio returns for KCP&L's nuclear decommissioning trust fund. The Signatories agree that any proposed changes to the annual contribution to KCP&L's nuclear decommissioning trust fund shall be based on capital market return expectation information provided by Great Plains Energy's pension plan consultant, unless the Signatories agree to use a different source and/or methodology for capital

market return expectations or the Commission finds in a contested case that different source and/or methodology for capital market return expectation are more appropriate.

8. KCP&L shall continue its Missouri retail jurisdiction expense accruals and trust fund payments at current levels without any change in its Missouri retail jurisdictional rates, unless and until the Commission subsequently approves such a change.

9. Annual Missouri retail jurisdictional decommissioning costs, inclusive of the ISFSI, in the amount of $1,281,264 are, and should continue to be, included in KCP&L's cost of service and reflected in its current rates for ratemaking purposes. The Signatories request that this finding be specifically recognized in the Commission's Report and Order and note that this finding is required in order for the decommissioning fund to retain its qualified tax status.

10. The Signatories agree and acknowledge that this Agreement does not prevent any Signatory from proposing changes to the annual contribution amount to the nuclear decommissioning trust fund in a subsequent rate proceeding.

11. The Signatories agree that KCP&L shall continue to record and preserve Wolf Creek asset retirement obligation costs, as agreed to by the Staff, Public Counsel, and KCP&L, and authorized by the Commission, in Case No. EU-2004-0294.

12. To the extent the Commission believes that 4 CSR 240-4.017 applies, KCP&L requests a waiver for good cause of this rule. KCP&L attaches as Exhibit A, a verified statement that it had no communication with the Office of the Commission within the prior 150 days to the filing of the Application in File No. EO-2018-0062 regarding any substantive issue likely to be in this case.

13. Except as explicitly agreed otherwise herein, none of the Signatories to this Agreement shall be deemed to have approved or acquiesced in any question of Commission authority, decommissioning methodology, ratemaking principle, valuation methodology, cost of service methodology or determination, depreciation principle or method, rate design methodology, cost allocation, cost recovery, or prudence that may underlie this Agreement or for which provision is made in this Agreement.

14. If the Commission does not unconditionally approve this Agreement without modification, and notwithstanding its provision that it shall become void thereon, neither this Agreement nor any matters associated with its consideration by the Commission shall be considered or argued to be a waiver of the rights that any Signatory has to a hearing on the issues presented by the Agreement, regarding cross-examination or a decision in accordance with Section 536.080.1 RSMo or Art. V, Section 18 Mo. Const. The Signatories shall retain all procedural and due process rights as fully as though this Agreement had not been presented for approval, and any suggestions or memoranda, testimony or exhibits that may have been offered or received in support of or in opposition to this Agreement shall thereupon become privileged as reflecting the substantive content of settlement discussions, and shall be stricken from and not be considered as part of the administrative or evidentiary record before the Commission for any further purpose whatsoever.

15. To assist the Commission in its review of this Agreement, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories related to the matters addressed in this Agreement, including any procedures for furnishing such information to the Commission.

16. If requested by the Commission, the Staff shall submit to the Commission a memorandum responsive to the Commission's request. Each party of record shall be served with a copy of any memorandum and shall be entitled to submit to the Commission within five (5) days of receipt of the Staff's memorandum, a responsive memorandum which shall also be served on all parties. The contents of any memorandum provided by any party are its own and are not acquiesced in or otherwise adopted by the other Signatories to this Agreement, whether or not the Commission approves and adopts this Agreement.

17. The Staff also shall provide, at any agenda meeting at which this Agreement is noticed to be considered by the Commission, whatever oral explanation the Commission requests. The Staff shall, to the extent reasonably practicable, provide the other parties with advance notice of when the Staff shall respond to the Commission's request for such explanation once such explanation is requested from the Staff. The Staff's oral explanation shall be subject to public disclosures, except to the extent it refers to matters that are privileged or protected from disclosure pursuant to any Protective Order issued in this case.

18. Because this is an Agreement with the sole purpose of addressing the authority requested by the Application of KCP&L, except as specified herein, the Signatories to the Agreement shall not be prejudiced, bound by, or in any way affected by the terms of this Agreement: (i) in any future proceeding; (ii) in any proceeding currently pending under a separate docket; and/or (iii) in this proceeding, should the Commission decide not to approve the Agreement or in any way condition its approval of the same, except as stated herein. Because this is an Agreement for the purpose of settling matters in this case, it shall not be cited as precedent or referred to in testimony as an assertion

of the particular position of any Signatory in any subsequent or pending judicial or administrative proceeding, except that this shall not be construed to prohibit reference to its existence in future proceedings, including proceedings to enforce compliance with its terms.

19. The 2017 Study shall be received into evidence.

20. Pursuant to Section 393.290 RSMo, the Signatories agree that the Commission may review and authorize changes to KCP&L's Missouri retail jurisdictional rates and charges as a result in a change in the annual accrual of funding for the Missouri jurisdictional sub-account of the Wolf Creek decommissioning trust after a full hearing, including but not limited to any general rate increase case or excess earnings complaint case, and after considering all facts relevant to such accrual rate.

21. The provisions of this Agreement have resulted from numerous discussions/negotiations among the Signatories and are interdependent. In the event that the Commission does not approve and adopt the terms of this Agreement in total, it shall be void and no Signatory hereto shall be bound by, prejudiced, or in any way affected by any of the agreements or provisions hereof unless otherwise provided herein.

22. In the event the Commission accepts the specific terms of this Agreement, the Signatories waive their respective rights: (i) to cross-examine witnesses pursuant to Section 536.070(2) RSMo; (ii) to present oral argument and written briefs pursuant to Section 536.080.1 RSMo; (iii) to the reading of the transcript by the Commission pursuant to Section 536.080.2 RSMo; and (iv) to judicial review pursuant to Section 386.510 RSMo. This waiver applies only to a Commission Report and Order respecting this Agreement issued in this proceeding, and does not apply to any matters raised in any

subsequent Commission proceeding, or any matters not explicitly addressed by this Agreement.

WHEREFORE, the Signatories hereto request that the Commission issue an order:

1. Approving this Non-Unanimous Stipulation and Agreement;

2. Receiving into evidence this Non-Unanimous Stipulation and Agreement, the 2017 Study (Schedule A to the Application), and the Funding Analysis (Schedule B to the Application);

3. Finding that KCP&L's 2017 Study and Funding Analysis satisfy the requirements of 4 CSR 240-3.185(3);

4. Finding, pursuant to this Non-Unanimous Stipulation and Agreement, that KCP&L's Missouri retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264;

5. Finding, in order for the decommissioning fund to retain its qualified tax status, that the current decommissioning costs for Wolf Creek, inclusive of the ISFSI, are included in KCP&L's current Missouri cost of service and are reflected in its current Missouri retail rates for ratemaking purposes; and

6. Authorizing KCP&L to continue to record and preserve Wolf Creek asset retirement obligation costs, as agreed to by the Staff, Pubic Counsel and KCP&L, and authorized by the Commission, in Case No. EU-2004-0294.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, transmitted by facsimile or electronically mailed to all counsel of record this 5th day of January, 2018.

/s/ Roger W. Steiner
Counsel for Kansas City Power & Light Company

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels	))))	**File No. EO-2018-0062**

VERIFIED DECLARATION OF LOIS J. LIECHTI

Lois J. Liechti, being first duly sworn on his oath, states:

1. My name is Lois J. Liechti. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company ("KCP&L") as Director – Regulatory Affairs.

2. Pursuant to the requirements of 4 CSR 240-4.017(D), I hereby certify, to the best of my knowledge, information, and belief, that KCP&L personnel have had no communications with the office of the Missouri Public Service Commission within the prior one hundred fifty (150) days of the filing of the Application in File No. EO-2018-0062 regarding any substantive issues likely to be in this case.

Lois J. Liechti

Lois J. Liechti, Director – Regulatory Affairs
Kansas City Power & Light Company

Subscribed and sworn before me this 5th day of January, 2018.

Anthony R Westenkirchner

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

Direct Testimony of Adam H. Gatewood (June 11, 2018)
(104 pages)

20180611150514
Filed Date: 06/11/2018
State Corporation Commission
of Kansas

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of the Application of the Joint Application of Westar Energy, Inc. and Kansas Gas & Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service	))))))	**Docket No. 18-WSEE-328-RTS**

DIRECT TESTIMONY

PREPARED BY

Adam H. Gatewood

UTILITIES DIVISION

KANSAS CORPORATION COMMISSION

June 11, 2018

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Q. Would you please state your name and business address?

A. My name is Adam H. Gatewood. My business address is 1500 Southwest Arrowhead Road, Topeka, Kansas, 66604.

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

A. I am employed in the Utilities Division of the Kansas Corporation Commission as a Managing Financial Analyst.

Q. What is your educational and professional background?

A. I graduated from Washburn University with a B.A. in Economics and a Masters of Business Administration. I have filed testimony on cost of capital and related financial issues before

1 the Commission in more than 120 proceedings. I have also filed testimony on cost of
2 capital issues before the Federal Energy Regulatory Commission in natural gas pipeline
3 and electric transmission dockets.

4 Executive Summary

5 **Q. What issues are you testifying to in this Docket?**

6 A. My testimony addresses the annual accrual for Westar's nuclear decommissioning trust
7 (NDT) and the rate of return used to calculate Westar's revenue requirement.

8 With respect to annual accrual for the NDT, I recommend that an annual accrual of
9 $7,793,500 based on the decommissioning methodology advocated by Staff witness Leo
10 Haynos. I also recommend that the Commission create a factor in Westar's (WR's) Retail
11 Energy Cost Adjustment (RECA) to recognize changes to the annual accrual that occur
12 outside of general rate cases.

13 With respect to the rate of return, I recommend that the Commission adopt a rate of return
14 of 7.06% that incorporates the 9.30% return on equity set out in the Non-Unanimous
15 Settlement approved in 18-KCPE-095-MER (18-095). My analysis in this Docket provides
16 substantial evidence that 9.30% is a fair and reasonable return for both shareholders and
17 ratepayers and, therefore, it should be adopted by the Commission to set Westar's revenue
18 requirement.

19 **Q. What documents did you review to prepare your analysis?**

20 A. In preparing my rate of return analysis and recommendation, I reviewed the following

1 documents directly connected to this Docket: 18-WSEE-328-RTS (18-328) Testimony &
2 Application; 18-095 Non-Unanimous S&A; responses to data requests issued by KCC
3 Staff and other parties; cost of capital work-papers provided in response to KCC data
4 request 85; and updates to Section 7 (cost of capital) provided in response to KCC data
5 request 159. In preparing my recommendations for Westar's annual accrual, I reviewed
6 the 18-107 Testimony and Application; the testimony of Leo Haynos filed in 18-WCNE-
7 107-GIE (18-107); responses to KCC data requests 126, 156, 157, and 158 in Docket 18-
8 328.

9 **Decommissioning Trust Annual Accrual**

10 **Q. Please summarize your recommendation for Westar's annual accrual.**

11 A. With respect to Westar's NDT, I recommend an annual accrual of $8,694,000 if the
12 Commission adopts the SAFESTOR methodology, or $7,793,500 if the Commission
13 adopts the DECON Alternative with Long-Term Spent Fuel Management methodology.
14 In addition, I recommend that the Commission include a variable in Westar's RECA to
15 account for any difference between the NDT annual accrual in base rates and the amount
16 set by any subsequent decommissioning cost review.

17 Staff's recommendation to recognize the increased costs associated with spent fuel
18 management results in an increase in the annual accrual. Staff witness Leo Haynos
19 explained in his 18-107 Direct Testimony that the U.S. Department of Energy's inability
20 to accept spent fuel for final disposal brings on the necessity for managing the spent fuel

at the reactor site for an indefinite period of time.[1] His recommendation recognizes those additional costs. Wolf Creek owners are not paying a fuel disposal surcharge[2] to DOE at this time.[3] That surcharge was more than the increase in the annual accrual that Staff recommends.[4] At this time, with the suspension of that surcharge, recognizing the costs of managing the spent fuel is not an increase to consumers. It is an issue that is in flux, and a solution could be many years in the future, but regardless of the solution, there will be costs incurred to manage and dispose of spent fuel. It is Staff's view that it is in all parties' interest to accrue funds for those costs over the life of the plant.

Q. Describe the triennial review process of the decommissioning cost estimates.

A. The triennial review is done in two phases. In phase one, the Commission reviews the decommissioning cost study, selects the decommissioning methodology, and decides on the inflation rate to apply the decommission cost estimate. By selecting the methodology, the Commission is selecting a cost estimate that is in current-year dollars. The inflation rate is necessary to escalate those costs to the year they will occur. The sum of those inflated costs is the amount that the owners must accumulate in their respective NDTs. Phase two determines the annual accrual necessary to fully fund the owner's NDT.

Q. What was decided in phase one?

A. At the time I filed testimony in this Docket on June 11, 2018, there is no decision by the Commission in phase one. My recommendation in phase two is based on the

[1] 18-WCNE-107-GIE; Direct Testimony of Leo M. Haynos; May 15, 2018; p. 15.
[2] DOE surcharge of 1 mil/kWhr to fund the final disposal of spent fuel.
[3] 18-WCNE-107-GIE; Response to Staff Data Request 21.
[4] 18-WCNE-107-GIE; Response to Staff Data Request 21. (Estimated DOE 2017 surcharge for Westar is $4.7m).

1 recommendations by Staff witness Leo Haynos in phase one. Staff witness Leo Haynos
2 recommends the DECON Alternative with Long-Term Spent Fuel Management[1]
3 (DECON-LTSFM). As an alternative, he recommends the SAFESTOR method as it also
4 provides a cost estimate that recognizes the spent fuel storage issues. If the Commission
5 adopts a different methodology in the 18-107 Docket, I will file additional testimony to
6 reflect the Commission's decision.

7 **Q. Please explain Staff's rationale for introducing the NDT variable to the RECA.**

8 A. Adding an NDT variable to the RECA will ensure that Westar collects through rates the
9 amount that it deposits in its NDT account. Staff witness Justin Grady will explain the
10 mechanics of the adjustment factor in the RECA formula. Commission Orders in 1984
11 established a three-year cycle for Wolf Creek's decommissioning cost studies. In reality,
12 this three-year review cycle may not sync up with each owners' rate cases, thus the annual
13 accrual collected in base rates may not match up with the Commission's latest adopted cost
14 NDT funding level. The five-year moratorium in the 18-095 Agreement highlights the
15 timing miss-match that we want to avoid.

16 **Q. What amount did WR propose for its NDT annual accrual?**

17 A. Westar proposes to keep its NDT annual accrual unchanged at $5,772,700. This
18 calculation encompasses forecasted asset returns published by J.P. Morgan Asset
19 Management (2017); the current NDT balance of $222,277,308 (net of tax liabilities) at
20 September 30, 2017, using the DECON decommissioning methodology; and an inflation
21 rate of 2.91% to escalate costs to future years.

1 Staff's recommendation is higher than Westar's proposal due to: 1) lower forecasted
2 returns; and 2) a change to the decommissioning methodology from DECON to DECON-
3 LTSFM which is a longer and costlier decommissioning process. The decommissioning
4 methodology and the inflation rate are subject to Commission determination in the 18-107
5 Docket.

6 **Q. Why are you using a lower return in your calculation than the return used by Westar**
7 **witness McGrath?**

8 A. We are using the same source for the forecasted return data, but Westar relied on the data
9 published for 2017 and my calculations use the 2018 edition, which reports lower expected
10 returns than the 2017 forecasts. We are both using Long-Term Capital Market
11 Assumptions (LTCMA) published by J.P. Morgan Asset Management (JPMAM) as our
12 source for expected returns over the long-run (more than ten years) for various asset
13 classes. The following table shows the 2017 and 2018 forecasts for the asset classes used
14 in the NDT and highlights the lowered forecasts.

J.P. Morgan Asset Management
Long-Term Capital Market Assumptions

	2017	2018
Equities-Large Cap	7.63%	6.41%
Equities-Small Cap	8.67%	7.35%
Equities-International (EAFE)	7.95%	7.61%
Core Bonds	3.44%	3.67%
High Yield Bonds	6.13%	5.59%
Real Estate	7.32%	7.42%
Cash & Equivalents	2.00%	2.00%

https://am.jpmorgan.com/us/institutional/2018-long-term-capital-market-assumptions

15

16 **Q. Is JPMAM's publication a reasonable source for these types of forecasts?**

1 A. Yes, J.P. Morgan's forecasts in this publication are consistent with forecasted returns by
2 other money management firms and reflect the expected returns of institutional portfolio
3 managers.

4 **Q. Did you quantify the impact of the lower forecasted returns?**

5 A. Substituting the lower 2018 forecasts for the 2017 forecasts in Westar's work-papers
6 increases the annual accrual from $5,772,700 to $6,441,000; a $668,300 increase using the
7 DECON methodology. Thus, a majority of the increase is associated with the added costs
8 of the DECON- LTSFM or SAFESTOR methodologies.

9 **Q. Historically, what has Westar's NDT earned?**

10 A. I performed an internal rate of return analysis on Westar's deposits to its NDT from 1986
11 through the present. Over that time period, Westar's NDT experienced an annual return of
12 5.68%.

13 **Q. How does the NDT's historic return compare to the forecasted return?**

14 A. The 2018 forecasted returns, using Westar's proposed portfolio structure and the DECON
15 methodology's projected cash-flows, indicates a return of 3.18% for the time period of
16 2017 through 2053. The difference reflects changes in lower expected returns in the future
17 as compared to the past occurring across all asset classes, as well as a progressively more
18 conservative portfolio as we near the decommissioning date. Virtually all of the economic
19 and financial literature point to this same scenario playing out in the capital markets.
20 Investors can expect lower returns in the future relative to the past due to lower inflation

1 and slow real economic growth; each of these variables put downward pressure on expected
2 returns.

3 **Q. How did you calculate the annual accrual amount?**

4 A. My calculation appears in Schedule AHG-1, which assumes the DECON-LTSFM
5 methodology, an NDT balance (net of income taxes) as of March 31, 2018, and forecasted
6 returns from the 2018 edition of the JPMAM-LTCMA. The blended returns of the portfolio
7 across time appear in Schedule AHG-2. The annual accrual is the amount that equates the
8 cash in-flows (annual accrual plus returns on the portfolio) to the cash out-flows (the
9 decommissioning expenses). The combination of variables that I discussed result in an
10 annual accrual of $7,793,500 for Westar's NDT to meet its future obligations.

11 **Rate of Return Analysis**

12 **Q. Please discuss the framework of Staff's rate of return (ROR) analysis in this Docket.**

13 A. Staff's ROR analysis in this Docket is, in part, a continuation of the analysis that Staff
14 performed in the 18-095 Merger Docket. These two Dockets are made interdependent by
15 the 18-095 S&A,[5] where signing parties committed to supporting an allowed return on
16 equity (ROE) of 9.30%[6] in this Docket for Westar, as well as the 18-KCPE-480-RTS
17 Docket for Kansas City Power & Light. On May 24, 2018, the Commission approved the
18 Non-Unanimous Stipulation and Agreement filed in the Docket 18-095 S&A.[7]

[5] Non-Unanimous Settlement Agreement; 18-KCPE-095-MER; filed March 17, 2018.
[6] Non-Unanimous Settlement Agreement; 18-KCPE-095-MER; filed March 17, 2018; at paragraph 32, iv, 1; p. 15.
[7] Order Approving Merger; 18-KCPE-095-MER; Issued May 24, 2018.

1 **Q. With regard to Westar's ROR, what are your findings and recommendations?**

2 A. The following table summarizes my recommended ROR and the components of the
3 calculation.

Staff Recommended Rate of Return Updated Capital Structure via KCC DR#159 & 18-095 S&A March 31, 2018			
	Weight	Cost	Weighted Cost
Long-term Debt	48.33%	4.68%	2.26%
Common Equity	51.24%	9.30%	4.77%
Post 1970 ITC	0.43%	7.06%	0.03%
			7.06%
Source: KCC DR#159			

4

5 As a point of comparison, Westar's Application is based on the following ROR.

Westar Energy Rate of Return Proposed Rate of Return in Section 7 of Application Test Year Ended June 30, 2017 Updated to September 30, 2017			
	Weight	Cost	Weighted Cost
Long-term Debt	48.19%	4.65%	2.24%
Common Equity	51.36%	9.85%	5.06%
Post 1970 ITC	0.44%	7.33%	0.03%
			7.33%
Source: 18-WSEE-328-RTS; Section 7			

6

7 Setting the rate of return requires decisions on the cost of debt, the cost of equity, and the
8 weight of each in the utility's capital structure. Staff is preparing its revenue requirement
9 incorporating an update to March 31, 2018, account balances from the September 31, 2017,

1 balances used in the Application. The ROR that I recommend is based on the updated
2 account balances and costs for the capital items. I agree with the capital structure and cost
3 of debt contained in WR's March 31, 2018, update. I do not agree with the 9.85% cost of
4 equity.

5 **Capital Structure**

6 **Q. Do you have any adjustments to WR's capital structure?**

7 A. Only that I recommend updating the cost and account balances from September 31, 2017,
8 to March 31, 2018. Westar provided this updated information in response to KCC DR
9 #159. As displayed in the previous two tables, there is a minor change in the capital ratios
10 from the September 31, 2017, balances to the March 31, 2018. It is reasonable to use the
11 March 31, 2018, capital structure because the update better reflects the capital costs and
12 ratios that is financing WR's rate base. The rate of return calculation in Staff's ROR will
13 reflect a long-term debt ratio of about 48.33% and an equity ratio of 51.24% (these numbers
14 include some rounding; Staff's Schedule C contains the non-truncated calculations).

15 **Q. Is WR's updated capitalization within the range seen in the electric utility industry?**

16 A. Yes, financially sound electric utilities have traditionally employed capitalization policies
17 of about 50% debt and 50% equity. The group of electric utilities selected as the proxy-
18 group for my cost of capital analysis follows this same pattern as seen in the following
19 table.

Staff Proxy Group							
Long-Term Debt Ratios Reported by Value-Line Investment Survey							
18-WSEE-328-RTS							
					Value-Line Forecasts		
		2015	2016	2017	*2018*	*2019*	*'21 - '23*
Allete Inc	ALE	46.3%	42.0%	41.0%	***40.5%***	***38.5%***	***38.0%***
Alliant Energy Corp	LNT	48.6%	52.8%	49.0%	***50.0%***	***50.0%***	***50.0%***
Ameren Corp	AEE	49.3%	47.7%	49.5%	***49.5%***	***49.0%***	***49.5%***
American Electric Power Co.	AEP	49.8%	50.0%	51.5%	***52.5%***	***54.5%***	***50.5%***
Consolidated Edison Inc	ED	47.9%	50.8%	50.0%	***50.5%***	***49.5%***	***48.0%***
Duke Energy Corp New	DUK	48.6%	52.6%	54.0%	***54.5%***	***55.5%***	***57.0%***
Edison International	EIX	45.0%	41.8%	45.6%	***48.0%***	***48.0%***	***47.5%***
El Paso Electric Co	EE	52.7%	52.7%	51.2%	***53.0%***	***52.0%***	***54.5%***
IDACORP Inc	IDA	45.6%	44.8%	43.7%	***44.0%***	***42.0%***	***44.0%***
NorthWestern Corporation	NWE	53.1%	52.0%	50.2%	***49.5%***	***48.5%***	***46.0%***
OGE Energy Corp	OGE	44.3%	41.1%	41.7%	***43.0%***	***44.0%***	***45.5%***
Pinnacle West Capital Corp	PNW	43.0%	45.6%	48.9%	***48.0%***	***48.5%***	***45.5%***
Portland General Electric Co.	POR	47.8%	48.4%	50.1%	***47.0%***	***50.5%***	***48.5%***
Xcel Energy Inc	XEL	54.1%	56.3%	55.9%	***58.0%***	***57.0%***	***58.0%***
	Average	48.3%	48.5%	48.7%	49.1%	49.1%	48.8%
	Median	48.3%	49.2%	49.8%	49.5%	49.3%	48.3%
	Min	43.0%	41.1%	41.0%	40.5%	38.5%	38.0%
	Max	54.1%	56.3%	55.9%	58.0%	57.0%	58.0%
Source: Value-Line Investment Survey (February 16, 2018; March 16, 2018; & April 27, 2018)							

Q. Is WR's updated capitalization consistent with the capital structure limitations discussed in the 18-095 S&A?

A. Yes, WR's capitalization complies with the provisions of Attachment 1 of the 18-095 S&A.

Cost of Debt

Q. Do you propose any adjustments to WR's cost of debt?

A. As with the capital structure, I recommend an update from September 31, 2017, to March 31, 2018. There are very minor cost differences between these two periods. The updated cost of debt is 4.68%. This current cost of debt compares to a 5.687% cost of debt in WR's last rate case (15-WSEE-115-RTS). The reduction reflects WR's refunding or refinancing

1 of debt that has occurred since the test year of December 31, 2014, that was used in that
2 rate case.

3 **Cost of Equity Analysis**

4 **Q. Please summarize Staff's position on Westar's cost of equity?**

5 A. Staff recommends that the Commission authorize a 9.30% return on Westar's equity capital
6 (ROE), the same ROE applied for purposes of the Earnings Review & Sharing Plan (ERSP)
7 that was accepted by the Commission in the 18-095 Docket. My analysis of the current
8 capital markets finds that, inclusive of the benefits from the ERSP and other terms of the
9 18-095 S&A, an ROE of 9.30% is reasonable for Westar and consumers. The benefits that
10 accrue to consumers through the 18-095 S&A are made available with some additional
11 risks to the shareholders of Westar. My testimony in the 18-095 Docket[8] discussed the
12 benefits and risks related to 18-095 S&A and I will repeat that discussion because they are
13 equally important to adjudicating the cost of capital issues in this Docket.

14 **Q. Is Staff recommending an ROE range for the Commission?**

15 A. No, at least not in the sense that would be done in a traditional rate case. I recommend the
16 Commission adopt a 9.30% ROE, the same that is used in the ERSP. If for some reason
17 the Commission finds a need to deviate from the 9.30% ROE, then I recommend that a
18 range of 9.10% to 9.50%, which is consistent with the terms of the 18-095 S&A.[9] This
19 range is fully supported by my analysis.

[8] Testimony of Adam H. Gatewood, 18-KCPE-095-MER filed January 29, 2018; p. 11-15.
[9] Non-Unanimous Settlement Agreement; 18-KCPE-095-MER filed March 17, 2018; at paragraph 32, iv, 1; p. 15.

1 **Q. Do you believe the Commission can deviate from the 9.30% ROE even though it**
2 **adopted the 18-095 S&A?**

3 A. Yes, the Commission can deviate from the 9.30% ROE in setting the revenue requirement
4 in this Docket. If the Commission adopts an ROE lower than 9.30%, Westar has the option
5 of shortening the rate moratorium from five years to three years. Staff believes there are
6 benefits for consumers to the full five-year rate moratorium that may not be present in a
7 three-year moratorium, such as an incentive to capture merger related synergies and a
8 period of relative rate stability. Those are two examples that are not easily quantified.

9 **Q. How broad is the support for the 9.30% ROE for Westar?**

10 A. The 9.30% ROE set in the 18-095 S&A is supported by Staff (representing the public
11 generally), CURB (representing residential and small business consumers), Westar (on
12 behalf of shareholders), Sunflower Electric Cooperative, Mid-Kansas Electric Company,
13 The Kansas Power Pool, Midwest Energy, Inc., and Bright Energy, LLC. The signatories
14 to the 18-095 S&A represent diverse and often opposing interests, especially on the issue
15 of an allowed return; seldom do they agree on this issue. In fact, there have been rate cases
16 where practically *all issues* could be settled among parties *except* the ROE, thus requiring
17 a hearing and Commission determination just for the allowed return.

18 **Q. How does a 9.30% ROE compare to recent decisions from around the country?**

19 A. A 9.30% return on equity is at the low-end of recent observations for electric utility rate
20 cases. For the first quarter of 2018, the average ROE granted was 9.75% with thirteen

1 observations.[10] Separating out only those decisions associated with vertically integrated
2 electric utilities and not tied to a limited-issue rider brings the number of observations down
3 to five with an average of 9.78%.[11] Over the past decade, allowed returns have declined
4 nationally, although the rate at which those declines have occurred vary from jurisdiction
5 to jurisdiction. That decline has happened at a more rapid pace in Kansas than in most
6 other jurisdictions. Over the past several quarters, there appears to be a plateau in allowed
7 returns; that is the rate of decline has fallen off as shown in the graphs that follow.

8 **Q. Please provide some background on how Staff arrived at the 9.30% ROE for the**
9 **ERSP.**

10 A. Staff was searching for a productive and fair settlement position for the 18-095 Merger,
11 which led Staff to consider a rate moratorium and a sharing mechanism of earnings above
12 an allowed return. Thus, it was necessary for Staff to perform a fresh and thorough analysis
13 of capital costs to determine the appropriate threshold for measuring earnings. At that time,
14 we were also aware that both Westar and KCP&L would be filing rate cases in 2018 and
15 the two utilities expressed a need to have some level of certainty regarding the cost of
16 equity recommendations in their upcoming rate cases, especially if they were going to
17 commit to an extended rate moratorium or an earnings sharing plan. For that reason, parties
18 agreed that the negotiated ROE applied in the ERSP would also become their

[10] RRA Regulatory Focus Major Rate Case Decisions: January – March 2018; S&P Global Market Intelligence; April 17, 2018; p. 10.

[11] Kentucky Power Co., 9.70% (Kentucky); Public Service Company of Oklahoma, 9.30% (Oklahoma); Interstate Power and Light, Co, 9.98% (Iowa); Duke Energy Progress, LLC, 9.90% (North Carolina); and Consumers Energy Co, 10.00% (Michigan).

1 recommendation to use in setting the revenue requirements in the 2018 rate cases.

2 As I discussed in my 18-095 testimony,[12] my cost of capital analysis was developed in a
3 manner and using conventions identical to those applied in rate cases. The results of my
4 analysis indicated that 9.30% was within a reasonable range for the ERSP. I also found
5 that capital costs were similar to those observed during Westar's and KCPL's last rate cases
6 which occurred in 2015. The Commission set KCPL's ROE at 9.30% and adopted a
7 settlement in which Westar's ROE was about 9.35%. Thus, the cost of capital analysis
8 provided Staff with the position that KCPL's and Westar's ROE could remain in place
9 from their last rate cases to be used for the ERSP and setting rates in their 2018 rate cases.

10 **Q. If the parties to the 18-095 S&A agreed to support a 9.30% ROE in this Docket, why**
11 **did you perform a new cost of capital study?**

12 A. I did this to provide the Commission with a comparative record on which to base its
13 decision and to establish facts that demonstrate an ROE of 9.30% is a just and reasonable
14 return in determining Westar's revenue requirement. The signatories to the 18-095 S&A
15 are very much aware that we cannot make a decision for the Commission. Ultimately, it
16 is the Commission that has to review the evidence and decide if 9.30% is a just and
17 reasonable return for setting Westar's revenue requirement. The legal standards that I
18 discuss later still apply to the Commission's decision, regardless of the fact that several
19 parties have reached an agreement on the issue.

20 **Q. How much time has elapsed since the analysis you prepared for the 18-095 docket?**

[12] Testimony of Adam H. Gatewood, 18-KCPE-095-MER filed January 29, 2018; p. 33.

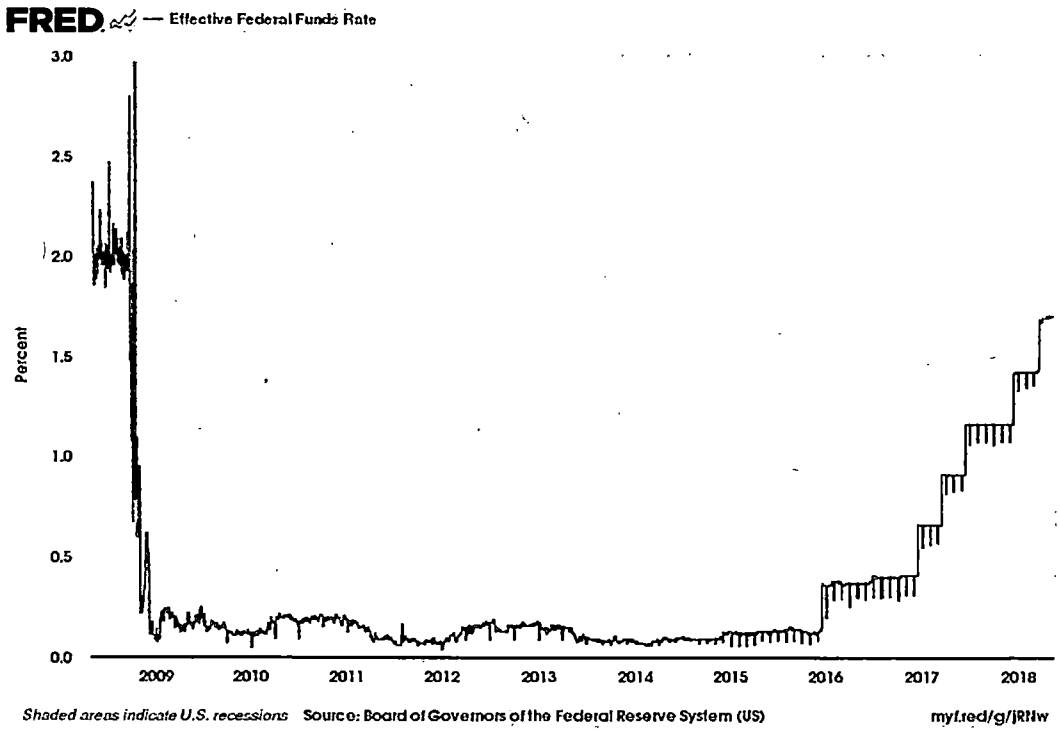
1 A. The time period of the capital market data I used in the 18-095 analysis was January 1,
2 2017, through December 31, 2017, and Staff filed its testimony on January 29, 2018. The
3 Application in this Docket was filed just days later on February 1, 2018. In this analysis,
4 I relied on financial data gathered from the one year time span of May 2017 through May
5 2018. Thus, there is a considerable overlap in the time periods when data was gathered.
6 In developing our position in the 18-095 Docket, Staff was cognizant of the timing of the
7 rate filings. Since the timing of these interrelated events were relatively close together,
8 Staff was comfortable with connecting the two while recognizing our responsibility to
9 prove the 9.3% ROE included in the 18-095 Docket is reasonable for both the ERSP and
10 the following rate cases. Had we been looking at a wider time-gap between the 18-095
11 Docket and the rate cases, it likely would have been much more difficult or not possible to
12 have connected the recommendations.

13 **Q. What has occurred in the capital markets since the 18-095 analysis?**

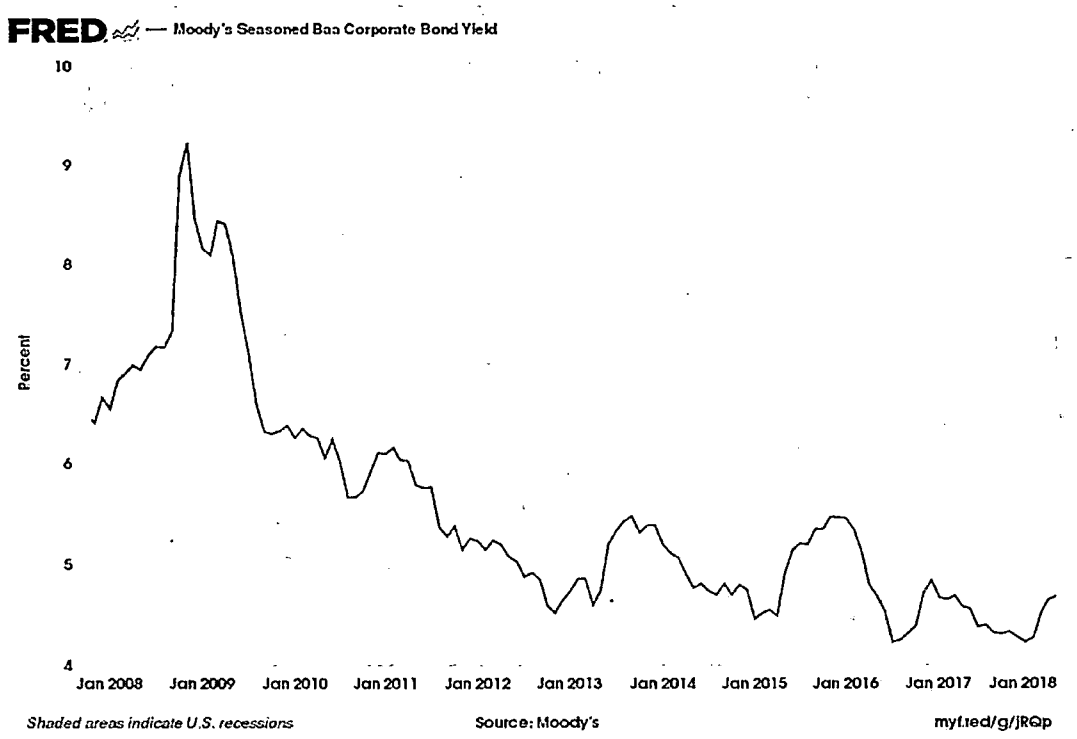
14 A. There are some observable increases in capital costs in the time since the 18-095 analysis.
15 These changes are not dramatic increases to the capital costs observed since Westar's last
16 rate case in 2015 nor outside of the capital costs observed during 2017. In the past six
17 months, the Federal Open Markets Committee (FOMC) of the U.S. Federal Reserve Board
18 has authorized open market operations transactions to increase the Federal Funds Rate[13] in
19 December of 2017 and March of 2018. In both cases, the FOMC authorized open market

[13] The Federal Funds Rate is the rate at which funds are loaned between Federal Reserve depository institutions on an overnight basis. The Fed Funds Rate is a tool the FOMC uses to carry out its statutory objectives maximum employment, stable prices, and moderating long-term interest rates (12 U.S.C. § 225a). The first two statutory objectives are known as the "dual mandate" because of the inherent difficulty in balancing these two objectives.

operations to increase the effective Federal Funds Rate by 25 basis points to target a Federal Funds Rate of 1.50% to 1.75%. This is an exercise of policy that does not directly change long-term capital costs of public utilities; rather, it is an indication that the policy makers of the FOMC believe that both the U.S. and global economies are sound and growing, thus capable of withstanding minor increases in short-term interest rates. Statements and projection material from the March 2018 FOMC meeting indicate continued real GDP growth in the range of 2.0% annually and a desired or targeted inflation rate of 2.0%. A 2.0% rate of inflation has been the Fed's target since the Great Recession, although the actual rate of inflation has rarely been as high as this target.



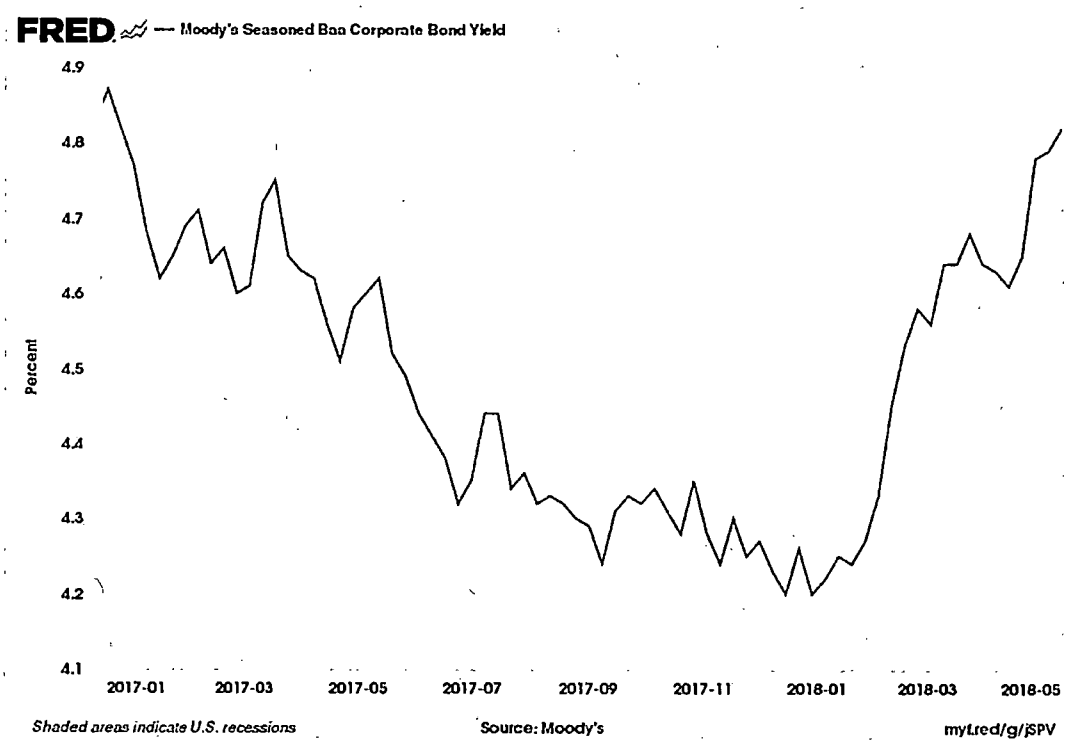
Longer-term interest rates that are set in the capital markets are also higher than the observations at the end of 2017 when I prepared my 18-095 analysis, though well within the ranges seen since the Great Recession and during early 2017.



A view of corporate interest rates for the time period associated with Staff's 18-095 investigation through the investigative period for this Docket indicates a distinct trough in corporate bond yields. Clearly, current bond yields have increased from those lows and they are well within the range experienced last year and experienced since the Great Recession. The observations of corporate bond yields are consistent with my cost of capital analyses which show that the cost of equity for electric utilities have not changed since my analysis for the 18-095 investigation.

Staff frequently cautions the Commission against relying on cost of capital witness' economic forecasts because the capital markets are widely viewed as efficient, that is, participants factor all available information (including forecasts) into their pricing of securities. Thus, the market prices embody the forecasts and expectations of investors. For that reason, adding a regulatory body's "forecast" is not necessary and could be

counterproductive (it could be wrong or contrary to investors' expectations). That being said, from Staff's perspective in negotiating the 18-095 S&A, we were aware that allowed returns set by commission and interest rates exhibited a plateau from a multi-year decline. And, given the length of the economic expansion, we were likely at a juncture where there is more upside potential with capital costs than a continuation of the decline that we have witnessed over the past ten years.



Q. Please discuss the additional risks posed by the 18-095 S&A that was approved by the Commission on May 24, 2018.

A. The added risks to shareholders include: 1) a five year rate moratorium during which Westar cannot file a rate case in Kansas; 2) the minimum annual credits to consumers; 3) $225 million of merger savings built into the revenue requirement in this rate case; and 4) the presence of a sharing mechanism for excess earnings above the 9.30% allowed return.

1 Staff believes the 18-095 S&A presents additional risks to shareholders because it: 1)
2 demands annual credits to consumers that has the effect of lowering Westar's earned return;
3 2) reduces the value of earnings if Westar earns above its allowed return; 3) sets a period
4 of five years during which Westar cannot file a rate case if its earnings are less than its
5 allowed return; and 4) sets a period of five years during which Westar cannot file a rate
6 case if its capital costs increase. With the 18-095 S&A in place that sets a period of five
7 years during which Westar cannot file a rate case, Westar must find cost savings equal to
8 the guaranteed fixed annual credits in order to achieve its authorized return. Consumers
9 could also see additional annual credits if the Applicants profits exceed the 9.30%
10 threshold. Westar's shareholders will only benefit by retaining a portion of any earnings
11 above the allowed return over the rate moratorium.

12 **Q. Without the 18-095 S&A, would Staff be inclined to recommend a 9.30% ROE for**
13 **Westar?**

14 A. Without the 18-095 S&A, Staff would likely be recommending a lower allowed return for
15 Westar given the current financial markets. As I discussed earlier, and in my 18-095
16 testimony, there are risks and benefits to the 18-095 S&A, primarily the ERSP. Five year
17 rate moratorium and bill credits to consumers cause me to distinguish this Docket from a
18 traditional rate case. Without those risks and benefits, Staff's recommendation – based
19 purely on the results of my financial analysis – would likely be closer to 9.00%. However,
20 Staff's recommendation would also have to consider the fact that a 9.00% recommendation
21 is a full 30 basis points below the lowest authorized ROE observation in the current national
22 average and would, thus, be a highly contentious recommendation, which would most

1 likely result in litigation. I would also note that I have been applying a gradual approach
2 to my ROE recommendations over the last several years. So, it is likely my
3 recommendation would be between 9.10% and 9.20% given the plateau of allowed returns
4 over the last several quarters and the fact that a 9.00% return is 30 basis points below the
5 lowest observation in the recent national average.[14]

6 **Q. Please summarize the results of your cost of equity analysis.**

7 A. The following table summarizes the cost of equity estimates from my study in this Docket;
8 the details of each financial model appears later in my testimony. I relied on a discounted
9 cash flow (DCF) model, a variation of the DCF model known as an internal rate of return
10 (IRR) analysis, and the capital asset pricing model (CAPM). These are the models I
11 typically use to estimate a utility's required return on equity. The results in this table are
12 based on the capital markets using data from May of 2017 through April of 2018.

[14] RRA Regulatory Focus Major Rate Case Decisions: January – March 2018; S&P Global Market Intelligence; April 17, 2018; p. 10.

Summary of Staff's Cost of Equity Estimates 18-WSEE-328-RTS			
Discounted Cash Flow Analyses			
	Mean	**Low**	**High**
Two-Stage Growth DCF Model: Based on the Average of Short-Term Growth Forecasts & Long-Term nGDP Forecasts	8.22%	7.79%	8.64%
Internal Rate of Return-Multi-Stage DCF Analysis: Using Short-Term Growth EPS Growth & Long-Term nGDP Forecast	8.02%	7.20%	9.08%
Capital Asset Pricing Models			
Based on Historical Return Data; gathered from 1926 - 2017; Reported by SBBI; Duff & Phelps	9.00%	7.83%	10.93%
Based on Forecasted Return Data Published by J.P. Morgan Asset Management (2018 edition)	6.09%	5.43%	7.17%

Q. For a point of comparison, please summarize return on equity decisions by this Commission and Commissions across the country?

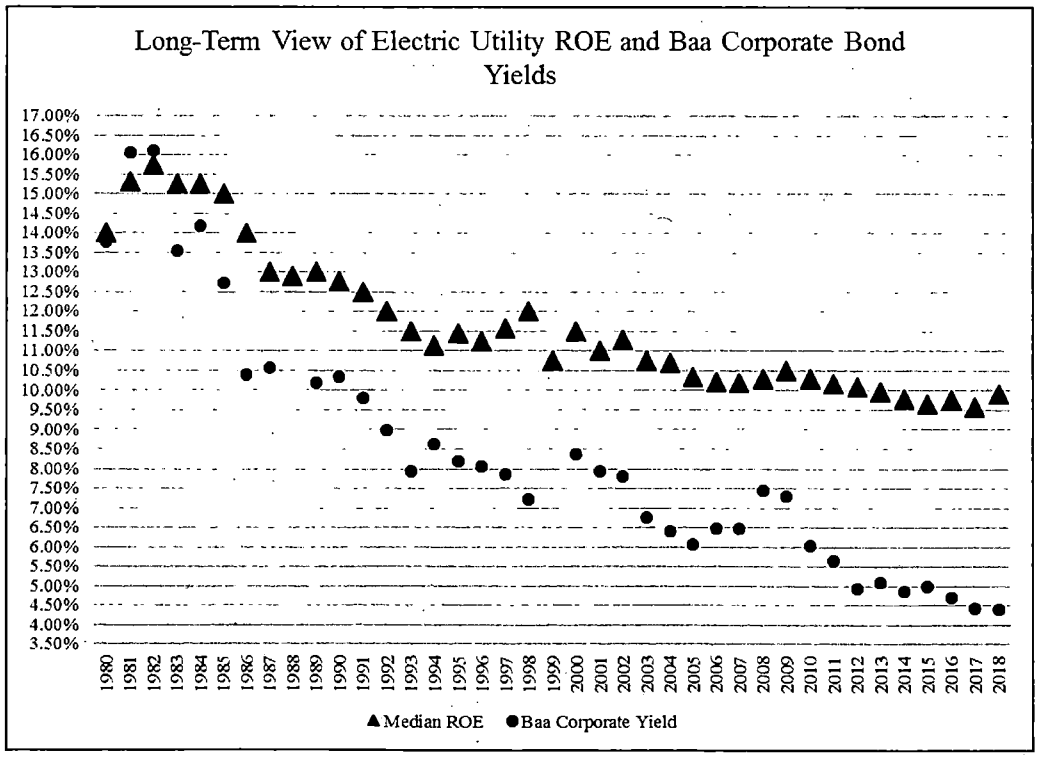
A. The first table contains allowed return on equity decisions made by this Commission in litigated rate cases. As a point of reference to the prevailing capital markets at that time, I included the yield on the Baa rated corporate bonds as of the month of the Commission's decision.

Commission Determined Allowed ROEs -- Kansas Utilities

Company	Docket	Order Date	Requested ROE	Ordered ROE	Baa Bond Yield
Kansas City Power & Light	15-KCPE-116-RTS	9/10/2015	10.30%	9.30%	4.86%
Atmos Energy Corp.	14-ATMG-320-RTS	9/4/2014	10.53%	9.10%	4.89%
Kansas City Power & Light	12-KCPE-764-RTS	12/13/2012	10.40%	9.50%	4.80%
Kansas City Power & Light	10-KCPE-415-RTS	11/22/2010	10.75%	10.00%	5.56%
Westar Energy Inc.	05-WSEE-981-RTS	12/28/2005	11.50%	10.00%	6.10%
Westar Energy Inc.	01-WSRE-436-RTS	7/25/2001	12.75%	11.02%	7.97%
Kansas Gas Service Co.	193,305-U	4/15/1996	12.00%	10.50%	7.77%

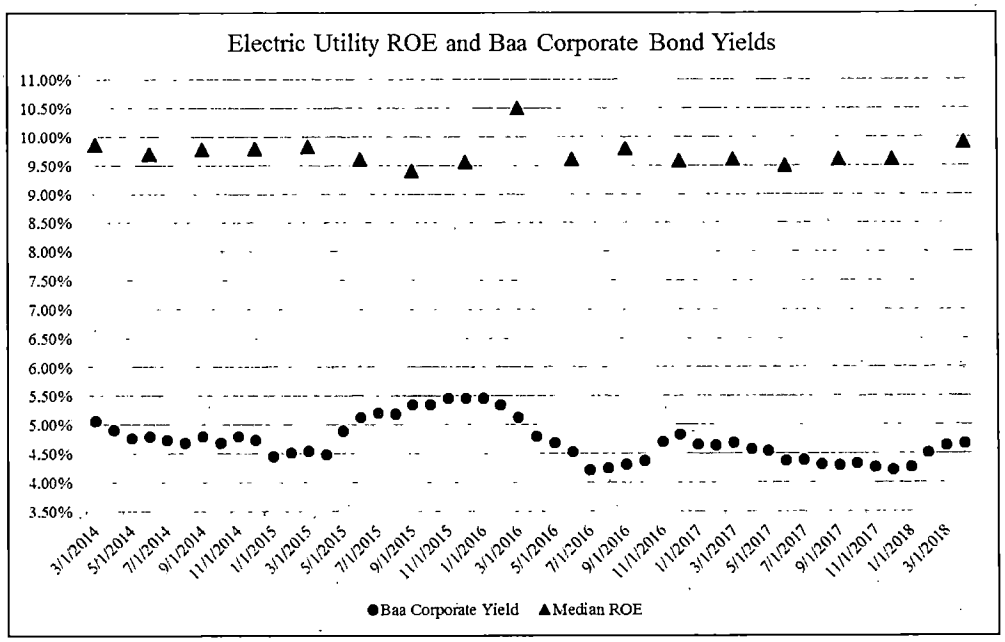
Sources: SNL/RRA; Federal Reserve Bank of St. Louis, FRED

The following chart is broader in both the time period and reporting scope. It indicates the median return on equity granted in fully litigated rate cases across the nation from 1980 through March of 2018. As a point of reference to the prevailing capital markets, I included the average yield to maturity of Baa corporate bonds.



The next chart highlights a shorter time period, the last four years from early 2014 through

March of 2018. Compared to the decline seen in the chart of the long-term changes, the past four years show a plateau in the median allowed return granted.



Q. How does Staff's recommendation compare to the returns available on other investments?

A. The following table shows that Staff's recommendation of a 9.30% return on equity allows investors a risk premium over less risky debt investments. These types of income producing securities are viewed as alternatives to investments in utility stocks because, like utility stocks, bonds offer stable valuations and higher current income, relative to the equity market. Risk premiums vary over time and across market conditions; thus, there is not a benchmark risk premium or formula that sets a reasonable return on equity at a given interest rate. The Commission has not set a definitive spread over bond yields, but the Commission's Order in 15-KCPE-115-RTS (15-116) noted that its decision allowed

1 KCP&L a risk premium of 525 basis points over the yield on its long-term debt.[15] At that
2 time, just as now, KCP&L and Westar have almost identical bond ratings, thus, they should
3 be viewed as comparable in risk. In that Docket, Staff argued that a 525 basis point risk
4 premium over the bond yield was reasonable as it offered stockholders a higher return than
5 available on the lower risk debt securities. The Commission agreed and applied Staff's
6 risk premium to arrive at an allowed return for KCP&L. I believe the 9.30% ROE is
7 consistent with the Commission's rationale in the 15-116 Order because it allows for a risk
8 premium in excess of 540 basis points over the yields on Westar's long-term bonds.

[15] Order issued on KCP&L's Application on Rate Change; 15-KCPE-116-RTS; September 10, 2015; para. 34.

KCC Staff's Risk Premium Over Fixed Income Yields
Based on a 9.30% Return on Equity
Fixed Income Yield Observations May 2017 through April 2018
18-WSEE-328-RTS

	30 Year (1)	Utility Bonds (2)		Moody's (3)	Westar (4)
	Treasury Bond	A/A	Baa/BBB	Corporate Baa	Bonds YTM
Apr-18	3.08%	4.17%	4.50%	4.71%	4.06%
Mar-18	3.09%	4.12%	4.45%	4.65%	4.03%
Feb-18	3.13%	4.14%	4.42%	4.47%	3.94%
Jan-18	2.88%	3.87%	4.14%	4.25%	3.71%
Dec-17	2.77%	3.80%	4.08%	4.22%	3.70%
Nov-17	2.81%	3.84%	4.11%	4.06%	3.72%
Oct-17	2.88%	3.92%	4.21%	4.32%	3.79%
Sep-17	2.78%	3.89%	4.19%	4.30%	3.76%
Aug-17	2.80%	3.87%	4.20%	4.32%	3.79%
Jul-17	2.88%	3.99%	4.31%	4.40%	3.82%
Jun-17	2.80%	3.94%	4.28%	4.38%	3.85%
May-17	2.96%	4.12%	4.48%	4.56%	4.04%
Average	2.90%	3.97%	4.28%	4.39%	3.85%

Risk Premiums Over Fixed Income Securities

KCC Staff's Recommended ROE	9.30%
Average Yield on 30 Year Treasury Bond	2.90%
Equity Risk Premium Over the 30-Year Treasury Bond Yield	**6.40%**
KCC Staff's Recommended ROE	9.30%
Average Yield on "A" Rated Utility Bonds	3.97%
Equity Risk Premium Over "A" Utility Bond Yield	**5.33%**
KCC Staff's Recommended ROE	9.30%
Average Yield on "BBB/Baa" Rated Utility Bonds	4.28%
Equity Risk Premium Over "Baa/BBB" Utility Bond Yield	**5.02%**
KCC Staff's Recommended ROE	9.30%
Average Yield on "BBB/Baa" Rated Utility Bonds	4.39%
Equity Risk Premium Over Moody's "Baa/BBB" Corporate Bond Yield	**4.91%**
KCC Staff's Recommended ROE	9.30%
Average Yield on Westar Bonds	3.85%
Premium over Yield on Westar Bonds	**5.45%**

1) Board of Governors of the Federal Reserve System (US), 30-Year Treasury Constant Maturity (Federal Reserve Bank of St. Louis; Release H.15)
2) Yield on A and BBB/Baa Rated Public Utilty Bonds 25 to 30 Maturity Reported weekly in Value-Line Investment Survey, Selection & Opinion Section.
3) Yield on Moody's Baa Corporate Bonds reported at FRED (Federal Reserve Bank of St. Louis Electronic Data)
4) Average yield to maturity reported by FINRA on WR 4.10%, 2043; WR 4.625%, 2043; and WR 4.125%, 2042.

Standards for a Just & Reasonable Rate of Return

Q. What is the role of rate of return in setting a revenue requirement for public utilities?

1 A. The standards for setting a just and reasonable rate of return require that, to be reasonable,
2 the allowed return must reflect the risks associated with an equity investment in the utility.
3 For the allowed return to be in that reasonable range, it must compensate for those added
4 risks while capturing a fair proportion of benefits for consumers. The terms of the 18-095
5 S&A, although beneficial to all stake-holders, possess several risks to shareholders not seen
6 in a traditional rate case and the Commission must consider these risks.

7 The allowed ROE is best described as the forward-looking discount rate that is necessary
8 to induce equity investors to commit their capital to the enterprise. Standards used to gauge
9 the fairness and reasonableness of an allowed ROE have been stated by courts, as the result
10 of appeals of decisions issued by regulatory agencies. Financial analysts and policy-
11 makers rely on the courts' decisions as a guide in estimating the appropriate cost of capital.
12 The opinions do not articulate precisely how to estimate or model a reasonable cost of
13 capital. Instead, the decisions provide critical questions for policy makers and analysts to
14 consider in determining a reasonable return for a regulated utility.

15 In general, United States Supreme Court decisions state that returns granted to regulated
16 public utilities should: 1) be commensurate with returns on investments of similar risk; 2)
17 be sufficient to assure the financial integrity of the utility under efficient economic
18 management; and 3) change over time with changes in the money market and business
19 conditions.[16] An important take-away from these decisions is that the Supreme Court of
20 the United States has afforded regulatory agencies a significant amount of latitude in

[16] *Smyth v. Ames*, 169 U.S. 466 (1898); *Wilcox v. Consolidated Gas Co.*, 212 U.S. 19, 48-49 (1909); *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-3 (1923); *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

1 establishing an appropriate ROR and ROE for a utility. The Kansas Supreme Court has
2 recognized and follows this body of law.[17] This Commission has noted this fact in Orders
3 issued in previous dockets.[18]

4 **Q. Discuss how financial analysts apply the standards established by the Court.**

5 A. For an allowed ROE to meet the legal standards, the return should be as specific as possible
6 to the utility in question. There are several court cases that, as a group, are viewed as the
7 keystone to measuring the adequacy of a utility's allowed return. The earliest of these
8 decisions go back to an era when it was not only the "rate of return" at issue but also the
9 fundamental measurement of the investment in the utility enterprise, commonly referred to
10 as rate base. This is less of an issue today as regulators, utility management, and investors
11 readily accept actual historic-depreciated value as the measure of investment to estimate
12 the value of a utility's rate base (as opposed to reproduction cost or market value). The
13 Court's decision in *Bluefield* addressed both rate base and ROR.[19] Treatises on rate of
14 return for public utilities, such as The Cost of Capital – A Practitioner's Guide, agree that
15 *Bluefield* lays out the four standards for a fair return.

16 *1) Comparable Earnings* – a utility is entitled to a return similar to that being earned by
17 other enterprises with similar risks, but not as high as those earned by highly profitable
18 or speculative ventures;
19 *2) Financial Integrity* – a utility is entitled to a return level reasonably sufficient to assure
20 financial soundness;
21 *3) Capital Attraction* – a utility is entitled to a return sufficient to support its credit and
22 raise capital; and

[17] *Kansas Gas & Elec. Co. v. State Corp. Comm'n*, 239 Kan. 483, 491, 720 P. 2d 1063, 1072 (1986).
[18] Order: 1) Addressing Prudence; 2) Approving Application, in Part; & 3) Ruling on Pending Requests, Docket No. 10-KCPE-415-RTS; November 22, 2010; 37-38.
[19] *Bluefield Water Works & Improvement Co. v. Pub. Svc. Comm'n of West Virginia*, 262 U.S. 679, 692-3 (1923).

1 4) *Changing Level of Returns* – a fair return can change along with economic conditions
2 and capital markets.[20]

3 As a financial analyst formulating rate of return analyses for our state commission, I take
4 from *Bluefield* that the Court requires a rate order that allows a utility an opportunity to
5 earn a return consistent with the utility's risk profile and consistent with observations in
6 the capital markets. The Court's decision in *Hope,*[21] like that in *Bluefield,* dealt with both
7 valuation of rate base, as well as rate of return on that rate base. With respect to the rate of
8 return, the Court in *Hope* affirmed the four standards set out in *Bluefield.*

9 **KCC Proxy Group**

10 **Q. How did you select a proxy group for your cost of equity analysis?**

11 A. Using the following parameters, identical to those that I used in the 18-095 Docket, I was
12 able to select a group of fourteen electric utilities that are comparable to Westar. To narrow
13 the universe of potential proxy companies, I used the following selection criteria:

14 • Has publicly traded common stock
15 • Is an electric utility followed by Value-Line Investment Survey
16 • No recent spin-offs, mergers or distressed assets

[20] The Cost of Capital – A Practitioner's Guide by David C. Parcell; Prepared for the Society of Utility and Regulatory Financial Analysts; 1997; pp. 3-13 to 3-14.

[21] *Federal Power Comm'n. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). "The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint."

- Exhibits stable dividends—No recent dividend cuts
- Possesses an investment grade bond rating between A3/A- and Baa2/BBB
- Earns at least 70% of its annual revenues by providing regulated electric utility services

Stock-price data is critical to a cost of equity analysis as that price data encapsulates the market participants' valuation of the company. Selecting companies that investment research companies like Value-Line categorize as electric utilities focuses the analysis on companies facing similar types of business risks and opportunities and insures that publically available financial data is available. As a starting point, this parameter is important as it assures us the companies generally derive their earnings in electric utility industry. The following table contains all of the electric utilities followed by Value-Line. The bold and boxed cells indicate the primary reason for rejection from the proxy group.

Proxy Company Selection (18-WSEE-328-RTS)

1	2	3	4	5	6	7	8	9	10
					FERC Selection Criteria			*KCC Staff Screens*	
Value-Line: Electric Utilities Company Name		***Bond Rating*** Moody's	S&P		No Announced Merger	Dividends No Planned Reductions	2017 History	2017 Electric Operations %Rev	%Assets*
Allete Inc	ALE	A3	BBB+	Yes	x	x	x	74.9%	
Alliant Energy Corp	LNT	Baa1	A-	Yes	x	x	x	85.6%	82.6%
Ameren Corp	AEE	Baa1	BBB+	Yes	x	x	x	86.0%	85.0%
American Electric Power Company Inc	AEP	Baa1	A-	Yes	x	x	x	86.7%	94.1%
~~AVANGRID Inc~~	AGR	Baa1	BBB+	Yes	x	x	x	81.0%	85.7%
~~Avista Corp~~	AVA				*Hydro-One Merger*				
~~Black Hills Corp~~	BKH				*Selling oil & gas assets*				
~~CenterPoint Energy Inc~~	CNP	Baa1	A-	Yes	x	x	x	31.7%	45.4%
~~CMS Energy Corp~~	CMS	Baa1	BBB+	Yes	x	x	x	67.5%	60.3%
Consolidated Edison Inc	ED	A3	A-	Yes	x	x	x	76.6%	73.3%
~~Dominion Energy~~	D				*Acquiring SCANA*				
~~DTE Energy Company~~	DTE	Baa1	BBB+	Yes	x	x	x	40.5%	62.7%
Duke Energy Corp New	DUK	Baa1	A-	Yes	x	x	x	90.5%	86.6%
Edison International	EIX	A3	BBB+	Yes	x	x	x	99.0%	89.9%
El Paso Electric Co	EE	Baa1	BBB	Yes	x	x	x	100.0%	
~~Entergy Corp~~	ETR	Baa2	BBB+	Yes	Closing 4 non-reg nuclear plants				
~~Eversource Energy~~	ES	Baa1	A+	SPLT	x	x	x	71.5%	53.0%
~~Exelon Corp~~	EXC	Baa2	BBB	Yes	x	x	x	44.4%	
~~FirstEnergy Corp~~	FE	Baa3	BBB-	NO	Sub. Bankruptcy/elim. non-reg	x	x	69.4%	64.2%
~~Fortis, Inc~~	FTS.TO	Baa3	A-			x	x	54.0%	
~~Great Plains Energy Inc~~	GXP	Baa2	BBB+	Yes	Westar				
~~Hawaiian Electric Industries Inc~~	HE		BBB-	NO	x	x	x	88.0%	47.0%
IDACORP Inc	IDA	Baa1	BBB	Yes	x	x	x	99.0%	99.0%
~~MGE Energy Inc~~	MGEE	A1	AA-	NO	x	x	x	73.5%	56.2%
~~NextEra Energy Inc~~	NEE	Baa1	A-	Yes	x	x	x	69.0%	51.4%
NorthWestern Corporation	NWE	Baa1	BBB	Yes	x	x	x	79.3%	80.1%
OGE Energy Corp	OGE	A3	A-	Yes	x	x	x	100.0%	
~~Otter Tail Corp~~	OTTR	Baa2	BBB	Yes	x	x	x	51.0%	84.3%
~~Pacific Gas and Electric Company~~	PCG	Baa1	BBB+	Yes	x	Suspended			
Pinnacle West Capital Corp	PNW	A3	A-	Yes	x	x	x	99.0%	98.0%
~~PNM Resources Inc~~	PNM	Baa3	BBB+	SPLIT	x	x	x	100.0%	
Portland General Electric Company	POR	A3	BBB	Yes	x	x	x	100.0%	
~~PPL Corporation~~	PPL	Baa2	A-	Yes	Forex risk	x	x	71.9%	59.2%
~~Public Service Enterprise Group Inc~~	PEG	Baa1	BBB+	Yes	x	x	x	68.1%	66.9%
~~SCANA Corporation~~	SCG				Construction issues/ACQ				
~~Sempra Energy~~	SRE	Baa1	BBB+	Yes	Onocor acquisition	x	x	39.4%	35.7%
~~Southern Co~~	SO	Baa2	A-	Yes	Construction issues	x	x	73.0%	65.8%
~~Vectren Corp~~	VVC		A-	Yes	x	x	x	21.4%	29.1%
WEC Energy Group	WEC	A3	A-	Yes	x	x	x	60.0%	
~~Westar Energy Inc~~	WR	Baa1	BBB+	Yes	Great Plains			100.0%	
Xcel Energy Inc	XEL	A3	A-	Yes	x	x	x	84.9%	

1) Electric utilities followed by Value-Line Investment Survey (U.S. companies)
2) Ticker symbol
3) Moody's credit rating (LTR) data from S&P Global Market Intelligence
4) S&P credit rating (LTR) data from S&P Global Market Intelligence
5) Within credit rating range of both rating agencies
6) No merger, acquistion, or sale of assets (Value-Line & S&P Global Market Intelligence)
7) No forecasted dividend reduction (Value-Line)
8) No dividend reduction in 2017 (Value-Line & S&P Global Market Intelligence)
9) Revenues from regulated electric operations--% of total revenues (S&P Global Market Intelligence)
10) Assets of regulated electric operations (S&P Global Market Intelligence)

Credit Rating Range		
Moody's	S&P	
A3	A-	
Baa1	BBB+	Westar
Baa2	BBB	

x = no reduction
x = no forecasted reduction
70% of Revenues from electric utility industry

Credit ratings shown in columns three and four are the first screen applied to the population. The current ratings for Westar is Baa1 by Moody's and BBB+ by S&P; these ratings are firmly in the mid-range of the investment-grade ratings. The selection criteria uses a range

that is one notch either side of Westar's ratings which is a range of A3/A- to Baa2/BBB.[22]

In column six, I listed any merger or acquisitions in process or any significant financial issues that make it difficult to assess the utility's long-term earnings prospects. In this criteria, I found there are several utilities involved in acquisitions. SCANA and Southern Co. are excluded due to their construction problems with nuclear power plants; SCANA has also signed in acquisition plan with Dominion. I excluded utilities involved in acquisitions and those with significant construction issues because both types of events cause uncertainty around future earnings. I also excluded PPL Corp. due to its investments overseas. PPL reports that 30% of its revenues are subject to foreign exchange risk. This is an atypical situation in the U.S. electric utility industry and a risk that is distinct from Westar. The filter in column six focuses the study on electric utilities with known prospective earnings power.

Columns seven and eight are similar to column five in that these criteria would eliminate firms that have or are forecasted to reduce annual dividends. In the public utility sectors where management and boards strive for a record of stable dividend growth, a dividend

22

Credit Rating Table		
	Moody's	S&P
Investment Grade	Aaa	AAA
	Aa1	AA+
	Aa2	AA
	Aa3	AA-
	A1	A+
	A2	A
	A3	A-
	Baa1	BBB+
	Baa2	BBB
	Baa3	BBB-
Less Than Investment Grade	Ba1	BB+
	Ba2	BB
	Ba3	BB-
	B1	B+
	B2	B
	B3	B-
	Caa1	CCC+
	Caa2	CCC
	Caa3	CCC-
	Ca	CC
		C+
		C
	C	D

reduction signals major change in ongoing operations and is probably a sign that managements cannot expect stable earnings growth in the foreseeable years. Such candidates should not be in the proxy group for Westar because that situation is not consistent with Westar's prospects. Pacific Gas & Electric is the only utility eliminated with this criteria; it suspended its dividend payments in December of 2017.

The criteria in columns nine and ten attempt to ascertain whether providing regulated electric utilities services is the primary business of the company. I set the threshold for revenues from electric utility service at 70% of total revenues. This is a subjective cutoff, but it works for this analysis because meeting that threshold means that the company is largely focused on, and earnings are derived from, providing regulated electric utility services. The following table contains Staff's proxy group of 14 electric utilities for the cost of equity and capital structure analyses.

1	2	3	4	5	6	7	8	9	10
				FERC Selection Criteria				*KCC Staff Screens*	
Value-Line: Electric Utilities		***Bond Rating***			No	Dividends		2017	
Company Name		Moody's	S&P		Announced Merger	No Planned Reductions	2017 History	Electric Operations %Rev	%Assets*
Allete Inc	ALE	A3	BBB+	Yes	x	x	x	74.9%	
Alliant Energy Corp	LNT	Baa1	A-	Yes	x	x	x	85.6%	82.6%
Ameren Corp	AEE	Baa1	BBB+	Yes	x	x	x	86.0%	85.0%
American Electric Power Company Inc	AEP	Baa1	A-	Yes	x	x	x	86.7%	94.1%
Consolidated Edison Inc	ED	A3	A-	Yes	x	x	x	76.6%	73.3%
Duke Energy Corp New	DUK	Baa1	A-	Yes	x	x	x	90.5%	86.6%
Edison International	EIX	A3	BBB+	Yes	x	x	x	99.0%	89.9%
El Paso Electric Co	EE	Baa1	BBB	Yes	x	x	x	100.0%	
IDACORP Inc	IDA	Baa1	BBB	Yes	x	x	x	99.0%	99.0%
NorthWestern Corporation	NWE	Baa1	BBB	Yes	x	x	x	79.3%	80.1%
OGE Energy Corp	OGE	A3	A-	Yes	x	x	x	100.0%	
Pinnacle West Capital Corp	PNW	A3	A-	Yes	x	x	x	99.0%	98.0%
Portland General Electric Company	POR	A3	BBB	Yes	x	x	x	100.0%	
Xcel Energy Inc	XEL	A3	A-	Yes	x	x	x	84.9%	

1) Electric utilities followed by Value-Line Investment Survey (U.S. companies)
2) Ticker symbol
3) Moody's credit rating (LTR) data from S&P Global Market Intelligence
4) S&P credit rating (LTR) data from S&P Global Market Intelligence
5) Within credit rating range of both rating agencies
6) No merger, acquistion, or sale of assets (Value-Line & S&P Global Market Intelligence)
7) No forecasted dividend reduction (Value-Line)
8) No dividend reduction in 2017 (Value-Line & S&P Global Market Intelligence)
9) Revenues from regulated electric operations 70% of total revenues (S&P Global Market Intelligence)
10) Assets of regulated electric operations (S&P Global Market Intelligence)

Credit Rating Range		
Moody's	S&P	
A3	A-	
Baa1	BBB+	Westar
Baa2	BBB	

1 **Return on Equity Analysis**

2 **Q. How did you perform the cost of equity analysis?**

3 A. I am using discounted cash flow models and capital asset pricing models; essentially the
4 same form of analysis used in all recent rate cases and the 18-095 Docket to establish the
5 9.30% threshold for the ERSP.

6 **Q. Does the DCF model meet the legal standards discussed earlier in your testimony?**

7 A. Yes, a cost of equity estimate derived from the DCF model meets the legal standards
8 discussed above if the model incorporates current information from the capital markets via
9 current stock prices and accurate data that investors use to establish their discount rate.
10 This market-based information ensures the cost of equity estimates evaluate investors'
11 required rate of return or discount rate that reflects the current economic environment.

12 The DCF model is a valuation model used by investors to value different types of
13 investments such as real estate, bonds, and equity securities. The DCF model is a useful
14 tool to value any investment that involves regular, periodic cash flows. The notion of
15 discounting a future receipt of cash back to the present so as to place a price or value on an
16 investment goes back centuries.[23] The premise of the DCF model in the valuation of
17 common stock is that investors determine the value of a company's common stock by
18 discounting its future dividend payments back to the present. The cornerstone of the DCF
19 model is the process of discounting those future cash flows back to the present at the

[23] The formal presentation of the DCF model as we use it today dates back to the 1930's in Irving Fisher's book: The Theory of Interest and John Burr Williams' 1938 text: The Theory of Investment Value. These two authors expressed the DCF model in modern economic terms.

investors' required return. An investor's required rate of return is risk-sensitive and sensitive to the returns available on investments of comparable risk throughout the global capital markets. In other words, as the risk of the investment increases, so will the investors' required return. A higher required rate of return decreases the present value of the stream of dividends that equates to the price of the stock. So, all other variables being equal, investors price the riskier of two common stocks lower because the cash flows or dividends are discounted back to the present at a higher rate.

The form of the DCF model that regulatory agencies are accustomed to seeing is often referred to as the Gordon Growth Model, which is a model that values the security at the present value of a stream of cash flows (dividends) growing at a constant rate into perpetuity. The basic form of this DCF equation is:

$$P_0 = \frac{D_0(1+g)}{(Ke-g)}$$

where:

P_0 = the value of the common stock or asset

D_0 = the current dividend of the stock or annual cash flow from the asset

g = the annual growth rate of the dividend or cash flow forever

Ke = cost of equity or required rate of return for the stockholders

Or

Stock Price = Annual Dividend / (Req'd Rate of Return – Dividend Growth Rate)

This is the form of the equation commonly found in texts regarding finance, investments, and asset valuation. Such texts are inclusive of both theory and practical application.

Regulatory agencies responsible for setting rates and revenue requirements want to know the investors' required rate of return or Ke in the equation. So, we solve the equation for that variable. The equation below shows the algebraic isolation of the investors' required rate of return. By isolating investors' required rate of return in the equation, we can estimate it by knowing the stock's dividend yield and the annual dividend growth rate expected by investors. That form of the equation is:

$$Ke = \frac{D_0(1+g)}{P_0} + g$$

This equation is frequently written out as:

Req'd Rate of Return = (Dividend/Current Stock Price) + Dividend Growth Rate

or

Req'd Rate of Return = Dividend Yield + Dividend Growth Rate

Or as commonly abbreviated by regulatory agencies

$$Ke = y + g$$

Where: y = Dividend Yield

g = Expected Dividend Growth

Through a handful of inputs, the DCF model distills down to an equation, a complex cognitive process performed by investors to arrive at a discount rate and valuation of the security. As with any equation that attempts to model behavior, there are a host of assumptions that come along with it. Those assumptions are:

- Ke corresponds only to the specific stream of future dividends, rather than earnings, and that constitutes the source of value.
- The discount rate (Ke) must exceed the growth rate (g).
- The constant growth rate will continue for an indefinite future.
- Investors require the same discount rate (Ke) each year.
- There is no external financing.

Q. Why is it reasonable to accept these assumptions?

A. The DCF model is attempting to emulate investors' behavior; distilling human behavior into a handful of inputs demands simplifying assumptions. The question becomes whether the assumptions are so contrary to investors' behavior in the real-world that the model output becomes meaningless or illogical. I do not believe the assumptions of the DCF model are contrary to investor behavior. Moreover, there are methods I use to evaluate whether an output falls outside of the realm of reality. For example, the output can be compared with the returns available on other investments such as long-term corporate bonds. There were no observations eliminated using this screen.[24]

<u>Discounted Cash Flow Model</u>

Q. How did you calculate the dividend yield (y) component of the DCF model?

A. The dividend yield (y) is the easier of the two components to measure as it is easily observable in daily stock price reports. It is calculated by dividing the stock's annual dividend payment per share by its market price per share.

[24] Staff applies this screen using the interest rates of Baa Utility Bonds and the yields on utility specific debt shown in the Risk Premium Table. Staff adds 100 basis points to these yields as a minimum risk premium test. Cost of equity observations below this level are eliminated from the average. FERC proceedings apply a similar test for outliers.

1 **Q. What is the source of the dividend information?**

2 A. Historic and current dividend information is easily obtained from public sources
3 subscription services such as Value-Line. The DCF model requires a forward-looking
4 dividend payment which is often the current year's dividend payment increased by the
5 forecasted growth rate for next year. In lieu of forecasting, I obtained the 2019 forecasted
6 dividend per share information from Value-Line Investment Survey. The Value-Line
7 reports for each of the proxy companies are attached as Schedule AHG-3. I obtained the
8 stock prices for the dividend yields from YahooFinance. For this analysis, I used weekly
9 stock price observations taken from May 8, 2017, through May 7, 2018. The stock prices
10 for each of the proxy companies appears on Schedule AHG-4. My DCF analysis
11 incorporates a dividend yield based on expected 2019 dividend payments.

Staff Proxy Group
Dividend Yields May 8, 2017 - May 7, 2018
18-WSEE-328-RTS

		1	2	3	4	5	6	7
		DPS	Prices				Dividend Yield	
		2019	Min	Max	Mid-Point	Mean	Min	Max
Allete Inc	ALE	$ 2.34	$ 66.64	$ 81.24	$ 73.94	$ 74.28	2.88%	3.51%
Alliant Energy Corp	LNT	$ 1.42	$ 36.84	$ 45.55	$ 41.19	$ 41.58	3.12%	3.85%
Ameren Corp	AEE	$ 1.93	$ 51.89	$ 64.89	$ 58.39	$ 57.85	2.97%	3.72%
American Electric Power Co.	AEP	$ 2.63	$ 63.32	$ 78.07	$ 70.70	$ 70.81	3.37%	4.15%
Consolidated Edison Inc	ED	$ 2.96	$ 73.73	$ 89.70	$ 81.72	$ 81.80	3.30%	4.01%
Duke Energy Corp New	DUK	$ 3.80	$ 72.93	$ 91.80	$ 82.37	$ 83.14	4.14%	5.21%
Edison International	EIX	$ 2.57	$ 57.63	$ 83.38	$ 70.50	$ 72.46	3.08%	4.46%
El Paso Electric Co	EE	$ 1.52	$ 48.05	$ 61.15	$ 54.60	$ 53.72	2.49%	3.16%
IDACORP Inc	IDA	$ 2.56	$ 79.59	$ 100.04	$ 89.81	$ 88.59	2.56%	3.22%
NorthWestern Corporation	NWE	$ 2.30	$ 50.01	$ 64.47	$ 57.24	$ 57.97	3.57%	4.60%
OGE Energy Corp	OGE	$ 1.54	$ 29.59	$ 37.32	$ 33.46	$ 34.18	4.13%	5.20%
Pinnacle West Capital Corp	PNW	$ 3.02	$ 73.81	$ 92.48	$ 83.15	$ 84.62	3.27%	4.09%
Portland General Electric Co.	POR	$ 1.50	$ 39.02	$ 50.11	$ 44.57	$ 44.71	2.99%	3.84%
Xcel Energy Inc	XEL	$ 1.60	$ 41.51	$ 52.22	$ 46.86	$ 47.16	3.06%	3.85%
						Range:	2.49%	5.21%

1) Dividends per Share for 2019 Forecasted by Value-Line Investment Survey
2) Minimum 12 month price observed from May 8, 2017, through May 7, 2018
3) Maximum 12 month price observed from May 8, 2017, through May 7, 2018
4) Mid-point is the average of minimum price and maximum price
5) Mean price for the time period of May 8, 2017, through May 7, 2018 (weekly observations)
6) Minimum dividend yield available from time period
7) Maximum dividend yield available from time period

Forecasted Growth Rates for the DCF Model

Q. Please discuss the importance of the second component, the growth rate (g), in the DCF equation.

A. The "g" represents the anticipated annual growth rate in cash-flows that investors expect to receive through dividends from the stock. This is a challenging and contentious issue in a DCF analysis for two reasons. First, it is a key element in the DCF model or any form of a discounted cash flow analysis because the growth rate has a one-for-one effect on the required return produced by the model. All other factors being equal, a higher growth rate results in an equally higher return on equity for the utility. Second, there is an element of

1 subjectivity to the growth rate, due to the uncertainty about future earnings and dividends.

2 **Q. How did you estimate the growth rate in the DCF model?**

3 A. The appropriate growth estimate is that which is expected by the market and factored into
4 investors' analyses to estimate stock prices. That is, it is the growth estimate investors
5 used to determine the stock price. Earnings per share growth forecasts are commonly
6 incorporated into the DCF model. Investment firms that publish growth forecasts typically
7 publish three to five-year annual growth estimates for earnings. Value-Line Investment
8 Survey also provides dividend growth rate forecasts; it is the only firm that I am aware of
9 that does so. Three to five years is as far into the future as analysts forecast for a specific
10 company.

11 **Q. How do investors estimate the dividend growth rate beyond the three to five-year**
12 **horizon of the short-term growth forecasts?**

13 A. For a long-term perspective of potential growth, investors rely on forecasts of the broad
14 economy as measured by annual changes forecasted for the nation's gross domestic product
15 (GDP). There are sources for long-term growth estimates of this country's GDP that extend
16 out more than 20 years. Academic texts and investment professionals use these forecasts
17 in DCF models as a forecast of potential long-term growth of corporate dividend payments.

18 GDP refers to the market value of all final goods and services produced within a country
19 in a given period. Nominal GDP (nGDP) is that measure of goods and services which
20 *includes* effects of price changes - better known as inflation. Inflation must be included
21 for our forecast because the DCF analysis is interested in the nominal required return. That

is to say, investors' expectations of inflation are contained in their required return. Keep in mind that the "headline" GDP reported in the media is *real* GDP, which is GDP less the inflation experienced over the measurement period.

Q. Is it accepted practice in securities valuation to use nGDP growth estimates in the DCF model?

A. Yes, in the federal regulatory arena, similar to the responsibilities of the KCC, the Federal Energy Regulatory Commission (FERC) uses nGDP to estimate the cost of equity. FERC has reviewed the issue of long-term growth estimates used in DCF models. It took comments from stakeholders that included state commissions, customers, investment bankers, and interstate pipeline companies.[25] Testimony from these parties made it clear that long-term estimates of nGDP are a common component of valuation analyses conducted by investment professionals. From that proceeding, FERC concluded that long-term growth estimates of nGDP should be the estimate of long-term growth in the DCF models used to estimate required returns for interstate pipeline companies because that is consistent with investor behavior.[26] In June of 2014, FERC concluded that the same methodology should be used in setting the required returns for electric transmission companies.[27] Although the Commission has never explicitly endorsed long-run GDP growth as an input, it is clear that the growth estimate used by Staff in the 15-116 Docket were considered credible by the Commission.[28] In that analysis, I relied on the same

[25] Transcript from Technical Conference held on January 23, 2008: FERC Docket PL07-2-000.
[26] Policy Statement, FERC Docket PL07-2-000 (April 17, 2008); FERC Opinion No. 486, FERC Docket RP04-274 (Oct. 19, 2006).
[27] Opinion No. 531; June 19, 2014; 147 FERC 61,234; para 36.
[28] Order issued September 10, 2015; Docket 15-KCPE-116-RTS; para. 34; p. 15-16.

1 sources for long-term nGDP growth as I am using in this analysis.

2 **Q. Is there academic support for this issue?**

3 A. Yes, academic research has shown that nGDP growth forecasts are an important input to
4 valuation studies because the analyst has to consider whether a company's annual earnings
5 can grow as fast as, or even faster than, the broad economy. In two of his books devoted
6 to the subject of asset valuation, Dr. Aswath Damodaran discusses the nature of a stable
7 growth rate for DCF models.[29] He argues for viewing nominal economic growth as the
8 absolute maximum when using a stable-growth model, such as the DCF model we are
9 using.

10 *"The stable growth rate cannot exceed the growth rate of the economy in*
11 *which a firm operates, but it can be lower. There is nothing that prevents*
12 *us from assuming that mature firms will become a smaller part of the*
13 *economy and it may, in fact, be the more reasonable assumption to make.*
14 *Note that the growth rate of an economy reflects the contributions of both*
15 *young, higher growth firms and mature, stable growth firms. If the former*
16 *grow at a rate much higher than the growth rate of the economy, the latter*
17 *have to grow at a rate that is lower."* (Damodaran on Valuation: Security
18 Analysis for Investment and Corporate Finance, 2nd edition; Aswath
19 Damodaran; p. 148)

20 *"The growth rate of a company cannot be greater than that of the economy*
21 *but it can be less. Firms can become smaller over time relative to the*
22 *economy. Thus, even though the cap on the growth rate may be the nominal*
23 *growth rate of the economy, analysts may use growth rates much lower than*
24 *this value for individual companies."* (Damodaran on Valuation: Security
25 Analysis for Investment and Corporate Finance, 2nd edition; Aswath
26 Damodaran; p.159)

[29] Investment Valuation: Tools and Techniques for Determining the Value of Any Asset, 2nd Edition and Damodaran on Valuation: Security Analysis for Investment and Corporate Finance, 2nd Edition.

It is worth noting that Professor Damodaran cites the nGDP growth projection as a *ceiling* for long-term growth in most valuation studies. Certainly, there are industries that will exceed the average for a period of time, but even for those industries, rapid growth cannot continue forever.

Q. Does the view that nGDP growth is a ceiling on long-term earnings growth exist outside of academia?

A. Yes, valuation analysts carefully consider the long-run growth rates used to value assets very carefully because using an incorrect growth estimate will lead to incorrectly valuing an asset. The authors of the previous discussion, Peter L. Bernstein and Robert D. Arnott, have both published in peer-reviewed academic journals and books on investment strategy, as well as building careers in the field of asset management and investment strategy.

Furthermore, institutions directly involved in asset valuation and asset management that apply valuation models to analyze potential acquisition and merger transactions recognize that estimates of firm-specific growth are a driver to the value of an asset; overstating growth would cause a model to overestimate the value of the asset which would result in an economic loss to the investor. These experts also warn of a ceiling to earnings growth rates as being no more than that of broad economic growth.

> *"Growth rate: Few companies can be expected to grow faster than the economy for long periods. The best estimate is probably the expected long-term rate of consumption growth for the industry's products, plus inflation."* (Valuation: Measuring and Managing the Value of Companies; Tim Koller, Mark Goedhart, and David Wessels; McKinsey & Co; 4th ed; p. 275.)

1 The following quote from J.P. Morgan Asset Management (JPMAM) addresses the macro
2 or economy-wide measures of profits, and it is consistent with the firm-specific view
3 expressed by asset valuation experts in that analysts must be aware of the forecasted growth
4 rates applied in valuation models and how those growth forecasts comport with broad
5 measures of forecasted economic growth.

6 *"One common mistake is to assume that earnings and dividends received*
7 *by investors can grow in line with—or even in excess of—overall economic*
8 *growth (GDP) in perpetuity. Granted, it is almost a truism that aggregate*
9 *earnings must grow at the same pace as the overall economy in the very*
10 *long run; otherwise, profits would eventually outstrip the size of the entire*
11 *economy or dwindle to an insignificant share of it. But not all of this*
12 *earnings growth accrues to existing shareholders. On the contrary, a large*
13 *portion of economic growth comes from the birth of new enterprises. Some*
14 *commentators suggest (for example, Bernstein and Arnott, 2003; Cornell,*
15 *2010) that new enterprises account for more than half of GDP growth in*
16 *the U.S., while in some rapidly developing economies new enterprises may*
17 *account for the lion's share of overall economic growth."*[30]

18 Goldman Sachs Asset Management explains to its clients, "Our analysis reveals that the
19 link between GDP growth and equity returns is, in fact, very strong."[31] The asset pricing
20 formula of a dividend discount model shows how GDP growth influences the return they
21 earn on equity assets: "...the dividend growth rate will equate to the growth rate in
22 earnings. Assuming that earnings growth is equal to, or just associated with GDP growth,
23 a direct link with equity returns is established."[32] Goldman Sachs also states that research
24 has demonstrated that GDP growth is a proxy for earnings growth.

[30] Long-term Capital Market Return Assumptions: 2015 Estimates and Thinking Behind the Numbers; J.P. Morgan Asset Management; p. 25; https://am.jpmorgan.com/us/institutional/ltcmra

[31] "Linking GDP Growth and Equity Returns"; Monthly Insights: From the Office of the Chairman; Goldman Sachs Asset Management; May 2011; p. 1.

[32] "Linking GDP Growth and Equity Returns"; Monthly Insights: From the Office of the Chairman; Goldman Sachs Asset Management; May 2011; p. 2.

1 **Q. Do you believe this evidence justifies incorporating long-run nGDP growth forecasts**
2 **into cost of equity analyses of utility companies?**

3 A. Yes, because we have to ascertain the discount rate investors apply to the future cash flows
4 from an investment in these utilities. Therefore, the Commission should emulate investors'
5 analytical practices as closely as possible to determine investors' discount rate. As noted
6 above, investment professionals include a long-run growth forecast for the general
7 economy (in addition to company-specific short-run growth estimates) when applying the
8 DCF and capital asset pricing model, and that measure of macro-economic growth serves
9 as the upper bounds of a firm-specific analysis. Therefore, the Commission should
10 consider the same information when estimating a utility's required return.

11 **Q. How did you estimate long-run nominal GDP growth?**

12 A. I averaged the long-run nGDP forecasts of the Energy Information Agency (EIA) and the
13 Social Security Administration (SSA). The average of these two forecasts composes the
14 long-run growth estimate in the DCF analysis. The nGDP growth forecasts published by
15 EIA and SSA-OADSI are the same sources that I relied on over the past decade.

Nominal GDP Estimates	
Energy Information Agency (EIA) 2015 - 2050	4.19%
Social Security Administration (SSA)	
OADSI Trustees Report 2017 - 2095	4.41%
Average	4.30%
Additional GDP Estimates	
Exxon-Mobile 2017 Outlook for Energy 2015 - 2040	
2.2% Real GDP + 2.2 GDP Deflator from SSA	4.40%
Congresssional Budget Office Nominal GDP Forecast	
2019 - 2020	3.50%
2021 - 2027	3.90%
Federal Reserve Open Market Committee Long-run Forecast	
2.2% Real GDP + 2.0 PCE Inflation	4.20%

Q. Are these two the only two sources for long-run GDP forecasts?

A. There are other source shown in the table and they are wholly consistent with the EIA and SSA forecasts.

DCF Results

A. Please discuss the results of your DCF analysis.

Q. The results of my DCF analysis appear in the following table. The results seen in this DCF analysis are very much the same as the DCF results in my 18-095 analysis. As I have set out the foundations for the DCF analysis in the previous pages, in this section, I will discuss the specific information that I relied on for the DCF model and interpret the results.

Staff Proxy Group
Discounted Cash Flow (DCF) Analysis
18-WSEE-328-RTS

		1	2	3	4	5
		Dividend Yield		Growth	DCF Estimated	
		Min	Max	Rate	Required Return	
Allete Inc	ALE	2.88%	3.51%	4.89%	7.77%	8.40%
Alliant Energy Corp	LNT	3.12%	3.85%	5.18%	8.30%	9.03%
Ameren Corp	AEE	2.97%	3.72%	5.22%	8.20%	8.94%
American Electric Power Co.	AEP	3.37%	4.15%	4.73%	8.10%	8.89%
Consolidated Edison Inc	ED	3.30%	4.01%	3.81%	7.11%	7.83%
Duke Energy Corp New	DUK	4.14%	5.21%	4.31%	8.45%	9.52%
Edison International	EIX	3.08%	4.46%	4.60%	7.68%	9.06%
El Paso Electric Co	EE	2.49%	3.16%	4.88%	7.36%	8.04%
IDACORP Inc	IDA	2.56%	3.22%	4.30%	6.86%	7.52%
NorthWestern Corp.	NWE	3.57%	4.60%	3.92%	7.49%	8.52%
OGE Energy Corp	OGE	4.13%	5.20%	4.71%	8.83%	9.91%
Pinnacle West Capital Corp	PNW	3.27%	4.09%	4.48%	7.75%	8.58%
Portland General Electric Co.	POR	2.99%	3.84%	4.11%	7.10%	7.95%
Xcel Energy Inc	XEL	3.06%	3.85%	4.98%	8.04%	8.83%
				Average of each column	7.79%	8.64%
				Average of all observations	8.22%	
				Range of all observations	6.86%	9.91%

1) 2018 annual dividend divided by maximum price observed (5/8/2017 through 5/7/2017)
2) 2018 annual dividend divided by minimum price observed (5/8/2017 through 5/7/2018)
3) Forecasted EPS growth
4) Low-end estimate = col 1 + col 3
5) High-end estimate = col 2 + col 3

Pricing data was gathered from YahooFinance for each of the proxy companies from the time period of May 8, 2017, through May 7, 2018, on a weekly basis. The low dividend yield is computed using the projected 2019 dividend divided by the average of the weekly high prices while the high dividend yield is computed using the average weekly low prices.

Q. How did you arrive at a growth rate for each proxy company?

1 A. The growth rate is the average of the short-term growth rates[33] and the long-run forecast
2 of nGDP of 4.30%. The following table summarizes all of the observed growth forecasts,
3 both historical and forecasted.

4 **Q. How is the long-run nGDP forecast applied in your DCF analysis?**

5 A. The long-run nGDP growth forecast of 4.30% is averaged with the short-run growth
6 forecasts. In my DCF analysis, I give equal weight to short-run and long-run growth
7 forecasts. The weighting is certainly debatable because we cannot know precisely how
8 investors weight the two forecast horizons. At FERC, in both natural gas pipeline and
9 electric transmission rate cases, the short-run growth is afforded a two-thirds weighting
10 and the nGDP forecast a one-third weighting. Whatever the weighting an analyst applies
11 between the short-term and long-term growth forecasts, the analysis needs to be
12 constructed in a manner that distinguishes between the growth potential of each time
13 horizon.

[33] For each proxy company, I gathered three short-run, three to five-year growth forecasts for earnings and dividend from Value-Line Investment Survey; as well as analysts' earnings growth projections by Thomson Financial Network (I/B/E/S) reported by YahooFinance. I/B/E/S aggregates analysts' earnings forecasts and reports the mean of those estimates. FactSet is a service similar to I/B/E/S in that it aggregates analysts' forecasts and publishes the mean and median of estimates. FactSet data was obtained through S&P Global Market Intelligence.

Staff Proxy Group
Growth Rate Summary
18-WSEE-328-RTS

		1	2	3	4	5	6	7	8	9	10	11
		Value-Line Historic Data				Forecasted Growth Rates						
		10 Year		5 Year		Value Line		Thomson	FactSet	Short-run	Long-term	DCF
		EPS	DPS	EPS	DPS	EPS	DPS	EPS	EPS	Average	nGDP	Growth Rate
Allete Inc.	ALE	1.50%	3.50%	5.50%	3.00%	4.50%	4.50%	6.00%	6.90%	5.48%	4.30%	4.89%
Alliant Energy Corp.	LNT	5.00%	7.50%	6.50%	6.50%	6.50%	6.00%	5.80%	5.93%	6.06%	4.30%	5.18%
Ameren Corp.	AEE	-1.00%	-4.00%	0.50%	2.00%	7.50%	4.50%	6.30%	6.28%	6.15%	4.30%	5.22%
American Electric Power Co.	AEP	3.00%	4.00%	5.50%	4.50%	4.50%	5.00%	5.79%	5.37%	5.17%	4.30%	4.73%
Consolidated Edison Inc.	ED	3.50%	1.50%	2.50%	2.00%	3.00%	3.50%	3.40%	3.38%	3.32%	4.30%	3.81%
Duke Energy Corp.	DUK	3.50%	0.00%	0.50%	2.50%	4.50%	4.50%	4.25%	4.06%	4.33%	4.30%	4.31%
Edison International	EIX	2.50%	6.00%	2.50%	9.00%	4.50%	8.00%	2.62%	4.47%	4.90%	4.30%	4.60%
El Paso Electric Co.	EE	6.50%	0.00%	0.00%	18.00%	4.50%	7.00%	5.20%	5.10%	5.45%	4.30%	4.88%
IDACORP Inc.	IDA	7.50%	5.50%	4.50%	10.50%	3.50%	6.50%	3.10%	4.12%	4.31%	4.30%	4.30%
NorthWestern Corp.	NWE	8.00%	5.50%	7.00%	7.00%	3.50%	4.50%	3.16%	3.01%	3.54%	4.30%	3.92%
OGE Energy Corp.	OGE	4.50%	5.50%	1.00%	8.50%	2.50%	8.00%	5.80%	4.15%	5.11%	4.30%	4.71%
Pinnacle West Capital Corp.	PNW	4.00%	2.50%	5.00%	2.50%	5.00%	5.50%	3.63%	4.54%	4.67%	4.30%	4.48%
Portland General Electric Co.	POR	4.00%	9.00%	3.50%	3.50%	4.00%	6.00%	2.65%	3.02%	3.92%	4.30%	4.11%
Xcel Energy Inc.	XEL	5.50%	4.50%	5.00%	5.50%	5.50%	5.50%	5.89%	5.73%	5.66%	4.30%	4.98%
	Min	-1.00%	-4.00%	0.00%	2.00%	2.50%	3.50%	2.62%	3.01%	3.32%		3.81%
	Max	8.00%	9.00%	7.00%	18.00%	7.50%	8.00%	6.30%	6.90%	6.15%		5.22%
	Mean	4.14%	3.64%	3.54%	6.07%	4.54%	5.64%	4.54%	4.72%	4.86%		4.58%

1) Historic 10-year earning per share annual growth rate reported by Value-Line
2) Historic 10-year divdend per share annual growth rate reported by Value-Line
3) Historic 5-year earnings per share annual growth rate reported by Value-Line
4) Historic 5-year dividend per share annual growth rate reported by Value-Line
5) 3 to 5-year forecasted annual earnings per share growth rate by Value-Line
6) 3 to 5-year forecasted annual dividends per share growth rate by Value-Line
7) 5-year forecasted annual earnings per share growth rate. Consensus forecasts gatherd by Thomson-Reuters and reported at YahooFinance on May 3, 2018
8) Long-term forecasted annual earnings per share growth rate. Consensus forecasts gathered by FactSet and reported at S&P Global Market Intelligence (fka: SNL Financial) on May 3, 2018
9) Average of 3 to 5-year forecasted annual growth rates
10) Long-term forecasted nominal GDP growth rate
11) Average of short-term and long-term growth rates

Q. What are your observations of the short-run growth forecasts?

A. The average of the short-run growth forecasts for the proxy group is 4.86% with a range of 3.32% to 6.15%.

Internal Rate of Return (IRR) Analysis

Q. Please discuss the internal rate of return (IRR) analysis that you performed.

A. An IRR analysis of an investment is a form of a discounted cash flow analysis, only with a more complex equation than the Gordon Growth Model that we applied in the previous

section. In the IRR analysis, we are able to apply the five-year growth forecasts to only the intended next five years of dividends, with the remaining years growing at the long-run nGDP forecasted growth rate. In the age of spreadsheets, the IRR equation is not that much harder to manage than the basic dividend yield plus growth DCF model (a.k.a. Gordon Growth Model) and, as the IRR model allows us to apply the growth forecasts to their respective forecast periods, the IRR model provides important information to policy makers because it recognizes the respective time spans of both the short-run (three to five-year earnings growth) and long-run (nGDP growth rate) forecasts. The full output of the IRR calculations appears in Schedule AHG-5; the following table summarizes the results. In the IRR model, short-term growth forecasts are given much less weight than in the two-stage DCF analysis; five years of a several hundred year time horizon or five percent as opposed to a weighting of 50 percent that I applied in the two-stage DCF model. As a result of the greater weighting of the long-term growth estimate, the average for the proxy group in the IRR analysis is 16 basis points lower than the two-stage DCF results.

Staff Proxy Group	
Internal Rate of Return (IRR) Results	
18-WSEE-328-RTS	
Allete Inc	7.68%
Alliant Energy Corp	8.00%
Ameren Corp	7.98%
American Electric Power Company Inc	8.25%
Consolidated Edison Inc	7.94%
Duke Energy Corp New	9.08%
Edison International	8.03%
El Paso Electric Co	7.25%
IDACORP Inc	7.20%
NorthWestern Corporation	8.30%
OGE Energy Corp	8.89%
Pinnacle West Capital Corp	8.00%
Portland General Electric Company	7.67%
Xcel Energy Inc	7.95%
Mean	8.02%
Min	7.20%
Max	9.08%

In this instance, as is usually the case with public utilities, there is not a wide difference between the short-term growth rates and long-term nGDP growth, therefore the difference in weighting of the two growth rates between the DCF and IRR analyses do not cause a large difference in results.

Capital Asset Pricing Model (CAPM) Analysis

Q. Please describe the capital asset pricing model (CAPM).

A. The CAPM offers an explanation of the positive relationship between risk and ROR required by investors.[34] It is appealing to regulators because it meets the legal standards I

[34] The theoretical support for the CAPM is the work done by Harry Markowitz ("Portfolio Selection," Journal of Finance, March, 1952). W.F. Sharpe added the concept of a risk-free rate of return to the Markowitz model ("A Simplified Model of Portfolio Analysis," Management Science, January, 1963).

discussed above, as it can be structured to incorporate current data from the financial markets and the unique risks of the utility in question.

$$Ke = Rf + Beta\ (Rm - Rf) \quad \text{or}$$

$$Ke = Rf + Beta\ (Rp)$$

Where:

Ke = required return on equity

Rf = return on a risk-free security

Rm = an expected return from the market as a whole

Rp = risk premium available to investors through purchasing common stocks instead of risk-free securities often calculated as Rm - Rf

Beta = volatility of the security's or portfolio's return relative to the volatility of the market's return with the market beta equal to 1.0

Rf

The Rf estimate is the interest rate investors believe represents a riskless return. Although it is a simple concept, the answer is not universally agreed upon. It is widely accepted that a debt instrument issued by the U.S. Government is a risk-free instrument. An investment in U.S. Treasury Bonds is a risk-free investment if the investor plans to hold it until maturity. The risk-free instrument chosen will have an effect on the results of the CAPM analysis. Whichever instrument is selected, it should be used consistently in the equation.

Beta

The beta coefficient measures the volatility of the return earned by the utility's stock relative to the volatility of the returns earned by the broader equity market. The broad

1 equity market is frequently measured using the S&P 500 Index. This measure provides a
2 look at the risk and volatility of a stock relative to other investments. A stock with a beta
3 of 1 is equally as volatile as the market as a whole. A stock with a beta of 0.5 is half as
4 volatile as the market. Value-Line reports that Westar has a beta coefficient of 0.70. These
5 are similar to the average for the proxy group of 0.67.

6 **Rm**

7 Rm is the expected return on the stock market as measured by a broad market index such
8 as the S&P 500. This represents the total return consisting of the price change of the index
9 plus dividends earned for the year.

10 **Rp**

11 The risk premium is the difference between investors' expected return from the stock
12 market and their expected return from the risk-free investment over the same time period.
13 The risk premium is written as Rm-Rf. The market return and the risk-free return should
14 be taken from the same time period so as to accurately measure the additional return
15 required by investors to take on the risk of common stocks over the risk-free investment.

16 **Q. Please discuss your CAPM analysis.**

17 A. I took two distinct approaches to the CAPM analysis. I performed one analysis using
18 purely historic measures of returns from the stock and bond markets and a second analysis
19 using forecasted returns. The results using historic returns are drastically higher, 9.38%,
20 when compared to results using forecasted returns of 6.93%.

1 Both forms of my CAPM analysis incorporate the high and low beta coefficients observed
2 in the proxy group. This beta indicates that the volatility of the proxy group is about 65%
3 of that exhibited by the broad market and, accordingly, investors would expect a relatively
4 lower return from stocks of public utilities than the broad market. This is a clear indication
5 that public utility companies like Applicants and the proxy group are less volatile (and less
6 risky) than the broad stock market, and investors expect a return lower than that expected
7 of the market. Reviewing the high and low beta coefficients observed in the proxy group
8 provides a picture of the range that the new company could exhibit in the future.

Beta Coefficients, Staff's Proxy Group		
Updated on May 10, 2018		
18-WSEE-328-RTS		
Allete Inc	ALE	0.75
Alliant Energy Corp	LNT	0.70
Ameren Corp	AEE	0.65
American Electric Power Co Inc	AEP	0.65
Consolidated Edison Inc	ED	0.50
Duke Energy Corp New	DUK	0.60
Edison International	EIX	0.60
El Paso Electric Co	EE	0.75
IDACORP Inc	IDA	0.70
NorthWestern Corp	NWE	0.65
OGE Energy Corp	OGE	0.95
Pinnacle West Capital Corp	PNW	0.65
Portland General Electric Co	POR	0.65
Xcel Energy Inc	XEL	0.60
	Min	0.50
	Max	0.95
	Mean	0.67
	Median	0.65
Westar		0.70
Source: Value-Line Investment Survey		

9

10 **Q. Please describe the forecasted CAPM analysis.**

1 A. For the forecasted CAPM, I relied on the expected returns published by JPMAM in its
2 annual publication, Long-Term Capital Market Assumptions for 2018, to establish the
3 expected return for the market. JPMAM publishes 10 to 15-year forecasts of expected
4 returns on dozens of investment asset classes in its annual publication, the Long Term
5 Capital Market Return Assumptions (LTCMRA). JPMAM forecasts an annual return on
6 common stocks of 6.93%. The JPMAM's forecasted returns on common stocks has
7 declined over the past two years; generally a product of the increase in stock prices over
8 the past two years.

9 Following the calculations and inputs through the CAPM equation in line 2 of the following
10 table, the forecasted return on a risk-free investment, 10-Year U.S. Treasury Bonds, is
11 subtracted from the expected return on common stocks resulting in a risk premium of
12 3.86%. This risk premium is the additional return necessary to induce investors to take on
13 the added risk associated with common stocks over the risk-free investment. The beta
14 coefficient is applied to the risk premium to ascertain how much of a risk premium is
15 necessary for investors to take on risks of investing in utility stocks as opposed to the risk-
16 free U.S. Treasury Bond.

Capital Asset Pricing Model -- Forecasted Risk Premium
Using Forecasted Market Returns & Treasury Bond Yields
18-WSEE-328-RTS

			Low Beta	High Beta	Avg Beta
1)	Forecasted Returns on Common Stocks		6.93%	6.93%	6.93%
2)	Forecasted Total Return on 10-Year T-Bonds	-	3.07%	3.07%	3.07%
3)	Resulting Risk Premium		3.86%	3.86%	3.86%
4)	Beta Coefficient	x	0.50	0.95	0.67
5)	Risk Premium		1.93%	3.67%	2.59%
6)	Forecasted Yield on 10-Year T-Bonds	+	3.50%	3.50%	3.50%
7)	For Cost of Equity		5.43%	7.17%	6.09%
			6.30%		

1) Forecasted 10 to 15-year annual arithmetic return on stocks for mid-sized companiesby J.P. Morgan Asset Management, 2018 Edition
2) Forecasted 10 to 15-year annual arithmetic return on intermediate term U.S. Government bonds by J.P. Morgan Asset Management, 2018 Edition
3) Resulting risk premium (1-2)
4) Beta coefficient range of proxy group reported by Value-Line
5) Row 3 x Row 4 = asset specific risk premium
6) Forecasted yield on 10-Year U.S. Treasury bonds forecasted by J.P. Morgan Asset Management, 2018 Edition (page 55)
7) Forecasted cost of equity capital row 5 + row 6

Sources:
J.P. Morgan Asset Management, Long-term Capital Market Return Assumptions, 2018 Edition; J.P. Morgan Asset Management (published October of 2017)
www.jpmorganinstitutional.com/pages/jpmorgan/am/ia/research_and_publications/long-term_capital_market

The expected risk-free yield of 3.50% forecasted by JPMAM is added to the beta specific risk premium to arrive at the cost of equity for the given beta coefficient of 0.70 - about 60 basis points less than the returns JPMAM is forecasting for the broad stock market indexes. These results appear low by historic measures of the past 40 years. The results are in line with the returns offered on other investments in the current capital markets. For instance, investors in Applicants' long-term bonds are purchasing bonds with the expectation for returns of less than 4.00%.

Q. Please discuss the historical CAPM analysis.

A. I performed a CAPM analysis incorporating historic data of returns earned from 1926

through 2014. The process is the same as that applied in the Forecasted CAPM.

Capital Asset Pricing Model -- Historic Risk Premium				
Based on Historic Risk Premiums from 1926 to 2015				
18-WSEE-328-RTS				
		Low Beta	High Beta	Avg Beta
1) Total Returns on Common Stocks		12.10%	12.10%	12.10%
2) Total Return on Government Bonds	-	5.20%	5.20%	5.20%
3) Resulting Risk Premium		6.90%	6.90%	6.90%
4) Beta Coefficient	x	0.50	0.95	0.67
5) Risk Premium		3.45%	6.56%	4.62%
6) Historic Yield on Government Bonds	+	4.38%	4.38%	4.38%
7) Forecasted Cost of Equity Based on Historic Returns		7.83%	10.93%	9.00%
			9.38%	
1) Historic returns on common stocks 1926-2017 (SBBI; Exhibit 2-3)				
2) Historic returns on intermediate-term government bonds 1926-2017				
3) Resulting risk premium (1-2)				
4) Beta coefficient of the proxy group (Reported by Value-Line)				
5) Row 3 x Row 4 = Asset Specific Risk Premium				
6) Historic year-end yield on intermediate-term government bonds 1926-2017				
7) Forecasted cost of equity capital; row 5 + row 6				
Sources:				
Ibbotson SBBI: 2018 Classic Yearbook (Duff & Phelps) & Value-Line Investment Survey				

In relying on purely historic data, we are assuming that certain trends observed in the past 80 years will continue in the future. Most notably, we would be assuming that the returns observed on common stocks from decades past will continue in the future, which of course assumes this historical data accurately measures the past returns. There is strong evidence that these frequently-quoted returns do not present a complete picture of historic returns.[35] The simple step of beginning measurement period in 1926 brings questions as to whether the time period represents all of the modern-era securities trading. The historic returns are reported and might influence expectations despite warnings that surround historic

[35] McQuarrie, Edward F; "The Myth of 1926: How Much Do We Know Long-Term Returns on U.S. Stocks?"; The Journal of Investing; Winter 2009; p. 96.

1 economic growth rates. There are well regarded financial publications that focus solely on
2 this type of historic data and how to apply it in cost of capital studies. Thus, I have to argue
3 that the historic data is part of the cost of capital universe, although given only light
4 consideration in the final decision.

5 **Q. Does that conclude your testimony?**

6 A. Yes, thank you.

DECON--With Long-Term Spent Fuel Management Costs
KCC Staff's Primary Recommendation in 18-WCNE-107-GIE

$ 7,793,513 Annual Payment

Time	Year	Annual Inflow	Annual Outflow	Annual Earnings	Balance	Annual Return
1	2018	$ 7,793,513	$ -		$ 237,154,291	4.20%
2	2019	$ 7,793,513	$ -	$ 10,114,502	$ 255,062,306	4.20%
3	2020	$ 7,793,513	$ -	$ 10,865,922	$ 273,721,741	4.20%
4	2021	$ 7,793,513	$ -	$ 11,648,872	$ 293,164,126	4.20%
5	2022	$ 7,793,513	$ -	$ 12,464,675	$ 313,422,313	4.20%
6	2023	$ 7,793,513	$ -	$ 13,314,708	$ 334,530,534	4.20%
7	2024	$ 7,793,513	$ -	$ 14,200,409	$ 356,524,456	4.20%
8	2025	$ 7,793,513	$ -	$ 15,123,274	$ 379,441,243	4.20%
9	2026	$ 7,793,513	$ -	$ 16,084,862	$ 403,319,618	4.20%
10	2027	$ 7,793,513	$ -	$ 17,086,799	$ 428,199,930	4.20%
11	2028	$ 7,793,513	$ -	$ 18,130,777	$ 454,124,220	4.20%
12	2029	$ 7,793,513	$ -	$ 19,218,560	$ 481,136,293	4.20%
13	2030	$ 7,793,513	$ -	$ 20,351,987	$ 509,281,792	4.20%
14	2031	$ 7,793,513	$ -	$ 21,532,972	$ 538,608,277	4.20%
15	2032	$ 7,793,513	$ -	$ 22,763,511	$ 569,165,301	4.20%
16	2033	$ 7,793,513	$ -	$ 24,045,684	$ 601,004,497	4.20%
17	2034	$ 7,793,513	$ -	$ 25,381,657	$ 634,179,667	4.20%
18	2035	$ 7,793,513	$ -	$ 26,773,687	$ 668,746,866	4.20%
19	2036	$ 7,793,513	$ -	$ 28,224,126	$ 704,764,505	4.20%
20	2037	$ 7,793,513	$ -	$ 29,735,427	$ 742,293,444	4.20%
21	2038	$ 7,793,513	$ -	$ 31,310,141	$ 781,397,098	4.20%
22	2039	$ 7,793,513	$ -	$ 32,950,930	$ 822,141,541	4.20%
23	2040	$ 7,793,513	$ -	$ 34,660,567	$ 864,595,621	4.20%
24	2041	$ 7,793,513	$ -	$ 36,441,940	$ 908,831,074	4.20%
25	2042	$ 7,793,513	$ -	$ 38,298,060	$ 954,922,646	4.20%
26	2043	$ 7,793,513	$ -	$ 40,232,062	$ 1,002,948,221	4.20%
27	2044	$ 7,793,513	$ -	$ 42,247,215	$ 1,052,988,949	4.20%
28	2045	$ -	$ (78,411,865)	$ 44,183,416	$ 1,018,760,500	4.20%
29	2046	$ -	$ (169,068,348)	$ 42,747,191	$ 892,439,343	4.20%
30	2047	$ -	$ (183,090,767)	$ 37,446,755	$ 746,795,331	4.20%
31	2048	$ -	$ (156,256,606)	$ 26,455,673	$ 616,994,398	3.54%
32	2049	$ -	$ (127,910,434)	$ 21,857,397	$ 510,941,361	3.54%
33	2050	$ -	$ (117,066,127)	$ 18,100,404	$ 411,975,638	3.54%
34	2051	$ -	$ (71,555,507)	$ 14,594,484	$ 355,014,615	3.54%
35	2052	$ -	$ (54,464,502)	$ 12,576,606	$ 313,126,718	3.54%
36	2053	$ -	$ (38,482,991)	$ 11,092,702	$ 285,736,429	3.54%
37	2054	$ -	$ (12,722,791)	$ 10,122,384	$ 283,136,022	3.54%
38	2055	$ -	$ (13,093,025)	$ 10,030,263	$ 280,073,261	3.54%
39	2056	$ -	$ (13,511,435)	$ 9,921,763	$ 276,483,589	3.54%
40	2057	$ -	$ (13,866,126)	$ 9,794,597	$ 272,412,060	3.54%
41	2058	$ -	$ (14,269,630)	$ 9,650,361	$ 267,792,790	3.54%
42	2059	$ -	$ (14,684,876)	$ 8,165,752	$ 261,273,666	3.05%
43	2060	$ -	$ (15,154,158)	$ 7,966,966	$ 254,086,474	3.05%
44	2061	$ -	$ (15,551,972)	$ 7,747,808	$ 246,282,310	3.05%
45	2062	$ -	$ (16,004,534)	$ 7,509,837	$ 237,787,613	3.05%
46	2063	$ -	$ (16,470,266)	$ 7,250,810	$ 228,568,158	3.05%
47	2064	$ -	$ (16,996,602)	$ 6,969,683	$ 218,541,238	3.05%
48	2065	$ -	$ (17,442,782)	$ 6,663,934	$ 207,762,390	3.05%
49	2066	$ -	$ (17,950,367)	$ 6,335,257	$ 196,147,280	3.05%
50	2067	$ -	$ (18,472,723)	$ 5,981,080	$ 183,655,636	3.05%
51	2068	$ -	$ (19,063,052)	$ 5,600,175	$ 170,192,759	3.05%
52	2069	$ -	$ (19,563,479)	$ 5,189,654	$ 155,818,934	3.05%
53	2070	$ -	$ (20,132,776)	$ 2,676,969	$ 138,363,128	1.72%
54	2071	$ -	$ (20,718,640)	$ 2,377,079	$ 120,021,567	1.72%
55	2072	$ -	$ (21,380,741)	$ 2,061,971	$ 100,702,797	1.72%
56	2073	$ -	$ (21,942,009)	$ 1,730,074	$ 80,490,862	1.72%
57	2074	$ -	$ (58,404,136)	$ 1,382,833	$ 23,469,559	1.72%
58	2075	$ -	$ (23,872,766)	$ 403,207	$ 0	1.72%

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KCC Staff's Alternative Recommendation in 18-WCNE-107-GIE

$ 8,693,911 Annual Payment

Time	Year	Annual Inflow	Annual Outflow	Annual Earnings	Balance	Annual Return
1	2018	$ 8,693,911	$ -		$ 237,154,291	4.20%
2	2019	$ 8,693,911	$ -	$ 10,133,392	$ 255,981,594	4.20%
3	2020	$ 8,693,911	$ -	$ 10,923,386	$ 275,598,891	4.20%
4	2021	$ 8,693,911	$ -	$ 11,746,528	$ 296,039,329	4.20%
5	2022	$ 8,693,911	$ -	$ 12,604,208	$ 317,337,448	4.20%
6	2023	$ 8,693,911	$ -	$ 13,497,878	$ 339,529,236	4.20%
7	2024	$ 8,693,911	$ -	$ 14,429,045	$ 362,652,192	4.20%
8	2025	$ 8,693,911	$ -	$ 15,399,284	$ 386,745,387	4.20%
9	2026	$ 8,693,911	$ -	$ 16,410,235	$ 411,849,532	4.20%
10	2027	$ 8,693,911	$ -	$ 17,463,605	$ 438,007,047	4.20%
11	2028	$ 8,693,911	$ -	$ 18,561,174	$ 465,262,131	4.20%
12	2029	$ 8,693,911	$ -	$ 19,704,797	$ 493,660,839	4.20%
13	2030	$ 8,693,911	$ -	$ 20,896,407	$ 523,251,157	4.20%
14	2031	$ 8,693,911	$ -	$ 22,138,017	$ 554,083,084	4.20%
15	2032	$ 8,693,911	$ -	$ 23,431,724	$ 586,208,719	4.20%
16	2033	$ 8,693,911	$ -	$ 24,779,716	$ 619,682,346	4.20%
17	2034	$ 8,693,911	$ -	$ 26,184,269	$ 654,560,526	4.20%
18	2035	$ 8,693,911	$ -	$ 27,647,758	$ 690,902,195	4.20%
19	2036	$ 8,693,911	$ -	$ 29,172,654	$ 728,768,759	4.20%
20	2037	$ 8,693,911	$ -	$ 30,761,535	$ 768,224,205	4.20%
21	2038	$ 8,693,911	$ -	$ 32,417,086	$ 809,335,202	4.20%
22	2039	$ 8,693,911	$ -	$ 34,142,103	$ 852,171,216	4.20%
23	2040	$ 8,693,911	$ -	$ 35,939,502	$ 896,804,629	4.20%
24	2041	$ 8,693,911	$ -	$ 37,812,320	$ 943,310,860	4.20%
25	2042	$ 8,693,911	$ -	$ 39,763,722	$ 991,768,492	4.20%
26	2043	$ 8,693,911	$ -	$ 41,797,004	$ 1,042,259,407	4.20%
27	2044	$ 8,693,911	$ -	$ 43,915,603	$ 1,094,868,921	4.20%
28	2045	$ -	$ (63,088,403)	$ 45,940,700	$ 1,077,721,218	4.20%
29	2046	$ -	$ (90,464,645)	$ 45,221,182	$ 1,032,477,755	4.20%
30	2047	$ -	$ (41,393,404)	$ 43,322,767	$ 1,034,407,117	4.20%
31	2048	$ -	$ (42,593,237)	$ 43,403,723	$ 1,035,217,603	4.20%
32	2049	$ -	$ (43,584,004)	$ 43,437,731	$ 1,035,071,330	4.20%
33	2050	$ -	$ (32,822,082)	$ 43,431,593	$ 1,045,680,841	4.20%
34	2051	$ -	$ (6,098,522)	$ 43,876,768	$ 1,083,459,087	4.20%
35	2052	$ -	$ (6,275,776)	$ 45,461,943	$ 1,122,645,254	4.20%
36	2053	$ -	$ (6,425,023)	$ 47,106,195	$ 1,163,326,426	4.20%
37	2054	$ -	$ (6,594,873)	$ 48,813,177	$ 1,205,544,730	4.20%
38	2055	$ -	$ (6,769,285)	$ 50,584,657	$ 1,249,360,102	4.20%
39	2056	$ -	$ (6,966,308)	$ 52,423,150	$ 1,294,816,944	4.20%
40	2057	$ -	$ (7,132,295)	$ 54,330,519	$ 1,342,015,168	4.20%
41	2058	$ -	$ (7,321,154)	$ 56,310,956	$ 1,391,004,971	4.20%
42	2059	$ -	$ (7,515,094)	$ 58,366,569	$ 1,441,856,445	4.20%
43	2060	$ -	$ (7,734,135)	$ 60,500,296	$ 1,494,622,606	4.20%
44	2061	$ -	$ (7,918,782)	$ 62,714,365	$ 1,549,418,188	4.20%
45	2062	$ -	$ (8,128,821)	$ 65,013,587	$ 1,606,302,954	4.20%
46	2063	$ -	$ (8,344,524)	$ 67,400,472	$ 1,665,358,902	4.20%

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KCC Staff's Alternative Recommendation in 18-WCNE-107-GIE

$ 8,693,911 Annual Payment

Time	Year	Annual Inflow	Annual Outflow	Annual Earnings	Balance	Annual Return
47	2064	$ -	$ (8,588,097)	$ 69,878,460	$ 1,726,649,265	4.20%
48	2065	$ -	$ (8,793,550)	$ 72,450,203	$ 1,790,305,918	4.20%
49	2066	$ -	$ (9,027,198)	$ 75,121,236	$ 1,856,399,956	4.20%
50	2067	$ -	$ (9,267,161)	$ 77,894,542	$ 1,925,027,337	4.20%
51	2068	$ -	$ (9,538,074)	$ 80,774,147	$ 1,996,263,410	4.20%
52	2069	$ -	$ (9,766,735)	$ 83,763,213	$ 2,070,259,888	4.20%
53	2070	$ -	$ (10,026,710)	$ 86,868,105	$ 2,147,101,282	4.20%
54	2071	$ -	$ (10,293,728)	$ 90,092,370	$ 2,226,899,924	4.20%
55	2072	$ -	$ (10,595,124)	$ 93,440,721	$ 2,309,745,521	4.20%
56	2073	$ -	$ (10,849,682)	$ 96,916,922	$ 2,395,812,761	4.20%
57	2074	$ -	$ (11,139,026)	$ 100,528,303	$ 2,485,202,038	4.20%
58	2075	$ -	$ (11,436,229)	$ 104,279,078	$ 2,578,044,887	4.20%
59	2076	$ -	$ (11,771,622)	$ 108,174,763	$ 2,674,448,029	4.20%
60	2077	$ -	$ (12,055,094)	$ 112,219,839	$ 2,774,612,775	4.20%
61	2078	$ -	$ (12,377,214)	$ 116,422,752	$ 2,878,658,313	4.20%
62	2079	$ -	$ (12,708,107)	$ 120,788,503	$ 2,986,738,709	4.20%
63	2080	$ -	$ (13,081,436)	$ 125,323,556	$ 3,098,980,829	4.20%
64	2081	$ -	$ (13,397,204)	$ 130,033,236	$ 3,215,616,861	4.20%
65	2082	$ -	$ (13,755,921)	$ 134,927,283	$ 3,336,788,223	4.20%
66	2083	$ -	$ (14,124,437)	$ 140,011,634	$ 3,462,675,421	4.20%
67	2084	$ -	$ (14,540,115)	$ 145,293,861	$ 3,593,429,166	4.20%
68	2085	$ -	$ (14,891,978)	$ 127,299,384	$ 3,705,836,572	3.54%
69	2086	$ -	$ (15,291,579)	$ 131,281,484	$ 3,821,826,478	3.54%
70	2087	$ -	$ (15,702,131)	$ 135,390,496	$ 3,941,514,843	3.54%
71	2088	$ -	$ (16,165,110)	$ 139,630,528	$ 4,064,980,262	3.54%
72	2089	$ -	$ (16,557,336)	$ 144,004,365	$ 4,192,427,290	3.54%
73	2090	$ -	$ (17,002,637)	$ 148,519,252	$ 4,323,943,905	3.54%
74	2091	$ -	$ (17,460,184)	$ 153,178,307	$ 4,459,662,029	3.54%
75	2092	$ -	$ (17,976,023)	$ 135,987,582	$ 4,577,673,588	3.05%
76	2093	$ -	$ (18,413,418)	$ 139,586,085	$ 4,698,846,255	3.05%
77	2094	$ -	$ (18,909,833)	$ 143,280,979	$ 4,823,217,401	3.05%
78	2095	$ -	$ (19,419,952)	$ 147,073,404	$ 4,950,870,853	3.05%
79	2096	$ -	$ (19,994,901)	$ 150,965,915	$ 5,081,841,867	3.05%
80	2097	$ -	$ (20,482,876)	$ 154,959,588	$ 5,216,318,578	3.05%
81	2098	$ -	$ (42,997,311)	$ 89,616,353	$ 5,262,937,620	1.72%
82	2099	$ -	$ (202,494,640)	$ 90,417,268	$ 5,150,860,248	1.72%
83	2100	$ -	$ (1,251,269,068)	$ 88,491,779	$ 3,988,082,959	1.72%
84	2101	$ -	$ (1,843,454,798)	$ 68,515,265	$ 2,213,143,426	1.72%
85	2102	$ -	$ (781,487,440)	$ 38,021,804	$ 1,469,677,790	1.72%
86	2103	$ -	$ (818,350,434)	$ 25,249,064	$ 676,576,420	1.72%
87	2104	$ -	$ (459,929,593)	$ 11,623,583	$ 228,270,410	1.72%
88	2105	$ -	$ (141,421,602)	$ 3,921,686	$ 90,770,493	1.72%
89	2106	$ -	$ (92,329,930)	$ 1,559,437	$ (0)	1.72%

Estimates of Returns on Nuclear Decommissioning Trusts Across Investment Periods

JPMAM Long-Term Capital Market Assumptions

	2017		2018	
	Arithmatic	Geometric	Arithmatic	Geometric
Equities-Large Cap	7.63%	6.25%	6.41%	5.50%
Equities-Small Cap	8.67%	7.00%	7.35%	5.75%
Equities-International (EAFE)	7.95%	6.75%	7.61%	6.25%
Core Bonds	3.44%	3.25%	3.67%	3.50%
High Yield Bonds	6.13%	5.75%	5.59%	5.25%
Real Estate	7.32%	6.00%	7.42%	6.25%
Cash & Equivalents	2.00%	2.00%	2.00%	2.00%

Management Fees	0.55%
Tax Rate	20.00%

DECON Methodology 2018-2053

		Pre-Tax	Post-Tax
Time Period 1	2017-2025	5.93%	4.20%
Time Period 2	2026-2035	5.12%	3.54%
Time Period 3	2036-2044	4.50%	3.05%
Time Period 4	2045-2053	2.84%	1.72%

DECON-Alt (Appendix E) Methodology 2018-2075

		Pre-Tax	Post-Tax
Time Period 1	2017-2047	5.93%	4.20%
Time Period 2	2048-2058	5.12%	3.54%
Time Period 3	2059-2069	4.50%	3.05%
Time Period 4	2070-2075	2.84%	1.72%

SAFESTOR Methodology 2018-2106

		Pre-Tax	Post-Tax
Time Period 1	2017-2075	5.93%	4.20%
Time Period 2	2076-2086	5.12%	3.54%
Time Period 3	2087-2097	4.50%	3.05%
Time Period 4	2098-2106	2.84%	1.72%

Sources: J.P.Morgan Asset Management 2018 & 2017 Long-term Asset Returns
Management fees estimated by Applicant; Susan M. McGrath Direct Testimony 18-WSEE-328-RTS; Filed February 1, 2018.

Time Period 1	Asset Weight	Proj. Return	Pre-Tax Weighted Return	After Tax
Equities-Large Cap	27.00%	6.41%	1.73%	1.38%
Equities-Small Cap	6.00%	7.35%	0.44%	0.35%
Equities-International (EAFE)	20.00%	7.61%	1.52%	1.22%
Core Bonds	25.00%	3.67%	0.92%	0.73%
High Yield Bonds	17.00%	5.59%	0.95%	0.76%
Real Estate	5.00%	7.42%	0.37%	0.30%
Cash & Equivalents	0.00%	2.00%	0.00%	0.00%
Time Period 2				
Equities-Large Cap	20.00%	6.41%	1.28%	1.03%
Equities-Small Cap	5.00%	7.35%	0.37%	0.29%
Equities-International (EAFE)	12.00%	7.61%	0.91%	0.73%
Core Bonds	44.00%	3.67%	1.61%	1.29%
High Yield Bonds	8.00%	5.59%	0.45%	0.36%
Real Estate	5.00%	7.42%	0.37%	0.30%
Cash & Equivalents	6.00%	2.00%	0.12%	0.10%
Time Period 3				
Equities-Large Cap	10.00%	6.41%	0.64%	0.51%
Equities-Small Cap	5.00%	7.35%	0.37%	0.29%
Equities-International (EAFE)	5.00%	7.61%	0.38%	0.30%
Core Bonds	57.00%	3.67%	2.09%	1.67%
High Yield Bonds	8.00%	5.59%	0.45%	0.36%
Real Estate	5.00%	7.42%	0.37%	0.30%
Cash & Equivalents	10.00%	2.00%	0.20%	0.16%
Time Period 4				
Equities-Large Cap	0.00%	6.41%	0.00%	0.00%
Equities-Small Cap	0.00%	7.35%	0.00%	0.00%
Equities-International (EAFE)	0.00%	7.61%	0.00%	0.00%
Core Bonds	50.00%	3.67%	1.84%	1.47%
High Yield Bonds	0.00%	5.59%	0.00%	0.00%
Real Estate	0.00%	7.42%	0.00%	0.00%
Cash & Equivalents	50.00%	2.00%	1.00%	0.80%

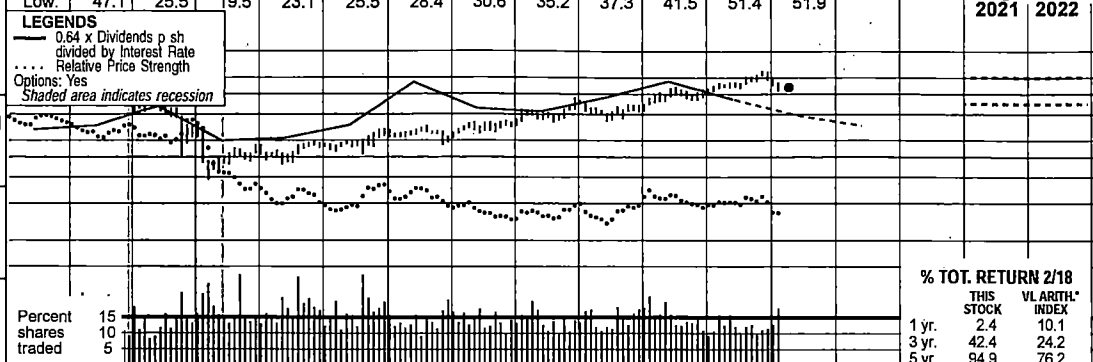
AMEREN NYSE-AEE

RECENT PRICE 53.94 | P/E RATIO 17.7 (Trailing: 19.4 Median: 15.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 2 Raised 3/2/18
SAFETY 2 Raised 6/20/14
TECHNICAL 3 Lowered 2/23/18
BETA .65 (1.00 = Market)

High:	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8	54.1	64.9	59.0
Low:	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	45	(-15%)	Nil

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	0	21
to Sell	0	1	0	0	0	0	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	247	229	212
to Sell	209	215	192
Hld's(000)	185587	186752	171005

Percent shares traded 15 10 5

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.4	10.1
3 yr.	42.4	24.2
5 yr.	94.9	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	*25.20*	*25.85*	Revenues per sh	*28.00*
5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	*7.35*	*7.85*	"Cash Flow" per sh	*9.25*
2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	*3.05*	*3.25*	Earnings per sh A	*3.75*
2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	*1.85*	*1.93*	Div'd Decl'd per sh B ■	*2.25*
5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	*9.80*	*10.45*	Cap'l Spending per sh	*8.50*
24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	*31.00*	*32.45*	Book Value per sh C	*37.25*
154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	*244.00*	*245.50*	Common Shs Outst'g D	*250.00*
15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.02	*Value Line*		Relative P/E Ratio	*.80*
6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $8419 mill. **Due in 5 Yrs** $2862 mill.
LT Debt $7094 mill. **LT Interest** $348 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $10 mill.
Pension Assets-12/17 $4293 mill. **Oblig** $4827 mill.
Pfd Stock $142 mill. **Pfd Div'd** $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. **as of 1/31/18**
MARKET CAP: $13 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	*6150*	*6350*	Revenues ($mill)	*7000*
615.0	624.0	669.0	602.0	589.0	518.0	593.0	585.0	659.0	683.0	*755*	*805*	Net Profit ($mill)	*950*
33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	3.5%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	*49.5%*	*49.0%*	Long-Term Debt Ratio	*49.5%*
50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	*49.5%*	*50.0%*	Common Equity Ratio	*50.0%*
13712	15991	15185	14738	13384	12190	12975	13968	13840	14420	*15225*	*15925*	Total Capital ($mill)	*18600*
16567	17610	17853	18127	16096	16205	17424	18799	20113	21466	*22800*	*24225*	Net Plant ($mill)	*27100*
5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
88%	56%	56%	63%	66%	76%	67%	70%	64%	64%	*61%*	*60%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.1	-4.2	-3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	343	351	362

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-3.0%	-3.5%	*2.0%*
"Cash Flow"	.5%	1.5%	*6.5%*
Earnings	-1.0%	.5%	*7.5%*
Dividends	-4.0%	2.0%	*4.5%*
Book Value	-1.0%	-1.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1556	1401	1833	1308	6098.0
2016	1434	1427	1859	1356	6076.0
2017	1514	1538	1723	1402	6177.0
2018	*1500*	*1500*	*1750*	*1400*	*6150*
2019	*1550*	*1550*	*1800*	*1450*	*6350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.45	.40	1.41	.12	2.38
2016	.43	.61	1.52	.13	2.68
2017	.42	.79	1.18	.39	2.77
2018	*.55*	*.70*	*1.40*	*.40*	*3.05*
2019	*.60*	*.70*	*1.50*	*.45*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.40	.40	.41	1.61
2015	.41	.41	.41	.425	1.66
2016	.425	.425	.425	.44	1.72
2017	.44	.44	.44	.4575	1.78
2018	.4575				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Acq'd CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric rev. breakdown: residential, 46%; commercial, 35%; industrial, 8%; other, 11%. Generating sources: coal, 71%; nuclear, 19%; hydro & other, 4%; purchased, 6%. Fuel costs: 27% of revs. '17 reported deprec. rates: 3%-4%. Has 8,600 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We think Ameren's earnings will exceed the $3.00-a-share level in 2018. The company will benefit from a full year's effect of the rate increase that took effect in Missouri at the start of April of 2017. A return to normal weather patterns would help after unfavorable weather was a drag on profits last year. The Callaway nuclear facility will not have a refueling outage this year. The refinancing of debt will boost earnings. Our earnings estimate is at the midpoint of Ameren's targeted range of $2.95-$3.15 a share. Note that the 2017 tally was depressed by the revaluation of deferred taxes, which stemmed from the new federal tax law. This forced Ameren to take a nonrecurring charge of $0.63 a share in the fourth quarter.

We forecast further profit growth in 2019. One factor that boosts Ameren's earning power annually is the utility's investment in electric transmission. There is still uncertainty about what the allowed return on equity will be—the Federal Energy Regulatory Commission must still issue a ruling on this—but this will still exceed the allowed ROEs in Missouri and Illinois. Our 2019 earnings estimate indicates profit growth of 7%, which is within management's annual goal of 5%-7%.

Will 2018 be the year in which a regulatory law is passed in Missouri? Utilities in the state have been hurt by regulatory lag because Missouri uses a historical test year and doesn't use a lot of mechanisms that allow for concurrent recovery of certain kinds of capital spending or expenses. The state senate has passed a bill that would be beneficial for utilities in this regard. If the bill is enacted into law, Ameren will boost its capital spending in the state, with an estimated $1 billion for grid modernization through 2023.

Ameren filed a gas rate application in Illinois. The utility requested a $49 million increase, based on a 10.3% return on a 50% common-equity ratio. A ruling is expected in late 2018, with new tariffs taking effect in January of 2019.

This timely stock has a dividend yield that is about average, by utility standards. Like many utility equities, the recent quotation is within our 3- to 5-year Target Price Range. Accordingly, total return potential over that time frame is low.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '16-'17 EPS don't sum due to rounding. Next egs. report due early May. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '17: $6.76/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '17: elec., none spec.; in '11: gas, none spec.; in IL in '14: elec., 8.7%, in '16: gas, 9.6%; earned on avg. com. eq., '17: 7.3%. Reg. Climate: Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

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AMERICAN ELEC. PWR. NYSE-AEP

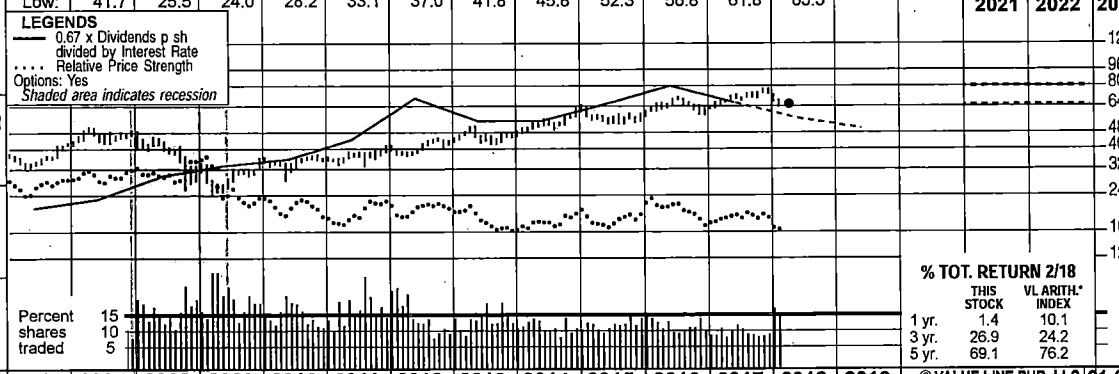
RECENT PRICE 65.50 | P/E RATIO 16.5 (Trailing: 18.1 Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 1/19/18
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 3/2/18
BETA .65 (1.00 = Market)

High:	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	78.1	73.4					
Low:	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8	63.3					

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+20%)	9%
Low	65	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	9	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	376	388	371
to Sell	369	351	342
Hld's(000)	384520	382879	352776

Percent shares traded 15 10 5

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.4	10.1
3 yr.	26.9	24.2
5 yr.	69.1	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	*30.60*	*31.30*	Revenues per sh	*33.00*
6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	*8.30*	*8.60*	"Cash Flow" per sh	*9.50*
2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	*3.90*	*4.10*	Earnings per sh A	*5.00*
2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	*2.51*	*2.63*	Div'd Decl'd per sh B ■	*3.05*
5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	*12.50*	*12.95*	Cap'l Spending per sh	*11.25*
20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	*38.70*	*40.25*	Book Value per sh C	*46.75*
338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	*493.50*	*495.00*	Common Shs Outst'g D	*516.00*
12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.96	*Value Line*		Relative P/E Ratio	*.80*
6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $22812 mill. **Due in 5 Yrs** $9694 mill.
LT Debt $19420 mill. **LT Interest** $874 mill.
Incl. $1410.5 mill. securitized bonds. Incl. $294 mill. capitalized leases.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $245.9 mill.
Pension Assets-12/17 $5174.1 mill. **Oblig** $5215.8 mill.
Pfd Stock None
Common Stock 492,005,598 shs.
MARKET CAP: $32 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
14440	13489	14427	15116	14945	15357	17020	16453	16380	15425	*15100*	*15500*	Revenues ($mill)	*17000*
1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	*1870*	*1960*	Net Profit ($mill)	*2490*
31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*6.0%*
59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	*52.5%*	*54.5%*	Long-Term Debt Ratio	*50.5%*
40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	*47.5%*	*45.5%*	Common Equity Ratio	*49.5%*
26290	28958	29184	29747	30823	32913	33001	35633	34775	37707	*40325*	*43775*	Total Capital ($mill)	*48800*
32987	34344	35674	36971	38763	40997	44117	46133	45639	50262	*54250*	*58450*	Net Plant ($mill)	*68700*
6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
55%	56%	66%	60%	63%	62%	61%	60%	54%	67%	*66%*	*66%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.2	+.3	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	NA	NA
Fixed Charge Cov. (%)	356	374	354

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	--	1.5%	*Nil*
"Cash Flow"	2.5%	4.0%	*2.5%*
Earnings	3.0%	5.5%	*4.5%*
Dividends	4.0%	4.5%	*5.0%*
Book Value	4.0%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4580	3827	4431	3615	16453
2016	4045	3893	4652	3790	16380
2017	3933	3577	4105	3810	15425
2018	*3850*	*3450*	*4100*	*3700*	*15100*
2019	*4000*	*3650*	*4200*	*3650*	*15500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.27	.88	1.04	.41	3.59
2016	1.02	1.03	1.43	.76	4.23
2017	.94	.76	1.11	.81	3.62
2018	*1.10*	*.80*	*1.25*	*.75*	*3.90*
2019	*1.15*	*.85*	*1.30*	*.80*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	2.15
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62				

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 34% of revenues. '17 reported depreciation rates (utility): 1.6%-9.2%. Has 17,700 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power's earnings will likely advance solidly in 2018 and 2019. The company's utilities are benefiting from rate relief. Public Service of Oklahoma received an $84 million rate increase (before passing through to customers the reduction in federal taxes), based on a 9.3% return on equity. Also this quarter, SWEPCo was granted a hike of $50 million, based on a 9.6% ROE. Indiana & Michigan has rate cases pending in each state. In Indiana, the utility reached a settlement (subject to approval by the state commission) for an increase of $97 million, based on a 9.95% ROE. New tariffs would take effect in mid-2018. In Michigan, I&M requested a $52 million hike, based on a 10.6% ROE. An order is expected in April. Heavy investment in electric transmission (some $3 billion annually) is also expanding the company's earning power. Our 2018 and 2019 share-earnings estimates are within AEP's targeted ranges of $3.75-$3.95 and $4.00-$4.20, respectively.

The company wants to build a large wind project to serve four states. The 2,000-megawatt facility would cost $4.5 billion and would be completed by the fourth quarter of 2020. This needs the approval of the state commissions in Oklahoma, Arkansas, Texas, and Louisiana. (Opposition to the project has emerged in Oklahoma.) Rulings on the proposals are expected by the end of April.

AEP no longer has exposure to the vagaries of the power markets. The company has sold or written off its nonregulated generating facilities. (This caused a large nonrecurring charge in 2016.) It is still seeking a buyer for its remaining generating assets.

Finances are solid. The fixed-charge coverage, common-equity ratio, and earned ROE are healthy. AEP's exit from merchant (uncontracted) power has lowered its business risk, too. The company's Financial Strength rating is A+.

The stock has a dividend yield that is somewhat above the utility average. This might well appeal to conservative investors, given the stock's Safety rank of 1 (Highest). Total return potential to 2021-2023 does not stand out among electric companies, however.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; disc. ops.: '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). '15-'16 EPS don't sum due to rounding. Next egs. report due late April. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '17: $12.59/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	85

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ALLETE NYSE-ALE

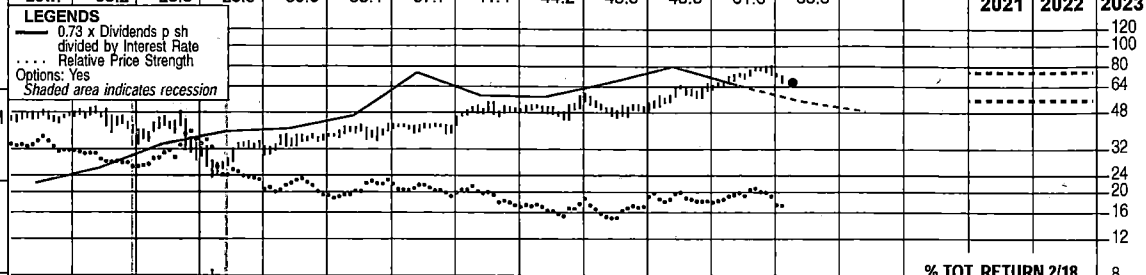
RECENT PRICE 67.19 | P/E RATIO 21.6 (Trailing: 21.5 Median: 16.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 1/26/18
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 3/2/18
BETA .75 (1.00 = Market)

High:	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2	74.4	
Low:	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	6%
Low	55	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	8	0	0	1	0	0	0	8
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	140	118	117
to Sell	108	124	98
Hld's(000)	43781	44573	38769

Percent shares traded 15 10 5

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.5	10.1
3 yr.	38.0	24.2
5 yr.	73.9	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	*28.45*	*28.85*	Revenues per sh	*30.75*
--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	*7.00*	*7.35*	"Cash Flow" per sh	*8.50*
--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	*3.40*	*3.60*	Earnings per sh A	*4.25*
--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	*2.24*	*2.34*	Div'd Decl'd per sh B ■ †	*2.70*
--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	*6.25*	*6.80*	Cap'l Spending per sh	*6.25*
--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	*42.10*	*43.80*	Book Value per sh C	*49.25*
--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	*52.00*	*53.00*	Common Shs Outst'g D	*56.00*
--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.14	*Value Line*		Relative P/E Ratio	*.85*
--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	*1480*	*1530*	Revenues ($mill)	*1725*
						82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	*175*	*190*	Net Profit ($mill)	*235*
						34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	*NMF*	*Nil*	Income Tax Rate	*Nil*
						5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
						41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	*40.5%*	*38.5%*	Long-Term Debt Ratio	*38.0%*
						58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	*59.5%*	*61.5%*	Common Equity Ratio	*62.0%*
						1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	*3685*	*3785*	Total Capital ($mill)	*4450*
						1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	*3960*	*4120*	Net Plant ($mill)	*4275*
						6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
						10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
						10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
						3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						61%	93%	81%	66%	71%	72%	67%	60%	66%	68%	*66%*	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1503.3 mill. **Due in 5 Yrs** $450.5 mill.
LT Debt $1439.2 mill. **LT Interest** $61.9 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $14.2 mill.

Pension Assets-12/17 $628.2 mill. **Oblig** $793.2 mill.

Pfd Stock None

Common Stock 51,143,656 shs. as of 2/1/18

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-8.9	-2.3	+8.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.40	NA	NA
Capacity at Peak (Mw)	1942	NA	NA
Peak Load, Winter (Mw)	1631	1520	1599
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	381	318	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	2.5%	*1.5%*
"Cash Flow"	5.0%	7.5%	*3.5%*
Earnings	1.5%	5.5%	*4.5%*
Dividends	3.5%	3.0%	*4.5%*
Book Value	6.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	320.0	323.3	462.5	380.6	1486.4
2016	333.8	314.8	349.6	341.5	1339.7
2017	365.6	353.3	362.5	337.9	1419.3
2018	*370*	*360*	*390*	*360*	*1480*
2019	*380*	*375*	*400*	*375*	*1530*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.85	.46	1.23	.83	3.38
2016	.93	.50	.81	.89	3.14
2017	.97	.72	.88	.56	3.13
2018	*1.00*	*.60*	*.95*	*.85*	*3.40*
2019	*1.05*	*.65*	*1.00*	*.90*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56				

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 41%; wind, 12%; other, 6%; purchased, 41%. Fuel costs: 28% of revs. '17 deprec. rate: 3.2%. Has 2,000 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's main utility subsidiary received a disappointing rate decision. Minnesota Power had sought a rate increase of $55 million (8.6%), based on a 10.25% return on a 53.8% common-equity ratio. The state commission (through a verbal order) granted a hike of $13 million (2.0%), based on a 9.25% return on the same common-equity ratio. Minnesota Power expected to receive a written order shortly after our report went to press, and plans to decide what steps it will take once management reviews the order.

We think earnings will advance solidly in 2018. Minnesota Power should benefit from healthy industrial demand for power. The utility is also earning a return on the construction work in progress for a transmission line that is scheduled for completion in 2020. ALLETE's wind-energy subsidiary should benefit from increased production and the construction and sale of a 50-megawatt project to a utility in North Dakota. U.S. Water Services is seeing rising demand for its water-treatment services and a full year of revenues from an acquisition it made last September. Our 2018 share-earnings estimate is within ALLETE's targeted range of $3.20-$3.50. Note that the company's profits in the fourth quarter of 2017 benefited from the revaluation of deferred taxes due to the new federal tax law. This added $0.25 a share to the bottom line, which we excluded as a nonrecurring item.

We forecast solid profit growth next year. The factors that are likely to help earnings in 2018 should be present in 2019, as well. We look for a 6% increase in share net, which is within ALLETE's annual growth goal of 5%-7%.

The board of directors raised the dividend in the first quarter. The annual increase was $0.10 a share (4.7%), a greater hike than in recent years. The accelerated growth rate is in line with the company's expectation of faster profit growth. ALLETE is targeting a payout ratio of 60%-65%.

This stock's dividend yield is close to the average for electric utility equities. With the recent quotation above the midpoint of our 3- to 5-year Target Price Range, total return potential is unappealing.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '17: $11.95/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '17: 8.6%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	85

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DUKE ENERGY NYSE-DUK

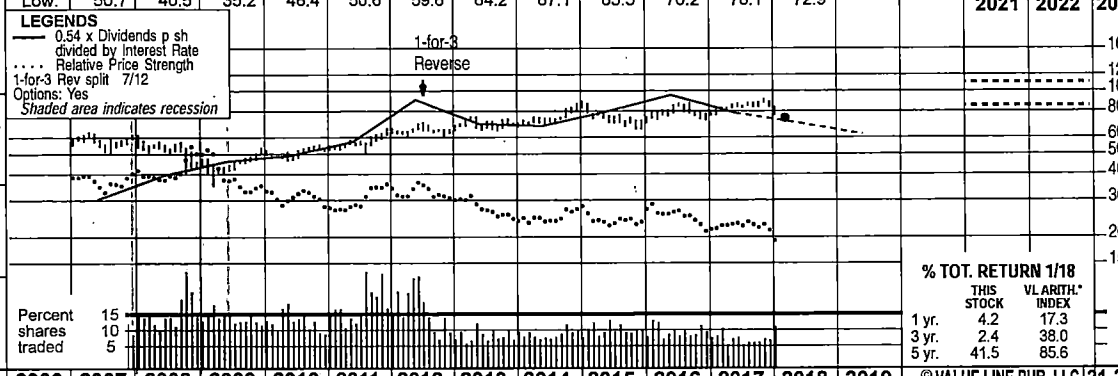
RECENT PRICE 74.49 | P/E RATIO 15.9 (Trailing: 19.1 Median: 17.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 4 Lowered 6/23/17
SAFETY 2 New 6/1/07
TECHNICAL 1 Raised 12/22/17
BETA .60 (1.00 = Market)

High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	91.8	84.4
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.9

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.54 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+50%)	14%
Low	85	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	2	0	0	0	0	0	0	0
Options	0	6	0	0	0	0	0	0	0
to Sell	0	2	0	0	1	0	0	1	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	552	528	531
to Sell	500	509	494
Hld's(000)	437355	435858	442941

% TOT. RETURN 1/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.2	17.3
3 yr.	2.4	38.0
5 yr.	41.5	85.6

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	--	--	--	--	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	*33.50*	*33.85*	*34.80*	Revenues per sh	*37.75*
--	--	--	--	--	--	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	*10.15*	*10.95*	*11.40*	"Cash Flow" per sh	*13.00*
--	--	--	--	--	--	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	*4.30*	*4.80*	*5.00*	Earnings per sh A	*5.50*
--	--	--	--	--	--	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	*3.64*	*3.80*	Div'd Decl'd per sh B ■	*4.40*
--	--	--	--	--	--	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	*13.45*	*15.35*	*15.25*	Cap'l Spending per sh	*12.75*
--	--	--	--	--	--	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	*59.35*	*60.45*	*61.60*	Book Value per sh C	*65.00*
--	--	--	--	--	--	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	*701.00*	*702.00*	*703.00*	Common Shs Outst'g D	*706.00*
--	--	--	--	--	--	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	*19.6*	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
--	--	--	--	--	--	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	*.95*	*Value Line*		Relative P/E Ratio	*1.00*
--	--	--	--	--	--	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $53313 mill. **Due in 5 Yrs** $18876 mill.
LT Debt $48929 mill. **LT Interest** $1795 mill.
Incl. $1100 mill. capitalized leases.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $218 mill.
Pension Assets-12/16 $8531 mill.
Oblig $8006 mill.

Pfd Stock None

Common Stock 699,975,614 shs.

MARKET CAP: $52 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
13207	12731	14272	14529	19624	24598	23925	23459	22743	*23500*	*23750*	*24450*	Revenues ($mill)	*26650*
1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	*3005*	*3385*	*3515*	Net Profit ($mill)	*3970*
32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	*31.5%*	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	*13.0%*	*12.0%*	*12.0%*	AFUDC % to Net Profit	*11.0%*
38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	*54.0%*	*54.5%*	*55.5%*	Long-Term Debt Ratio	*57.0%*
61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	*46.0%*	*45.5%*	*44.5%*	Common Equity Ratio	*43.0%*
34238	37863	40457	41451	77307	79482	78088	77222	86609	*90200*	*93525*	*96900*	Total Capital ($mill)	*107000*
34036	37950	40344	42661	68558	69490	70046	75709	82520	*87850*	*94325*	*100525*	Net Plant ($mill)	*112900*
4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	*4.5%*	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	*7.0%*	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	*7.0%*	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	*1.5%*	*2.0%*	*2.0%*	Retained to Com Eq	*2.0%*
89%	84%	73%	72%	82%	78%	76%	79%	91%	*81%*	*75%*	*76%*	All Div'ds to Net Prof	*78%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.2	+.6	-.3
Avg. Indust. Use (MWH)	2876	2883	3486
Avg. Indust. Revs. per KWH (¢)	6.15	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.0	+1.2	+1.4
Fixed Charge Cov. (%)	315	317	264

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	3.0%	1.5%	*1.5%*
"Cash Flow"	1.5%	2.5%	*5.0%*
Earnings	3.5%	.5%	*4.5%*
Dividends	--	2.5%	*4.5%*
Book Value	-.5%	3.0%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	6065	5589	6483	5322	23459
2016	5377	5213	6576	5577	22743
2017	5729	5555	6482	*5734*	*23500*
2018	*5750*	*5600*	*6600*	*5800*	*23750*
2019	*5900*	*5700*	*6950*	*5900*	*24450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.87	1.44	.70	4.10
2016	.83	.90	1.44	.53	3.71
2017	1.02	.98	1.36	*.94*	*4.30*
2018	*1.05*	*1.05*	*1.65*	*1.05*	*4.80*
2019	*1.10*	*1.10*	*1.70*	*1.10*	*5.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018					

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.4 mill. elec. customers in NC, FL, IN, SC, Oh, & KY, and 1.5 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 43%; commercial, 29%; industrial, 14%; other, 14%. Generating sources: coal, 27%; nuclear, 27%; gas, 23%; other, 1%; purchased, 22%. Fuel costs: 30% of revs. '16 reported deprec. rate: 2.8%. Has 28,800 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

One of Duke Energy's utilities has reached a partial settlement of its rate case. Duke Energy Progress filed for an increase of $477 million (14.9%), based on a 10.75% return on a 53% common-equity ratio. The settlement with the staff of the North Carolina Utilities Commission (NCUC) would provide for a hike (before the pass-through of reduced federal income taxes) of $127 million (4.0%), based on a return of 9.9% on a common-equity ratio of 52%. The treatment of deferred costs associated with storms and coal ash basin remediation has not been resolved, so far.

Other rate cases are pending. Duke Energy Carolinas asked the NCUC for an increase of $647 million (13.6%), based on a 10.75% return on a 53% common-equity ratio. New tariffs should take effect in the second quarter. Duke asked the Kentucky commission for a boost of $48.6 million (15%), based on a 10.3% return on a 49% common-equity ratio. New rates are likely to take effect in April.

We estimate a sharp earnings increase in 2018, followed by a more moderate rise in 2019. Last year, the third-period tally was weakened by unfavorable weather conditions, an $0.08-a-share write-off of a nonregulated wind-farm, and a $0.12-a-share charge for the cancelation of a nuclear project that was under consideration in Florida. Rate relief should be a positive factor for the bottom line each year. All told, we estimate share earnings of $4.80 this year and $5.00 in 2019.

Some significant capital projects are under way. Duke is building gas-fired plants in South Carolina and Florida and modernizing the electric system in Indiana and the western Carolinas. This will expand the company's rate base, and thus, its earning power. Duke also intends to expand its gas pipeline infrastructure. The company's goal for average annual profit growth is 4%-6%.

This stock is ranked unfavorably for Timeliness, but offers a dividend yield that is well above the utility average. The yield is about a percentage point above the norm for this industry. Total return potential over the 3- to 5-year period is attractive.

Paul E. Debbas, CFA *February 16, 2018*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; gains (losses) on disc. ops.: '12, 6¢; '13, 2¢; '14, (80¢); '15, 5¢; '16, (60¢). '16 EPS don't sum due to rounding. Next egs. report due early May. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '16: $46.17/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC: 10.2%; in '17 in SC: 10.1%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earn. on avg. com. eq., '16: 6.3%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	85

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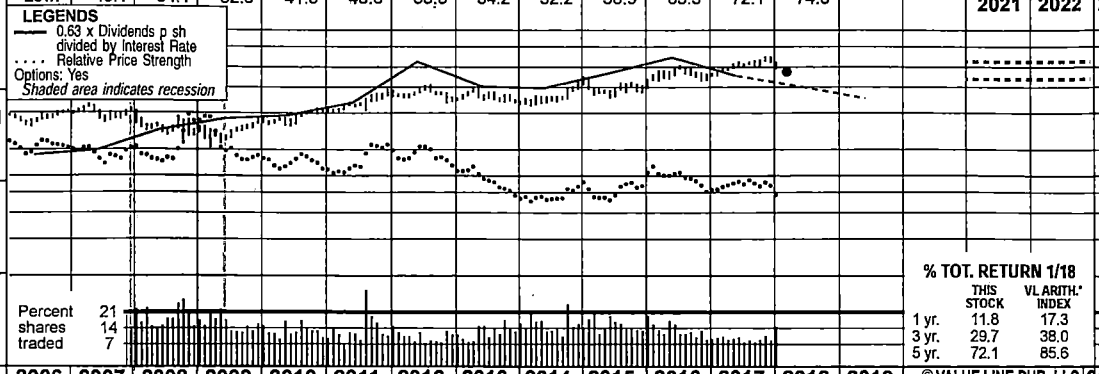
CON. EDISON NYSE-ED

RECENT PRICE 75.88 | P/E RATIO 17.8 (Trailing: 19.2 / Median: 15.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 8/18/17
SAFETY 1 New 7/27/90
TECHNICAL 2 Lowered 2/9/18
BETA .50 (1.00 = Market)

High:	52.9	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9
Low:	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5	72.1	74.6

Target Price Range 2021 | 2022 | 2023



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+10%)	7%
Low	70	(-10%)	2%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	11	9	8	11	8	8	11	8	8
Options	3	9	2	0	0	0	2	2	0
to Sell	0	0	0	0	1	0	0	0	0

Institutional Decisions

	1Q2017	2Q2017	3Q2017
to Buy	322	330	335
to Sell	336	323	322
Hld's(000)	197947	196270	197384

% TOT. RETURN 1/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.8	17.3
3 yr.	29.7	38.0
5 yr.	72.1	85.6

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	*37.60*	*38.80*	*39.80*	Revenues per sh	*43.00*
5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	*8.40*	*8.80*	*9.15*	"Cash Flow" per sh	*10.50*
3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	*4.05*	*4.20*	*4.30*	Earnings per sh A	*4.75*
2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	*2.86*	*2.96*	Div'd Decl'd per sh B ■	*3.30*
5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	*11.90*	*12.45*	*11.40*	Cap'l Spending per sh	*11.50*
27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	*48.65*	*50.15*	*51.65*	Book Value per sh C	*56.50*
213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	*311.00*	*312.00*	*313.00*	Common Shs Outst'g D	*316.00*
13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	*20.0*	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	*1.00*	*Value Line*		Relative P/E Ratio	*.90*
5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
						13583	13032	13325	12938	12188	12381	12919	12554	12075	*11700*	*12100*	*12450*	Revenues ($mill)	*13600*
						933.0	868.0	992.0	1062.0	1141.0	1157.0	1066.0	1193.0	1189.0	*1265*	*1320*	*1320*	Net Profit ($mill)	*1550*
						36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	33.6%	35.3%	*36.0%*	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
						1.7%	2.6%	2.4%	1.6%	.5%	.5%	.3%	.7%	1.3%	*1.0%*	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
						48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	47.9%	50.8%	*50.0%*	*50.5%*	*49.5%*	Long-Term Debt Ratio	*48.0%*
						50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	52.1%	49.2%	*50.0%*	*49.5%*	*50.5%*	Common Equity Ratio	*52.0%*
						19160	20330	21952	21794	21933	22735	24207	25058	29033	*30175*	*31600*	*31950*	Total Capital ($mill)	*34400*
						20874	22464	23863	25093	26939	28436	29827	32209	35216	*37550*	*40025*	*42075*	Net Plant ($mill)	*47900*
						6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	5.6%	6.0%	5.3%	*5.5%*	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
						9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	8.5%	9.1%	8.3%	*8.5%*	*8.5%*	*8.5%*	Return on Shr. Equity	*8.5%*
						9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	8.5%	9.1%	8.3%	*8.5%*	*8.5%*	*8.5%*	Return on Com Equity E	*8.5%*
						3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	2.6%	3.5%	3.0%	*2.5%*	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						67%	71%	65%	66%	62%	62%	69%	61%	64%	*67%*	*67%*	*67%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $15694 mill. **Due in 5 Yrs** $3585 mill.
LT Debt $14651 mill. **LT Interest** $667 mill.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $61 mill.

Pension Assets-12/16 $12472 mill.
Oblig $14095 mill.

Pfd Stock None

Common Stock 310,068,797 shs.
as of 10/31/17
MARKET CAP: $24 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.1	+1.9	-.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NA
Peak Load, Summer (Mw)	13568	13721	NA
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	366	370	352

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-.5%	-1.5%	.5%
"Cash Flow"	4.5%	4.5%	4.5%
Earnings	3.5%	2.5%	3.0%
Dividends	1.5%	2.0%	3.5%
Book Value	4.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3616	2788	3443	2707	12554
2016	3157	2794	3417	2707	12075
2017	3228	2633	3211	*2628*	*11700*
2018	*3300*	*2750*	*3300*	*2750*	*12100*
2019	*3400*	*2825*	*3400*	*2825*	*12450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.26	.74	1.45	.60	4.05
2016	1.05	.77	1.47	.64	3.94
2017	1.27	.57	1.48	*.73*	*4.05*
2018	*1.30*	*.63*	*1.60*	*.67*	*4.20*
2019	*1.30*	*.65*	*1.65*	*.70*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.63	.63	.63	.63	2.52
2015	.65	.65	.65	.65	2.60
2016	.67	.67	.67	.67	2.68
2017	.69	.69	.69	.69	2.76
2018	.715				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16. Purchases most of its power. Fuel costs: 26% of revenues. '16 reported depreciation rates: 2.9%-3.1%. Has 15,000 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

We estimate that Consolidated Edison's earnings will advance modestly in 2018 and 2019. The company's primary utility subsidiary, Consolidated Edison Company of New York, will benefit from rate increases each year. Electric and gas hikes of $155.3 million (2.0%) and $92.3 million (5.6%), respectively, took effect at the start of 2018. Electric and gas increases of $155.2 million (1.9%) and $89.4 million (5.1%) will go into effect at the start of 2019. In addition, the company's utilities continue to see customer conversions from oil heat to gas heat. And ConEd's clean energy (solar and wind) businesses are boosting their income by adding projects. Finally, ConEd has a 12.5% stake in a gas pipeline that is scheduled for an in-service date in late 2018. This represents a $400 million investment for the company.

The board of directors raised the dividend in the first quarter of 2018. This is the usual timing of the annual increase. The board boosted the yearly disbursement by $0.10 a share (3.6%). This was the largest increase in a long time and continued a pattern of accelerating dividend growth in recent years. ConEd's goal is a payout ratio in a range of 60%-70%.

Finances are strong. The fixed-charge coverage and common-equity ratios are solid. The latter figure was augmented by the sale of 4.1 million common shares last August. Earned returns on equity are not exceptionally high, but have been relatively consistent in recent years as the utilities have earned (or have come close to earning) their allowed returns on equity. The company merits a Financial Strength rating of A+, our second highest.

The installation of smart meters is under way. The $1.4 billion investment is scheduled for completion by 2022, with the peak spending set to occur two years from now. All told, 5.4 million smart meters will be installed in New York City and Westchester.

This top-quality stock is ranked unfavorably for Timeliness. The dividend yield is about average for a utility. Like most utility equities, the recent quotation is within our 2021-2023 Target Price Range. Accordingly, total return potential is unspectacular.

Paul E. Debbas, CFA *February 16, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; '16, 15¢; gain on discontinued operations: '08, $1.01. '16 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '16: $25.29/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '17: 9.0%; O&R in '15: 9.0%; earned on avg. com. eq., '16: 8.6%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	95

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EL PASO ELECTRIC NYSE-EE

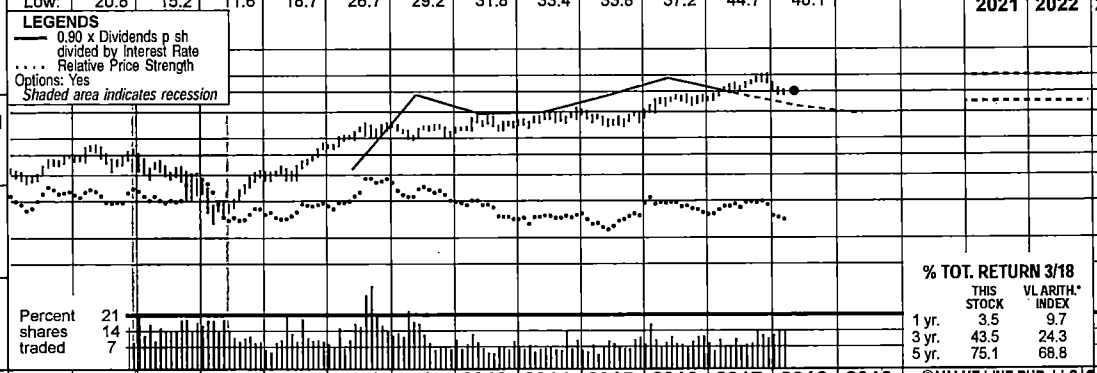
RECENT PRICE 50.25 | P/E RATIO 20.4 (Trailing: 20.8 Median: 15.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 1/26/18
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Lowered 4/6/18
BETA .75 (1.00 = Market)

High:	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	61.2	55.8
Low:	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	44.7	48.1

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	3	4	0	0	4	0	0	4	7
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	117	96	86
to Sell	78	83	67
Hld's(000)	45099	45123	39640

Percent shares traded 21 14 7

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.5	9.7
3 yr.	43.5	24.3
5 yr.	75.1	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.89	22.59	22.80	23.35	Revenues per sh	25.00
2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.98	6.17	6.35	6.60	"Cash Flow" per sh	7.50
.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.39	2.42	2.45	2.60	Earnings per sh A	3.00
--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	1.32	1.42	1.52	Div'd Decl'd per sh B	1.85
1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.03	5.91	6.80	6.85	Cap'l Spending per sh	7.25
9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.52	28.14	29.20	30.25	Book Value per sh C	33.50
49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.52	40.58	40.60	40.70	Common Shs Outst'g D	41.00
23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	18.7	21.8	Bold figures are		Avg Ann'l P/E Ratio	17.0
1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	.98	1.10	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	2.7%	2.5%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1369.5 mill. **Due in 5 Yrs** $218.5 mill.
LT Debt $1196.0 mill. **LT Interest** $72.3 mill.
(LT interest earned: 2.9x)

Pension Assets-12/17 $304.4 mill. **Oblig** $362.0 mill.

Pfd Stock None

Common Stock 40,661,003 shs. as of 1/31/18

MARKET CAP: $2.0 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	886.9	916.8	925	950	Revenues ($mill)	1025
77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	96.8	98.3	100	105	Net Profit ($mill)	125
32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	35.8%	34.2%	24.5%	24.5%	Income Tax Rate	24.5%
20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	17.6%	11.2%	13.0%	12.0%	AFUDC % to Net Profit	14.0%
53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	52.7%	51.2%	53.0%	52.0%	Long-Term Debt Ratio	54.5%
46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	47.3%	48.8%	47.0%	48.0%	Common Equity Ratio	45.5%
1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2269.9	2338.2	2530	2575	Total Capital ($mill)	3025
1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2821.2	2928.4	3045	3160	Net Plant ($mill)	3550
6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.8%	5.8%	5.5%	5.5%	Return on Total Cap'l	6.0%
11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	8.5%	8.5%	Return on Shr. Equity	9.0%
11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	8.5%	8.5%	Return on Com Equity E	9.0%
11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	4.4%	3.9%	3.5%	3.5%	Retained to Com Eq	3.5%
--	--	--	26%	43%	47%	49%	57%	51%	54%	57%	58%	All Div'ds to Net Prof	61%

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+2.3	+.1	+.4
Avg. Indust. Use (MWH)	21687	21036	21553
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2055	2080	2082
Peak Load, Summer (Mw)	1794	1892	1935
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.6	+1.7
Fixed Charge Cov. (%)	218	267	263

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.0%	--	2.5%
"Cash Flow"	5.5%	1.0%	4.0%
Earnings	6.5%	--	4.5%
Dividends	--	18.0%	7.0%
Book Value	7.5%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	163.8	219.5	289.7	176.9	849.9
2016	157.8	217.9	323.2	188.0	886.9
2017	171.3	251.8	297.5	196.2	916.8
2018	170	255	305	195	925
2019	175	260	315	200	950

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.09	.52	1.40	.02	2.03
2016	d.14	.55	1.84	.14	2.39
2017	d.10	.89	1.47	.16	2.42
2018	d.15	.75	1.70	.15	2.45
2019	d.10	.80	1.75	.15	2.60

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295	.31	.31	.31	1.23
2017	.31	.335	.335	.335	1.32
2018	.335				

BUSINESS: El Paso Electric Company (EPE) provides electric service to 417,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 49%; gas, 36%; purchased, 15%. Fuel costs: 27% of revenues. '17 reported depreciation rate: 2.3%. Has about 1,100 employees. Chairman: Charles A. Yamarone. President & CEO: Mary E. Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, TX 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

We estimate that El Paso Electric Company's earnings will advance slightly this year. The utility will have a full year's worth of the rate increase in Texas that took effect in July of 2017. EPE is also benefiting from above-average customer growth that stems from the healthy economy in El Paso and environs. On the other hand, the weather was favorable for the company in 2017, and we assume normal weather this year. Our 2018 earnings estimate, which we lowered by $0.20 a share, is within management's guidance of $2.30-$2.65 a share. Next year, the utility will benefit from rate relief in Texas through transmission and distribution regulatory mechanisms. However . . .

Earnings have become less predictable. The company owns a 15.8% share of the Palo Verde nuclear station in Arizona. Like any utility that owns nuclear assets, EPE invests in a trust to provide funds for nuclear decommissioning. The gains or losses on the nuclear decommissioning trust are now being reflected in the income statement, instead of through Accumulated Other Comprehensive Income on the balance sheet. This will make earnings more volatile.

The utility is required to file a general rate case in New Mexico by July of 2019. EPE may file sooner; we note that the portion of Units 3 and 4 of a new gas-fired generating station that is allocated to New Mexico is not reflected in rates. However, the regulatory climate in New Mexico is difficult (not just for EPE), so the company might well wait until it is required to file before it puts forth its rate application.

We expect a dividend hike at the board meeting in May. This has been the pattern since the directors initiated a common dividend several years ago. We estimate an increase of $0.10 a share (7.5%) in the annual disbursement. EPE's goal is a payout ratio in a range of 55%-65%.

This stock has a dividend yield that is below the industry mean. Like many utility issues, the recent quotation is within our 2021-2023 Target Price Range. Accordingly, total return potential over that time frame is unspectacular, despite good dividend growth prospects.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted earnings. Excl. nonrecurring gains (loss): '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. Next earnings report due early May. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '17: $96.0 mill., $2.37/sh. (D) In millions. (E) Rate allowed on common equity in TX in '17: 9.65%; in NM in '16: 9.48%; earned on avg. com. eq., '17: 8.9%. Regulatory Climate: TX, Average; NM, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	75

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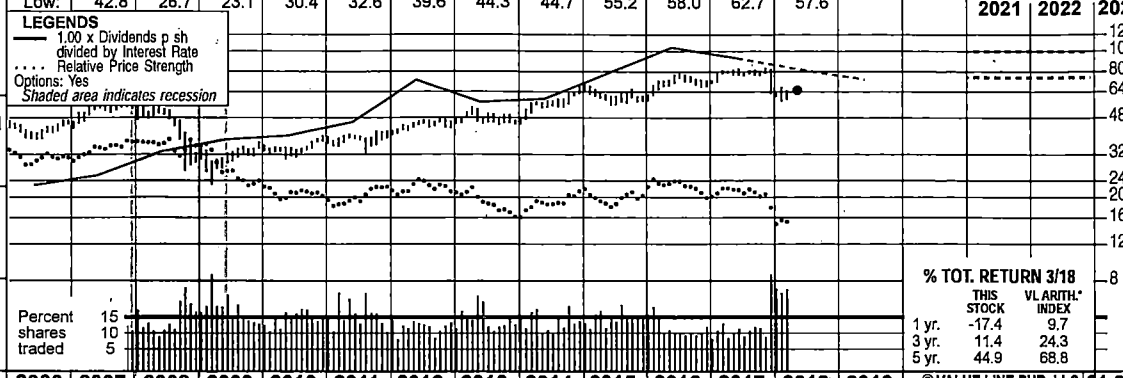
EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 65.22 | P/E RATIO 14.3 (Trailing: 14.5 Median: 12.0) | RELATIVE P/E RATIO 0.76 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Lowered 3/2/18
SAFETY 2 Raised 5/3/13
TECHNICAL 4 Raised 4/20/18
BETA .60 (1.00 = Market)

High:	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	83.4	67.6
Low:	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	62.7	57.6

Target Price Range 2021 | 2022 | 2023



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+55%)	14%
Low	75	(+15%)	8%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	1	0	0	1	0	1	0
to Sell	2	0	1	0	0	1	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	299	274	278
to Sell	236	258	225
Hld's(000)	290101	288374	267652

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-17.4	9.7
3 yr.	11.4	24.3
5 yr.	44.9	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	*38.35*	*40.20*	Revenues per sh	*46.75*
4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	*11.45*	*12.05*	"Cash Flow" per sh	*14.25*
1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	*4.55*	*4.70*	Earnings per sh A	*5.50*
--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	*2.45*	*2.57*	Div'd Decl'd per sh B ■	*3.10*
4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	*13.30*	*15.05*	Cap'l Spending per sh	*15.75*
13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	*37.35*	*38.90*	Book Value per sh C	*44.50*
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
7.8	7.0	37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.43	.40	1.99	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.85	*Value Line*		Relative P/E Ratio	*.85*
--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*
						14112	12374	12409	12760	11862	12581	13413	11524	11869	12320	*12500*	*13100*	Revenues ($mill)	*15200*
						1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	*1620*	*1670*	Net Profit ($mill)	*1970*
						30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	*10.0%*	*10.0%*	Income Tax Rate	*10.0%*
						8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
						51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*47.5%*
						44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	*44.0%*	*44.5%*	Common Equity Ratio	*45.5%*
						21374	21185	23861	24773	20422	21516	23216	24352	24362	25506	*27500*	*28525*	Total Capital ($mill)	*31800*
						18969	21966	24778	32116	30273	30455	32981	35085	37000	39050	*41125*	*43675*	Net Plant ($mill)	*50700*
						7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
						12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	*11.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
						12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	*12.5%*	*12.0%*	Return on Com Equity E	*12.5%*
						8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
						35%	41%	40%	43%	32%	40%	37%	44%	53%	52%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $14516 mill. **Due in 5 Yrs** $4793 mill.
LT Debt $11642 mill. **LT Interest** $569 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $335 mill.
Pens. Assets-12/17 $3616 mill. **Oblig** $4179 mill.
Pfd Stock $2193 mill. **Pfd Div'd** $124 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 2/20/18**
MARKET CAP: $21 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.4	-2.6	+.2
Avg. Indust. Use (MWH)	703	664	NA
Avg. Indust. Revs. per KWH (¢)	9.07	6.51	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23079	23091	23508
Annual Load Factor (%)	52.2	50.7	NA
% Change Customers (yr-end)	+.6	+.5	+.7
Fixed Charge Cov. (%)	247	246	241

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	-.5%	*4.0%*
"Cash Flow"	4.0%	3.5%	*5.0%*
Earnings	2.5%	2.5%	*4.5%*
Dividends	6.0%	9.0%	*8.0%*
Book Value	4.5%	3.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2512	2908	3763	2341	11524
2016	2440	2777	3767	2885	11869
2017	2463	2965	3672	3220	12320
2018	*2500*	*3000*	*3800*	*3200*	*12500*
2019	*2600*	*3150*	*4000*	*3350*	*13100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.91	1.15	1.15	.94	4.15
2016	.85	.86	1.27	.96	3.94
2017	1.11	.85	1.43	1.12	4.51
2018	*1.10*	*.90*	*1.45*	*1.10*	*4.55*
2019	*1.15*	*.90*	*1.50*	*1.15*	*4.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.355	.355	.355	.355	1.42
2015	.4175	.4175	.4175	.4175	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425	.5425	2.17
2018	.605	.605			

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 6%; nuclear, 6%; hydro, 5%; purchased, 83%. Fuel costs: 38% of revs. '17 reported depr. rate: 3.8%. Has 12,500 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Investors remain concerned about the possible wildfire liability of Edison International's utility subsidiary. Southern California Edison's service area had wildfires in the fall of 2017. The cause of the wildfires has not yet been determined, but SCE has already been hit with some lawsuits alleging that its power lines were at fault. (It has $1 billion in liability insurance.) Under California's inverse condemnation law, a utility can be held liable if its power lines contributed to the wildfires, even if the utility followed accepted inspection and safety rules. If this occurs, there is no assurance that the utility will be allowed to pass these costs through to ratepayers. So, the company is pursuing a three-pronged strategy to address this risk, seeking legislative, regulatory, and judicial solutions to this problem.

SCE is awaiting an order on its general rate case. The utility has revised its request to pass through to customers the benefits of federal tax reform. SCE is asking for a reduction of $106 million in 2018 and increases of $431 million and $503 million at the start of 2019 and 2020, respectively. (The order will be retroactive to the beginning of 2018.) The utility's three-year capital spending plan calls for $1.4 billion for grid modernization, which is somewhat controversial because the California commission has not been asked to approve such spending in previous rate cases. An order is expected by yearend.

Tax reform is slightly negative for the company. Edison International has about $1.75 billion of long-term debt at the parent level, so corporate interest and other expenses will have a lower tax shield. This is also true for the company's nonutility energy-services subsidiary, Edison Energy, which is still in its start-up phase and is in the red. Management estimates that the corporate and nonutility drag on earnings will amount to $0.25-$0.30 a share this year. Note that the company is not providing earnings guidance as long as the general rate case is pending.

The wildfire risks hurt the stock last year, and the price has risen just slightly in 2018. The dividend yield and 3- to 5-year total return potential are above average for this industry.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); gains (loss) from discontinued operations: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢. Next earnings report due late July. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '17: $15.08/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '17: 12.2%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	60

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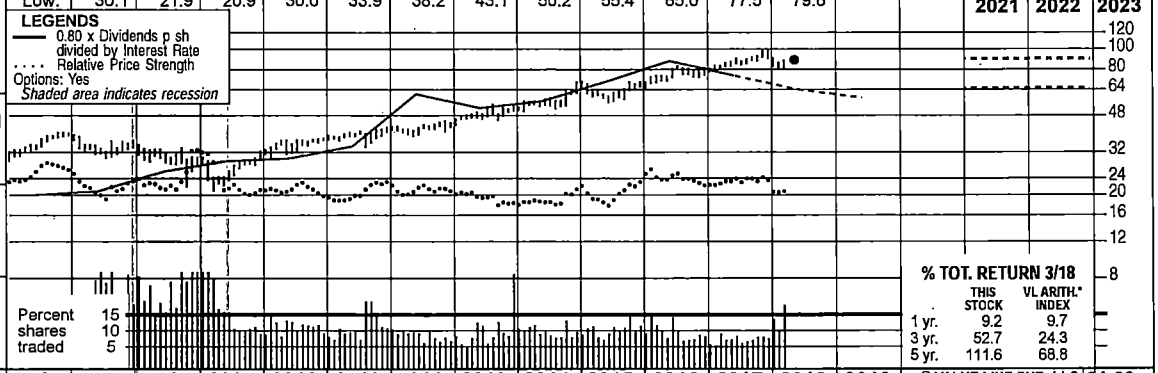
IDACORP, INC. NYSE-IDA

RECENT PRICE 88.84 | P/E RATIO 21.1 (Trailing: 21.1 Median: 14.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 2 Raised 12/22/17
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Lowered 2/23/18
BETA .70 (1.00 = Market)

High:	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	100.0	91.4
Low:	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2021 | 2022 | 2023

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(Nil)	3%
Low	65	(-25%)	-4%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	10
to Sell	2	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	139	116	127
to Sell	91	113	86
Hld's(000)	45985	45708	38200

Percent shares traded 15 10 5

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	9.7
3 yr.	52.7	24.3
5 yr.	111.6	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	*26.60*	*27.00*	Revenues per sh	*28.75*
4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	*7.65*	*8.05*	"Cash Flow" per sh	*9.25*
1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	*4.15*	*4.35*	Earnings per sh A	*4.75*
1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	*2.40*	*2.56*	Div'd Decl'd per sh B ■ †	*3.05*
3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	*6.25*	*6.40*	Cap'l Spending per sh	*6.75*
23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	*46.40*	*48.15*	Book Value per sh C	*53.25*
38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	*50.40*	*50.40*	Common Shs Outst'g D	*50.40*
18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	*Value Line*		Relative P/E Ratio	*.90*
6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1746.1 mill. **Due in 5 Yrs** $305.0 mill.
LT Debt $1746.1 mill. **LT Interest** $82.0 mill.
(LT interest earned: 3.9x)

Pension Assets-12/17 $697.7 mill.
Oblig $999.3 mill.

Pfd Stock None

Common Stock 50,392,360 shs.
as of 2/16/18

MARKET CAP: $4.5 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	*1340*	*1360*	Revenues ($mill)	*1450*
98.4	124.4	142.5	166.9	168.9	182.4	193.5	194.7	198.3	212.4	*210*	*220*	Net Profit ($mill)	*245*
16.3%	15.2%	--	--	13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	*10.5%*	*10.5%*	Income Tax Rate	*10.5%*
10.2%	10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	*14.0%*	*14.0%*	AFUDC % to Net Profit	*14.0%*
47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	*44.0%*	*42.0%*	Long-Term Debt Ratio	*44.0%*
52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	*56.0%*	*58.0%*	Common Equity Ratio	*56.0%*
2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	*4180*	*4165*	Total Capital ($mill)	*4775*
2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	*4425*	*4560*	Net Plant ($mill)	*4850*
5.3%	5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.0%*
7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	*4.0%*	*4.0%*	Retained to Com Eq	*3.5%*
55%	46%	41%	36%	41%	43%	46%	50%	53%	53%	*57%*	*59%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.2	-.5	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.70	5.63	5.83
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3402	3299	3422
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.8	+2.0
Fixed Charge Cov. (%)	307	295	329

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.5%	4.0%	*2.0%*
"Cash Flow"	5.5%	4.0%	*4.5%*
Earnings	7.5%	4.5%	*3.5%*
Dividends	5.5%	10.5%	*6.5%*
Book Value	5.5%	5.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	279.4	336.3	369.2	285.4	1270.3
2016	281.0	315.4	372.0	293.6	1262.0
2017	302.6	333.0	408.3	305.6	1349.5
2018	*310*	*335*	*390*	*305*	*1340*
2019	*315*	*340*	*395*	*310*	*1360*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.47	1.31	1.46	.63	3.87
2016	.51	1.12	1.65	.66	3.94
2017	.66	.99	1.80	.77	4.21
2018	*.60*	*1.00*	*1.85*	*.70*	*4.15*
2019	*.65*	*1.05*	*1.90*	*.75*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016	.51	.51	.51	.55	2.08
2017	.55	.55	.55	.59	2.24
2018	.59				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 545,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 41%; commercial, 24%; industrial, 14%; irrigation, 11%; other, 10%. Generating sources: hydro, 50%; coal, 18%; gas, 8%; purchased, 24%. Fuel costs: 33% of revenues. '17 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's 10-year streak of earnings growth might well come to an end in 2018. This is despite the performance of the company's utility subsidiary, Idaho Power, which is faring well, is financially sound, and has good growth prospects. A year ago, IDACORP's income benefited from some tax adjustments. Favorable weather conditions, helped, as well. Our earnings estimate of $4.15 a share, which we trimmed by a nickel, is within the company's targeted range of $4.10-$4.25. Given that IDACORP earned $4.21 a share in 2017, another year of profit growth is hardly out of the question, based on the company's guidance.

We expect dividend growth to continue, even if earnings growth is interrupted. Management anticipates recommending to the board annual increases of at least 5%. The company is targeting a payout ratio in a range of 50%-60%.

Idaho Power is performing well. The economy of the company's service area is healthy. Customer growth was 2.0% last year, which is more than double the industry norm. Kilowatt-hour sales generally aren't rising as fast (the 2.6% increase in 2017 was driven in part by weather) due to the effects of energy efficiency. The utility's cost control has been effective, too.

We forecast a resumption of profit growth in 2019. We think IDACORP will benefit from the growth of Idaho Power. Our $4.35-a-share estimate would produce an increase of 5%.

The utility has a regulatory mechanism to supplement its income, if necessary. If Idaho Power's earned return on equity falls below 9.5% through 2019, the utility may use up to $25 million of accumulated deferred investment tax credits annually to bring its ROE to that level. (A proposed regulatory settlement would extend this mechanism indefinitely beyond next year.) Note that the ROEs shown in the statistical array are for IDACORP as a whole, not just its utility subsidiary.

This stock is timely, but is priced expensively. The dividend yield is below average for a utility. The recent quotation is near the upper end of our 2021-2023 Target Price Range. Accordingly, total return potential is negligible.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '03, 26¢; '05, (24¢); '06, 17¢. '17 earnings don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '17: $21.49/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '11: 10% (imputed); earned on avg. com. eq., '17: 9.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	95

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ALLIANT ENERGY NYSE-LNT

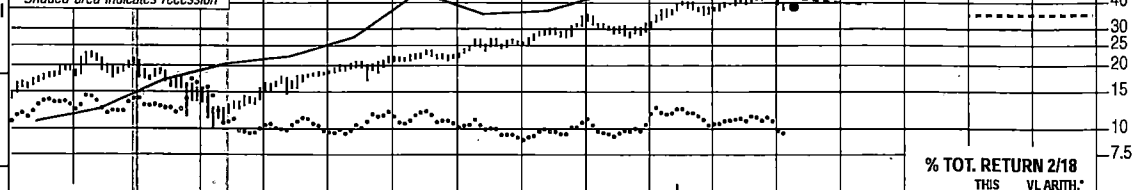
RECENT PRICE 38.17 | P/E RATIO 17.7 (Trailing: 19.2 Median: 15.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 2 Raised 3/9/18
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 3/2/18
BETA .70 (1.00 = Market)

High:	23.3	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	45.6	42.7
Low:	17.5	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-10%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	1	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	198	194	190
to Sell	188	187	165
Hld's(000)	179256	182717	166325

Percent shares traded 24 16 8

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.0	10.1
3 yr.	34.3	24.2
5 yr.	92.2	76.2

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	*15.30*	*15.55*	Revenues per sh	*17.75*
2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97	*4.25*	*4.45*	"Cash Flow" per sh	*5.00*
1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	*2.10*	*2.25*	Earnings per sh A	*2.60*
.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	*1.34*	*1.42*	Div'd Decl'd per sh B ■ †	*1.66*
3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	*6.75*	*7.10*	Cap'l Spending per sh	*5.30*
12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	*19.00*	*20.25*	Book Value per sh C	*22.85*
220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	*233.00*	*235.00*	Common Shs Outst'g D	*235.00*
13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.01	*Value Line*		Relative P/E Ratio	*.85*
4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*
3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	*3560*	*3650*	Revenues ($mill)	*4175*
280.0	208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	455.9	*490*	*530*	Net Profit ($mill)	*610*
33.4%	--	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
--	--	--	--	--	--	--	6.5%	7.0%	*7.0%*	*7.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	51.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	*8300*	*8400*	Total Capital ($mill)	*8700*
5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	10797.9	*11125*	*11645*	Net Plant ($mill)	*12900*
7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	5.6%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.5%*
9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	10.9%	*11.0%*	*11.0%*	Return on Com Equity E	*11.5%*
3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
62%	88%	64%	67%	64%	57%	59%	65%	72%	63%	*64%*	*63%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $5186.5 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $4010.6 mill. **LT Interest** $180.0 mill.
(LT interest earned: 4.0x)

Pension Assets-12/17 $950.7 mill. **Oblig.** $1303.1 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 231,348,646 shs.

MARKET CAP: $8.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	+2.0	1.0
Avg. Indust. Use (MWH)	11735	11987	12102
Avg. Indust. Revs. per KWH (¢)	6.92	7.04	7.16
Capacity at Peak (Mw)	5385	5615	5375
Peak Load, Summer (Mw)	5385	5615	5375
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	+.4
Fixed Charge Cov. (%)	315	295	319

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	.5%	-1.5%	*3.0%*
"Cash Flow"	3.5%	6.5%	*5.5%*
Earnings	5.0%	6.5%	*6.5%*
Dividends	7.5%	6.5%	*6.0%*
Book Value	4.0%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	897.4	717.2	898.9	740.1	3253.6
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	765.3	906.9	856.1	3382.2
2018	*950*	*790*	*945*	*875*	*3560*
2019	*960*	*815*	*975*	*900*	*3650*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.44	.30	.80	.15	1.69
2016	.43	.37	.57	.28	1.65
2017	.44	.41	.73	.41	1.99
2018	*.50*	*.40*	*.85*	*.35*	*2.10*
2019	*.53*	*.43*	*.90*	*.39*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.255	.255	.255	.255	1.02
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335				

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 38%; IA, 61%; MN, 1%. Elect. rev.: residential, 36%; commercial, 24%; industrial, 30%; wholesale, 8%; other, 2%. Fuel sources, 2017: coal, 40%; gas, 17%; other, 43%. Fuel costs: 45% of revs. 2017 depreciation rate: 5.5%. Estimated plant age: 15 years. Has approximately 3,989 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy's largest utility subsidiary has reached a settlement of its rate case. Under the agreement, electric rates for Interstate Power and Light Company (IPL) would rise $130 million (7.8%) in 2018. That is down from the original $176 million (11.6%) request, but within our range of estimates. The Iowa Utilities Board also approved a return on common equity of 9.6% and said that temporary rates, which have been in effect since April 2017, would remain until the board reviews and approves tariff filings to be made by Alliant. The company said it would use the funds to upgrade power grids and improve facilities like the Marshalltown natural gas generating station.

Earnings should advance in 2018 and 2019. Each year, the utility is expected to benefit from electric and gas rate increases at IPL and Wisconsin Power and Light Company (WPL). Our 2018 profit estimate is near the midpoint of management's guidance range of $2.04-$2.18 a share, while our 2019 estimate calls for 7% year-on-year growth. It should be noted that tax reform is not forecasted to have a material impact on earnings. This is because much of the anticipated savings will be returned to customers through fewer/lower rate increases over time.

Wind energy remains an area of focus for Alliant. In December, the utility agreed to purchase English Farms Wind Farm for an undisclosed sum. The 170-megawatt, Iowa-based project is expected to power approximately 75,000 homes upon completion. Alliant is aiming to generate at least one-third of its Iowa energy mix from wind starting in 2020.

The board raised the dividend in the first quarter of 2018. This is the usual timing of the annual increase. The directors boosted the yearly disbursement by $0.08 a share (6.3%), the same increase as in each of the past four years. Alliant is targeting a payout ratio of 60%-70%.

This good-quality stock is well ranked for year-ahead relative price performance. The dividend yield is slightly below the median for a utility. Appreciation potential, while improved since our December report, is still well below the *Value Line* median. Accordingly, we advise long-term investors to wait on the sidelines.

Daniel Henigson *March 16, 2018*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '08, 4¢; '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings report due early May. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '17: $69.7 mill., $0.30/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '17: 10.5%; in WI in '17 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	90

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NORTHWESTERN NYSE-NWE

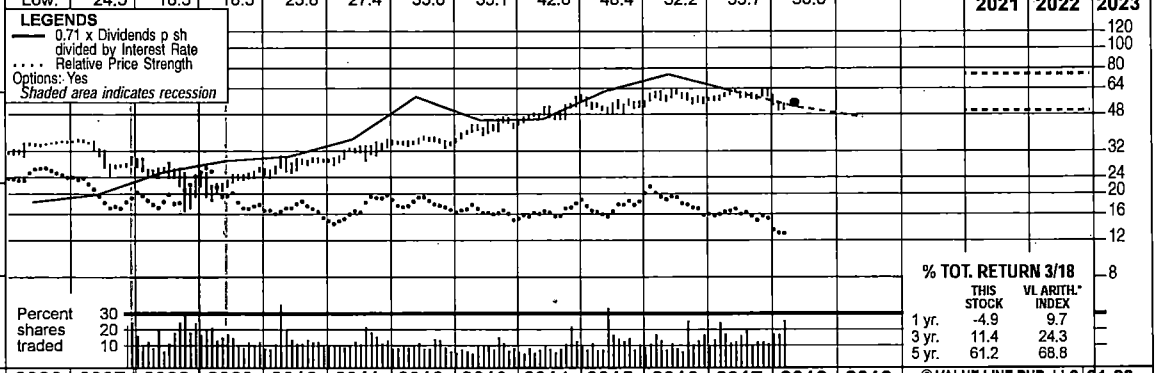
RECENT PRICE 54.59 | P/E RATIO 16.2 (Trailing: 16.3 Median: 16.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 2/23/18
SAFETY 3 New 5/4/12
TECHNICAL 5 Lowered 4/6/18
BETA .65 (1.00 = Market)

High:	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	64.5	59.8
Low:	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+35%)	11%
Low	50	(-10%)	2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	1	0	0	1	0	2	15
to Sell	0	0	1	1	0	0	1	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	124	118	96
to Sell	101	100	97
Hld's(000)	56186	53930	45947

Percent shares traded 30 20 10

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.9	9.7
3 yr.	11.4	24.3
5 yr.	61.2	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	**26.25**	**27.00**	Revenues per sh	**29.50**
--	--	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	**6.95**	**7.30**	"Cash Flow" per sh	**8.25**
--	--	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	**3.45**	**3.55**	Earnings per sh A	**4.00**
--	--	--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	**2.20**	**2.30**	Div'd Decl'd per sh B ■ †	**2.60**
--	--	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	**5.70**	**6.70**	Cap'l Spending per sh	**6.25**
--	--	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	**37.95**	**39.10**	Book Value per sh C	**42.75**
--	--	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	**50.25**	**50.40**	Common Shs Outst'g D	**51.00**
--	--	--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
--	--	--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.89	*Value Line*		Relative P/E Ratio	**.90**
--	--	--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	*estimates*		Avg Ann'l Div'd Yield	**4.1%**

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2137.3 mill. **Due in 5 Yrs** $332.0 mill.
LT Debt $1815.6 mill. **LT Interest** $83.5 mill.
Incl. $22.2 mill. capitalized leases.
(LT interest earned: 3.1x)

Pension Assets-12/17 $586.5 mill. **Oblig** $696.8 mill.

Pfd Stock None

Common Stock 49,397,196 shs. as of 2/9/18

MARKET CAP: $2.7 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	**1320**	**1360**	Revenues ($mill)	**1500**
67.6	73.4	77.4	92.6	83.7	94.0	120.7	138.4	164.2	162.7	**170**	**180**	Net Profit ($mill)	**205**
37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	--	13.7%	13.7%	7.6%	**2.5%**	**3.5%**	Income Tax Rate	**6.5%**
2.3%	4.4%	14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	**6.0%**	**6.0%**	AFUDC % to Net Profit	**5.0%**
46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	**49.5%**	**48.5%**	Long-Term Debt Ratio	**46.0%**
53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	**50.5%**	**51.5%**	Common Equity Ratio	**54.0%**
1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	**3775**	**3840**	Total Capital ($mill)	**4050**
1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	**4465**	**4620**	Net Plant ($mill)	**4975**
7.0%	6.0%	5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	**9.0%**	**9.0%**	Return on Shr. Equity	**9.5%**
8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	**9.0%**	**9.0%**	Return on Com Equity E	**9.5%**
2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	**3.5%**	**3.5%**	Retained to Com Eq	**3.5%**
74%	66%	63%	56%	65%	61%	54%	65%	58%	62%	**64%**	**64%**	All Div'ds to Net Prof	**64%**

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	-.7	+3.8
Avg. Indust. Use (MWH)	30133	29784	30987
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2096	2138	2133
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.2	+1.3
Fixed Charge Cov. (%)	252	253	275

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.0%	-3.0%	2.0%
"Cash Flow"	5.5%	5.0%	4.0%
Earnings	8.0%	7.0%	3.5%
Dividends	5.5%	7.0%	4.5%
Book Value	5.5%	8.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	346.0	270.6	272.7	325.0	1214.3
2016	332.5	293.1	301.0	330.6	1257.2
2017	367.3	283.9	309.9	344.6	1305.7
2018	**365**	**300**	**315**	**340**	**1320**
2019	**375**	**310**	**325**	**350**	**1360**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.38	.51	.93	2.90
2016	.82	.73	.92	.92	3.39
2017	1.17	.44	.75	.98	3.34
2018	**1.15**	**.45**	**.80**	**1.05**	**3.45**
2019	**1.20**	**.45**	**.85**	**1.05**	**3.55**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.40	.40	.40	1.60
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525	.525	2.10
2018	.55				

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 433,000 electric customers in Montana and South Dakota and 286,000 gas customers in Montana (87% of gross margin), South Dakota (12%), and Nebraska (1%). Electric revenue breakdown: residential, 40%; commercial, 51%; industrial, 5%; other, 4%. Generating sources: hydro, 36%; coal, 29%; wind, 6%; other, 4%; purchased, 25%. Fuel costs: 31% of revenues. '17 reported deprec. rate: 3.0%. Has 1,600 employees. Chairman: Stephen P. Adik. President & CEO: Robert C. Rowe. Inc.: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

We estimate that NorthWestern's earnings will advance moderately this year. In 2018, the company will benefit from a full year's effect of a $5.1 million gas rate hike that took effect in Montana last September. The refinancing of debt in the fourth quarter of 2017 is another plus. However, there will be some dilution from the equity issued in 2017 and 2018 via its at-the-market program. Our 2018 share-earnings estimate, which we trimmed by $0.05 a share, is within NorthWestern's targeted range of $3.35-$3.50.

An electric rate case is upcoming in Montana. The utility expects to file an application by September, with an order due by mid-2019. NorthWestern has some assets that are not reflected in rates. However, regulation in Montana has worsened in recent years, which is a cause for concern. Still, a partial year of rate relief would benefit earnings in 2019.

NorthWestern had a setback in the U.S. Court of Appeals. The utility appealed an unfavorable ruling from the Federal Energy Regulatory Commission, which ruled that just 4% of the cost of a gas-fired plant could be allocated to wholesale customers (versus the company's request for a 20% allocation). This forced NorthWestern to take a $0.12-a-share charge in 2012. Management is deciding whether pursuing this matter further is worthwhile.

Another legal matter is pending. The Montana commission disallowed recovery of certain costs associated with a plant outage in 2013. This forced NorthWestern to take a $0.13-a-share charge in the 2016. The utility is seeking relief in the Montana District Court. It expects a decision within the next 12 months.

The board of directors raised the dividend in the first quarter. The hike was $0.10 a share (4.8%) annually, the same as a year earlier. NorthWestern is targeting a payout ratio in a range of 60%-70%.

This stock has a dividend yield and 3- to 5-year total return potential that are above the utility average. This follows a price decline of more than 10% since the start of 2018. This has been a bad year for utility equities, but the falloff has been greater than most in this industry. There isn't a clear reason why.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. gain (loss) on discont. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢. '15 EPS don't add due to rounding. Next earnings report due late July. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '17: $14.42/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '17: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	85

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OGE ENERGY CORP. NYSE-OGE

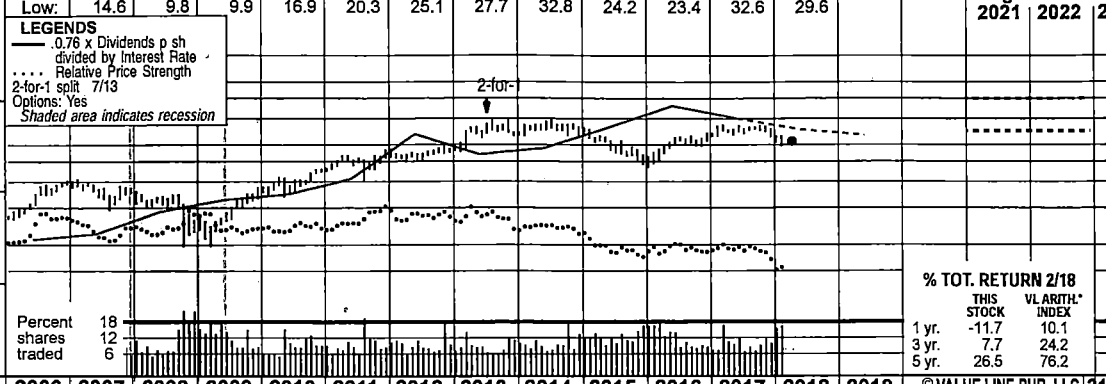
RECENT PRICE 31.20 | P/E RATIO 15.2 (Trailing: 16.3 Median: 15.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Lowered 1/12/18
SAFETY 2 Lowered 12/18/15
TECHNICAL 4 Raised 3/16/18
BETA .95 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High:	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4	33.1
Low:	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+60%)	16%
Low	35	(+10%)	8%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	2	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	159	151	155
to Sell	202	155	138
Hld's(000)	145860	145781	124353

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.7	10.1
3 yr.	7.7	24.2
5 yr.	26.5	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	*11.75*	*12.50*	Revenues per sh	*14.75*
1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	*3.60*	*4.00*	"Cash Flow" per sh	*4.75*
.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	*2.05*	*2.15*	Earnings per sh A	*2.50*
.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	*1.40*	*1.54*	Div'd Decl'd per sh B ■	*1.85*
1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	*3.15*	*3.15*	Cap'l Spending per sh	*2.75*
6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	*19.95*	*20.55*	Book Value per sh C	*22.50*
157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	*199.70*	*199.70*	Common Shs Outst'g D	*199.70*
14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.91	*Value Line*		Relative P/E Ratio	*.95*
6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $3168.1 mill. **Due in 5 Yrs** $668.9 mill.
LT Debt $2749.6 mill. **LT Interest** $140.4 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $4.8 mill.

Pension Assets-12/17 $635.3 mill. **Oblig** $687.5 mill.

Pfd Stock None

Common Stock 199,706,104 shs. as of 1/31/18
MARKET CAP: $6.2 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	*2350*	*2500*	Revenues ($mill)	*2950*
231.4	258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	*410*	*430*	Net Profit ($mill)	*500*
30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	*43.0%*	*44.0%*	Long-Term Debt Ratio	*45.5%*
46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	*57.0%*	*56.0%*	Common Equity Ratio	*54.5%*
4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	*6980*	*7350*	Total Capital ($mill)	*8225*
5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	*8660*	*8910*	Net Plant ($mill)	*9450*
7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	*10.0%*	*10.5%*	Return on Com Equity E	*11.0%*
5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
55%	53%	48%	43%	44%	43%	47%	61%	67%	64%	*68%*	*72%*	All Div'ds to Net Prof	*74%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.9	-1.1	-2.2
Avg. Indust. Use (MWH)	754	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.05	5.17	5.30
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6537	6538	6456
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.1	+1.0
Fixed Charge Cov. (%)	314	336	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-8.0%	-10.0%	*4.5%*
"Cash Flow"	4.0%	-.5%	*4.5%*
Earnings	4.5%	1.0%	*2.5%*
Dividends	5.5%	8.5%	*8.0%*
Book Value	7.5%	6.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	480.1	549.9	719.8	447.1	2196.9
2016	433.1	551.4	743.9	530.8	2259.2
2017	456.0	586.4	716.8	501.9	2261.1
2018	*475*	*600*	*750*	*525*	*2350*
2019	*500*	*650*	*800*	*550*	*2500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.22	.44	.88	.15	1.69
2016	.13	.35	.92	.29	1.69
2017	.18	.52	.92	.30	1.92
2018	*.20*	*.50*	*1.05*	*.30*	*2.05*
2019	*.20*	*.55*	*1.10*	*.30*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 842,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.7% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 26%; industrial, 9%; oilfield, 7%; other, 18%. Generating sources: coal, 34%; gas, 25%; wind, 4%; purchased, 37%. Fuel costs: 40% of revenues. '17 reported depreciation rate (utility): 2.5%. Has 2,400 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary has filed a general rate case in Oklahoma. Oklahoma Gas and Electric is asking the Oklahoma Corporation Commission (OCC) for an increase of $1.9 million, based on a return of 9.9% on a common-equity ratio of 53%. (The request would have been over $70 million were it not for the pass-through to customers of reduced federal taxes.) The utility is seeking to place in the rate base a $390 million project to modernize the 462-megawatt Mustang gas-fired plant; restore the depreciation rates to their level before the OCC cut these last year; and raise its allowed ROE from the current 9.5%. New tariffs are expected to take effect at the start of October. Note that in Arkansas, OG&E will recover its investment in Mustang through the state's formula rate plan.

The new federal tax law is benefiting earnings. The revaluation of deferred taxes produced a nonrecurring gain of $1.18 a share in the fourth quarter of 2017. This year, the lower tax rate applied to OGE Energy's income from its interest in Enable Midstream Partners will add $0.08 to share net.

Rate relief should benefit the company's profits this year and next. Our 2018 estimate of $2.05 a share is at the upper end of OGE Energy's targeted range of $1.90-$2.05. Also, we expect higher equity income from the stake in Enable as the master limited partnership's prospects improve.

Two environmental compliance projects are on track for completion by yearend. OG&E is adding scrubbers to two units at the Sooner coal-fired plant at a cost of $542 million. Another coal-fired unit is being converted to a gas-fired facility at cost of $76 million. The utility will file a rate application in Oklahoma in late 2018 in order to place these projects in the rate base.

The dividend yield of this stock is above the utility average. What's more, OGE Energy expects to hike the disbursement by 10% annually through next year. Even if the board doesn't maintain such a high growth rate beyond 2019, the increases we project should produce a respectable total return over the 3- to 5-year period.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '02, (20¢); '03, (7¢); '04, (3¢); '15, (33¢); '17, $1.18; gains on disc. ops.: '02, 6¢; '05, 25¢; '06, 20¢. Next earnings report due early May. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '17: $1.42/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '16: 9.5%; in AR in '11: 9.95%; earned on avg. com. eq., '17: 17.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	80

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PINNACLE WEST NYSE-PNW

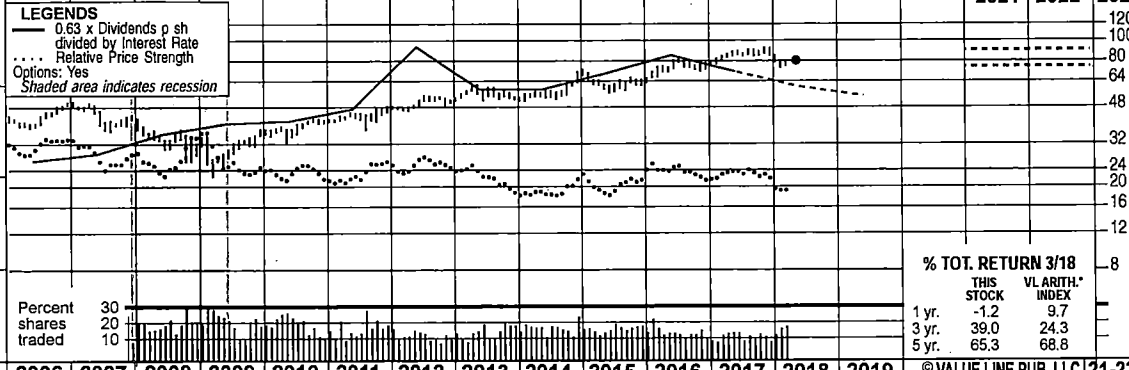
RECENT PRICE 80.15 | P/E RATIO 18.1 (Trailing: 18.1 Median: 15.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 3/30/18
SAFETY 1 Raised 5/3/13
TECHNICAL 5 Lowered 4/6/18
BETA .65 (1.00 = Market)

High:	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8	92.5	85.6
Low:	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.8

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.63 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+10%)	7%
Low	75	(-5%)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	12	0	0	1	12
to Sell	0	0	3	0	0	2	1	1	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	194	218	182
to Sell	224	185	183
Hld's(000)	107032	104825	94333

Percent shares traded 30 20 10

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.2	9.7
3 yr.	39.0	24.3
5 yr.	65.3	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	*32.80*	*34.30*	Revenues per sh	*39.75*
7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	*10.10*	*10.65*	"Cash Flow" per sh	*12.75*
2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	*4.50*	*4.70*	Earnings per sh A	*5.50*
1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	*2.86*	*3.02*	Div'd Decl'd per sh B ■	*3.50*
9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	*11.25*	*10.80*	Cap'l Spending per sh	*11.00*
29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	*46.35*	*48.00*	Book Value per sh C	*54.00*
91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	*112.00*	*112.25*	Common Shs Outst'g D	*113.00*
14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	*Value Line*		Relative P/E Ratio	*.85*
4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $4829.4 mill. **Due in 5 Yrs** $1188.4 mill.
LT Debt $4789.7 mill. **LT Interest** $213.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $13.4 mill.
Pension Assets-12/17 $3057.0 mill. **Oblig** $3394.2 mill.
Pfd Stock None

Common Stock 111,799,789 shs. as of 2/16/18
MARKET CAP: $9.0 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	*3675*	*3850*	Revenues ($mill)	*4500*
213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	442.0	497.8	*505*	*535*	Net Profit ($mill)	*630*
23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	*13.0%*	*10.0%*	AFUDC % to Net Profit	*8.0%*
46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	*48.0%*	*48.5%*	Long-Term Debt Ratio	*45.5%*
53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	*52.0%*	*51.5%*	Common Equity Ratio	*54.5%*
6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	*9985*	*10480*	Total Capital ($mill)	*11175*
8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	12714	13445	*14075*	*14625*	Net Plant ($mill)	*16125*
4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
96%	89%	66%	68%	58%	58%	62%	59%	62%	58%	*63%*	*63%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.3	+.3	--
Avg. Indust. Use (MWH)	658	640	620
Avg. Indust. Revs. per KWH (¢)	8.17	8.37	8.34
Capacity at Peak (Mw)	9250	9192	8438
Peak Load, Summer (Mw)	7031	7051	7363
Annual Load Factor (%)	48.3	48.0	46.3
% Change Customers (yr-end)	+1.3	+1.3	+1.8
Fixed Charge Cov. (%)	438	416	425

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	1.0%	*4.0%*
"Cash Flow"	1.5%	5.0%	*5.0%*
Earnings	4.0%	5.0%	*5.0%*
Dividends	2.5%	2.5%	*5.5%*
Book Value	2.0%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	671.2	890.7	1199.1	734.4	3495.4
2016	677.2	915.4	1166.9	739.2	3498.7
2017	677.7	944.6	1183.3	759.7	3565.3
2018	*700*	*975*	*1225*	*775*	*3675*
2019	*725*	*1025*	*1300*	*800*	*3850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.14	1.10	2.30	.37	3.92
2016	.04	1.08	2.35	.47	3.95
2017	.21	1.49	2.46	.27	4.43
2018	*.25*	*1.30*	*2.60*	*.35*	*4.50*
2019	*.25*	*1.35*	*2.70*	*.40*	*4.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.568	.568	.568	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017	.655	.655	.655	.695	2.66
2018	.695				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.2 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 50%; commercial, 40%; industrial, 5%; other, 5%. Generating sources: nuclear, 29%; gas & other, 26%; coal, 22%; purchased, 23%. Fuel costs: 28% of revenues. '17 reported deprec. rate: 2.8%. Has 6,300 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has asked the Arizona Corporation Commission for a rate increase. Although the rate order last year for Arizona Public Service froze base tariffs mid-2020, the ruling also allowed APS to file for recovery of an environmental project at the Four Corners coal-fired station through a rider (surcharge) on customers' bills. The utility is seeking an increase of $65 million (about 2%), and no change in the allowed return on equity of 10%. A decision is expected in time for the rider to take effect at the start of 2019. The project should be completed soon at a cost of $390 million. The costs that the company will incur this year will be deferred for recovery beginning next year under the rider.

Another large capital project is under construction. APS is building five gas-fired units and retiring two at an estimated cost of $500 million. This will increase the utility's generating capacity by 290 megawatts. Costs associated with this project will be deferred until APS recovers these in its next base rate increase, presumably in mid-2020.

We estimate a modest earnings increase this year. Pinnacle West raised its 2018 earnings guidance by a dime a share, to $4.35-$4.55, due largely because the company raised its expectation for the Allowance for Funds Used During Construction, a noncash credit to income. Additional expense-management initiatives are another factor. We raised our estimate by $0.10 a share, to $4.50.

We forecast higher profit growth in 2019. The aforementioned rate rider should help. In addition, the utility's strong (and rising) customer growth rate is stimulating modest kilowatt-hour sales growth, despite the effects of energy efficiency. Our $4.70-a-share earnings estimate would produce an increase of 4%.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards. Perhaps conservative investors will find this acceptable, given the equity's top-notch Safety rank and the company's high rating for Financial Strength. However, like most utility issues, the recent price is within our 2021-2023 Target Price Range.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (77¢); '09, ($1.45); '17, 8¢; gains (losses) from disc. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically pd. in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '17: $14.34/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '17: 10.0%; earned on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

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PORTLAND GENERAL NYSE-POR

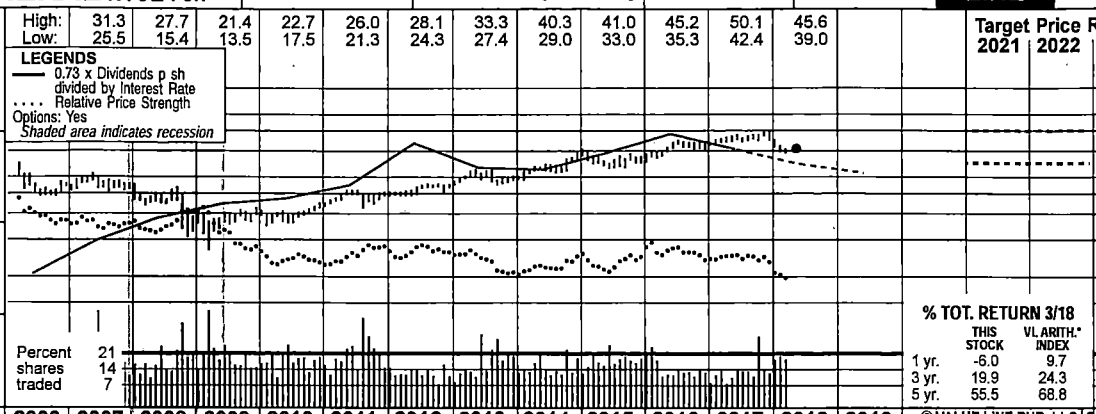
RECENT PRICE 40.92 | P/E RATIO 18.4 (Trailing: 17.9 Median: 16.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Lowered 3/23/18
SAFETY 2 Raised 5/4/12
TECHNICAL 5 Lowered 4/20/18
BETA .65 (1.00 = Market)

High:	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2	50.1	45.6
Low:	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	9%
Low	35	(-15%)	1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	10	0	0	10	0	0	0	0	5
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	147	122	136
to Sell	112	118	91
Hld's(000)	88988	88359	81125

Percent shares traded 21 14 7

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.0	9.7
3 yr.	19.9	24.3
5 yr.	55.5	68.8

2002	2003	2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.70	23.50	Revenues per sh	25.75
--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.40	6.85	"Cash Flow" per sh	8.00
--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.20	2.35	Earnings per sh A	2.75
--	--	--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.42	1.50	Div'd Decl'd per sh B ■ †	1.80
--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.35	5.10	Cap'l Spending per sh	5.00
--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	27.85	28.70	Book Value per sh C	31.50
--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.25	89.40	Common Shs Outst'g D	90.00
--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	Bold figures are		Avg Ann'l P/E Ratio	15.5
--	--	--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	Value Line		Relative P/E Ratio	.85
--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	estimates		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2426 mill. **Due in 5 Yrs** $460 mill.
LT Debt $2426 mill. **LT Interest** $123 mill.
Incl. $49 mill. capitalized leases.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $9 mill.
Pension Assets-12/17 $629 mill. **Oblig** $869 mill.
Pfd Stock None

Common Stock 89,114,522 shs. as of 2/2/18

MARKET CAP: $3.6 billion (Mid Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	2025	2100	Revenues ($mill)	2325
87.0	95.0	125.0	147.0	141.0	137.0	175.0	172.0	193.0	204.0	195	210	Net Profit ($mill)	255
28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	12.5%	12.5%	Income Tax Rate	12.5%
17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	7.0%	5.0%	AFUDC % to Net Profit	4.0%
46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	47.0%	50.5%	Long-Term Debt Ratio	48.5%
53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.0%	49.5%	Common Equity Ratio	51.5%
2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4710	5190	Total Capital ($mill)	5500
3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6930	6985	Net Plant ($mill)	7000
5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.5%	5.5%	Return on Total Cap'l	6.0%
6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.0%	8.5%	Return on Shr. Equity	9.0%
6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.0%	8.5%	Return on Com Equity E	9.0%
2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.0%	3.0%	Retained to Com Eq	3.5%
69%	76%	62%	54%	57%	61%	50%	56%	57%	58%	64%	63%	All Div'ds to Net Prof	63%

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.6	-2.1	+3.9
Avg. Indust. Use (MWH)	17485	16146	16041
Avg. Indust. Revs. per KWH (¢)	5.01	4.99	4.94
Capacity at Peak (Mw)	4609	4730	4743
Peak Load, Summer (Mw)	3914	3726	3976
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.3
Fixed Charge Cov. (%)	243	271	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.5%	-2.0%	3.0%
"Cash Flow"	1.5%	3.0%	5.5%
Earnings	4.0%	3.5%	4.0%
Dividends	9.0%	3.5%	6.0%
Book Value	3.0%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	473.0	450.0	476.0	499.0	1898.0
2016	487.0	428.0	484.0	524.0	1923.0
2017	530.0	449.0	515.0	515.0	2009.0
2018	530	455	515	525	2025
2019	555	470	530	545	2100

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.62	.44	.40	.57	2.04
2016	.68	.42	.38	.68	2.16
2017	.82	.36	.44	.67	2.29
2018	.70	.42	.43	.65	2.20
2019	.75	.45	.45	.70	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30	.30	.32	.32	1.24
2017	.32	.32	.34	.34	1.32
2018	.34	.34			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 875,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 33%; industrial, 11%; other, 8%. Generating sources: gas, 28%; coal, 15%; wind, 8%; hydro, 8%; purchased, 41%. Fuel costs: 30% of revenues. '17 reported depreciation rate: 3.6%. Has 2,900 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has filed a rate case. The utility requested an increase of $89 million (4.8%), based on a return of 9.5% on a common-equity ratio of 50%. An order from the Oregon Public Utility Commission (OPUC) is expected in December, with new tariffs taking effect at the start of 2019.

Earnings are likely to decline this year. Favorable weather patterns helped the bottom line in 2017, but the weather in early 2018 turned the other way. In fact, the Portland area had its second-warmest January on record. We have lowered our earnings estimate by $0.20 a share, to $2.20. Our revised estimate is within PGE's guidance of $2.10-$2.25 a share.

There is a possible risk to earnings this year. PGE is going to ask the OPUC for permission to defer (for future recovery) costs in 2018 associated with the upgraded customer information system the company expects to complete soon. If the OPUC doesn't approve this request and the utility must incur these costs, this would reduce earnings by $0.10 a share this year.

Unrecovered costs associated with the Carty gas-fired plant continue to be a drag on earnings. The facility was completed in 2016, several months after PGE declared the contractor of the project in default of the construction agreement. However, $123 million of the plant's $637 million cost are not reflected in rates. PGE filed suit against the contractor's insurer, seeking to collect a $145.6 million performance bond, plus damages. The company expects resolution of this matter to take two to four years, but was citing the same time frame two years ago. Unrecovered costs and litigation expenses reduced earnings by $0.09 a share in 2017, and the loss will widen to an estimated $0.12 a share this year due to the lower tax shield from the reduced federal tax rate.

We forecast an earnings recovery in 2019. We assume normal weather conditions and reasonable treatment in the aforementioned rate case.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average for a utility.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring losses: '13, 42¢; '17, 19¢. '15 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '17: $4.92/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '18: 9.5%; earned on avg. com. eq., '17: 8.5%. Regulatory Climate: Average. (F) '05 per-share data are pro forma, based on shs. outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	80

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XCEL ENERGY NDQ-XEL

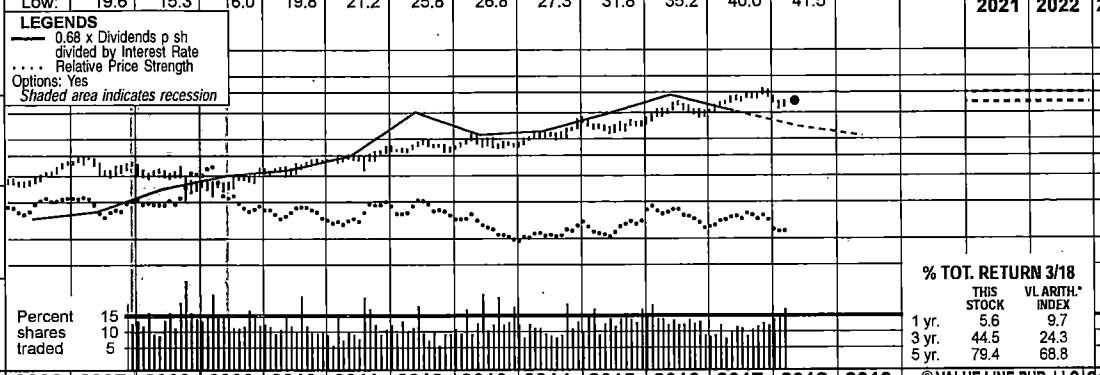
RECENT PRICE 45.61 | P/E RATIO 18.8 (Trailing: 19.7 Median: 15.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 3/23/18
SAFETY 1 Raised 5/1/15
TECHNICAL 5 Lowered 4/27/18
BETA .60 (1.00 = Market)

High:	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	52.2	48.4
Low:	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.68 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	6%
Low	45	(Nil)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	12
to Sell	0	0	1	0	0	1	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	294	286	280
to Sell	242	246	216
Hld's(000)	416718	418292	379245

Percent shares traded 15 10 5

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.6	9.7
3 yr.	44.5	24.3
5 yr.	79.4	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	*22.55*	*22.90*	Revenues per sh	*25.25*
3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	*5.90*	*6.15*	"Cash Flow" per sh	*7.25*
.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	*2.45*	*2.55*	Earnings per sh A	*3.00*
1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	*1.52*	*1.60*	Div'd Decl'd per sh B ■	*1.90*
6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	*8.25*	*7.95*	Cap'l Spending per sh	*6.75*
11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	*23.55*	*24.85*	Book Value per sh C	*28.00*
398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	*509.50*	*518.00*	Common Shs Outst'g D	*522.50*
NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	*Value Line*		Relative P/E Ratio	*.90*
6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $15791 mill. **Due in 5 Yrs** $4262 mill.
LT Debt $14520 mill. **LT Interest** $646 mill.
Incl. $151 mill. capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $238 mill.
Pension Assets-12/17 $3088 mill.
Oblig $3828 mill.
Pfd Stock None

Common Stock 508,064,983 shs.
as of 2/19/18
MARKET CAP: $23 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
11203	9644.3	10311	10655	10128	10915	11686	11024	11107	11404	*11500*	*11850*	Revenues ($mill)	*13250*
645.7	685.5	727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	*1240*	*1320*	Net Profit ($mill)	*1575*
34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	*58.0%*	*57.0%*	Long-Term Debt Ratio	*58.0%*
47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	*42.0%*	*43.0%*	Common Equity Ratio	*42.0%*
14800	15277	17452	17331	19018	20477	21714	23092	25216	25975	*28450*	*29775*	Total Capital ($mill)	*34800*
17689	18508	20663	22353	23809	26122	28757	31206	32842	34329	*36775*	*39050*	Net Plant ($mill)	*42900*
6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*10.5%*
3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
59%	61%	59%	56%	54%	54%	55%	57%	61%	62%	*62%*	*62%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.6	+.3	-.7
Large C & I Use (MWH)	23521	22519	22642
Large C & I Revs. per KWH (¢)	6.10	6.17	6.36
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19583	20423	19591
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.9
Fixed Charge Cov. (%)	358	342	330

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.0%	.5%	*2.5%*
"Cash Flow"	4.0%	6.0%	*6.5%*
Earnings	5.5%	5.0%	*5.5%*
Dividends	4.5%	5.5%	*5.5%*
Book Value	4.5%	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2962	2515	2901	2646	11024
2016	2772	2500	3040	2795	11107
2017	2946	2645	3017	2796	11404
2018	*2900*	*2650*	*3050*	*2900*	*11500*
2019	*3000*	*2700*	*3150*	*3000*	*11850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.46	.39	.84	.41	2.10
2016	.47	.39	.90	.45	2.21
2017	.47	.45	.97	.42	2.30
2018	*.55*	*.45*	*1.00*	*.45*	*2.45*
2019	*.58*	*.47*	*1.03*	*.47*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.28	.30	.30	.30	1.18
2015	.30	.32	.32	.32	1.26
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.6 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 40% of revs. '17 reported depr. rate: 3.1%. Has 11,500 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy is awaiting orders on rate cases in three states. The largest ones are Public Service of Colorado's multiyear electric and gas applications. The utility requested electric hikes totaling $245 million from 2018 through 2020, and gas increases totaling $139 million over that span. Each filing is based on a 10% return on a 55.25% common-equity ratio. An interim gas increase of $63 million took effect at the start of 2018, and the company is asking for a $75 million interim gas raise at the start of June. Southwestern Public Service asked the regulators in Texas and New Mexico for a total of $97 million, based on a 10.25% return on a 58% common-equity ratio. Rulings are expected this summer in New Mexico and early in the fourth quarter (retroactive to January of 2018) in Texas.

Rate relief is boosting Xcel's earning power and enabling the company to reduce the gap between its earned and allowed returns on equity. Management's earnings guidance for 2018 is $2.37-$2.47 a share. Our estimate of $2.45 is near the upper end of this range. We forecast more-modest profit growth in 2019. Xcel's goal for long-term earnings growth is 5%-6% annually.

Xcel's utilities have some proposals pending involving renewable energy. The aim is to retire coal-fired units and replace them with renewables, gas, and storage — and to do this without raising rates for customers. SPS received approval in New Mexico, and awaits a decision in Texas, for a $1.6 billion project to add wind in the two states. P.S. of Colorado expects a ruling in July on its plan to spend up to $1.5 billion to add wind, solar, and gas.

The board of directors raised the common dividend, effective with the April payment. The increase was $0.02 a share (5.6%) quarterly, the same as in recent years. Xcel's goals for the dividend are growth of 5%-7% annually and a payout ratio of 60%-70%.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards. This might be acceptable for conservative accounts, given the issue's top rank for Safety.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '02, ($6.27); '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '17 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '17: $5.92/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '17: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

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All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

Electric companies have been disseminating their new long-term capital spending plans. In many cases, the capital budgets are increasing. We discuss where these monies are going.

We provide an update of merger and acquisition activity in the Electric Utility Industry.

Most equities in this industry have performed extremely well in 2017. The stocks are expensively priced.

INDUSTRY TIMELINESS: 63 (of 97)

Rising Capital Budgets

At the Edison Electric Institute Financial Conference, held annually in November, many electric companies unveil their long-term (typically three or five years) capital spending plans. For many utilities, the budget for the period beginning in 2018 is higher than the one for the period that began in 2017. This doesn't necessarily mean that capital spending in 2018 will be greater than the 2017 figure, only that the expenditures over the multiyear period will probably exceed those of the previous period.

Where is this spending targeted? This depends on the company. Electric transmission is a key area of investment for *Fortis* (the parent company of ITC Holdings, a transmission-only utility in the upper Midwest), *American Electric Power*, *Ameren*, and *ALLETE*. Several companies are adding wind or solar projects to meet their states' renewable-energy requirements. *CMS Energy* is replacing old equipment, some of which dates back before 1970. *WEC Energy Group* is replacing gas mains at its utility that serves Chicago. *Vectren* is modernizing its electric system. *Entergy* plans to install an advanced metering infrastructure and is building gas-fired power plants to meet the rising demand for electricity in its service area. (By contrast, many utilities are seeing little or no load growth due to energy efficiency measures and the slow recovery from the severe 2007-2009 recession.) And *OGE Energy* is spending money for environmental compliance.

How will the utilities fund these projects? To the extent that internal cash flow is insufficient, most will rely on debt financing. Low interest rates make this kind of financing attractive. Some companies, such as *Ameren*, expect to avoid equity issuances of any kind. *Fortis* intends to limit its equity needs to stock that is issued through its dividend reinvestment and other stock plans. *CMS Energy* will raise some stock in this way as well, but will also benefit from the use of tax-loss carryforwards. *DTE Energy* and *Vectren* will need to issue some equity, however.

This capital spending will expand the utilities' rate base, and thus, boost their earning power. The utility subsidiaries of *American Electric Power*, *CMS Energy*, and *DTE Energy* will have frequent rate cases to earn a return on its capital expenditures. Companies recover their transmission investment through forward-looking formula rate plans. *Entergy* and *CenterPoint Energy* have formula rate plans that cover other kinds of spending in most of their jurisdictions. The aforementioned gas main replacement by *WEC Energy*'s Chicago utility is being recovered through monthly surcharges on customers' bills.

Merger And Acquisition Update

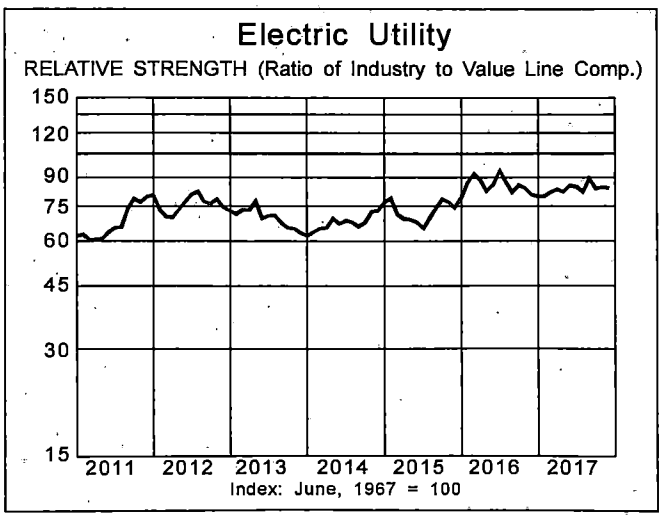
The roster of companies in the Electric Utility Industry has shrunk in recent years thanks to mergers and acquisitions. Pending deals that await regulatory approval include the combination of *Great Plains Energy* and *Westar Energy* and the takeover of Avista (covered in Issue 11). This year, the share prices of several other utilities have risen sharply due to takeover speculation. This includes *Vectren*. We advise against buying a stock solely because of takeover speculation, however. Even if a deal is reached, obtaining regulatory approval is often difficult. Many proposed transactions in this industry have fallen through, including the first deal between *Great Plains* and *Westar*. The companies reworked their agreement to make it (presumably) amenable to the regulators.

Conclusion

In 2017, most electric utility equities have risen sharply in price. Those that have advanced at a mere single-digit pace are the exception, not the rule. There are some exceptions. SCANA (covered in Issue 1) has plummeted due to the severe problems with its utility's nuclear construction project, which was canceled. The equities of two California companies, PG&E Corp. and Edison International (covered in Issue 11), have been weak due to the market's worries about liability for wildfires in the Golden State this year. Otherwise, steep price increases have been the norm. Takeover speculation has buoyed some stocks, and investors continue to reach for yield in a low interest-rate environment.

The average dividend yield of stocks in the Electric Utility Industry is just 3.3%. Seeing yields below 3% is no longer unusual, and one equity, *MGE Energy*, has a yield of just 2%. Seeing a recent quotation above the upper end of our 2020-2022 Target Price Range is also no longer unusual. Although many of these stocks might well continue to perform well in the near term, we advise long-term investors to exercise caution here.

Paul E. Debbas, CFA



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All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

We discuss the new federal tax law's effects on companies in the Electric Utility Industry.

Some companies in this Industry are making a transition from a hybrid (utility and nonutility) company to an entirely regulated entity.

Mergers and acquisitions are an ongoing theme in this industry.

Following a stellar showing in 2017, the prices of most of the stocks in this industry have declined so far in 2018. Still, the group isn't cheap.

INDUSTRY TIMELINESS: 13 (of 97)

More On The New Federal Tax Law

Now that every company in the Electric Utility Industry has reported its results for the fourth quarter of 2017, we can say more than we did in the Electric Utility (East) report in Issue 1 about the effects of the new federal tax law on this industry. The lower tax rate forced each company to revalue its deferred taxes and record a noncash credit or charge in the fourth quarter of 2017. For some companies, such as *CenterPoint Energy*, *DTE Energy*, and *OGE Energy*, this resulted in a large gain. On the other hand, charges sent the bottom lines of *Ameren*, *CMS Energy*, and *Entergy* into the red for the period. Note that we have changed the way we are treating these items in our earnings presentations, which are now excluded as nonrecurring items.

What about the effects of tax reform on earnings and cash flow in 2018? For regulated utility operations, there is virtually no doubt that the benefit of lower federal taxes will be passed through to customers. The only questions are how, and in which time frame? Many utility parent companies have debt that is held at the parent level, and the lower tax shield on the interest expense will have a modest negative effect on profits. (*Fortis* says this will hurt its earnings by 3% this year.) Companies that have nonutility operations or investments, such as the equity income that *CenterPoint* and *OGE* get from their stakes in Enable Midstream Partners, will see a benefit of lower tax rates. Tax reform will reduce cash flow for utilities, however. That's because federal income taxes are mostly or entirely a noncash item, while the pass-through to ratepayers means less cash from them. In order to compensate for this, and maintain their credit ratings, some companies are issuing common equity. This includes *Ameren* and *Entergy*, which have issued little or no equity in recent years. Other companies, such as *WEC Energy Group*, do not need to sell common stock.

From Partly Regulated To Entirely Regulated

Some companies in the Electric Utility Industry are (or were) hybrids. That is, they have nonregulated operations in addition to their regulated utilities. Most notably, several companies own nonregulated generating assets. This was attractive a decade ago, when natural gas (and thus, power) prices were much higher than they are today. However, the decline in profitability of these assets has induced several companies to get out of this business. *Ameren* discontinued its nonregulated operations in 2013. *American Electric Power* has all but completed the transition from a hybrid company to a regulated entity. *Entergy* is also exiting almost all of its nonregulated activities, although this process will not be completed until 2022. This will reduce the business risk that these companies face. Not every company is ceasing its nonutility operations. *DTE Energy* is retaining them, as they have less risk than nonregulated power generation and account for about 20% of corporate profits. *Vectren* also has some nonutility operations.

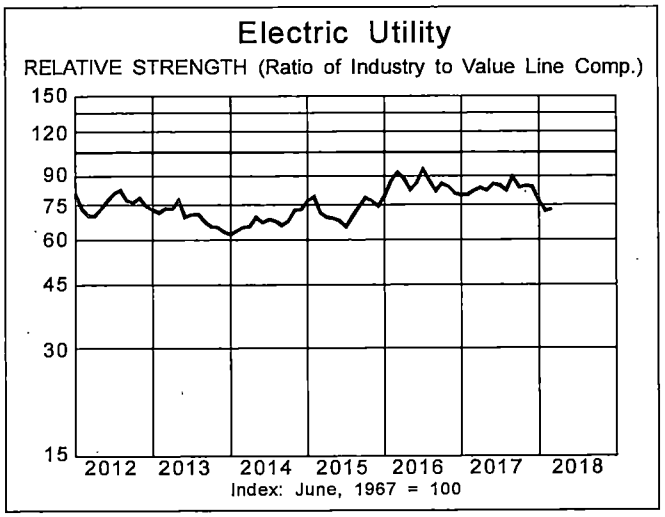
Mergers And Acquisitions

In recent years, there has been a lot of merger and acquisition activity among electric companies, or with electric utilities buying gas utilities. A few deals are pending. *Great Plains Energy* and *Westar Energy* hope to complete their combination by mid-2018. Avista (covered in Issue 11) has agreed to be acquired by Hydro One, a Canadian company. And Sempra Energy (also reviewed in Issue 11) intends to buy Oncor, an electric transmission and distribution utility in Texas.

Conclusion

Most electric utility equities performed extremely well in 2017, aided by a strong, broader stock market, the desire of many investors for high-yielding issues in an era of low interest rates, and (in some cases) takeover offers or takeover speculation. Many stock prices didn't just rise, they advanced more than 10%. This has changed so far in 2018, as electric utility issues have given back some of their gains of last year. We think this is due partly to reversion to the mean, and partly to investors' trepidation about rising interest rates. Even after the price declines, many recent quotations are still within their 2021-2023 Target Price Range. Thus, most stocks in this Industry are not cheap. The average dividend yield is 3.6%, which is low, by historical standards. Total return potential over the 3- to 5-year period is just 6%.

Paul E. Debbas, CFA



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All of the major electric utilities located in the eastern region of the United States are reviewed in this Issue; western electrics, in Issue 11; and the remaining utilities, in Issue 5.

We discuss how tax reform will affect companies in the Electric Utility Industry.

Several companies covered in Issue 1 have involvement with nuclear power. Two have worries stemming from nuclear construction, and a few have nonregulated assets that are threatened by unfavorable market conditions.

Most electric utility stocks have retreated in price so far in 2018. However, they are still expensive, by historical standards.

INDUSTRY TIMELINESS: 88 (of 97)

The New Federal Tax Law

A new federal tax law took effect at the start of 2018. For regulated utilities, it is highly likely that all of the benefits of a lower tax rate will be passed through to customers. The only questions are when, and how? However, although a one-for-one pass-through will not affect reported profits, this will reduce a utility's cash flow. That's because it will receive less cash from its customers, but its cash outlays for taxes won't decline correspondingly because utilities' tax liabilities aren't entirely in cash. Some companies are paying no cash taxes at all. In addition, as a trade-off for retaining full tax deductibility for interest payments on utility-issued debt, utilities are no longer eligible for bonus depreciation, which was a boon for cash flow. (In some cases, interest payments on debt issued at the parent level will be only partially deductible.) The absence of bonus depreciation will have a positive effect on a utility's rate-base growth, because deferred taxes that are subtracted from the rate base will be lower than they otherwise would have been. This should benefit long-term earnings growth. However, due to the negative effects on cash flow, the credit-rating agencies have placed a negative outlook on some electric companies' creditworthiness.

Of course, not every company covered in the Electric Utility Industry is entirely regulated. *NextEra Energy* and *Dominion Energy*, which each have significant nonutility operations, have stated that the lower federal tax rate will boost earnings in 2018. Nonregulated entities are not expected to pass the tax savings onto their customers.

The decline in federal tax rates meant that companies had to revalue their deferred tax balances. For *NextEra Energy* and *Dominion Energy*, this resulted in noncash credits that led to profits that were significantly higher than normal in the fourth quarter of 2017. We are *including* these credits or charges in our earnings presentation.

Nuclear Worries

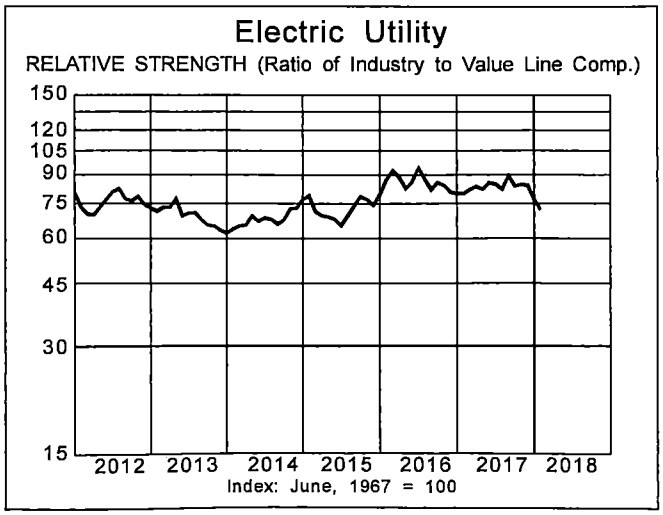
Georgia Power (a subsidiary of *Southern Company*) and South Carolina Electric & Gas (a subsidiary of *SCANA*) each have electric utility subsidiaries with nuclear construction projects that experienced significant delays and cost overruns. However, the future of each project is very much different. Georgia Power has received permission from the state commission to continue construction, despite the problems. The project will be a bit less lucrative than it would have been had it been completed on time and on budget, though, and the utility is still assuming construction risk. By contrast, SCE&G canceled its project, and the state legislature does not want the utility to continue to collect money from customers for the unsuccessful project. (The company believes the state's Base Load Review Act allows it to continue collecting these monies.) *Dominion Energy* agreed to take over *SCANA*, as long as there is no unfavorable regulatory or legislative changes. With the price of *SCANA* stock well below the value of *Dominion Energy*'s offer, the market is skeptical that the deal will be completed.

Other companies reviewed in Issue 1 have a different concern: the lack of profitability of their nonregulated nuclear plants. A combination of low gas prices, subsidized renewable energy, and weak demand for power has hurt these assets. Utilities believe current market prices don't recognize the benefits of nuclear generation (fuel diversity and no carbon emissions). So, some companies are seeking subsidies from the states in which their nuclear units are based, similar to the "zero emissions credits" that were granted by the Illinois legislature and the New York regulators for plants owned by *Exelon*. However, this company still has a unit in Pennsylvania that is threatened with a premature closing, and its facility in New Jersey will be shut in 2018, a year ahead of schedule. Some companies are still seeking some kind of subsidy that would allow them to keep their troubled nuclear plants open: *FirstEnergy* in Ohio, *Public Service Enterprise Group* in New Jersey, and *Dominion Energy* in Connecticut.

Conclusion

After the stellar performance of most stocks in the Electric Utility Industry in 2017, share prices of most electric companies declined in the first few weeks of 2018. In our view, this is partly due to reversion to the mean, and partly due to investors' increased concern about the likelihood of a few interest-rate increases by the Federal Reserve this year. The average dividend yield for this industry is up to 3.6%. This is above the level seen in 2017, but is still low, by historical standards. Moreover, many of these equities continue to trade within their 3- to 5-year Target Price Range.

Paul E. Debbas, CFA



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All of the major electric utilities located in the eastern region of the United States are reviewed in this Issue; western electrics, in Issue 11; and the remaining utilities, in Issue 5.

Most electric utilities covered in Issue 1 have some involvement with nuclear power. We discuss the latest happenings affecting these companies' nuclear plants. Most noteworthy is the divergent paths that the two nuclear projects in the Southeast are taking.

Most electric utility equities have performed well in 2017. We discuss some of the outliers. The group remains expensively priced, in our view.

INDUSTRY TIMELINESS: 91 (of 97)

Nuclear Update

Except for *AVANGRID*, *Consolidated Edison*, *Eversource Energy*, and *PPL Corporation*, every electric company covered in this Issue owns nuclear plants—at the utility level, a nonutility subsidiary, or both. Companies with regulated nuclear plants are in the best position because these units are not affected by unfavorable conditions in the power markets. On the other hand, many nonutility nuclear plants without power contracts (i.e., merchant plants) have seen their margins squeezed in recent years due to low prices of natural gas, subsidized renewable energy, and weak demand for power. Some facilities are even losing money. The most worrisome situation of all is the construction of nuclear units, which has been plagued by significant delays and cost overruns.

Duke Energy, which has utility-owned plants solely, is in the most stable situation, although the company took a modest charge in the third quarter to write off the costs it incurred for a possible new unit. *NextEra Energy* has both regulated and nonregulated nuclear facilities. Its nonregulated units have not faced severe market problems, and the company is in a good position. On the other hand, nonregulated plants owned by *Exelon* and *FirstEnergy* have been hurt by poor market conditions for the past several years, which weakened each company's earning power to the point where the board decided to cut the dividend. *Dominion Energy* and *Public Service Enterprise Group* are also experiencing challenges, but these are much less severe. In order to address unfavorable market conditions that do not recognize the environmental benefits of nuclear plants (no carbon emissions), Illinois and New York have enacted laws or regulations that provide zero-emissions credits for nuclear facilities. These subsidies should help, although they are not a cure-all. Connecticut just passed a law allowing the Millstone plant (owned by Dominion) to bid into markets along with other nonemitting sources of power. So far, Ohio, Pennsylvania, and New Jersey have not passed similar laws. (*Exelon* has said it will shut the Three Mile Island plant in Pennsylvania if legislation is not enacted.) There is also the possibility of changes at the federal level (from the Federal Energy Regulatory Commission) that would be favorable for owners of merchant nuclear plants.

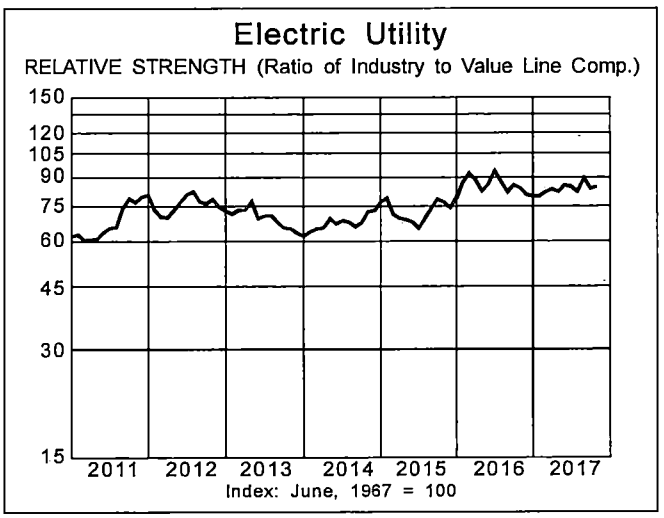
Several years ago, electric utility subsidiaries of *Southern Company* (Georgia Power) and *SCANA* (South Carolina Electric & Gas) each started building two units at the site of an existing nuclear plant. These projects had extensive delays and cost overruns that led to the bankruptcy filing of the contractor, Westinghouse. The utilities have moved in different directions. SCE&G canceled construction of the project. The utility has come under much criticism since then, and although it believes it is entitled to a return on its investment under state law, this is in question. Georgia Power, a larger utility with a larger parent company, intends to proceed with construction. Its plan requires the go-ahead from the state commission, however. More information on each of these situations is available in our full-page reports on *Southern Company* and *SCANA* in this Issue.

Conclusion

Most electric utility stocks have performed very well in 2017. Price increases of more than 10% are the rule, not the exception. Despite interest-rate increases from the Federal Reserve (and the expectation of more to come), interest rates are still low, by historical standards, and yields on money-market funds, CDs, and savings accounts remain low enough to be unappealing to some income-oriented investors. Electric utility stocks appeal to these accounts thanks to their above-average dividend yields. Indeed, even at a historically low average yield of 3.3%, this figure is still more than a percentage point above the median of all dividend-paying issues under our coverage. Another positive factor for stock prices is takeover speculation. Several deals (mostly involving mid-cap utilities) have occurred in recent years. Most stocks in the Electric Utility Industry are trading within their 2020-2022 Target Price Range, and some are *above* this range.

AVANGRID has been one of the top performers this year, having risen more than 30%. We think takeover speculation can be credited. Another top performer is Avista (covered in Issue 11). The company has accepted a takeover offer from a Canadian utility. *NextEra Energy* has seen its stock price rise over 30%, as the company's solid performance and presence in renewable energy have attracted investors. On the other hand, the price of *SCANA* stock has plummeted nearly 40% due to the aforementioned nuclear problems. PG&E Corporation (covered in Issue 11) has seen its share price decline modestly due to concern that its utility caused or contributed to recent wildfires in northern California. The price of Westar stock (covered in Issue 5) has fallen because its revised deal with Great Plains Energy is not as lucrative as the initial transaction that failed to win regulatory approval.

Paul E. Debbas, CFA



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From time to time, we discuss regulatory climates and provide a list showing each state's regulatory climate, plus that of the Federal Energy Regulatory Commission (FERC).

California is trying to resolve regulatory and legal matters associated with wildfires in the state.

Most electric utility stocks have lost value so far this year. This does not mean that the group is cheap, however.

INDUSTRY TIMELINESS: 77 (of 97)

Ranking The Regulators

Occasionally, *The Value Line Investment Survey* presents its rankings of regulatory climates for most states, the District of Columbia, and the Federal Energy Regulatory Commission (FERC). Each utility (even those in states that have deregulated the power-generation function) is still subject to regulatory oversight of their transmission and distribution operations. Every utility will need to deal with a regulatory commission at some point to place new plant in the rate base, recover increased expenses, or make changes in rate design (i.e., the levels of rates among customer classes and the proportion of customers' bills that comes from fixed monthly charges).

A state's regulatory environment is a key factor in our rankings, but is not the only one. The governor, legislature, and courts also play a role. For instance, California is dealing with problems associated with a state law that can increase a utility's liability for wildfires. (We discuss this matter later in this report.) The legislature and governor will likely have a bigger impact on this law than the commission will.

Note that the table below does not include some states because we do not cover a utility that serves that state or because investor-owned utilities have virtually no presence in the state. These are Nebraska, Nevada, Rhode Island, Tennessee, Utah, and Vermont. Washington and Alaska will probably be removed from the table if the pending takeover of *Avista* by Hydro One, a Canadian company, is completed.

• *Above Average:* Alabama, Alaska, Colorado, Georgia, Idaho, Indiana, Massachusetts, Ohio, South Carolina, Wisconsin, FERC.

• *Average:* Arizona, California, Delaware, Florida, Iowa, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, New Hampshire, New Jersey, North Carolina, North Dakota, Oklahoma, Oregon, Pennsylvania, South Dakota, Texas, Virginia, Washington, Wyoming.

• *Below Average:* Arkansas, Connecticut, District of Columbia, Hawaii, Illinois, Maryland, Missouri, Montana, New Mexico, New York, West Virginia.

Since we last ran this table, in July of 2017, we have lowered the regulatory climate of Montana from Average to Below Average. Most recent rulings in the state have not been good for *NorthWestern*. In fact, the company's chief executive officer has mentioned this problem in recent conference calls for quarterly earnings. We are still keeping an eye on Oklahoma for a possible downgrade, since the latest rate orders in the state have been disappointing for utilities there. On the other hand, we continue to consider Illinois and Michigan for possible upgrades.

Wildfires In California

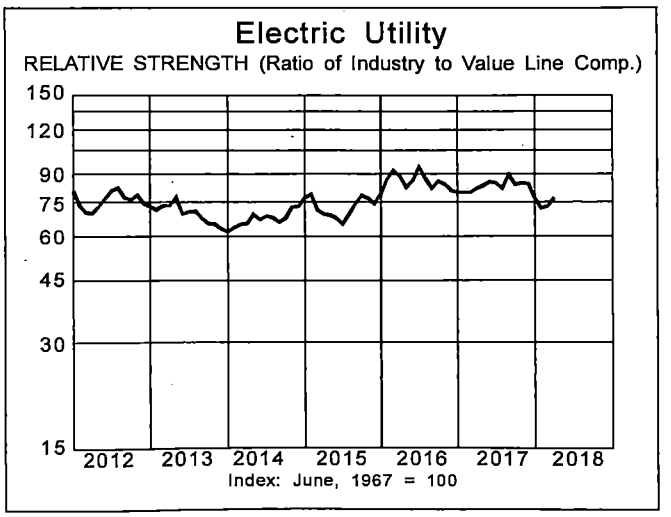
The three California-based companies reviewed in this Issue (*PG&E*, *Edison International*, and *Sempra Energy*) are concerned about adverse legal and regulatory outcomes associated with wildfires in the Golden State. Pacific Gas and Electric (a subsidiary of *PG&E*) and Southern California Edison (a subsidiary of *Edison International*) had wildfires in their service areas in 2017. The companies' stocks fell sharply last year due to investors' worries about a possibly huge liability stemming from the state's inverse condemnation law, which holds that utilities may be held liable for damages caused by their power lines, even if they followed established inspection and safety procedures. *PG&E* suspended its common and preferred dividends, too. Also in 2017, San Diego Gas & Electric (a subsidiary of *Sempra*) took a charge for costs associated with a wildfire 10 years earlier after the regulators ruled that the utility may not pass these costs through to their ratepayers. The utilities are trying to find a solution to the inverse condemnation problem through the legislature, the commission, and the courts.

Conclusion

So far in 2018, most stocks covered in the Electric Utility Industry have declined in price. This is partly due to reversion to the mean, following a stellar performance for most of these equities in 2017, and partly due to the rise in interest rates (and the market's expectation that these will climb further). Even after the pullback this year, these issues are not cheap. Many are still trading within their 2021-2023 Target Price Range.

Since Issue 11 came out three months ago, we decided to change the way we treat credits or charges that most utilities took in the fourth period of 2017 for the effects of the new federal tax law. We are now *excluding* these from our earnings presentations.

Paul E. Debbas, CFA



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We look back at 2017 and look forward to 2018. The new year has brought changes in federal tax laws.

The potentially high liability for wildfires is concerning to electric utilities in California.

After a strong showing last year, electric utility equities have given back some of their gains in early 2018. However, they have hardly become cheap.

INDUSTRY TIMELINESS: 3 (of 97)

A Look Back At 2017 And A Look Ahead To 2018

The year that just ended was a good one for the Electric Utility Industry as a whole. The prices of most stocks didn't just rise, they rose more than 10%. Investors continued to "reach for yield" in an environment of low interest rates. Merger and acquisition activity (and speculation) also sent share prices higher. Among the standout performers were *Avista*, which rose 29% because the company agreed to be acquired. Two utilities covered in Issue 1, AVANGRID and NextEra Energy, advanced over 30%. For the former company, we attribute this to takeover speculation; for the latter, simply a strong performance.

On the other hand, the prices of a few electric utility equities fell sharply last year. *PG&E Corporation* and *Edison International* were hurt by the market's worries about possibly huge liabilities resulting from wildfires in California in 2017. (We discuss this matter in the next section.) SCANA (reviewed in Issue 1) lost 46% of its value due to the cancelation of its nuclear construction project, which faced significant delays and cost overruns. These were the exceptions to the rule.

Ironically, in early 2018 SCANA stock was the top performer in the industry. The company agreed to a takeover by Dominion Energy (also covered in Issue 1). Otherwise, the new year has seen declines in most issues. We suspect some investors are locking in profits. Perhaps the expectation of rate hikes by the Federal Reserve is also weighing on stock prices in this industry.

This year might well see additional merger and acquisition activity. Besides the deals mentioned above, the proposed combination of Great Plains Energy and Westar Energy (reviewed in Issue 5) is expected to be completed in 2018.

Changes in federal tax laws require a discussion. Most companies are still evaluating the effects of the new law, and might not make any public statements about it until they release fourth-quarter earnings in February (for most companies). For the regulated utility business, whatever benefits the companies receive from lower taxes will be passed through to customers—the only real question is how, and over which time frame. However, some utilities have nonutility siblings under the umbrella of their parent companies, and these should benefit from tax reform. *Hawaiian Electric Industries*, with its American Savings Bank subsidiary, is an example. Another consideration is the deferred tax assets and liabilities on companies' balance sheets. For those that did not arise from the regulated operations, there will be one-time, noncash gains or losses for the fourth quarter of 2017. We will *include* these in our earnings presentation. So far, CenterPoint Energy (covered in Issue 5) and AVANGRID (covered in Issue 1) have stated that this will be positive, but *Sempra Energy* and *Xcel Energy* will take charges against December-period results. *Sempra* also expects some negative effects associated with its foreign operations.

Wildfires In California

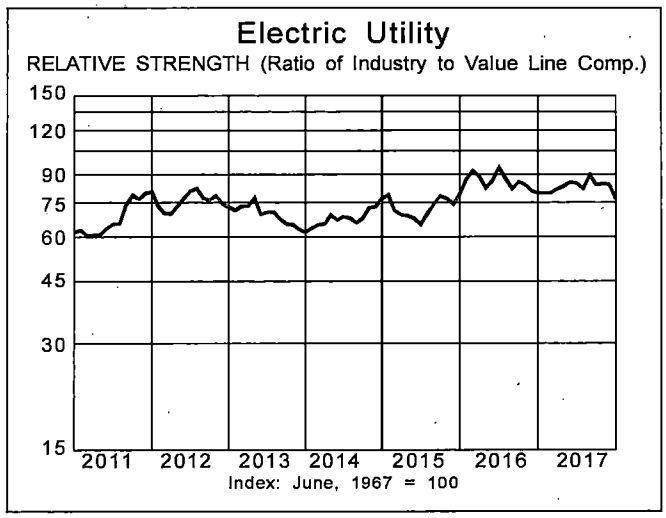
In 2017, wildfires in California affected the service areas of the utilities owned by *PG&E Corporation* and *Edison International*. The causes of the fires have not yet been determined, but the market is worried that the utilities will be found liable due to the effects their power lines might have had on the wildfires. Under the state's inverse condemnation law, this may occur even if the company complied with established inspection and safety rules. The possibly huge liability prompted the board of directors of *PG&E* to suspend common and preferred dividends. (By contrast, the board of *Edison International* raised the disbursement.) Changes to these laws might come, but at this point, no bills to address this problem have been introduced in the California legislature. And even if the law is changed, there is no assurance that this will apply to the wildfires of last year.

Another question is whether utilities will be allowed to pass costs of restoration and repair through to customers. Last year, the California regulators ruled that San Diego Gas & Electric (a subsidiary of *Sempra*) may not do so in connection with a 2007 wildfire. This forced the company to write off a regulatory asset in the third quarter of 2017.

Conclusion

Although electric utility equities have not performed well so far in 2018, their valuations are still high, by historical standards. The average dividend yield of stocks in this industry is 3.6%. Moreover, many of these issues are still trading within their 2020-2022 Target Price Range. Accordingly, the group's average annual total return potential over that time frame is just 4%.

Paul E. Debbas, CFA



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WESTAR ENERGY NYSE-WR

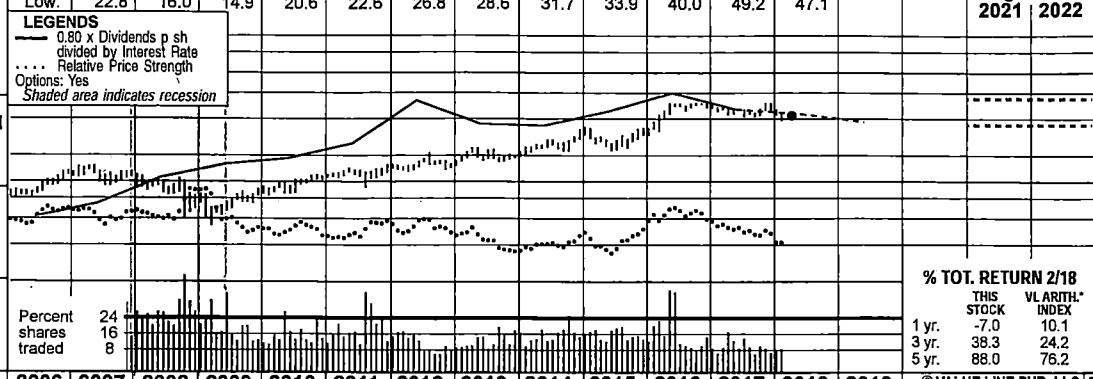
RECENT PRICE 49.72 | P/E RATIO 20.1 (Trailing: 21.9 Median: 16.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS — Suspended 6/10/16
SAFETY 2 Raised 4/1/05
TECHNICAL — Suspended 6/10/16
BETA .70 (1.00 = Market)

High:	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0	57.5	57.3	53.3
Low:	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40.0	49.2	47.1

Target Price Range 2021 | 2022 | 2023

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	6	0	0	0	0	0	16
to Sell	0	0	0	4	0	0	5	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	130	164	141
to Sell	201	146	130
Hld's(000)	118673	118474	107206

Percent shares traded 24 16 8

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.0	10.1
3 yr.	38.3	24.2
5 yr.	88.0	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	17.40	18.07	18.09	*18.60*	*18.95*	Revenues per sh	*20.70*
4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	4.26	4.83	4.90	*5.30*	*5.65*	"Cash Flow" per sh	*6.75*
1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	2.09	2.43	2.27	*2.60*	*2.80*	Earnings per sh A	*3.45*
1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	1.44	1.52	1.60	*1.60*	*1.68*	Div'd Decl'd per sh B■†	*1.92*
1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	4.95	7.67	5.38	*6.50*	*6.75*	Cap'l Spending per sh	*7.50*
13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	25.87	26.84	27.50	*28.35*	*29.10*	Book Value per sh C	*31.60*
71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	141.35	141.79	142.09	*142.50*	*143.00*	Common Shs Outst'g E	*145.00*
14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	18.5	21.6	23.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	.93	1.13	1.15	*Value Line*		Relative P/E Ratio	*.85*
8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	3.7%	2.9%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $3963.3 mill. **Due in 5 Yrs** $725 mill.
LT Debt $3687.6 mill. **LT Interest** $170.0 mill.
(LT interest earned: 3.8x)

Pension Assets 12/17 $719 mill. **Oblig.** $1.1 bill.

Pfd Stock None

Common Stock 142,094,275 shs.
MARKET CAP: $7.1 billion (Large Cap)

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		21-23
1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	2459.2	2562.1	2571.0	*2650*	*2710*	Revenues ($mill)	*3000*
136.8	141.3	203.9	214.0	275.1	292.5	313.3	291.9	346.6	323.9	*370*	*400*	Net Profit ($mill)	*500*
24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	33.5%	33.8%	31.0%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
--	--	--	--	--	--	--	10.4%	10.4%	*10.0%*	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	47.5%	47.9%	51.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	52.5%	52.1%	49.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	6958.8	7305.8	7595.7	*7750*	*7850*	Total Capital ($mill)	*8225*
5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	8793.1	9506.3	9553.8	*9700*	*9800*	Net Plant ($mill)	*10500*
4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	5.3%	5.7%	4.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	8.0%	9.1%	8.3%	*9.0%*	*9.5%*	Return on Shr. Equity	*11.0%*
6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	8.0%	9.1%	8.3%	*9.0%*	*9.5%*	Return on Com Equity D	*11.0%*
1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	2.9%	3.7%	2.4%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
80%	87%	63%	65%	57%	56%	55%	69%	63%	70%	*62%*	*60%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.5	+3.5	-1.3
Avg. Indust. Use (MWH)	5654	5781	5689
Avg. Indust. Revs. per KWH (¢)	6.68	6.77	6.71
Capacity at Peak (Mw)	7187	7523	7834
Peak Load, Summer (Mw)	5167	5184	5242
Annual Load Factor (%)	56.1	56.4	56.8
% Change Customers (yr-end)	+.2	+.3	+.6
Fixed Charge Cov. (%)	330	335	305

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	0.5%	1.0%	*2.5%*
"Cash Flow"	3.0%	3.0%	*6.5%*
Earnings	4.0%	7.0%	*7.5%*
Dividends	5.0%	3.0%	*4.0%*
Book Value	4.5%	4.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	590.8	589.6	732.8	546.0	2459.2
2016	569.5	621.4	764.7	606.5	2562.1
2017	572.6	609.3	794.3	594.8	2571.0
2018	*590*	*620*	*800*	*640*	*2650*
2019	*600*	*640*	*815*	*655*	*2710*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.38	.46	.97	.28	2.09
2016	.46	.51	1.08	.38	2.43
2017	.42	.50	1.11	.24	2.27
2018	*.50*	*.58*	*1.15*	*.37*	*2.60*
2019	*.54*	*.63*	*1.22*	*.41*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	1.43
2016	.38	.38	.38	.38	1.52
2017	.40	.40	.40	.40	1.60
2018	.40				

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 708,000 customers mostly in Kansas. 2017 Electric revenue sources: residential and rural, 32%; commercial and business, 28%; industrial, 16%; other, 24%. The company sold its investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2017 depreciation rate: 2.5%. Estimated plant age: 17 years. Fuels: coal, 41%; nuclear, 7%; gas, 30%; renewable, 22%. Has 2,205 employees. Chief Executive Officer and President: Mark A. Ruelle. Chairman: Charles Q. Chandler. Incorporated: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

The proposed merger of equals between Westar Energy and Great Plains Energy is on track to close in the first half of 2018. Under the agreement, no premium would be paid and no cash would be exchanged with respect to either entity. A holding company would be created in which Westar stockholders receive one share for each of their current shares, and Great Plains stockholders receive 0.5981 shares for each share that they own. The tax-free transaction has been approved by each company's stockholders and is expected to be finalized in May or June. In addition, settlements have been reached in Missouri and Kansas. Approval from the state commissions are expected in the coming weeks.

We continue to advise investors to hold their shares. The companies are targeting average annual earnings and dividend growth of 6%-8%, with a targeted payout ratio of 60%-70%. The utilities also expect to save $550 million in the first five years upon completion of the deal, and $140 million to $170 million annually thereafter. If the transaction fails to win regulatory approval, Westar would receive a $190 million termination fee from GXP.

The combined entity expects to set its initial dividend at a level that maintains the current payout for Great Plains stockholders. This would result in an increase of about 15% for Westar stockholders.

The new tax legislation will not have a material impact on earnings. In February, Westar asked the Kansas Corporation Commission to update its prices and reduce rates by approximately $74 million, which is the amount it expects to save each year under the new tax law. The company's request also included $11 million of initial savings in contemplation of its proposed merger with Great Plains Energy, and $29 million in savings achieved from refinancing debt. A decision by the KCC on all matters is due in September.

This stock is unranked for Timeliness due to the pending transaction. Although state regulators blocked the initial merger between Westar and Great Plains, the revised accord has been altered to appeal to all parties involved. Thus, we expect the deal to proceed as planned.

Daniel Henigson *March 16, 2018*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next earnings report due early May.
(B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2017: $5.66/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '17: 10.0%; earned on avg. com. eq., '17: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	85

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ALLETE, Inc. (ALE)

Date	High	Low	Close
5/8/2017	$ 70.32	$ 68.47	$ 69.36
5/15/2017	$ 69.88	$ 68.12	$ 69.26
5/22/2017	$ 73.52	$ 68.62	$ 73.15
5/29/2017	$ 74.55	$ 72.57	$ 74.11
6/5/2017	$ 74.34	$ 72.64	$ 74.27
6/12/2017	$ 74.59	$ 72.36	$ 73.02
6/19/2017	$ 73.79	$ 72.83	$ 73.37
6/26/2017	$ 74.01	$ 71.60	$ 71.68
7/3/2017	$ 72.20	$ 70.55	$ 71.26
7/10/2017	$ 71.67	$ 69.79	$ 70.29
7/17/2017	$ 73.53	$ 69.90	$ 73.45
7/24/2017	$ 73.76	$ 71.69	$ 72.57
7/31/2017	$ 75.12	$ 72.31	$ 73.98
8/7/2017	$ 75.17	$ 73.08	$ 73.30
8/14/2017	$ 75.26	$ 72.86	$ 75.07
8/21/2017	$ 77.02	$ 74.70	$ 76.81
8/28/2017	$ 77.73	$ 76.68	$ 77.52
9/4/2017	$ 79.27	$ 77.31	$ 79.14
9/11/2017	$ 79.61	$ 77.00	$ 78.41
9/18/2017	$ 78.35	$ 76.88	$ 76.91
9/25/2017	$ 78.16	$ 76.55	$ 77.29
10/2/2017	$ 78.85	$ 76.55	$ 78.31
10/9/2017	$ 79.69	$ 77.98	$ 78.38
10/16/2017	$ 79.54	$ 77.58	$ 78.93
10/23/2017	$ 79.85	$ 77.89	$ 79.69
10/30/2017	$ 80.00	$ 76.76	$ 76.93
11/6/2017	$ 77.74	$ 75.20	$ 76.34
11/13/2017	$ 78.59	$ 76.02	$ 77.50
11/20/2017	$ 78.69	$ 77.03	$ 78.18
11/27/2017	$ 80.93	$ 77.52	$ 80.21
12/4/2017	$ 81.24	$ 78.19	$ 79.33
12/11/2017	$ 79.50	$ 76.70	$ 77.90
12/18/2017	$ 78.53	$ 73.40	$ 73.45
12/25/2017	$ 74.97	$ 72.96	$ 74.36
1/1/2018	$ 74.42	$ 72.53	$ 73.55
1/8/2018	$ 74.13	$ 72.14	$ 73.00
1/15/2018	$ 74.04	$ 71.80	$ 71.98
1/22/2018	$ 73.97	$ 71.85	$ 72.84
1/29/2018	$ 72.63	$ 70.26	$ 70.42
2/5/2018	$ 70.64	$ 66.64	$ 69.89
2/12/2018	$ 69.97	$ 67.20	$ 69.34
2/19/2018	$ 69.98	$ 67.56	$ 69.98
2/26/2018	$ 70.06	$ 67.88	$ 68.58
3/5/2018	$ 68.72	$ 67.07	$ 68.08
3/12/2018	$ 71.20	$ 68.06	$ 71.07
3/19/2018	$ 72.61	$ 70.06	$ 70.12
3/26/2018	$ 72.80	$ 70.13	$ 72.25
4/2/2018	$ 72.66	$ 70.40	$ 71.72
4/9/2018	$ 72.65	$ 71.04	$ 71.67
4/16/2018	$ 74.78	$ 71.88	$ 73.10
4/23/2018	$ 77.44	$ 73.11	$ 77.08
4/30/2018	$ 79.86	$ 75.72	$ 79.62
5/7/2018	$ 79.40	$ 78.34	$ 78.86
Min	$ 68.72	**$ 66.64**	$ 68.08
Max	**$ 81.24**	$ 78.34	$ 80.21
Mean	$ 75.32	$ 72.90	**$ 74.28**

Source: YahooFinance.com

Growth Estimates	ALE
Current Qtr.	1.00%
Next Qtr.	N/A
Current Year	6.90%
Next Year	7.90%
Next 5 Years (per annum)	**6.00%**
Past 5 Years (per annum)	3.82%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	1.50%	3.50%
Past 5 Year	5.50%	3.00%
Est '15-'17 to '21-'23	**4.50%**	**4.50%**

March 16, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.14	$ 2.24	**$ 2.34**	$ 2.70

March 16, 2018 Value-Line

ALLETE, Inc. | Consensus	Mean	Median	High	Low	Analysts
LT Growth (%)	**6.9**	6.9	7.8	6	2

Source: SNL/S&P Global

Alliant Energy Corp. (LNT)

Date	High	Low	Close
5/8/2017	$ 40.14	$ 39.13	$ 39.61
5/15/2017	$ 40.00	$ 39.33	$ 39.75
5/22/2017	$ 41.64	$ 39.63	$ 41.36
5/29/2017	$ 41.91	$ 41.18	$ 41.83
6/5/2017	$ 41.85	$ 40.95	$ 41.26
6/12/2017	$ 42.19	$ 41.00	$ 42.18
6/19/2017	$ 42.18	$ 41.37	$ 41.45
6/26/2017	$ 41.93	$ 40.16	$ 40.17
7/3/2017	$ 40.36	$ 39.54	$ 39.71
7/10/2017	$ 40.21	$ 39.36	$ 39.97
7/17/2017	$ 41.39	$ 39.81	$ 41.38
7/24/2017	$ 41.66	$ 40.31	$ 40.47
7/31/2017	$ 41.40	$ 40.31	$ 41.09
8/7/2017	$ 41.75	$ 41.03	$ 41.37
8/14/2017	$ 42.32	$ 41.38	$ 42.24
8/21/2017	$ 43.09	$ 42.17	$ 42.87
8/28/2017	$ 43.23	$ 42.54	$ 42.57
9/4/2017	$ 43.24	$ 42.56	$ 43.19
9/11/2017	$ 43.69	$ 42.27	$ 42.90
9/18/2017	$ 42.91	$ 41.72	$ 41.73
9/25/2017	$ 42.32	$ 41.16	$ 41.57
10/2/2017	$ 42.14	$ 41.05	$ 41.92
10/9/2017	$ 43.46	$ 41.84	$ 43.05
10/16/2017	$ 43.97	$ 42.78	$ 43.87
10/23/2017	$ 43.95	$ 42.72	$ 43.75
10/30/2017	$ 44.39	$ 42.88	$ 43.83
11/6/2017	$ 44.29	$ 43.51	$ 43.68
11/13/2017	$ 45.55	$ 43.69	$ 44.40
11/20/2017	$ 44.49	$ 44.01	$ 44.22
11/27/2017	$ 45.38	$ 44.11	$ 44.83
12/4/2017	$ 45.22	$ 43.96	$ 44.94
12/11/2017	$ 45.10	$ 43.56	$ 44.43
12/18/2017	$ 44.37	$ 42.18	$ 42.50
12/25/2017	$ 42.97	$ 42.18	$ 42.61
1/1/2018	$ 42.72	$ 40.92	$ 41.08
1/8/2018	$ 41.58	$ 39.49	$ 39.53
1/15/2018	$ 40.17	$ 39.33	$ 39.41
1/22/2018	$ 40.54	$ 39.45	$ 40.30
1/29/2018	$ 40.18	$ 38.46	$ 38.91
2/5/2018	$ 39.34	$ 36.84	$ 38.42
2/12/2018	$ 39.81	$ 37.89	$ 39.75
2/19/2018	$ 39.70	$ 38.01	$ 39.42
2/26/2018	$ 39.82	$ 37.85	$ 38.22
3/5/2018	$ 38.99	$ 37.91	$ 38.71
3/12/2018	$ 40.22	$ 38.75	$ 40.13
3/19/2018	$ 40.58	$ 39.38	$ 39.45
3/26/2018	$ 41.04	$ 39.43	$ 40.86
4/2/2018	$ 41.45	$ 40.34	$ 41.02
4/9/2018	$ 41.36	$ 40.38	$ 41.11
4/16/2018	$ 42.30	$ 41.23	$ 41.54
4/23/2018	$ 43.13	$ 41.45	$ 43.06
4/30/2018	$ 43.47	$ 42.04	$ 43.27
5/7/2018	$ 43.29	$ 42.84	$ 42.94
Min	$ 38.99	**$ 36.84**	$ 38.22
Max	**$ 45.55**	$ 44.11	$ 44.94
Mean	$ 42.16	$ 40.89	**$ 41.58**

Source: YahooFinance.com

Growth Estimates	LNT
Current Qtr.	13.60%
Next Qtr.	4.90%
Current Year	9.30%
Next Year	6.60%
Next 5 Years (per annum)	**5.80%**
Past 5 Years (per annum)	4.13%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	5.00%	7.50%
Past 5 Year	6.50%	6.50%
Est '15-'17 to '21-'23	**6.50%**	**6.00%**

March 16, 2018 Value-Line

	2017	2018	2019	'21-'23
Dividends per Share	$ 1.26	$ 1.34	**$ 1.42**	$ 1.66

March 16, 2018 Value-Line

Alliant Energy Corporation | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**5.93**	6	6	5.73	4

Source: SNL/S&P Global

Ameren Corp. (AEE)

Date	High	Low	Close
5/8/2017	$ 55.09	$ 53.87	$ 54.93
5/15/2017	$ 55.88	$ 54.22	$ 55.60
5/22/2017	$ 57.09	$ 55.21	$ 56.15
5/29/2017	$ 57.21	$ 55.87	$ 57.17
6/5/2017	$ 57.21	$ 55.87	$ 56.29
6/12/2017	$ 57.08	$ 55.80	$ 57.08
6/19/2017	$ 57.16	$ 55.84	$ 55.94
6/26/2017	$ 56.64	$ 54.38	$ 54.67
7/3/2017	$ 54.92	$ 53.54	$ 54.14
7/10/2017	$ 54.63	$ 53.59	$ 54.43
7/17/2017	$ 56.58	$ 54.18	$ 56.53
7/24/2017	$ 56.67	$ 55.60	$ 56.16
7/31/2017	$ 57.65	$ 56.02	$ 57.50
8/7/2017	$ 58.75	$ 57.55	$ 57.95
8/14/2017	$ 59.75	$ 57.91	$ 59.21
8/21/2017	$ 60.58	$ 59.06	$ 60.37
8/28/2017	$ 60.79	$ 59.56	$ 59.80
9/4/2017	$ 60.28	$ 59.31	$ 60.09
9/11/2017	$ 60.91	$ 58.59	$ 59.81
9/18/2017	$ 59.85	$ 58.34	$ 58.51
9/25/2017	$ 59.78	$ 57.56	$ 57.84
10/2/2017	$ 58.90	$ 57.67	$ 58.78
10/9/2017	$ 60.74	$ 58.80	$ 60.41
10/16/2017	$ 61.74	$ 60.13	$ 61.56
10/23/2017	$ 61.96	$ 60.52	$ 61.80
10/30/2017	$ 62.83	$ 61.48	$ 62.19
11/6/2017	$ 63.15	$ 61.95	$ 62.48
11/13/2017	$ 64.89	$ 62.54	$ 63.30
11/20/2017	$ 63.66	$ 62.62	$ 62.98
11/27/2017	$ 64.36	$ 62.96	$ 63.75
12/4/2017	$ 64.02	$ 62.06	$ 63.19
12/11/2017	$ 63.71	$ 60.32	$ 60.94
12/18/2017	$ 61.22	$ 58.29	$ 58.69
12/25/2017	$ 59.44	$ 58.28	$ 58.99
1/1/2018	$ 59.03	$ 57.23	$ 57.39
1/8/2018	$ 58.09	$ 55.42	$ 55.52
1/15/2018	$ 55.94	$ 54.83	$ 55.16
1/22/2018	$ 57.09	$ 55.26	$ 56.92
1/29/2018	$ 56.74	$ 54.77	$ 54.89
2/5/2018	$ 55.72	$ 51.89	$ 55.42
2/12/2018	$ 56.85	$ 54.32	$ 56.32
2/19/2018	$ 56.39	$ 54.23	$ 56.35
2/26/2018	$ 56.46	$ 53.47	$ 54.03
3/5/2018	$ 55.32	$ 53.08	$ 53.99
3/12/2018	$ 55.64	$ 53.88	$ 55.49
3/19/2018	$ 55.96	$ 53.91	$ 54.01
3/26/2018	$ 56.79	$ 54.10	$ 56.63
4/2/2018	$ 57.92	$ 56.15	$ 57.13
4/9/2018	$ 57.55	$ 55.01	$ 55.51
4/16/2018	$ 57.49	$ 55.67	$ 56.27
4/23/2018	$ 58.72	$ 56.30	$ 58.60
4/30/2018	$ 59.18	$ 57.65	$ 58.90
5/7/2018	$ 58.98	$ 58.44	$ 58.54
Min	$ 54.63	**$ 51.89**	$ 53.99
Max	**$ 64.89**	$ 62.96	$ 63.75
Mean	$ 58.70	$ 56.89	**$ 57.85**

Source: YahooFinance.com

Growth Estimates	AEE
Current Qtr.	38.10%
Next Qtr.	N/A
Current Year	7.10%
Next Year	5.60%
Next 5 Years (per annum)	**6.30%**
Past 5 Years (per annum)	13.47%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	-1.00%	-4.00%
Past 5 Year	0.50%	2.00%
Est '15-'17 to '21-'23	**7.50%**	**4.50%**

March 16, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 1.78	$ 1.85	**$ 1.93**	$ 2.25

March 16, 2018 Value-Line

Ameren Corporation | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**6.28472**	6.28472	6.56943	6	2

Source: SNL/S&P Global

American Electric Power Co. (AEP)

Date	High	Low	Close
5/8/2017	$ 68.30	$ 66.93	$ 68.06
5/15/2017	$ 68.89	$ 67.81	$ 68.72
5/22/2017	$ 71.01	$ 68.60	$ 70.87
5/29/2017	$ 72.72	$ 70.70	$ 72.67
6/5/2017	$ 72.71	$ 71.37	$ 71.86
6/12/2017	$ 72.59	$ 71.05	$ 72.42
6/19/2017	$ 72.97	$ 71.43	$ 71.55
6/26/2017	$ 72.20	$ 69.19	$ 69.47
7/3/2017	$ 69.69	$ 68.47	$ 69.15
7/10/2017	$ 69.53	$ 68.11	$ 68.17
7/17/2017	$ 69.99	$ 68.12	$ 69.98
7/24/2017	$ 70.81	$ 68.59	$ 70.43
7/31/2017	$ 71.20	$ 70.03	$ 70.88
8/7/2017	$ 71.61	$ 70.37	$ 70.56
8/14/2017	$ 72.63	$ 70.46	$ 72.16
8/21/2017	$ 73.77	$ 72.13	$ 73.57
8/28/2017	$ 74.29	$ 73.27	$ 73.54
9/4/2017	$ 74.37	$ 73.24	$ 74.19
9/11/2017	$ 74.59	$ 72.29	$ 73.03
9/18/2017	$ 73.11	$ 70.44	$ 70.57
9/25/2017	$ 71.21	$ 69.93	$ 70.24
10/2/2017	$ 71.63	$ 69.55	$ 71.53
10/9/2017	$ 73.91	$ 71.45	$ 73.16
10/16/2017	$ 73.99	$ 72.52	$ 73.98
10/23/2017	$ 74.90	$ 72.53	$ 74.02
10/30/2017	$ 74.92	$ 73.57	$ 74.08
11/6/2017	$ 75.84	$ 73.56	$ 74.78
11/13/2017	$ 77.93	$ 74.70	$ 76.38
11/20/2017	$ 77.06	$ 76.02	$ 76.47
11/27/2017	$ 77.97	$ 76.45	$ 77.24
12/4/2017	$ 78.07	$ 75.86	$ 76.93
12/11/2017	$ 77.22	$ 75.77	$ 76.54
12/18/2017	$ 76.91	$ 73.62	$ 73.65
12/25/2017	$ 74.00	$ 72.94	$ 73.57
1/1/2018	$ 73.42	$ 70.31	$ 70.80
1/8/2018	$ 71.53	$ 67.23	$ 67.46
1/15/2018	$ 68.59	$ 67.11	$ 67.76
1/22/2018	$ 69.80	$ 68.04	$ 68.75
1/29/2018	$ 68.98	$ 67.52	$ 67.75
2/5/2018	$ 68.42	$ 63.32	$ 64.72
2/12/2018	$ 67.52	$ 64.19	$ 67.26
2/19/2018	$ 67.50	$ 65.43	$ 67.37
2/26/2018	$ 67.76	$ 64.60	$ 65.18
3/5/2018	$ 66.72	$ 64.65	$ 65.65
3/12/2018	$ 67.92	$ 65.57	$ 67.81
3/19/2018	$ 68.34	$ 66.25	$ 66.39
3/26/2018	$ 69.24	$ 66.56	$ 68.59
4/2/2018	$ 69.42	$ 67.69	$ 68.53
4/9/2018	$ 69.14	$ 66.46	$ 67.34
4/16/2018	$ 69.67	$ 67.42	$ 68.46
4/23/2018	$ 70.98	$ 68.19	$ 70.55
4/30/2018	$ 70.81	$ 68.52	$ 69.39
5/7/2018	$ 69.45	$ 68.64	$ 68.78
Min	$ 66.72	**$ 63.32**	$ 64.72
Max	**$ 78.07**	$ 76.45	$ 77.24
Mean	$ 71.84	$ 69.79	**$ 70.81**

Source: YahooFinance.com

Growth Estimates	AEP
Current Qtr.	13.30%
Next Qtr.	6.40%
Current Year	5.70%
Next Year	5.90%
Next 5 Years (per annum)	**5.79%**
Past 5 Years (per annum)	4.92%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	3.00%	4.00%
Past 5 Year	5.50%	4.50%
Est '15-'17 to '21-'23	**4.50%**	**5.00%**

March 16, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.39	$ 2.51	**$ 2.63**	$ 3.05

March 16, 2018 Value-Line

American Electric Power Company, Inc. | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**5.37**	5.8	6	3	9

Source: SNL/S&P Global

Consolidated Edison, Inc. (ED)

Date	High	Low	Close
5/8/2017	$ 80.08	$ 78.69	$ 79.90
5/15/2017	$ 80.38	$ 78.96	$ 80.37
5/22/2017	$ 82.40	$ 80.10	$ 82.10
5/29/2017	$ 83.99	$ 81.87	$ 83.53
6/5/2017	$ 83.95	$ 82.48	$ 83.25
6/12/2017	$ 85.04	$ 82.51	$ 84.85
6/19/2017	$ 85.13	$ 83.73	$ 83.84
6/26/2017	$ 84.58	$ 80.67	$ 80.82
7/3/2017	$ 81.28	$ 80.04	$ 80.53
7/10/2017	$ 81.22	$ 80.04	$ 80.73
7/17/2017	$ 82.98	$ 80.49	$ 82.93
7/24/2017	$ 82.98	$ 81.24	$ 82.38
7/31/2017	$ 83.62	$ 82.15	$ 82.80
8/7/2017	$ 84.16	$ 82.51	$ 82.87
8/14/2017	$ 84.07	$ 82.04	$ 83.53
8/21/2017	$ 84.87	$ 83.31	$ 84.48
8/28/2017	$ 84.92	$ 83.76	$ 83.99
9/4/2017	$ 85.68	$ 83.82	$ 85.53
9/11/2017	$ 86.16	$ 83.44	$ 84.44
9/18/2017	$ 84.55	$ 81.58	$ 81.59
9/25/2017	$ 82.35	$ 80.02	$ 80.68
10/2/2017	$ 81.93	$ 80.26	$ 81.56
10/9/2017	$ 84.09	$ 81.40	$ 83.08
10/16/2017	$ 85.08	$ 82.28	$ 84.86
10/23/2017	$ 86.33	$ 84.24	$ 85.92
10/30/2017	$ 87.58	$ 85.27	$ 87.04
11/6/2017	$ 88.08	$ 86.12	$ 87.19
11/13/2017	$ 89.58	$ 86.22	$ 86.53
11/20/2017	$ 87.25	$ 85.86	$ 86.90
11/27/2017	$ 89.57	$ 86.82	$ 88.82
12/4/2017	$ 89.26	$ 87.30	$ 88.92
12/11/2017	$ 89.70	$ 86.93	$ 88.24
12/18/2017	$ 88.27	$ 84.35	$ 84.75
12/25/2017	$ 85.45	$ 84.18	$ 84.95
1/1/2018	$ 84.94	$ 81.03	$ 81.74
1/8/2018	$ 82.91	$ 79.18	$ 79.49
1/15/2018	$ 79.86	$ 77.77	$ 78.27
1/22/2018	$ 80.61	$ 78.37	$ 80.40
1/29/2018	$ 80.65	$ 77.89	$ 77.96
2/5/2018	$ 78.72	$ 74.57	$ 76.89
2/12/2018	$ 77.98	$ 75.66	$ 77.77
2/19/2018	$ 77.93	$ 75.46	$ 77.63
2/26/2018	$ 78.04	$ 73.73	$ 74.35
3/5/2018	$ 76.34	$ 73.98	$ 75.24
3/12/2018	$ 77.58	$ 75.18	$ 77.45
3/19/2018	$ 78.22	$ 75.41	$ 75.58
3/26/2018	$ 78.40	$ 75.62	$ 77.94
4/2/2018	$ 79.39	$ 76.67	$ 78.56
4/9/2018	$ 79.12	$ 76.07	$ 76.69
4/16/2018	$ 79.19	$ 76.95	$ 77.60
4/23/2018	$ 80.78	$ 77.40	$ 80.43
4/30/2018	$ 80.82	$ 78.01	$ 79.25
5/7/2018	$ 79.39	$ 78.26	$ 78.36
Min	$ 76.34	**$ 73.73**	$ 74.35
Max	**$ 89.70**	$ 87.30	$ 88.92
Mean	$ 82.97	$ 80.60	**$ 81.80**

Source: YahooFinance.com

Growth Estimates	ED
Current Qtr.	1.60%
Next Qtr.	-3.40%
Current Year	3.40%
Next Year	4.70%
Next 5 Years (per annum)	**3.40%**
Past 5 Years (per annum)	2.08%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	3.50%	1.50%
Past 5 Year	2.50%	2.00%
Est '15-'17 to '21-'23	**3.00%**	**3.50%**

February 16, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.76	$ 2.86	**$ 2.96**	$ 3.30

February 16, 2018 Value-Line

Consolidated Edison, Inc. | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**3.383**	3.766	4	2	4

Source: SNL/S&P Global

Edison International (EIX)

Date	High	Low	Close
5/8/2017	$ 79.97	$ 77.69	$ 78.78
5/15/2017	$ 79.15	$ 77.21	$ 78.20
5/22/2017	$ 80.24	$ 77.92	$ 79.96
5/29/2017	$ 82.82	$ 79.84	$ 82.01
6/5/2017	$ 82.27	$ 80.48	$ 81.29
6/12/2017	$ 82.59	$ 79.72	$ 82.18
6/19/2017	$ 82.34	$ 79.82	$ 80.03
6/26/2017	$ 80.97	$ 77.26	$ 78.19
7/3/2017	$ 78.46	$ 76.44	$ 76.83
7/10/2017	$ 78.47	$ 76.38	$ 77.45
7/17/2017	$ 79.01	$ 77.32	$ 78.98
7/24/2017	$ 79.35	$ 78.08	$ 78.25
7/31/2017	$ 79.44	$ 77.75	$ 79.29
8/7/2017	$ 80.26	$ 78.94	$ 79.53
8/14/2017	$ 81.33	$ 78.70	$ 78.94
8/21/2017	$ 81.26	$ 78.91	$ 80.75
8/28/2017	$ 81.32	$ 79.54	$ 79.96
9/4/2017	$ 80.78	$ 79.40	$ 80.74
9/11/2017	$ 81.58	$ 80.34	$ 81.20
9/18/2017	$ 81.41	$ 78.22	$ 78.28
9/25/2017	$ 79.45	$ 76.93	$ 77.17
10/2/2017	$ 77.88	$ 76.55	$ 77.62
10/9/2017	$ 79.88	$ 77.39	$ 77.99
10/16/2017	$ 79.83	$ 76.93	$ 79.60
10/23/2017	$ 80.20	$ 78.55	$ 79.47
10/30/2017	$ 80.64	$ 78.63	$ 79.52
11/6/2017	$ 80.43	$ 78.68	$ 80.06
11/13/2017	$ 83.38	$ 80.16	$ 80.89
11/20/2017	$ 81.14	$ 79.72	$ 80.55
11/27/2017	$ 81.96	$ 80.34	$ 80.76
12/4/2017	$ 81.19	$ 67.80	$ 71.80
12/11/2017	$ 73.23	$ 67.28	$ 69.71
12/18/2017	$ 71.11	$ 62.67	$ 65.23
12/25/2017	$ 65.30	$ 63.19	$ 63.24
1/1/2018	$ 63.73	$ 62.03	$ 62.98
1/8/2018	$ 64.34	$ 61.25	$ 61.42
1/15/2018	$ 62.64	$ 60.64	$ 62.12
1/22/2018	$ 62.84	$ 61.52	$ 62.46
1/29/2018	$ 67.56	$ 61.16	$ 61.60
2/5/2018	$ 61.96	$ 57.63	$ 58.94
2/12/2018	$ 61.37	$ 58.69	$ 61.05
2/19/2018	$ 62.56	$ 58.87	$ 62.17
2/26/2018	$ 62.62	$ 59.04	$ 59.59
3/5/2018	$ 60.84	$ 58.80	$ 59.38
3/12/2018	$ 65.15	$ 59.12	$ 65.15
3/19/2018	$ 65.27	$ 61.77	$ 62.16
3/26/2018	$ 63.78	$ 61.47	$ 63.66
4/2/2018	$ 64.11	$ 62.09	$ 63.38
4/9/2018	$ 63.86	$ 62.60	$ 63.44
4/16/2018	$ 65.82	$ 63.30	$ 64.12
4/23/2018	$ 66.60	$ 63.73	$ 65.79
4/30/2018	$ 66.10	$ 62.54	$ 63.69
5/7/2018	$ 63.74	$ 62.98	$ 63.09
Min	$ 60.84	**$ 57.63**	$ 58.94
Max	**$ 83.38**	$ 80.48	$ 82.18
Mean	$ 74.03	$ 71.21	**$ 72.46**

Source: YahooFinance.com

Growth Estimates	EIX
Current Qtr.	-10.90%
Next Qtr.	9.40%
Current Year	-8.40%
Next Year	10.00%
Next 5 Years (per annum)	**2.62%**
Past 5 Years (per annum)	0.00%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	2.50%	6.00%
Past 5 Year	2.50%	9.00%
Est '15-'17 to '21-'23	**4.50%**	**8.00%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.23	$ 2.45	**$ 2.57**	$ 3.10

April 27, 2018 Value-Line

Edison International | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**4.47**	3.93	7	2.48	3

Source: SNL/S&P Global

Duke Energy Corp. (DUK)

Date	High	Low	Close
5/8/2017	$ 83.67	$ 82.01	$ 83.48
5/15/2017	$ 83.80	$ 82.27	$ 83.37
5/22/2017	$ 85.35	$ 83.19	$ 85.07
5/29/2017	$ 86.80	$ 84.88	$ 86.28
6/5/2017	$ 86.30	$ 84.75	$ 85.72
6/12/2017	$ 87.49	$ 85.08	$ 87.14
6/19/2017	$ 87.31	$ 85.86	$ 85.96
6/26/2017	$ 87.05	$ 83.59	$ 83.59
7/3/2017	$ 83.84	$ 82.72	$ 83.42
7/10/2017	$ 84.27	$ 82.80	$ 83.84
7/17/2017	$ 85.23	$ 83.60	$ 85.20
7/24/2017	$ 85.28	$ 83.60	$ 84.91
7/31/2017	$ 86.58	$ 84.65	$ 86.48
8/7/2017	$ 86.90	$ 85.16	$ 85.70
8/14/2017	$ 86.97	$ 85.61	$ 86.38
8/21/2017	$ 87.55	$ 86.11	$ 87.23
8/28/2017	$ 87.95	$ 86.73	$ 87.09
9/4/2017	$ 88.03	$ 86.79	$ 87.78
9/11/2017	$ 88.40	$ 86.53	$ 87.30
9/18/2017	$ 87.31	$ 84.22	$ 84.25
9/25/2017	$ 85.16	$ 83.40	$ 83.92
10/2/2017	$ 84.74	$ 83.52	$ 84.64
10/9/2017	$ 87.60	$ 84.69	$ 86.79
10/16/2017	$ 88.06	$ 86.42	$ 87.93
10/23/2017	$ 88.55	$ 86.71	$ 87.95
10/30/2017	$ 89.50	$ 87.56	$ 88.52
11/6/2017	$ 89.74	$ 87.61	$ 88.89
11/13/2017	$ 91.80	$ 88.45	$ 88.52
11/20/2017	$ 89.20	$ 88.29	$ 88.78
11/27/2017	$ 89.72	$ 88.19	$ 88.73
12/4/2017	$ 89.43	$ 87.45	$ 88.05
12/11/2017	$ 88.39	$ 86.72	$ 87.84
12/18/2017	$ 88.15	$ 83.75	$ 84.17
12/25/2017	$ 84.58	$ 83.56	$ 84.11
1/1/2018	$ 84.42	$ 81.35	$ 81.94
1/8/2018	$ 82.31	$ 78.55	$ 78.90
1/15/2018	$ 79.27	$ 76.64	$ 76.82
1/22/2018	$ 79.22	$ 76.85	$ 78.83
1/29/2018	$ 78.65	$ 76.43	$ 76.53
2/5/2018	$ 77.59	$ 72.93	$ 76.10
2/12/2018	$ 77.30	$ 74.66	$ 76.70
2/19/2018	$ 77.30	$ 74.82	$ 77.22
2/26/2018	$ 79.63	$ 74.58	$ 75.35
3/5/2018	$ 77.67	$ 74.87	$ 76.13
3/12/2018	$ 77.73	$ 76.06	$ 77.59
3/19/2018	$ 77.87	$ 75.03	$ 75.17
3/26/2018	$ 77.91	$ 75.23	$ 77.47
4/2/2018	$ 78.90	$ 76.57	$ 78.16
4/9/2018	$ 79.05	$ 75.96	$ 76.67
4/16/2018	$ 79.42	$ 76.80	$ 77.68
4/23/2018	$ 80.75	$ 77.57	$ 80.50
4/30/2018	$ 80.85	$ 78.82	$ 79.88
5/7/2018	$ 80.13	$ 79.44	$ 79.50
Min	$ 77.30	**$ 72.93**	$ 75.17
Max	**$ 91.80**	$ 88.45	$ 88.89
Mean	$ 84.28	$ 82.07	**$ 83.14**

Source: YahooFinance.com

Growth Estimates	DUK
Current Qtr.	9.60%
Next Qtr.	8.90%
Current Year	3.10%
Next Year	5.10%
Next 5 Years (per annum)	**4.25%**
Past 5 Years (per annum)	3.01%

Source: YahooFinance.com

Value-Line Investment Survey

Forecasted Growth Rates	EPS	DPS
Past 10 Year	3.50%	
Past 5 Year	0.50%	2.50%
Est '15-'17 to '21-'23	**4.50%**	**4.50%**

February 16, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 3.49	$ 3.64	**$ 3.80**	$ 4.40

February 16, 2018 Value-Line

Duke Energy Corporation | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**4.06**	4.4	5	2.78	7

Source: SNL/S&P Global

El Paso Electric Co. (EE)

Date	High	Low	Close
5/8/2017	$ 52.00	$ 50.65	$ 51.45
5/15/2017	$ 52.15	$ 51.15	$ 52.05
5/22/2017	$ 53.95	$ 52.00	$ 53.40
5/29/2017	$ 55.45	$ 53.10	$ 55.15
6/5/2017	$ 55.45	$ 53.75	$ 54.50
6/12/2017	$ 54.85	$ 52.70	$ 53.60
6/19/2017	$ 53.70	$ 52.30	$ 52.65
6/26/2017	$ 53.20	$ 51.15	$ 51.70
7/3/2017	$ 51.90	$ 50.30	$ 51.05
7/10/2017	$ 51.30	$ 50.25	$ 51.05
7/17/2017	$ 53.35	$ 50.85	$ 53.00
7/24/2017	$ 53.10	$ 51.45	$ 51.65
7/31/2017	$ 53.73	$ 51.55	$ 53.35
8/7/2017	$ 54.03	$ 52.83	$ 53.45
8/14/2017	$ 54.25	$ 53.00	$ 53.95
8/21/2017	$ 55.60	$ 53.65	$ 55.35
8/28/2017	$ 55.85	$ 54.85	$ 55.40
9/4/2017	$ 55.95	$ 54.95	$ 55.95
9/11/2017	$ 56.58	$ 54.35	$ 55.15
9/18/2017	$ 55.40	$ 54.30	$ 54.65
9/25/2017	$ 55.75	$ 54.58	$ 55.25
10/2/2017	$ 57.00	$ 55.30	$ 56.85
10/9/2017	$ 58.70	$ 56.85	$ 58.10
10/16/2017	$ 58.05	$ 56.00	$ 57.25
10/23/2017	$ 58.70	$ 56.75	$ 58.40
10/30/2017	$ 58.45	$ 55.45	$ 57.60
11/6/2017	$ 58.65	$ 57.25	$ 57.75
11/13/2017	$ 60.70	$ 57.50	$ 60.20
11/20/2017	$ 60.70	$ 59.15	$ 59.65
11/27/2017	$ 61.15	$ 59.30	$ 60.25
12/4/2017	$ 61.10	$ 58.55	$ 58.90
12/11/2017	$ 59.40	$ 57.98	$ 59.10
12/18/2017	$ 59.45	$ 54.75	$ 55.15
12/25/2017	$ 55.60	$ 54.60	$ 55.35
1/1/2018	$ 55.75	$ 53.65	$ 54.25
1/8/2018	$ 55.10	$ 50.70	$ 51.05
1/15/2018	$ 52.15	$ 50.70	$ 51.65
1/22/2018	$ 52.30	$ 51.15	$ 51.60
1/29/2018	$ 52.38	$ 50.95	$ 51.05
2/5/2018	$ 51.45	$ 48.15	$ 50.75
2/12/2018	$ 51.45	$ 49.70	$ 51.30
2/19/2018	$ 51.40	$ 49.65	$ 50.55
2/26/2018	$ 51.35	$ 48.05	$ 48.60
3/5/2018	$ 49.60	$ 48.05	$ 48.50
3/12/2018	$ 49.60	$ 48.25	$ 49.60
3/19/2018	$ 50.70	$ 48.85	$ 48.85
3/26/2018	$ 51.25	$ 48.80	$ 51.00
4/2/2018	$ 51.30	$ 49.60	$ 50.35
4/9/2018	$ 50.50	$ 48.50	$ 48.90
4/16/2018	$ 50.40	$ 48.90	$ 49.05
4/23/2018	$ 51.55	$ 49.05	$ 51.35
4/30/2018	$ 56.90	$ 49.45	$ 55.05
5/7/2018	$ 55.65	$ 54.90	$ 55.65
Min	$ 49.60	**$ 48.05**	$ 48.50
Max	**$ 61.15**	$ 59.30	$ 60.25
Mean	$ 54.64	$ 52.65	**$ 53.72**

Source: YahooFinance.com

Growth Estimates	EE
Current Qtr.	30.00%
Next Qtr.	-1.10%
Current Year	5.40%
Next Year	7.50%
Next 5 Years (per annum)	**5.20%**
Past 5 Years (per annum)	18.89%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	6.50%	
Past 5 Year		18.00%
Est '15-'17 to '21-'23	**4.50%**	**7.00%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 1.32	$ 1.42	**$ 1.52**	$ 1.85

April 27, 2018 Value-Line

El Paso Electric Company | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**5.1**	5.1	5.2	5	2

Source: SNL/S&P Global

IDACORP, Inc. (IDA)

Date	High	Low	Close
5/8/2017	$ 85.45	$ 82.52	$ 83.55
5/15/2017	$ 84.17	$ 82.55	$ 83.64
5/22/2017	$ 86.54	$ 83.65	$ 86.46
5/29/2017	$ 89.58	$ 85.93	$ 89.39
6/5/2017	$ 89.78	$ 87.90	$ 89.40
6/12/2017	$ 90.67	$ 88.40	$ 89.53
6/19/2017	$ 89.57	$ 87.54	$ 87.59
6/26/2017	$ 88.29	$ 85.20	$ 85.35
7/3/2017	$ 85.73	$ 83.75	$ 84.64
7/10/2017	$ 85.15	$ 83.46	$ 84.07
7/17/2017	$ 87.90	$ 83.60	$ 87.84
7/24/2017	$ 87.83	$ 85.59	$ 86.00
7/31/2017	$ 87.63	$ 85.31	$ 86.56
8/7/2017	$ 88.23	$ 86.23	$ 86.78
8/14/2017	$ 87.90	$ 86.26	$ 87.15
8/21/2017	$ 89.75	$ 86.44	$ 89.54
8/28/2017	$ 89.94	$ 88.36	$ 89.32
9/4/2017	$ 91.60	$ 89.17	$ 91.40
9/11/2017	$ 91.98	$ 89.05	$ 90.06
9/18/2017	$ 90.06	$ 87.74	$ 87.75
9/25/2017	$ 89.06	$ 87.61	$ 87.93
10/2/2017	$ 89.25	$ 87.55	$ 88.44
10/9/2017	$ 91.61	$ 88.18	$ 90.34
10/16/2017	$ 92.26	$ 89.79	$ 91.68
10/23/2017	$ 93.22	$ 90.10	$ 93.18
10/30/2017	$ 93.79	$ 91.06	$ 92.71
11/6/2017	$ 95.57	$ 92.50	$ 95.17
11/13/2017	$ 98.43	$ 95.08	$ 97.23
11/20/2017	$ 97.98	$ 96.20	$ 96.55
11/27/2017	$ 100.04	$ 96.19	$ 98.23
12/4/2017	$ 99.03	$ 95.95	$ 97.16
12/11/2017	$ 97.26	$ 93.92	$ 95.51
12/18/2017	$ 96.13	$ 90.03	$ 90.66
12/25/2017	$ 92.43	$ 89.81	$ 91.36
1/1/2018	$ 91.40	$ 87.23	$ 87.69
1/8/2018	$ 88.31	$ 82.08	$ 83.32
1/15/2018	$ 84.70	$ 82.62	$ 83.86
1/22/2018	$ 86.74	$ 83.10	$ 86.07
1/29/2018	$ 86.57	$ 83.25	$ 83.39
2/5/2018	$ 84.32	$ 79.59	$ 83.57
2/12/2018	$ 85.53	$ 82.02	$ 85.27
2/19/2018	$ 85.05	$ 82.23	$ 84.98
2/26/2018	$ 85.25	$ 80.45	$ 81.61
3/5/2018	$ 83.00	$ 80.29	$ 81.95
3/12/2018	$ 86.22	$ 81.54	$ 86.10
3/19/2018	$ 87.95	$ 84.25	$ 84.34
3/26/2018	$ 88.60	$ 84.45	$ 88.27
4/2/2018	$ 88.77	$ 85.55	$ 87.25
4/9/2018	$ 87.86	$ 84.82	$ 85.74
4/16/2018	$ 89.83	$ 85.85	$ 89.08
4/23/2018	$ 94.16	$ 89.23	$ 93.63
4/30/2018	$ 96.01	$ 91.84	$ 94.04
5/7/2018	$ 94.34	$ 92.90	$ 93.06
Min	$ 83.00	**$ 79.59**	$ 81.61
Max	**$ 100.04**	$ 96.20	$ 98.23
Mean	$ 89.97	$ 86.90	**$ 88.59**

Source: YahooFinance.com

Growth Estimates	IDA
Current Qtr.	6.10%
Next Qtr.	2.00%
Current Year	N/A
Next Year	3.80%
Next 5 Years (per annum)	**3.10%**
Past 5 Years (per annum)	9.47%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	7.50%	5.50%
Past 5 Year	4.50%	10.50%
Est '15-'17 to '21-'23	**3.50%**	**6.50%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.24	$ 2.40	**$ 2.56**	$ 3.05

April 27, 2018 Value-Line

IDACORP, Inc. | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**4.12**	4.12	5.5	2.74	2

Source: SNL/S&P Global

NorthWestern Corp. (NWE)

Date	High	Low	Close
5/8/2017	$ 61.08	$ 59.71	$ 60.68
5/15/2017	$ 60.98	$ 59.60	$ 60.05
5/22/2017	$ 61.50	$ 59.71	$ 61.41
5/29/2017	$ 63.22	$ 61.12	$ 63.02
6/5/2017	$ 62.98	$ 61.38	$ 62.55
6/12/2017	$ 63.86	$ 61.65	$ 63.78
6/19/2017	$ 63.84	$ 62.78	$ 63.14
6/26/2017	$ 63.54	$ 60.94	$ 61.02
7/3/2017	$ 61.58	$ 59.85	$ 60.30
7/10/2017	$ 60.75	$ 59.09	$ 59.68
7/17/2017	$ 61.80	$ 58.99	$ 61.77
7/24/2017	$ 61.14	$ 58.42	$ 58.54
7/31/2017	$ 60.36	$ 57.58	$ 60.28
8/7/2017	$ 61.36	$ 59.77	$ 60.18
8/14/2017	$ 60.70	$ 58.63	$ 59.24
8/21/2017	$ 60.97	$ 59.16	$ 60.78
8/28/2017	$ 60.97	$ 59.78	$ 60.23
9/4/2017	$ 60.52	$ 59.56	$ 60.24
9/11/2017	$ 60.82	$ 58.21	$ 58.96
9/18/2017	$ 59.06	$ 57.74	$ 57.75
9/25/2017	$ 58.23	$ 56.87	$ 56.94
10/2/2017	$ 57.98	$ 56.44	$ 57.37
10/9/2017	$ 59.04	$ 57.29	$ 58.44
10/16/2017	$ 59.41	$ 58.24	$ 58.70
10/23/2017	$ 59.46	$ 57.50	$ 59.22
10/30/2017	$ 59.97	$ 58.46	$ 59.78
11/6/2017	$ 61.17	$ 59.28	$ 60.34
11/13/2017	$ 62.12	$ 60.11	$ 61.60
11/20/2017	$ 62.28	$ 61.32	$ 62.22
11/27/2017	$ 64.38	$ 62.02	$ 63.76
12/4/2017	$ 64.47	$ 62.46	$ 63.28
12/11/2017	$ 63.33	$ 60.82	$ 61.60
12/18/2017	$ 62.13	$ 58.48	$ 59.27
12/25/2017	$ 59.91	$ 58.66	$ 59.70
1/1/2018	$ 59.82	$ 57.00	$ 57.41
1/8/2018	$ 57.80	$ 55.33	$ 55.40
1/15/2018	$ 55.50	$ 53.01	$ 53.21
1/22/2018	$ 54.75	$ 53.13	$ 54.36
1/29/2018	$ 54.51	$ 52.71	$ 52.86
2/5/2018	$ 53.35	$ 50.01	$ 52.13
2/12/2018	$ 52.61	$ 50.64	$ 52.27
2/19/2018	$ 52.50	$ 50.89	$ 52.50
2/26/2018	$ 52.76	$ 50.54	$ 51.06
3/5/2018	$ 52.13	$ 50.46	$ 51.07
3/12/2018	$ 52.07	$ 50.65	$ 51.90
3/19/2018	$ 53.31	$ 51.47	$ 51.52
3/26/2018	$ 54.19	$ 51.63	$ 53.80
4/2/2018	$ 54.51	$ 52.43	$ 53.89
4/9/2018	$ 54.33	$ 52.74	$ 53.27
4/16/2018	$ 55.20	$ 53.45	$ 53.85
4/23/2018	$ 55.65	$ 53.72	$ 55.36
4/30/2018	$ 55.80	$ 54.15	$ 55.53
5/7/2018	$ 55.67	$ 55.17	$ 55.34
Min	$ 52.07	**$ 50.01**	$ 51.06
Max	**$ 64.47**	$ 62.78	$ 63.78
Mean	$ 58.89	$ 57.00	**$ 57.97**

Source: YahooFinance.com

Growth Estimates	NWE
Current Qtr.	3.50%
Next Qtr.	-4.30%
Current Year	3.60%
Next Year	-0.60%
Next 5 Years (per annum)	**3.16%**
Past 5 Years (per annum)	8.34%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	8.00%	5.50%
Past 5 Year	7.00%	7.00%
Est '15-'17 to '21-'23	**3.50%**	**4.50%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.10	$ 2.20	**$ 2.30**	$ 2.60

April 27, 2018 Value-Line

NorthWestern Corporation | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**3.01**	3.01	3.02	3	2

Source: SNL/S&P Global

OGE Energy Corp. (OGE)

Date	High	Low	Close
5/8/2017	$ 34.35	$ 33.50	$ 34.14
5/15/2017	$ 34.47	$ 33.45	$ 34.22
5/22/2017	$ 35.46	$ 34.20	$ 35.15
5/29/2017	$ 36.09	$ 34.93	$ 35.79
6/5/2017	$ 35.95	$ 35.26	$ 35.37
6/12/2017	$ 37.25	$ 35.30	$ 36.47
6/19/2017	$ 36.58	$ 35.11	$ 35.47
6/26/2017	$ 35.90	$ 34.67	$ 34.79
7/3/2017	$ 35.01	$ 34.09	$ 34.22
7/10/2017	$ 34.90	$ 33.95	$ 34.57
7/17/2017	$ 35.42	$ 34.26	$ 35.42
7/24/2017	$ 35.92	$ 35.33	$ 35.80
7/31/2017	$ 36.14	$ 35.35	$ 35.91
8/7/2017	$ 36.40	$ 35.27	$ 35.42
8/14/2017	$ 35.75	$ 35.25	$ 35.59
8/21/2017	$ 36.36	$ 35.53	$ 36.22
8/28/2017	$ 36.51	$ 35.67	$ 35.76
9/4/2017	$ 36.21	$ 35.55	$ 36.15
9/11/2017	$ 36.67	$ 35.77	$ 36.31
9/18/2017	$ 36.41	$ 35.69	$ 35.84
9/25/2017	$ 36.39	$ 35.70	$ 36.03
10/2/2017	$ 36.36	$ 35.00	$ 35.58
10/9/2017	$ 37.30	$ 35.65	$ 36.82
10/16/2017	$ 37.21	$ 36.62	$ 37.09
10/23/2017	$ 37.32	$ 36.35	$ 37.08
10/30/2017	$ 37.20	$ 35.60	$ 35.63
11/6/2017	$ 36.00	$ 34.93	$ 35.01
11/13/2017	$ 36.01	$ 34.89	$ 35.20
11/20/2017	$ 35.27	$ 34.72	$ 34.90
11/27/2017	$ 36.00	$ 34.81	$ 35.23
12/4/2017	$ 35.67	$ 33.97	$ 34.46
12/11/2017	$ 34.72	$ 33.47	$ 34.15
12/18/2017	$ 34.40	$ 32.65	$ 33.01
12/25/2017	$ 33.20	$ 32.60	$ 32.91
1/1/2018	$ 33.07	$ 32.47	$ 32.50
1/8/2018	$ 32.84	$ 30.70	$ 30.74
1/15/2018	$ 31.78	$ 30.76	$ 31.42
1/22/2018	$ 32.54	$ 31.47	$ 32.14
1/29/2018	$ 32.36	$ 31.31	$ 31.35
2/5/2018	$ 31.54	$ 29.59	$ 30.39
2/12/2018	$ 31.66	$ 30.34	$ 31.56
2/19/2018	$ 33.06	$ 30.74	$ 32.95
2/26/2018	$ 33.00	$ 30.85	$ 31.19
3/5/2018	$ 32.08	$ 30.76	$ 31.35
3/12/2018	$ 32.17	$ 31.14	$ 32.00
3/19/2018	$ 32.39	$ 31.38	$ 31.43
3/26/2018	$ 32.83	$ 31.43	$ 32.77
4/2/2018	$ 32.98	$ 31.94	$ 32.37
4/9/2018	$ 32.31	$ 31.49	$ 31.61
4/16/2018	$ 32.91	$ 31.69	$ 32.47
4/23/2018	$ 33.16	$ 32.38	$ 32.91
4/30/2018	$ 34.37	$ 32.70	$ 34.17
5/7/2018	$ 34.59	$ 34.08	$ 34.33
Min	$ 31.54	**$ 29.59**	$ 30.39
Max	**$ 37.32**	$ 36.62	$ 37.09
Mean	$ 34.76	$ 33.63	**$ 34.18**

Source: YahooFinance.com

Growth Estimates	OGE
Current Qtr.	-16.70%
Next Qtr.	-3.80%
Current Year	4.20%
Next Year	5.00%
Next 5 Years (per annum)	**5.80%**
Past 5 Years (per annum)	5.45%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	4.50%	5.50%
Past 5 Year	1.00%	8.50%
Est '15-'17 to '21-'23	**2.50%**	**8.00%**

March 16, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 1.27	$ 1.40	**$ 1.54**	$ 1.85

March 16, 2018 Value-Line

OGE Energy Corp. | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**4.15**	4.15	4.3	4	2

Source: SNL/S&P Global

Pinnacle West Capital Corp. (PNW)

Date	High	Low	Close
5/8/2017	$ 85.09	$ 83.63	$ 84.76
5/15/2017	$ 85.28	$ 83.52	$ 84.57
5/22/2017	$ 87.80	$ 84.05	$ 87.40
5/29/2017	$ 89.56	$ 87.23	$ 89.22
6/5/2017	$ 89.23	$ 87.12	$ 87.99
6/12/2017	$ 89.06	$ 86.92	$ 88.92
6/19/2017	$ 89.12	$ 87.70	$ 87.84
6/26/2017	$ 88.71	$ 84.93	$ 85.16
7/3/2017	$ 85.87	$ 84.14	$ 84.67
7/10/2017	$ 85.68	$ 83.95	$ 85.13
7/17/2017	$ 87.25	$ 84.95	$ 87.23
7/24/2017	$ 87.38	$ 85.75	$ 86.14
7/31/2017	$ 88.95	$ 85.35	$ 88.06
8/7/2017	$ 89.11	$ 87.95	$ 88.53
8/14/2017	$ 89.91	$ 88.41	$ 89.29
8/21/2017	$ 90.41	$ 88.63	$ 90.02
8/28/2017	$ 90.87	$ 89.46	$ 89.86
9/4/2017	$ 90.16	$ 88.94	$ 90.01
9/11/2017	$ 90.92	$ 87.79	$ 89.27
9/18/2017	$ 89.29	$ 86.14	$ 86.15
9/25/2017	$ 87.17	$ 83.95	$ 84.56
10/2/2017	$ 85.89	$ 84.14	$ 85.33
10/9/2017	$ 88.04	$ 85.17	$ 87.38
10/16/2017	$ 88.84	$ 86.79	$ 88.78
10/23/2017	$ 89.22	$ 87.04	$ 88.91
10/30/2017	$ 89.21	$ 86.23	$ 89.12
11/6/2017	$ 90.00	$ 88.14	$ 88.34
11/13/2017	$ 92.48	$ 88.28	$ 90.05
11/20/2017	$ 90.25	$ 88.93	$ 89.52
11/27/2017	$ 92.30	$ 89.23	$ 91.01
12/4/2017	$ 91.52	$ 88.66	$ 90.75
12/11/2017	$ 91.28	$ 88.20	$ 89.54
12/18/2017	$ 89.90	$ 84.81	$ 85.14
12/25/2017	$ 85.55	$ 84.26	$ 85.18
1/1/2018	$ 85.55	$ 82.02	$ 82.42
1/8/2018	$ 83.18	$ 79.11	$ 79.22
1/15/2018	$ 79.92	$ 78.55	$ 79.08
1/22/2018	$ 81.33	$ 78.81	$ 80.94
1/29/2018	$ 80.65	$ 77.69	$ 77.73
2/5/2018	$ 78.35	$ 73.81	$ 76.29
2/12/2018	$ 78.88	$ 75.61	$ 78.69
2/19/2018	$ 80.41	$ 75.92	$ 80.15
2/26/2018	$ 80.83	$ 76.06	$ 76.92
3/5/2018	$ 78.31	$ 75.21	$ 76.38
3/12/2018	$ 78.00	$ 75.96	$ 77.97
3/19/2018	$ 80.14	$ 77.40	$ 77.76
3/26/2018	$ 80.21	$ 77.73	$ 79.80
4/2/2018	$ 80.54	$ 78.32	$ 79.75
4/9/2018	$ 80.37	$ 77.14	$ 78.14
4/16/2018	$ 80.73	$ 77.55	$ 78.02
4/23/2018	$ 81.85	$ 77.95	$ 81.61
4/30/2018	$ 81.61	$ 78.24	$ 80.20
5/7/2018	$ 80.29	$ 79.61	$ 79.75
Min	$ 78.00	**$ 73.81**	$ 76.29
Max	**$ 92.48**	$ 89.46	$ 91.01
Mean	$ 85.90	$ 83.27	**$ 84.62**

Source: YahooFinance.com

Growth Estimates	PNW
Current Qtr.	N/A
Next Qtr.	8.50%
Current Year	2.80%
Next Year	5.10%
Next 5 Years (per annum)	**3.63%**
Past 5 Years (per annum)	10.03%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	4.00%	2.50%
Past 5 Year	5.00%	2.50%
Est '15-'17 to '21-'23	**5.00%**	**5.50%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 2.70	$ 2.86	**$ 3.02**	$ 3.50

April 27, 2018 Value-Line

Pinnacle West Capital Corporation | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**4.54**	4.85	5	3.46	4

Source: SNL/S&P Global

Portland General Electric Company (POR)

Date	High	Low	Close
5/8/2017	$ 45.45	$ 44.65	$ 45.31
5/15/2017	$ 45.34	$ 44.54	$ 45.22
5/22/2017	$ 47.10	$ 45.10	$ 46.94
5/29/2017	$ 48.06	$ 46.73	$ 48.02
6/5/2017	$ 48.01	$ 46.95	$ 47.45
6/12/2017	$ 47.98	$ 46.99	$ 47.77
6/19/2017	$ 47.88	$ 46.69	$ 46.78
6/26/2017	$ 47.24	$ 45.17	$ 45.69
7/3/2017	$ 45.83	$ 44.55	$ 44.87
7/10/2017	$ 44.99	$ 44.20	$ 44.59
7/17/2017	$ 46.35	$ 44.41	$ 46.35
7/24/2017	$ 46.16	$ 44.27	$ 44.44
7/31/2017	$ 45.57	$ 44.45	$ 45.46
8/7/2017	$ 46.57	$ 45.24	$ 45.90
8/14/2017	$ 46.68	$ 45.61	$ 46.40
8/21/2017	$ 47.40	$ 46.27	$ 47.14
8/28/2017	$ 47.60	$ 47.02	$ 47.33
9/4/2017	$ 47.91	$ 47.10	$ 47.87
9/11/2017	$ 48.22	$ 46.60	$ 46.96
9/18/2017	$ 47.04	$ 45.48	$ 45.58
9/25/2017	$ 46.31	$ 45.53	$ 45.64
10/2/2017	$ 46.54	$ 45.52	$ 46.07
10/9/2017	$ 47.07	$ 45.95	$ 46.25
10/16/2017	$ 46.35	$ 44.70	$ 45.37
10/23/2017	$ 47.68	$ 45.25	$ 47.67
10/30/2017	$ 48.18	$ 47.10	$ 47.76
11/6/2017	$ 48.69	$ 47.48	$ 48.28
11/13/2017	$ 50.11	$ 48.35	$ 49.34
11/20/2017	$ 49.45	$ 48.38	$ 48.48
11/27/2017	$ 49.85	$ 48.23	$ 49.49
12/4/2017	$ 49.84	$ 48.23	$ 48.68
12/11/2017	$ 48.87	$ 47.00	$ 47.79
12/18/2017	$ 48.12	$ 45.36	$ 45.61
12/25/2017	$ 45.83	$ 45.00	$ 45.58
1/1/2018	$ 45.65	$ 43.63	$ 43.86
1/8/2018	$ 44.02	$ 42.38	$ 42.62
1/15/2018	$ 42.99	$ 42.25	$ 42.40
1/22/2018	$ 42.85	$ 41.89	$ 42.27
1/29/2018	$ 42.47	$ 41.00	$ 41.40
2/5/2018	$ 41.62	$ 39.40	$ 40.47
2/12/2018	$ 41.41	$ 39.77	$ 41.20
2/19/2018	$ 41.14	$ 39.86	$ 41.08
2/26/2018	$ 41.27	$ 39.41	$ 39.74
3/5/2018	$ 40.42	$ 39.02	$ 39.18
3/12/2018	$ 40.09	$ 39.07	$ 40.05
3/19/2018	$ 41.06	$ 39.09	$ 39.11
3/26/2018	$ 40.76	$ 39.27	$ 40.51
4/2/2018	$ 40.66	$ 39.56	$ 40.21
4/9/2018	$ 40.54	$ 39.18	$ 40.22
4/16/2018	$ 41.21	$ 40.07	$ 40.17
4/23/2018	$ 42.59	$ 40.15	$ 42.33
4/30/2018	$ 42.93	$ 41.63	$ 42.76
5/7/2018	$ 42.81	$ 42.14	$ 42.22
Min	$ 40.09	**$ 39.02**	$ 39.11
Max	**$ 50.11**	$ 48.38	$ 49.49
Mean	$ 45.41	$ 44.02	**$ 44.71**

Source: YahooFinance.com

Growth Estimates	POR
Current Qtr.	8.30%
Next Qtr.	-4.50%
Current Year	-4.40%
Next Year	7.30%
Next 5 Years (per annum)	**2.65%**
Past 5 Years (per annum)	5.40%

Source: YahooFinance.com

Value-Line Investment Survey

	EPS	DPS
Past 10 Year	4.00%	9.00%
Past 5 Year	3.50%	3.50%
Est '15-'17 to '21-'23	**4.00%**	**6.00%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 1.34	$ 1.42	**$ 1.50**	$ 1.80

April 27, 2018 Value-Line

Portland General Electric Company | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**3.02**	3	3.8	2.25	3

Source: SNL/S&P Global

Xcel Energy Inc (XEL)

Date	High	Low	Close
5/8/2017	$ 45.63	$ 44.63	$ 45.58
5/15/2017	$ 46.07	$ 45.30	$ 45.85
5/22/2017	$ 47.41	$ 45.71	$ 47.30
5/29/2017	$ 48.50	$ 47.21	$ 48.32
6/5/2017	$ 48.38	$ 46.94	$ 47.35
6/12/2017	$ 47.86	$ 46.67	$ 47.79
6/19/2017	$ 47.85	$ 47.05	$ 47.13
6/26/2017	$ 47.64	$ 45.79	$ 45.88
7/3/2017	$ 46.06	$ 45.18	$ 45.69
7/10/2017	$ 46.08	$ 45.41	$ 45.92
7/17/2017	$ 47.42	$ 45.85	$ 47.42
7/24/2017	$ 47.70	$ 46.55	$ 47.16
7/31/2017	$ 48.12	$ 46.96	$ 47.97
8/7/2017	$ 48.72	$ 47.79	$ 48.19
8/14/2017	$ 49.22	$ 48.19	$ 49.00
8/21/2017	$ 49.60	$ 48.93	$ 49.37
8/28/2017	$ 49.70	$ 49.19	$ 49.36
9/4/2017	$ 50.30	$ 49.17	$ 50.23
9/11/2017	$ 50.56	$ 48.59	$ 49.08
9/18/2017	$ 49.10	$ 47.29	$ 47.41
9/25/2017	$ 47.97	$ 46.69	$ 47.32
10/2/2017	$ 47.80	$ 46.86	$ 47.39
10/9/2017	$ 49.08	$ 47.37	$ 48.61
10/16/2017	$ 49.41	$ 48.26	$ 49.26
10/23/2017	$ 49.83	$ 48.56	$ 49.21
10/30/2017	$ 49.92	$ 48.93	$ 49.59
11/6/2017	$ 50.57	$ 49.29	$ 50.20
11/13/2017	$ 52.22	$ 50.13	$ 50.89
11/20/2017	$ 51.05	$ 50.35	$ 50.71
11/27/2017	$ 51.84	$ 50.61	$ 51.36
12/4/2017	$ 51.58	$ 50.40	$ 51.20
12/11/2017	$ 51.45	$ 50.16	$ 50.78
12/18/2017	$ 50.86	$ 48.12	$ 48.25
12/25/2017	$ 48.41	$ 47.53	$ 48.11
1/1/2018	$ 48.36	$ 46.63	$ 46.79
1/8/2018	$ 47.22	$ 45.06	$ 45.15
1/15/2018	$ 45.86	$ 44.89	$ 45.13
1/22/2018	$ 46.10	$ 45.12	$ 45.70
1/29/2018	$ 45.78	$ 44.45	$ 44.48
2/5/2018	$ 44.75	$ 41.51	$ 43.35
2/12/2018	$ 44.88	$ 43.04	$ 44.68
2/19/2018	$ 44.82	$ 43.50	$ 44.77
2/26/2018	$ 44.92	$ 42.65	$ 43.03
3/5/2018	$ 44.02	$ 42.57	$ 43.28
3/12/2018	$ 44.23	$ 43.23	$ 44.13
3/19/2018	$ 45.19	$ 43.66	$ 43.74
3/26/2018	$ 45.87	$ 43.81	$ 45.48
4/2/2018	$ 45.99	$ 44.68	$ 45.47
4/9/2018	$ 45.80	$ 43.93	$ 44.48
4/16/2018	$ 46.01	$ 44.49	$ 45.10
4/23/2018	$ 47.38	$ 45.12	$ 47.10
4/30/2018	$ 47.37	$ 45.93	$ 46.39
5/7/2018	$ 46.54	$ 45.99	$ 46.13
Min	$ 44.02	**$ 41.51**	$ 43.03
Max	**$ 52.22**	$ 50.61	$ 51.36
Mean	$ 47.83	$ 46.45	**$ 47.16**

Source: YahooFinance.com

Growth Estimates	XEL
Current Qtr.	4.40%
Next Qtr.	4.10%
Current Year	5.70%
Next Year	6.60%
Next 5 Years (per annum)	**5.89%**
Past 5 Years (per annum)	6.48%

Source: YahooFinance.com

Value-Line Investment Survey

Forecasted Growth Rates	EPS	DPS
Past 10 Year	5.50%	4.50%
Past 5 Year	5.00%	5.50%
Est '15-'17 to '21-'23	**5.50%**	**5.50%**

April 27, 2018 Value-Line

	2017	2018	**2019**	'21-'23
Dividends per Share	$ 1.44	$ 1.52	**$ 1.60**	$ 1.90

April 27, 2018 Value-Line

Xcel Energy Inc. | Consensus

	Mean	Median	High	Low	Analysts
LT Growth (%)	**5.73**	5.71	6.3	5	8

Source: SNL/S&P Global

Internal Rate of Return Analysis Summary

1	2	3	4	5	6	7	8	9	10	11	12	13	14
							Short-Term Growth EPS Growth				Long-Term Growth Years 5 Through 250		
	IRR	Average Price	ST Growth Estimate	LT Growth Estimate	2018 Dividends	2018 Year 0	2019 Year1	2020 Year2	2021 Year3	2022 Year4	2023 Year5	2024 Year6	2021 through 2264 Year 7 through Year 250
Allete Inc.	7.68%	$ 74.28	5.48%	4.30%	$ 2.24	$ (72.04)	$ 2.36	$ 2.49	$ 2.63	$ 2.77	$ 2.89	$ 3.02	$ 2,116,347
Alliant Energy Corp.	8.00%	$ 41.58	6.06%	4.30%	$ 1.34	$ (40.24)	$ 1.42	$ 1.51	$ 1.60	$ 1.70	$ 1.77	$ 1.84	$ 1,294,229
Ameren Corp.	7.98%	$ 57.85	6.15%	4.30%	$ 1.85	$ (56.00)	$ 1.96	$ 2.08	$ 2.21	$ 2.35	$ 2.45	$ 2.55	$ 1,792,792
American Electric Power Co.	8.25%	$ 70.81	5.17%	4.30%	$ 2.51	$ (68.30)	$ 2.64	$ 2.78	$ 2.92	$ 3.07	$ 3.20	$ 3.34	$ 2,343,686
Consolidated Edison Inc.	7.94%	$ 81.80	3.32%	4.30%	$ 2.86	$ (78.94)	$ 2.95	$ 3.05	$ 3.15	$ 3.26	$ 3.40	$ 3.55	$ 2,488,038
Duke Energy Corp.	9.08%	$ 83.14	4.33%	4.30%	$ 3.64	$ (79.50)	$ 3.80	$ 3.96	$ 4.13	$ 4.31	$ 4.50	$ 4.69	$ 3,291,829
Edison International	8.03%	$ 72.46	4.90%	4.30%	$ 2.45	$ (70.01)	$ 2.57	$ 2.70	$ 2.83	$ 2.97	$ 3.09	$ 3.23	$ 2,264,474
El Paso Electric Co.	7.25%	$ 53.72	5.45%	4.30%	$ 1.42	$ (52.30)	$ 1.50	$ 1.58	$ 1.67	$ 1.76	$ 1.83	$ 1.91	$ 1,340,341
IDACORP Inc.	7.20%	$ 88.59	4.31%	4.30%	$ 2.40	$ (86.19)	$ 2.50	$ 2.61	$ 2.72	$ 2.84	$ 2.96	$ 3.09	$ 2,168,565
NorthWestern Corp.	8.30%	$ 57.97	3.54%	4.30%	$ 2.20	$ (55.77)	$ 2.28	$ 2.36	$ 2.44	$ 2.53	$ 2.64	$ 2.75	$ 1,930,359
OGE Energy Corp.	8.89%	$ 34.18	5.11%	4.30%	$ 1.40	$ (32.78)	$ 1.47	$ 1.55	$ 1.63	$ 1.71	$ 1.78	$ 1.86	$ 1,304,627
Pinnacle West Capital Corp.	8.00%	$ 84.62	4.67%	4.30%	$ 2.86	$ (81.76)	$ 2.99	$ 3.13	$ 3.28	$ 3.43	$ 3.58	$ 3.73	$ 2,620,319
Portland General Electric Co.	7.67%	$ 44.71	3.92%	4.30%	$ 1.42	$ (43.29)	$ 1.48	$ 1.53	$ 1.59	$ 1.66	$ 1.73	$ 1.80	$ 1,264,107
Xcel Energy Inc.	7.95%	$ 47.16	5.66%	4.30%	$ 1.52	$ (45.64)	$ 1.61	$ 1.70	$ 1.79	$ 1.89	$ 1.98	$ 2.06	$ 1,445,921
Mean	8.02%												
Min	7.20%												
Max	9.08%												

Column 1) Proxy group
2) Internal rate of return calcuation -- Investors' discount rate that equates the stock price to the stream of future dividends
3) Average stock price May 8, 2017 through May 7, 2018
4) Average of short-term growth rates used in first 5 years
5) Long-term nGDP growth rate used after 2023
6) 2018 dividends reported by Value-Line
7) Year 0 Cashflow; stock price less 2018 dividend
8 through 11) Annual cashflow growing at short-term growth rate
12 through 250) Annual cashflow growing at long-term growth rate

STATE OF KANSAS)
) ss.
COUNTY OF SHAWNEE)

VERIFICATION

Adam Gatewood, being duly sworn upon his oath deposes and states that he is a Managing Financial Analyst for the Kansas Corporation Commission of the State of Kansas, that he has read and is familiar with the foregoing *Direct Testimony*, and that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Adam Gatewood
Managing Financial Analyst
State Corporation Commission of the
State of Kansas

Subscribed and sworn to before me this 6th day of June, 2018.

VICKI D. JACOBSEN
Notary Public - State of Kansas
My Appt Expires 6-30-18

Vicki D. Jacobsen
Notary Public

My Appointment Expires: June 30, 2018

CERTIFICATE OF SERVICE

18-WSEE-328-RTS

I, the undersigned, certify that a true and correct copy of the above and foregoing Direct Testimony of Adam Gatewood was served via electronic service this 11th day of June, 2018, to the following:

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/s/ Vicki Jacobsen
Vicki Jacobsen

Application of Kansas City Power & Light Company (KCPL) for Approval of the Accrual and Funding of WCGS Decommissioning Costs at Current Levels
(146 pages)

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels	)))))	Case No. EO-2018-_____

APPLICATION OF KANSAS CITY POWER & LIGHT COMPANY
FOR APPROVAL OF THE ACCRUAL AND FUNDING OF WOLF CREEK
GENERATING STATION DECOMMISSIONING COSTS AT CURRENT LEVELS

Pursuant to 4 CSR 240-3.185(3), Kansas City Power & Light Company ("KCP&L") hereby submits its application to the Missouri Public Service Commission ("Commission") for approval of the accrual and funding of Wolf Creek Generating Station ("Wolf Creek") decommissioning costs at current levels. In support thereof, KCP&L states as follows:

1. KCP&L is a corporation duly authorized and existing under the laws of the State of Missouri, with its principal office at 1200 Main Street, Kansas City, Missouri, and is an "electrical corporation" and "public utility" as defined in Mo. Rev. Stat. §§ 386.020 (12) and (32), respectively. KCP&L is engaged primarily in the generation, transmission, distribution, and sale of electric energy and power in western Missouri and eastern Kansas. KCP&L is a 47% co-owner of Wolf Creek and has established and is funding a decommissioning trust to ensure that adequate funds are available to decommission Wolf Creek.

2. KCP&L has filed with the Commission certified copies of its Articles of Incorporation and all amendments thereto. These documents are incorporated herein by reference.

3. Communications concerning this submission should be addressed to:

Lois Liechti
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4. Data requests concerning this Application should be addressed to Regulatory.Affairs@kcpl.com.

5. 4 CSR 240-3.185(3) requires KCP&L to file by September 1, 1990, and every three years thereafter, a cost study detailing KCP&L's latest cost estimate for decommissioning Wolf Creek. The Wolf Creek Generating Station Decommissioning Cost Estimate Update for September 1, 2017 ("2017 Study") is filed herewith as **Schedule A**.

6. The Missouri jurisdictional share of the current annual decommissioning trust fund accrual is $1,281,264 and was first authorized by the Commission in Case No. ER-2006-0314. KCP&L has accrued at this rate since January 1, 2007. The Commission order in Case No.

EO-2012-0068 approved the continuation of the annual decommissioning expense accruals and trust fund payment at the current level of $1,281,264. The current level of $1,281,264 was also included in the cost of service in KCP&L's general rate case in Case No. ER-2016-0285.

7. The 2017 Study shows the decommissioning cost estimate to be $813,733,000 in 2017 dollars. 4 CSR 240-3.185(3) also requires KCP&L to provide funding levels necessary to defray these decommissioning costs. **Schedule B** ("2017 Funding Analysis") along with supporting workpapers is filed herewith. The 2017 Funding Analysis demonstrates that the current annual trust fund contribution of $1,281,264 is sufficient to defray the estimated decommissioning cost within 0.40% of the Missouri jurisdictional share of future estimated total decommissioning costs. The 2017 Funding Analysis is based on the actual nuclear decommissioning trust fund balance as of June 30, 2017, the decommissioning cost estimate from the 2017 Study, a Missouri jurisdictional allocation based on average monthly peak demand over the life of the plant with the 2016 allocation used for the remaining years after 2016, capital market assumptions dated 7/01/2017 from KCP&L's pension consultants, Willis Towers Watson, as agreed to in the Stipulation and Agreement approved in Case No. EO-2012-0068, initial asset allocations based on the Wolf Creek Nuclear Decommissioning Trust Investment Guidelines authorized in Case No. EO-2009-439, and a decommissioning cost escalation rate based on inflation assumptions also from Willis Towers Watson dated 7/01/2017 in order to provide consistency with the capital market assumptions. The decommissioning cost escalation of 3.16% is based on a 3.70% wage inflation rate assumption for the labor portion of the decommissioning cost estimate and a 2.78% price inflation rate for the non-labor portion of the decommissioning cost estimate. KCP&L believes that it is reasonable and prudent to continue

the annual accruals at the current level of $1,281,264. KCP&L therefore requests that the Commission approve the continuation of the annual accrual at the current level.

8. Because KCP&L is not requesting a change in the current level of $1,281,264 already included in KCP&L's retail rates approved in Case No. ER-2016-0285, no new tariff(s) are being filed with this application.

WHEREFORE, KCP&L requests an order from the Commission: (i) finding that the 2017 Study and the 2017 Funding Analysis satisfy the requirements of 4 CSR 240-3.185(3); and (ii) approving the continuation of the annual decommissioning expense accrual and trust fund contribution at the current level of $1,281,264.

Respectfully submitted,

/s/ Roger W. Steiner

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Counsel for Kansas City Power & Light Company

CERTIFICATE OF SERVICE

The undersigned certifies that true and correct copies of the foregoing have been e-mailed or mailed, via first class United States Mail, postage pre-paid, to the service list of record this 1st day of September, 2017.

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/s/ Roger W. Steiner
Roger W. Steiner
Counsel for Kansas City Power & Light Company

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

James P. Gilligan, being first duly sworn, on his oath and in his capacity as Assistant Treasurer for Kansas City Power & Light Company, states that he is authorized to execute on behalf of Kansas City Power & Light Company this *Application for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels*, and has knowledge of the matters stated in this Application, and that said matters are true and correct to the best of his knowledge, information and belief.

James P. Gilligan

Subscribed and sworn to before me this 1st day of September, 2017.

Notary Public

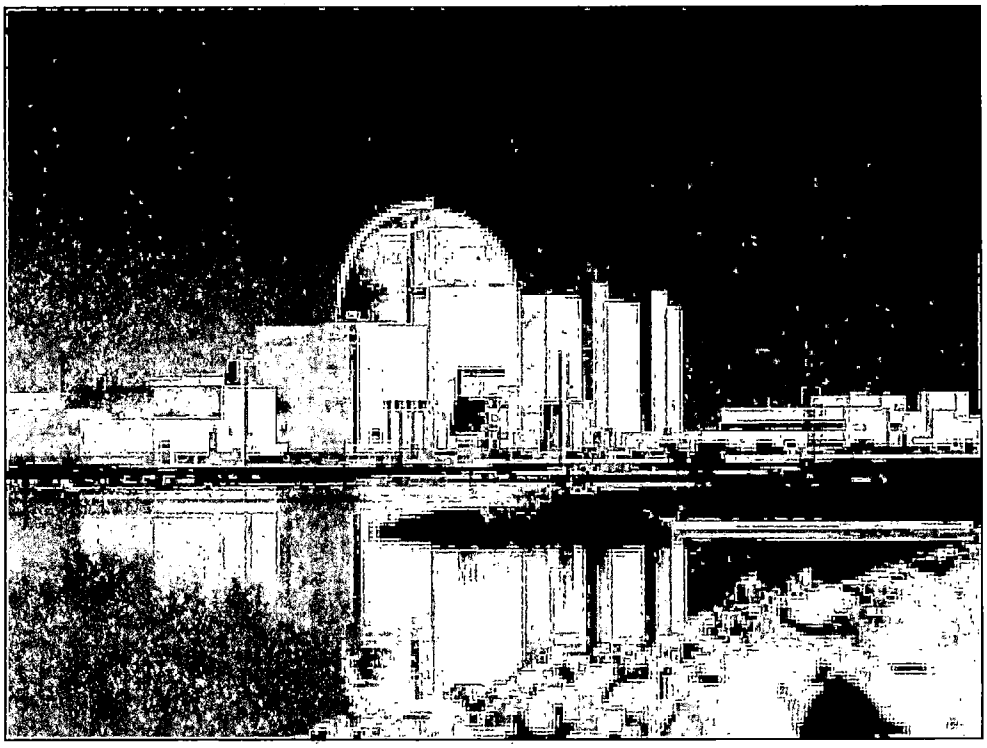
My Commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

DECOMMISSIONING COST ANALYSIS

for the

WOLF CREEK GENERATING STATION



prepared for the

Wolf Creek Nuclear Operating Corporation

prepared by

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REVISION LOG

No.	Date	Item Revised	Reason for Revision
0	08-21-2017		Original Issue

EXECUTIVE SUMMARY

This report presents estimates of the cost to decommission the Wolf Creek Generating Station (Wolf Creek) for the selected decommissioning alternatives following the scheduled and permanent cessation of plant operations. The estimates are designed to provide the Wolf Creek Nuclear Operating Corporation (WCNOC), the plant's operator, and its owners: Kansas Gas and Electric Company, a wholly owned subsidiary of Westar Energy, Inc., Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy Incorporated, and Kansas Electric Power Cooperative, Inc., with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The analysis relies upon site-specific, technical information from an evaluation prepared in 2014,[1] updated to reflect current assumptions pertaining to the disposition of the nuclear station and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but estimates prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission Wolf Creek; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The 2014 plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, was reviewed for this analysis. There were no substantive changes made to the plant inventory (that would impact decommissioning). The current analysis does include, however, the costs to decommission the structural changes made to the condensate storage tank (for missile projection) and the control building, the new refueling cavity elevator, the fire protection system and emergency service water system modifications, and other minor modifications identified by the site.

The costs to decommission Wolf Creek for the alternatives evaluated are tabulated at the end of this section. Costs are reported in 2017 dollars and include monies anticipated to be spent for radiological remediation and operating license termination, spent fuel management, and site restoration activities.

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1 "Decommissioning Cost Analysis for the Wolf Creek Generating Station," Document No. W11-1697-001, Rev. 0, TLG Services, Inc., August 2014

A complete discussion of the assumptions relied upon in this analysis is provided in Section 3, along with schedules of annual expenditures for the two scenarios. A sequence of significant project activities is provided in Section 4 with a timeline for each scenario. Detailed cost reports, used to generate the summary tables contained within this document, are provided in Appendices C and D.

Consistent with the 2014 analysis, the current cost estimates assume that the shutdown of the nuclear station is a scheduled and pre-planned event (e.g., there is no delay in transitioning the plant and workforce from operations or in obtaining regulatory relief from operating requirements, etc.). The estimates include the continued operation of the fuel handling building as an interim wet fuel storage facility for approximately five and one-half years after operations cease (years 2045 through 2050). During this time period, it is assumed that the Department of Energy (DOE) will complete the transfer of the spent fuel from the site to a federal facility.

Alternatives and Regulations

The ultimate objective of the decommissioning process is to reduce the inventory of contaminated and activated material so that the license can be terminated. The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule adopted on June 27, 1988.[2] In this rule, the NRC set forth financial criteria for decommissioning licensed nuclear power facilities. The regulations addressed planning needs, timing, funding methods, and environmental review requirements for decommissioning. The rule also defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB.

> DECON is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."[3]
>
> SAFSTOR is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred

2 U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72 "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (p 24018 et seq.), June 27, 1988

3 Ibid. Page FR24022, Column 3

decontamination) to levels that permit release for unrestricted use."[4] Decommissioning is to be completed within 60 years, although longer time periods will be considered when necessary to protect public health and safety.

ENTOMB is defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactive material decays to a level permitting unrestricted release of the property."[5] As with the SAFSTOR alternative, decommissioning is currently required to be completed within 60 years, although longer time periods will also be considered when necessary to protect public health and safety.

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 1997, the Commission directed its staff to re-evaluate this alternative and identify the technical requirements and regulatory actions that would be necessary for entombment to become a viable option. The resulting evaluation provided several recommendations; however, rulemaking has been deferred pending the completion of additional research studies, for example, on engineered barriers. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process.[6] The amendments allow for greater public participation and better define the transition process from operations to decommissioning. Regulatory Guide 1.184, issued in July 2000, (as revised in October 2013), further described the methods and procedures that are acceptable to the NRC staff for implementing the requirements of the 1996 revised rule that relate to the initial activities and the major phases of the decommissioning process. The costs and

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4 Ibid.

5 Ibid. Page FR24023, Column 2

6 U.S. Code of Federal Regulations, Title 10, Parts 2, 50, and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, Federal Register Volume 61, (p 39278 et seq.), July 29, 1996

schedules presented in this analysis follow the general guidance and sequence in the amended regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202, issued in February 2005.[7]

In 2011, the NRC issued regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[8] The regulations require licensees to report additional details in their decommissioning cost estimate, including a decommissioning estimate for any on-site Independent Spent Fuel Storage Installation (ISFSI). Since an ISFSI may be required to support continued operation at Wolf Creek, a representative decommissioning cost is included within the DECON and SAFSTOR estimates.

Decommissioning Scenarios

Two decommissioning scenarios were evaluated for the Wolf Creek nuclear unit. The scenarios selected are representative of alternatives currently available to the owners and are defined as follows:

1. The first scenario assumes that the nuclear unit is promptly decommissioned (DECON alternative) upon the expiration of the current operating license in 2045. Following the permanent cessation of operations, and over the first five and one-half years, the spent fuel is transferred directly from the wet storage pool to the DOE (the fuel stored on the ISFSI is also removed from the site during this time period). Concurrently, the majority of the plant components, including the nuclear steam supply system components, are removed. Once the spent fuel stored in the fuel handling building's pool has been transferred off-site, the remaining portions of the power block are decommissioned and the surrounding site remediated. Following the termination of the operating license, non-essential structures (not designated for reuse) are dismantled.

2. In the second scenario, the nuclear unit is placed into safe-storage (SAFSTOR alternative) upon the expiration of the current operating license in 2045. As with the first scenario, the spent fuel removed from the site (transferred to the DOE) during the first five and one-half years following the permanent cessation of operations. The facility is then placed into safe-storage (with non-essential systems de-energized and buildings secured).

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7 "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, Nuclear Regulatory Commission, February 2005

8 U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 70, and 72, "Decommissioning Planning," Nuclear Regulatory Commission, Federal Register Volume 76, (p 35512 et seq.), June 17, 2011

The start of decontamination and dismantling activities is deferred to the maximum extent (approximately 50 years from the cessation of operations) such that the license is terminated within the required 60-year period.

Methodology

The methodology used to develop the estimates described within this document follows the basic approach originally presented in the cost estimating guidelines[9] developed by the Atomic Industrial Forum (now Nuclear Energy Institute). This reference describes a unit factor method for determining decommissioning activity costs. The unit factors used in this analysis incorporate site-specific costs and the latest available information on worker productivity in decommissioning.

An activity duration critical path is used to determine the total decommissioning program schedule. This is required for calculating the carrying costs, which include program management, administration, field engineering, equipment rental, quality assurance, and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

The estimates also reflect lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Contingency

Consistent with cost estimating practice, contingencies are applied to the decontamination and dismantling costs developed as "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."[10] The cost elements in the estimates are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a

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9 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

10 Project and Cost Engineers' Handbook, Second Edition, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, p. 239

line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

Contingency funds are expected to be fully expended throughout the program. As such, inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks.

Low-Level Radioactive Waste Disposal

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,[11] and its Amendments of 1985,[12] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

With the exception of 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). The facility is also able to accept limited quantities of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to WCNOC. The majority of the low-level radioactive waste designated for controlled disposal (Class A[13]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon WCNOC's "Long Term Waste Disposal Agreement" with Energy*Solutions*. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The WCS facility is able to receive the Class B and C waste. As such, for this analysis, Class B and C waste was assumed to be shipped to the WCS facility for disposal. Disposal costs were based upon preliminary and indicative information for the WCS site.

The dismantling of the components residing closest to the reactor core generates radioactive waste that may be considered unsuitable for shallow-land disposal (i.e.,

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11 "Low-Level Radioactive Waste Policy Act of 1980," Public Law 96-573, 1980

12 "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, 1986.

13 Waste is classified in accordance with U.S. Code of Federal Regulations, Title 10, Part 61.55

low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis only, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and shipped directly to a DOE facility as it is generated.

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This material can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to eliminate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act"[14] (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. The DOE 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, despite DOE's submittal of its License Application for a geologic repository to the NRC in 2008. The Obama administration eliminated 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."[15] Towards this goal, the Obama administration appointed a Blue Ribbon Commission on

14 "Nuclear Waste Policy Act of 1982 and Amendments," DOE's Office of Civilian Radioactive Management, 1982

15 "Advisory Committee Charter, Blue Ribbon Commission on America's Nuclear Future," Appendix A, January 2012

America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter included a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[16]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of 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"[17]
- "[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."[18]

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..."[19] This document states:

"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

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16 Ibid.

17 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," p. 32, January 2012

18 Ibid., p.27

19 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."[20]

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)[21] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application, to the extent allowed by 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 adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

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 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. The current spent fuel management plan for the Wolf Creek spent fuel is based in general upon: 1) a 2025 start date for DOE initiating transfer of commercial spent fuel to a federal facility, and 2) a 2032 start date for the transfer of spent fuel from the Wolf Creek site based on an oldest fuel first priority, and the DOE achieving an annual rate of transfer (3,000 metric tons of uranium per year) as reflected in DOE's latest Acceptance Priority Ranking and Annual Capacity Report.[22]

The estimates also assume that the DOE would give priority to fuel at shutdown sites, i.e., it is assumed that Congress would "(1)...direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process."[23]

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20 Ibid., p.2

21 U.S. Court of Appeals for the District Of Columbia Circuit, In Re: Aiken County, et al, Aug. 2013

22 "Acceptance Priority Ranking and Annual Capacity Report," U.S. DOE, Office of Civilian Radioactive Waste Management, DOE/RW-0567, July 2004

23 "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

It is generally necessary that spent fuel be cooled and stored for a minimum period at the generating site prior to transfer. As such, the NRC requires that licensees establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE, pursuant to 10 CFR Part 50.54(bb).[24] The post-shutdown costs incurred to satisfy this requirement include the isolation and continued operation of the spent fuel pool and the ISFSI during the five and one-half years following the cessation of plant operations.

At shutdown, the spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core. Over the following five and one-half years the assemblies are packaged into multipurpose canisters for transfer to the DOE. It is assumed that this period provides the necessary cooling for the final core to meet the transportation system requirements for decay heat.

Interim storage of the fuel, until the DOE has completed the transfer, will be in the wet storage pool located in the fuel building (as well as on the ISFSI). The pool will be isolated, allowing WCNOC to proceed with decommissioning (or safe-storage preparations) in the shortest time possible.

Sensitivity of Spent Fuel Management Assumptions

The estimates described in this analysis were developed with the assumption that the DOE would give priority to removing spent fuel from shutdown sites. The estimates further assume that the spent fuel would be removed from the Wolf Creek site within five and one-half years of the cessation of plant operations (i.e., five and one-half years would provide sufficient cooling time for the spent fuel to meet DOE transportation requirements).

If DOE is unable to remove the spent fuel from the Wolf Creek site within this time period, wet storage pool operations would need to be extended (potentially delaying decommissioning) and/or the ISFSI would be used for the interim storage of the fuel so that decommissioning could proceed. Appendix E evaluates such a scenario (i.e., where spent fuel is accepted from generators in the order in which it was generated or oldest fuel first and the ISFSI is used for interim storage, similar to what has occurred at recently decommissioned reactor sites).

The resulting costs for long-term spent fuel management (summarized in Table E) are illustrative only and based upon current regulations and associated constraints that

24 U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

may change as a result of actions taken on the Blue Ribbon Commission's recommendations. It should also be noted that the costs, while incurred by the licensee, may also be recoverable as a result of DOE's breech of its contract to take possession of the spent fuel in a timely manner. However, the analysis described in Appendix E may prove useful as a planning basis should delays continue in the development of a national solution for the disposition of spent fuel and high-level waste.

Site Restoration

The efficient removal of the contaminated materials at the site may result in damage to many of the site structures. Blasting, coring, drilling, and the other decontamination activities can substantially damage power block structures, potentially weakening the footings and structural supports. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures with a work force already mobilized is more efficient and less costly than if the process is deferred.

Consequently, this study assumes that non-essential site structures addressed by this analysis are removed, once remediation is complete, to a nominal depth of three feet below the local grade level, wherever possible. The site is then graded and stabilized.

Summary

The costs to decommission Wolf Creek assume the removal of all contaminated and activated plant components and structural materials such that the owners may then have unrestricted use of the site with no further requirements for an operating license. Low-level radioactive waste, other than GTCC waste, is sent to a commercial processor for treatment/conditioning or to a controlled disposal facility.

Decommissioning is accomplished within the 60-year period required by current NRC regulations.

The decommissioning scenarios are described in Section 2. The assumptions are presented in Section 3, along with schedules of annual expenditures. The major cost contributors are identified in Section 6, with detailed activity costs, waste volumes, and associated manpower requirements delineated in Appendices C and D. The major cost components are also identified in the cost summary provided at the end of this section.

The cost elements in the estimates are assigned to one of three subcategories: NRC License Termination, Spent Fuel Management, and Site Restoration. The subcategory "NRC License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR Part 50.75). The cost reported for this subcategory is generally sufficient to terminate the station's operating license, recognizing that there may be some additional cost impact from spent fuel management. The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). Section 3.4.1 provides the basis for the ISFSI decommissioning cost.

The "Spent Fuel Management" subcategory contains costs associated with the transfer of the spent fuel to the DOE as well as the operation of the spent fuel pool until such time that the transfer is complete.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are removed to a depth of three feet and backfilled to conform to local grade.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligations determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, an owner may decide to remove non-contaminated structures early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As noted within this document, the estimates were developed and costs are presented in 2017 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the reactor or during the decommissioning period.

DECON COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Cost
Decontamination	16,486
Removal	120,128
Packaging	24,544
Transportation	12,533
Waste Disposal	84,171
Off-site Waste Processing	24,134
Program Management [1]	273,568
Security	115,889
Corporate Allocations	2,002
Spent Fuel Pool Isolation	13,445
Spent Fuel Management - Direct Costs [2]	46,385
Insurance and Regulatory Fees	19,065
Energy	14,431
Characterization and Licensing Surveys	24,313
Property Taxes	15,363
Miscellaneous Equipment	7,279
Total [3]	813,733

Cost Element	Cost
License Termination	711,273
Spent Fuel Management	48,251
Site Restoration	54,208
Total [3]	813,733

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

SAFSTOR COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Cost
Decontamination	14,346
Removal	123,154
Packaging	19,286
Transportation	9,751
Waste Disposal	62,163
Off-site Waste Processing	26,984
Program Management [1]	366,223
Security	224,686
Corporate Allocations	3,292
Spent Fuel Pool Isolation	13,445
Spent Fuel Management - Direct Costs [2]	46,385
Insurance and Regulatory Fees	71,272
Energy	29,815
Characterization and Licensing Surveys	24,929
Property Taxes	33,724
Miscellaneous Equipment	23,661
Total [3]	1,093,117

Cost Element	Cost
License Termination	980,846
Spent Fuel Management	58,028
Site Restoration	54,243
Total [3]	1,093,117

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

1. INTRODUCTION

This report presents estimates of the cost to decommission the Wolf Creek Generating Station (Wolf Creek) for the selected decommissioning scenarios following the scheduled cessation of plant operations. The estimates are designed to provide the Wolf Creek Nuclear Operating Corporation (WCNOC), the plant's operator, and its owners: Kansas Gas and Electric Company, a wholly owned subsidiary of Westar Energy, Inc., Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy Incorporated, and Kansas Electric Power Cooperative, Inc., with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The analysis relies upon site-specific, technical information from an earlier evaluation prepared in 2014,[1]* updated to reflect current assumptions pertaining to the disposition of the nuclear station and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but rather estimates prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission Wolf Creek; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The 2014 plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, were reviewed for this analysis. There were no substantive changes made to the plant inventory (that would impact decommissioning). The current analysis does include, however, the costs to decommission the structural changes made to the condensate storage tank (for missile projection) and the control building, the new refueling cavity elevator, the fire protection system and emergency service water system modifications, and other minor modifications identified by the site.

1.1 OBJECTIVES OF STUDY

The objectives of this study were to prepare comprehensive estimates of the costs to decommission Wolf Creek, to provide a sequence or schedule for the

* References provided in Section 7 of the document

associated activities, and to develop waste stream projections from the decontamination and dismantling activities.

An operating license was originally issued for Wolf Creek in June of 1985. A license renewal application was filed for the nuclear station in October 2006. The NRC approved the application and a renewed licensed was issued in November 2008. As such, this analysis is based upon a 60-year operating life, with a final shutdown date (license expiration) in March of 2045.

1.2 SITE DESCRIPTION

The Wolf Creek site is located approximately 3.5 miles northeast of the town of Burlington, in Coffey County, Kansas, approximately 75 miles southwest of Kansas City, Kansas. The site is on the east side of a man-made lake formed by impounding Wolf Creek. The station is an 1,170 MWe (nominal) pressurized water reactor with supporting facilities.

Westinghouse Electric Company designed the Nuclear Steam Supply System (NSSS). The system consists of a pressurized water reactor with four independent primary coolant loops, each of which contains a reactor coolant pump and a steam generator. An electrically heated pressurizer and connecting piping complete the system. The NSSS is rated at a thermal power level of 3,579 MWt (3,565 MWt reactor core plus 14 MWt for reactor coolant pumps), with a corresponding turbine-generator gross output of 1,267 MWe. The system is housed within a containment structure, a pre-stressed, post-tensioned concrete structure with cylindrical wall, a hemispherical dome, and a flat foundation slab. The wall and dome form a pre-stressed post-tensioned system. The inside surface of the structure is covered with a carbon steel liner, providing a leak tight membrane.

A power conversion system converts heat produced in the reactor to electrical energy. This system converts the thermal energy of the steam into mechanical shaft power and then into electrical energy. The turbine-generator is a tandem-compound, six-flow, four element, 1800-rpm unit. The unit consists of one high pressure and three low-pressure turbine elements driving a directly coupled generator. (The four turbine elements were replaced in 2010 with very similar equipment.) The turbine is operated in a closed feedwater cycle that condenses the steam; the feedwater is returned to the steam generators. Heat rejected in the main condensers is removed by the circulating water system.

The circulating water system supplies cooling water to the main condenser, condensing the steam exhausted from the turbine. A large cooling lake

provides the heat sink required for removal of waste heat in the power plant's thermal cycle.

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 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 ENTOMB alternative has not been viewed as a viable option for power reactors due to the significant time required to isolate the long-lived radionuclides for decay to permissible levels. However, with rulemaking permitting the controlled release of a site,[4] the NRC has re-evaluated this alternative. The resulting feasibility study, based upon an assessment by Pacific Northwest National Laboratory, concluded that the method did have

conditional merit for some, if not most reactors. However, the staff also found that additional rulemaking would be needed before this option could be treated as a generic alternative. The NRC had considered rulemaking to alter the 60-year time for completing decommissioning and to clarify the use of engineered barriers for reactor entombments.[5]

The NRC's staff has recommended that rulemaking be deferred, based upon several factors, e.g., no licensee has committed to pursuing the entombment option, and the NRC's current priorities, at least until after the additional research studies are complete. The NRC concurred with the staff's recommendation. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants.[6] When the decommissioning regulations were 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 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, along with related changes to Technical Specifications, 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 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 includes a license termination plan (LTP).

In 2011, the NRC issued regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[7] The regulations require licensees to report additional details in their decommissioning cost estimate including a decommissioning estimate for any on-site Independent Spent Fuel Storage Installation (ISFSI). Since an ISFSI may be required to support continued operation at Wolf Creek, a representative decommissioning cost is included within the DECON and SAFSTOR estimates.

1.3.1 High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act"[8] (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. The DOE 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 has 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."[9]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of 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."[10]

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..."[11]

"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)[12] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application, to the extent allowed by 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 adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

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 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. The current spent fuel management plan for the Wolf Creek spent fuel is based in general upon: 1) a 2025 start date for DOE initiating transfer of commercial spent fuel to a federal facility, and 2) a 2032 start date for the transfer of spent fuel from the Wolf Creek site based on an oldest fuel first priority, and the DOE achieving an annual rate of transfer (3,000 metric tons of uranium per year) as reflected in DOE's latest Acceptance Priority Ranking and Annual Capacity Report.[13]

The estimates also assume that the DOE would give priority to fuel at shutdown sites, i.e., it is assumed that Congress would "(1)...direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process."[14]

It is generally necessary that spent fuel be cooled and stored for a minimum period at the generating site prior to transfer. As such, the NRC requires that licensees establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE, pursuant to 10 CFR Part 50.54(bb).[15] The post-shutdown costs incurred to satisfy this requirement include the isolation and continued operation of the spent fuel pool and the ISFSI during the five and one-half years following the cessation of plant operations.

At shutdown, the spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core. Over the following five and one-half years the assemblies are packaged into multipurpose canisters for transfer to the DOE. It is assumed that this period provides the necessary cooling for the final core to meet the transportation system requirements for decay heat.

Interim storage of the fuel, until the DOE has completed the transfer, will be in the wet storage pool located in the fuel building (as well as on the ISFSI). The pool will be isolated, allowing WCNOC to proceed with decommissioning (or safe-storage preparations) in the shortest time possible.

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,[16] and its Amendments of 1985,[17] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

With the exception of 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). The facility is also able to accept limited volumes of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to WCNOC. The majority of the low-level radioactive waste designated for controlled disposal (Class A[18]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon WCNOC's "Long Term Waste Disposal Agreement" with Energy*Solutions*. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The WCS facility is able to receive the Class B and C waste. As such, for this analysis, Class B and C waste was assumed to be shipped to the WCS facility for disposal. Disposal costs were based upon preliminary and indicative information for the WCS site.

The dismantling of the components residing closest to the reactor core generates radioactive waste that may be considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste.

However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis only, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and shipped directly to a DOE facility as it is generated.

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This material can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to eliminate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

1.3.3 Radiological Criteria for License Termination

In 1997, the NRC published Subpart E, "Radiological Criteria for License Termination,"[19] amending 10 CFR Part 20. This subpart provides radiological criteria for releasing a facility for unrestricted use. The regulation states that the site can be released for unrestricted use if radioactivity levels are such that the average member of a critical group would not receive a Total Effective Dose Equivalent (TEDE) in excess of 25 millirem per year, and provided that residual radioactivity has been reduced to levels that are As Low As Reasonably Achievable (ALARA). The decommissioning estimates assume that the Wolf Creek site will be remediated to a residual level consistent with the NRC-prescribed level.

It should be noted that the NRC and the Environmental Protection Agency (EPA) differ on the amount of residual radioactivity considered acceptable in site remediation. The EPA has two limits that apply to radioactive materials. An EPA limit of 15 millirem per year is derived from criteria established by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[20] An additional and separate limit of 4 millirem per year, as defined in 40 CFR §141.66, is applied to drinking water.[21]

On October 9, 2002, the NRC signed an agreement with the EPA on the radiological decommissioning and decontamination of NRC-licensed sites. The Memorandum of Understanding (MOU)[22] provides that EPA will defer exercise of authority under CERCLA for the majority of facilities decommissioned under NRC authority. The MOU also includes provisions for NRC and EPA consultation for certain sites when, at the time of license termination, (1) groundwater contamination exceeds EPA-permitted levels; (2) NRC contemplates restricted release of the site; and/or (3) residual radioactive soil concentrations exceed levels defined in the MOU.

The MOU does not impose any new requirements on NRC licensees and should reduce the involvement of the EPA with NRC licensees who are decommissioning. Most sites are expected to meet the NRC criteria for unrestricted use, and the NRC believes that only a few sites will have groundwater or soil contamination in excess of the levels specified in the MOU that trigger consultation with the EPA. However, if there are other hazardous materials on the site, the EPA may be involved in the cleanup. As such, the possibility of dual regulation remains for certain licensees. The present study does not include any costs for this occurrence.

2. DECOMMISSIONING ALTERNATIVES

Detailed cost estimates were developed to decommission Wolf Creek for the approved decommissioning alternatives: DECON and SAFSTOR. Although the alternatives differ with respect to technique, process, cost, and schedule, they attain the same result: the ultimate release of the site for unrestricted use.

Two decommissioning scenarios were evaluated for the Wolf Creek nuclear unit. The scenarios selected are representative of alternatives currently available to the owners and are defined as follows:

1. The first scenario assumes that the nuclear unit is promptly decommissioned (DECON alternative) upon the expiration of the current operating license in 2045. Following the permanent cessation of operations, and over the first five and one-half years, the spent fuel is transferred directly from the wet storage pool to the DOE (the fuel stored on the ISFSI is also removed from the site during this time period). Concurrently, the majority of the plant components, including the nuclear steam supply system components, are removed. Once the spent fuel stored in the fuel handling building's pool has been transferred off-site, the remaining portions of the power block are decommissioned and the surrounding site remediated. Following the termination of the operating license, non-essential structures (not designated for reuse) are dismantled.

2. In the second scenario, the nuclear unit is placed into safe-storage (SAFSTOR alternative) upon the expiration of the current operating license in 2045. As with the first scenario, the spent fuel removed from the site (transferred to the DOE) during the first five and one-half years following the permanent cessation of operations. The facility is then placed into safe-storage (with non-essential systems de-energized and buildings secured). The start of decontamination and dismantling activities is deferred to the maximum extent (approximately 50 years from the cessation of operations) such that the license is terminated within the required 60-year period.

The following sections describe the basic activities associated with each alternative. Although detailed procedures for each activity identified are not provided, and the actual sequence of work may vary, the activity descriptions provide a basis not only for estimating but also for the expected scope of work, i.e., engineering and planning at the time of decommissioning.

The conceptual approach that the NRC has described in its regulations divides 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. During the first phase, notification is to be provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessel. The licensee is then prohibited from reactor operation.

The second phase encompasses activities during the storage period or during major decommissioning activities, or a combination of the two. The third phase pertains to the activities involved in license termination. The decommissioning estimates developed for Wolf Creek are also divided into phases or periods; however, demarcation of the phases is based upon major milestones within the project or significant changes in the projected expenditures.

2.1 DECON

The DECON alternative, as defined by the NRC, is "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." This study does not address the cost to dispose of the spent fuel residing at the site; such costs are funded through a surcharge on electrical generation.

2.1.1 Period 1 - Preparations

In anticipation of the cessation of plant operations, detailed preparations are undertaken to provide a smooth transition from plant operations to site decommissioning. Through implementation of a staffing transition plan, the organization required to manage the intended decommissioning activities is assembled from available plant staff and outside resources. Preparations include the planning for permanent defueling of the reactor, revision of technical specifications applicable to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

Engineering and Planning

The PSDAR, required prior to or within two years of permanent cessation of operations, provides a description of the licensee's planned decommissioning activities, a timetable, and the associated financial requirements of the intended decommissioning program. Upon receipt of the PSDAR, the NRC will make the document available to the public

for comment in a local hearing to be held in the vicinity of the reactor site. Ninety days following submittal and NRC receipt of the PSDAR, the licensee may begin to perform major decommissioning activities under a modified 10 CFR §50.59 procedure, i.e., without specific NRC approval. Major activities are defined as any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components (for shipment) containing GTCC, as defined by 10 CFR §61. Major components are further defined as comprising the reactor vessel and internals, large bore reactor coolant system piping, and other large components that are radioactive. The NRC includes the following additional criteria for use of the §50.59 process in decommissioning. The proposed activity must not:

- foreclose release of the site for possible unrestricted use,
- significantly increase decommissioning costs,
- cause any significant environmental impact, or
- violate the terms of the licensee's existing license.

Existing operational technical specifications are reviewed and modified to reflect plant conditions and the safety concerns associated with permanent cessation of operations. The environmental impact associated with the planned decommissioning activities is also considered. Typically, a licensee will not be allowed to proceed if the consequences of a particular decommissioning activity are greater than that bounded by previously evaluated environmental assessments or impact statements. In this instance, the licensee would have to submit a license amendment for the specific activity and update the environmental report.

The decommissioning program outlined in the PSDAR will be designed to accomplish the required tasks within the ALARA guidelines (as defined in 10 CFR §20) for protection of personnel from exposure to radiation hazards. It will also address the continued protection of the health and safety of the public and the environment during the dismantling activity. Consequently, with the development of the PSDAR, activity specifications, cost-benefit and safety analyses, work packages and procedures, would be assembled to support the proposed decontamination and dismantling activities.

Site Preparations

Following final plant shutdown, and in preparation for actual decommissioning activities, the following activities are initiated:

- Characterization of the site and surrounding environs. This includes radiation surveys of work areas, major components (including the reactor vessel and its internals), internal piping, and primary shield cores.
- Isolation of the spent fuel storage pool and fuel handling systems, such that decommissioning operations can commence on the balance of the plant. The pool will remain operational for approximately five and one-half years following the cessation of operations before the inventory resident at shutdown can be transferred to the DOE.
- Specification of transport and disposal requirements for activated materials and/or hazardous materials, including shielding and waste stabilization.
- Development of procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste (including dry-active waste, resins, filter media, metallic and non-metallic components generated in decommissioning), site security and emergency programs, and industrial safety.

2.1.2 Period 2 - Decommissioning Operations

This period includes the physical decommissioning activities associated with the removal and disposal of contaminated and activated components and structures, including the successful termination of the 10 CFR §50 operating license. Significant decommissioning activities in this phase include:

- Construction of temporary facilities and/or modification of existing facilities to support dismantling activities. This may include a centralized processing area to facilitate equipment removal and component preparations for off-site disposal.
- Reconfiguration and modification of site structures and facilities as needed to support decommissioning operations. This may include the upgrading of roads (on- and off-site) to facilitate hauling and transport. Modifications may be required to the containment structure to facilitate access of large/heavy equipment. Modifications may also be required to the refueling area of the building to support

the segmentation of the reactor vessel internals and component extraction.

- Design and fabrication of temporary and permanent shielding to support removal and transportation activities, construction of contamination control envelopes, and the procurement of specialty tooling.
- Procurement (lease or purchase) of shipping canisters, cask liners, and industrial packages for the disposition of low-level radioactive waste.
- Decontamination of components and piping systems as required to control (minimize) worker exposure.
- Removal of piping and components no longer essential to support decommissioning operations.
- Removal of control rod drive housings and the head service structure from the reactor vessel head. Segmentation of the vessel closure head.
- Removal and segmentation of the upper internals assemblies. Segmentation will maximize the loading of the shielded transport casks, i.e., by weight and activity. The operations are conducted under water using remotely operated tooling and contamination controls.
- Disassembly and segmentation of the remaining reactor internals, including the core shroud and lower core support assembly. Some material is expected to exceed Class C disposal requirements. As such, the segments will be packaged in modified fuel storage canisters for geologic disposal.
- Segmentation of the reactor vessel. A shielded platform is installed for segmentation as cutting operations are performed in-air using remotely operated equipment within a contamination control envelope. The water level is maintained just below the cut to minimize the working area dose rates. Segments are transferred in-air to containers that are stored under water, for example, in an isolated area of the refueling canal.
- Removal of the activated portions of the concrete biological shield and accessible contaminated concrete surfaces. If dictated by the steam generator and pressurizer removal scenarios, those portions of the associated cubicles necessary for access and component extraction are removed.

- Removal of the steam generators and pressurizer for material recovery and controlled disposal. The generators will be moved to an on-site processing center, the steam domes removed and the internal components segregated for recycling. The lower shell and tube bundle will be packaged for direct disposal. These components can serve as their own burial containers provided that all penetrations are properly sealed and the internal contaminants are stabilized, e.g., with grout. Steel shielding will be added, as necessary, to those external areas of the package to meet transportation limits and regulations. The pressurizer is disposed of intact.

At least two years prior to the anticipated date of license termination, an LTP is required. Submitted as a supplement to the Final Safety Analysis Report (FSAR) or its equivalent, the plan must include: a site characterization, description of the remaining dismantling activities, plans for site remediation, procedures for the final radiation survey, designation of the end use of the site, an updated cost estimate to complete the decommissioning, and any associated environmental concerns. The NRC will notice the receipt of the plan, make the plan available for public comment, and schedule a local hearing. LTP approval will be subject to any conditions and limitations as deemed appropriate by the Commission. The licensee may then commence with the final remediation of site facilities and services, including:

- Removal of remaining plant systems and associated components as they become nonessential to the decommissioning program or worker health and safety (e.g., waste collection and treatment systems, electrical power and ventilation systems).
- Removal of the steel liners from refueling canal, disposing of the activated and contaminated sections as radioactive waste. Removal of any activated/ contaminated concrete.
- Surveys of the decontaminated areas of the containment structure.
- Remediation and removal of the contaminated equipment and material from the fuel building and any other contaminated facility. Radiation and contamination controls will be utilized until residual levels indicate that the structures and equipment can be released for unrestricted access and conventional demolition. This activity may necessitate the dismantling and disposition of most of the systems and components (both clean and contaminated) located within these buildings. This activity facilitates surface decontamination and subsequent verification surveys required prior to obtaining release for demolition.

- Routing of material removed in the decontamination and dismantling to a central processing area. Material certified to be free of contamination is released for unrestricted disposition, e.g., as scrap, recycle, or general disposal. Contaminated material is characterized and segregated for additional off-site processing (disassembly, chemical cleaning, volume reduction, and waste treatment), and/or packaged for controlled disposal at a low-level radioactive waste disposal facility.

Incorporated into the LTP is the Final Survey Plan. This plan identifies the radiological surveys to be performed once the decontamination activities are completed and is developed using the guidance provided in the "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)."[23] This document incorporates the statistical approaches to survey design and data interpretation used by the EPA. It also identifies state-of-the-art, commercially available instrumentation and procedures for conducting radiological surveys. Use of this guidance ensures that the surveys are conducted in a manner that provides a high degree of confidence that applicable NRC criteria are satisfied. Once the survey is complete, the results are provided to the NRC in a format that can be verified. The NRC then reviews and evaluates the information, performs an independent confirmation of radiological site conditions, and makes a determination on final termination of the license.

The NRC will terminate the operating license if it determines that site remediation has been performed in accordance with the LTP, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release.

2.1.3 Period 3 - Site Restoration

Following completion of decommissioning operations, site restoration activities will begin. Efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below the NRC limits will result in substantial damage to many of the structures. Although performed in a controlled, safe manner, blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially degrade power block structures including the reactor, fuel handling, radioactive waste, solidification facility and condensate polishing buildings. Under certain circumstances, verifying that subsurface radionuclide concentrations meet NRC site release requirements will require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This removal

activity will be necessary for those facilities and plant areas, where historical records, when available, indicate the potential for radionuclides having been present in the soil, where system failures have been recorded, or where it is required to confirm that subsurface process and drain lines were not breached over the operating life of the station.

It is not currently anticipated that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures, once remediation is complete, with a work force already mobilized on site is more efficient than if the process is deferred.

This cost study presumes that non-essential structures and site facilities are dismantled as a continuation of the decommissioning activity. Foundations and exterior walls are removed to a nominal depth of three feet below grade. The three-foot depth allows for the placement of gravel for drainage, as well as topsoil, so that vegetation can be established for erosion control. Site areas affected by the dismantling activities are restored and the plant area graded as required to prevent ponding and inhibit the refloating of subsurface materials.

Non-contaminated concrete rubble produced by demolition activities is processed to remove reinforcing steel and miscellaneous embedments. The processed material is then used on site to backfill foundation voids. Excess non-contaminated materials are trucked to an off-site area for disposal as construction debris.

2.2 SAFSTOR

The NRC defines SAFSTOR as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." The facility is left intact (during the dormancy period), with structures maintained in a sound condition. Systems that are not required to support the spent fuel pool or site surveillance and security are drained, de-energized, and secured. Minimal cleaning/removal of loose contamination and/or fixation and sealing of remaining contamination are performed. Access to contaminated areas is secured to provide controlled access for inspection and maintenance.

The engineering and planning requirements are similar to those for the DECON alternative, although a shorter time period is expected for these

activities due to the more limited work scope. Site preparations are also similar to those for the DECON alternative. However, with the exception of the required radiation surveys and site characterizations, the mobilization and preparation of site facilities is less extensive.

2.2.1 Period 1 - Preparations

Preparations for long-term storage include the planning for permanent defueling of the reactor, revision of technical specifications appropriate to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

The process of placing the plant in safe-storage includes, but is not limited to, the following activities:

- Isolation of the spent fuel storage services and fuel handling systems so that safe-storage operations may commence on the balance of the plant. This activity may be carried out by plant personnel in accordance with existing operating technical specifications. Activities are scheduled around the fuel handling systems to the greatest extent possible.
- Transfer of the spent fuel from the storage pool to the DOE following the minimum required cooling period in the spent fuel pool (any spent fuel stored at the ISFSI is also removed from the site during this time period).
- Draining and de-energizing of the non-contaminated systems not required to support continued site operations or maintenance.
- Disposing of contaminated filter elements and resin beds not required for processing wastes from layup activities for future operations.
- Draining of the reactor vessel, with the internals left in place and the vessel head secured.
- Draining and de-energizing non-essential, contaminated systems with decontamination as required for future maintenance and inspection.
- Preparing lighting and alarm systems whose continued use is required; de-energizing portions of fire protection, electric power, and HVAC systems whose continued use is not required.
- Cleaning of the loose surface contamination from building access pathways.

- Performing an interim radiation survey of plant, posting warning signs where appropriate.
- Erecting physical barriers and/or securing all access to radioactive or contaminated areas, except as required for inspection and maintenance.
- Installing security and surveillance monitoring equipment and relocating security fence around secured structures, as required.

2.2.2 Period 2 - Dormancy

The second phase identified by the NRC in its rule addresses licensed activities during a storage period and is applicable to the dormancy phases of the deferred decommissioning alternatives. Dormancy activities include a 24-hour security force, preventive and corrective maintenance on security systems, area lighting, general building maintenance, heating and ventilation of buildings, routine radiological inspections of contaminated structures, maintenance of structural integrity, and a site environmental and radiation monitoring program. Resident maintenance personnel perform equipment maintenance, inspection activities, routine services to maintain safe conditions, adequate lighting, heating, and ventilation, and periodic preventive maintenance on essential site services.

An environmental surveillance program is carried out during the dormancy period to ensure that releases of radioactive material to the environment are prevented and/or detected and controlled. Appropriate emergency procedures are established and initiated for potential releases that exceed prescribed limits. The environmental surveillance program constitutes an abbreviated version of the program in effect during normal plant operations.

Security during the dormancy period is conducted primarily to prevent unauthorized entry and to protect the public from the consequences of its own actions. The security fence, sensors, alarms, and other surveillance equipment provide security. Fire and radiation alarms are also monitored and maintained.

Consistent with the DECON scenario, the spent fuel storage pool and the ISFSI are emptied within five and one-half years of the cessation of operations. The pool is secured for storage and decommissioned along with the power block structures in Period 4.

After a period of storage (such that license termination is accomplished within 60 years of final shutdown), it is required that the licensee submit an application to terminate the license, along with an LTP (described in Section 2.1.2), thereby initiating the third phase.

2.2.3 Periods 3 and 4 - Delayed Decommissioning

Prior to the commencement of decommissioning operations, preparations are undertaken to reactivate site services and prepare for decommissioning. Preparations include engineering and planning, a detailed site characterization, and the assembly of a decommissioning management organization. Final planning for activities and the writing of activity specifications and detailed procedures are also initiated at this time.

Much of the work in developing a termination plan is relevant to the development of the detailed engineering plans and procedures. The activities associated with this phase and the follow-on decontamination and dismantling processes are detailed in Sections 2.1.1 and 2.1.2. The primary difference between the sequences anticipated for the DECON and this deferred scenario is the absence, in the latter, of any constraint on the availability of the fuel storage facilities for decommissioning.

Variations in the length of the dormancy period are expected to have little effect upon the quantities of radioactive wastes generated from system and structure removal operations. Given the levels of radioactivity and spectrum of radionuclides expected from sixty years of plant operation, no plant process system identified as being contaminated upon final shutdown will become releasable due to the decay period alone, i.e., there is no significant reduction in the waste generated from the decommissioning activities. However, due to the lower activity levels, a greater percentage of the waste volume can be designated for off-site processing and recovery.

The delay in decommissioning also yields lower working area radiation levels. As such, the estimate for this delayed scenario incorporates reduced ALARA controls for the SAFSTOR's lower occupational exposure potential.

Although the initial radiation levels due to ^{60}Co will decrease during the dormancy period, the internal components of the reactor vessel will still exhibit sufficiently high radiation dose rates to require remote sectioning under water due to the presence of long-lived radionuclides

such as ^{94}Nb, ^{59}Ni, and ^{63}Ni. Therefore, the dismantling procedures described for the DECON alternative would still be employed during this scenario. Portions of the biological shield will still be radioactive due to the presence of activated trace elements with long half-lives (^{152}Eu and ^{154}Eu). Decontamination will require controlled removal and disposal. It is assumed that radioactive corrosion products on inner surfaces of piping and components will not have decayed to levels that will permit unrestricted use or allow conventional removal. These systems and components will be surveyed as they are removed and disposed of in accordance with the existing radioactive release criteria.

2.2.4 Period 5 - Site Restoration

Following completion of decommissioning operations, site-restoration activities can begin. Dismantling, as a continuation of the decommissioning process, is clearly the most appropriate and cost-effective option, as described in Section 2.1.3. The basis for the dismantling cost in this scenario is consistent with that described for DECON, presuming the removal of structures and site facilities to a nominal depth of three feet below grade and the limited restoration of the site.

3. COST ESTIMATE

The cost estimates prepared for decommissioning Wolf Creek consider the unique features of the site, including the nuclear steam supply system, electric power generating systems, structures and supporting facilities. The basis of the estimates, including the sources of information relied upon, the estimating methodology employed, site-specific considerations, and other pertinent assumptions, is described in this section.

3.1 BASIS OF ESTIMATE

The current estimates were developed using the site-specific, technical information relied upon in the decommissioning analysis prepared in 2014. This information was reviewed for the current analysis and updated as deemed appropriate. The site-specific considerations and assumptions used in the previous evaluation were also revisited. Modifications were incorporated where new information was available or experience from ongoing decommissioning programs provided viable alternatives or improved processes.

3.2 METHODOLOGY

The methodology used to develop the estimates follows the basic approach originally presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"[24] and the DOE "Decommissioning Handbook."[25] These documents present a unit factor method for estimating decommissioning activity costs, which simplifies the estimating calculations. Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) are developed using local labor rates. The activity-dependent costs are estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents. Removal rates and material costs for the conventional disposition of components and structures rely upon information available in the industry publication, "Building Construction Cost Data," published by RSMeans.[26]

The unit factor method provides a demonstrable basis for establishing reliable cost estimates. The detail provided in the unit factors, including activity duration, labor costs (by craft), and equipment and consumable costs, ensures that essential elements have not been omitted. Appendix A presents the detailed development of a typical unit factor. Appendix B provides the values contained within one set of factors developed for this analysis.

Regulatory Guide 1.184[27] Revision 1, issued in October 2013, describes the methods and procedures that are acceptable to the NRC staff for implementing the requirements that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202,[28] issued February 2005.

This analysis reflects lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Work Difficulty Factors

TLG has historically applied work difficulty adjustment factors (WDFs) to account for the inefficiencies in working in a power plant environment. WDFs are assigned to each unique set of unit factors, commensurate with the inefficiencies associated with working in confined, hazardous environments. The ranges used for the WDFs are as follows:

- Access Factor — 10% to 20%
- Respiratory Protection Factor — 10% to 50%
- Radiation/ALARA Factor — 10% to 37%
- Protective Clothing Factor — 10% to 30%
- Work Break Factor — 8.33%

The factors and their associated range of values were developed in conjunction with the AIF/NESP-036 study. The application of the factors is discussed in more detail in that publication.

Scheduling Program Durations

The unit factors, adjusted by the WDFs as described above, are applied against the inventory of materials to be removed in the radiological controlled areas. The resulting man-hours, or crew-hours, are used in the development of the

decommissioning program schedule, using resource loading and event sequencing considerations. The scheduling of conventional removal and dismantling activities is based upon productivity information available from the "Building Construction Cost Data" publication.

An activity duration critical path is used to determine the total decommissioning program schedule. The schedule is relied upon in calculating the carrying costs, which include program management, administration, field engineering, equipment rental, and support services such as quality control and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

3.3 FINANCIAL COMPONENTS OF THE COST MODEL

TLG's proprietary decommissioning cost model, DECCER, produces a number of distinct cost elements. These direct expenditures, however, do not comprise the total cost to accomplish the project goal, i.e., license termination and site restoration.

Inherent in any cost estimate that does not rely on historical data is the inability to specify the precise source of costs imposed by factors such as tool breakage, accidents, illnesses, weather delays, and labor stoppages. In the DECCER cost model, contingency fulfills this role. Contingency is added to each line item to account for costs that are difficult or impossible to develop analytically. Such costs are historically inevitable over the duration of a job of this magnitude; therefore, this cost analysis includes funds to cover these types of expenses.

3.3.1 Contingency

The activity- and period-dependent costs are combined to develop the total decommissioning cost. A contingency is then applied on a line-item basis, using one or more of the contingency types listed in the AIF/NESP-036 study. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook"[29] as "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." The cost elements in this analysis are based upon ideal conditions and maximum efficiency; therefore, consistent with industry practice, contingency is included. In the AIF/NESP-036 study, the types of

unforeseeable events that are likely to occur in decommissioning are discussed and guidelines are provided for percentage contingency in each category. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

Contingency funds are an integral part of the total cost to complete the decommissioning process. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, subsequent related activities. For this study, TLG examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, transport, and waste disposal) that necessitate a contingency. Individual activity contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from TLG's actual decommissioning experience. The contingency values used in this study are as follows:

• Decontamination	50%
• Contaminated Component Removal	25%
• Contaminated Component Packaging	10%
• Contaminated Component Transport	15%
• Low-Level Radioactive Waste Disposal	25%
• Low-Level Radioactive Waste Processing	15%
• Reactor Segmentation	75%
• NSSS Component Removal	25%
• Reactor Waste Packaging	25%
• Reactor Waste Transport	25%
• Reactor Vessel Component Disposal	50%
• GTCC Disposal	15%
• Non-Radioactive Component Removal	15%
• Heavy Equipment and Tooling	15%
• Supplies	25%
• Engineering	15%
• Energy	15%
• Insurance, Taxes and Fees	10%
• Staffing	15%
• Characterization and Termination Surveys	30%
• Operations and Maintenance Expense	15%
• ISFSI Decommissioning	25%

The contingency values are applied to the appropriate components of the estimates on a line item basis. A composite value is then reported at the end of each detailed estimate (as provided in Appendix C and D). A contingency of 25% is applied to the subtotal of the ISFSI decommissioning costs.

3.3.2 Financial Risk

In addition to the routine uncertainties addressed by contingency, another cost element that is sometimes necessary to consider when bounding decommissioning costs relates to uncertainty, or risk. Examples can include changes in work scope, pricing, job performance, and other variations that could conceivably, but not necessarily, occur. Consideration is sometimes necessary to generate a level of confidence in the estimate, within a range of probabilities. TLG considers these types of costs under the broad term "financial risk." Included within the category of financial risk are:

- Transition activities and costs: ancillary expenses associated with eliminating 50% to 80% of the site labor force shortly after the cessation of plant operations, added cost for worker separation packages throughout the decommissioning program, national or company-mandated retraining, and retention incentives for key personnel.
- Delays in approval of the decommissioning plan due to intervention, public participation in local community meetings, legal challenges, and national and local hearings.
- Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.
- Regulatory changes, for example, affecting worker health and safety, site release criteria, waste transportation, and disposal.
- Policy decisions altering national commitments (e.g., in the ability to accommodate certain waste forms for disposition), or in the timetable for such, for example, the start and rate of acceptance of spent fuel by the DOE.
- Pricing changes for basic inputs such as labor, energy, materials, and disposal. Items subject to widespread price competition (such as

materials) may not show significant variation; however, others such as waste disposal could exhibit large pricing uncertainties, particularly in markets where limited access to services is available.

This cost study does not add any additional costs to the estimate for financial risk, since there is insufficient historical data from which to project future liabilities. Consequently, the areas of uncertainty or risk are revisited periodically and addressed through repeated revisions or updates of the base estimates.

3.4 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impact of the considerations identified below is included in this cost study.

3.4.1 Spent Fuel Management

The cost to dispose the spent fuel generated from plant operations is not reflected within the estimates to decommission Wolf Creek. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, until recently, the disposal cost was being financed by a 1 mill/kWhr surcharge on nuclear generated energy delivered to customers, the fee being paid into the DOE's waste fund during operations. The D.C. Circuit ruling on November 19, 2013, ordered the DOE to submit a proposal to Congress to suspend the Nuclear Waste Fund fee "until such time as either the Secretary chooses to comply with the Act as it is currently written, or until Congress enacts an alternative waste management plan." The fee was reduced to 0.0 mill/kWh as of May 16, 2014. The fee is expected to be reinstated in the future.

Nonetheless, the NRC does requires licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor until title of the fuel is transferred to the Secretary of Energy. This funding requirement is fulfilled through inclusion of certain high-level waste cost elements within the estimates, as described below.

For estimating purposes, WCNOC has assumed that all spent fuel will be removed to a DOE facility within five and one-half years after shutdown. Interim storage of the fuel, until the DOE has completed the

transfer, will be in the spent fuel pool located in the fuel building (as well as on the ISFSI). The spent fuel storage pool and fuel handling systems will be isolated (i.e., a spent fuel island created). This will allow WCNOC to proceed with decommissioning (or safe-storage) operations in the shortest time possible. A delay in the start of fuel pickup, or a decrease in the spent fuel acceptance rate, will correspondingly prolong the transfer process and result in the fuel remaining at the Wolf Creek site longer.

It is assumed that the five and one-half years also provides the necessary cooling period for the final core to meet DOE's transport system requirements for decay heat. Once the pool is emptied, the spent fuel storage and handling facilities are available for decommissioning. Operation and maintenance costs for the spent fuel pool are included within the estimate as well as the costs to transfer the spent fuel to the DOE.

Supplemental Storage

It is likely that supplemental spent fuel storage will be required to support continued plant operations (i.e., maintain full core off-load capability). This analysis assumes that an ISFSI is constructed during operations and that 592 spent fuel assemblies (16 equivalent dry storage system modules) are transferred to the ISFSI during plant operations (assuming that the DOE begins removing fuel from the Wolf Creek site in 2032). The fuel will remain in storage until it is off-loaded into a DOE-provided transport cask. The transfer is assumed to occur once the spent fuel pool has been emptied. The estimates include the cost for the transfer only.

Canister Loading and Transfer

The estimates include the cost to load the spent fuel in the wet storage pool into a DOE-provided multi-purpose canister (e.g., Transport, Aging and Disposal or TAD canister), seal the canisters and place the canister into the DOE transport vehicle. The estimates also include the cost to transfer each canister stored at the ISFSI into the DOE transport vehicle.

Operations and Maintenance

The estimates include the cost of operating and maintaining the spent fuel pool for approximately five and one half years after the cessation of operations.

ISFSI Decommissioning

In accordance with 10 CFR §72.30, licensees must have a proposed decommissioning plan for the ISFSI site and facilities that includes a cost estimate for the plan. The plan needs to contain sufficient information on the proposed practices and procedures for the decontamination of the ISFSI and for the disposal of residual radioactive materials after the spent fuel has been removed.

For purposes of this study only, the decommissioning cost for a future ISFSI was included in the DECON and SAFSTOR estimates. The decommissioning estimate is based on the premise that some of the storage casks will contain low levels of neutron-induced residual radioactivity that would necessitate remediation at the time of decommissioning. As an allowance, 6 casks are assumed to be affected, i.e., contain residual radioactivity. The allowance is based upon the number of casks required for the final core off-load (i.e., 193 offloaded assemblies, 37 assemblies per cask) which results in 6 storage modules. It is assumed that these are the final casks offloaded; consequently they have the least time for radioactive decay of any neutron activation products.

No contamination or activation of the ISFSI pad is assumed. It would be expected that this assumption would be confirmed as a result of good radiological practice of surveying potentially impacted areas after each spent fuel transfer campaign. As such, only verification surveys are included for the pad in the decommissioning estimate. The estimate is limited to costs necessary to terminate the ISFSI's NRC license and meet the §20.1402 criteria for unrestricted use.

In accordance with the specific requirements of 10 CFR §72.30 for the ISFSI work scope, the cost estimate for decommissioning the ISFSI reflects: 1) the cost of an independent contractor performing the decommissioning activities; 2) an adequate contingency factor; and 3) the cost of meeting the criteria for unrestricted use.

GTCC

The dismantling of the reactor internals is expected to generate radioactive waste considered unsuitable for shallow land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. Although the DOE is responsible for disposing of GTCC waste, any costs for that service have not been determined.

For purposes of this study, GTCC is packaged in the same canisters used to transport spent fuel. The GTCC is assumed to be disposed of as it is generated during reactor vessel segmentation operations.

3.4.2 Reactor Vessel and Internal Components

The reactor pressure vessel and internal components are segmented for disposal in shielded, reusable transportation casks. Segmentation is performed in the refueling canal, where a turntable and remote cutter are installed. The vessel is segmented in place, using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the reactor cavity. Transportation cask specifications and transportation regulations dictate the segmentation and packaging methodology.

Intact disposal of reactor vessel shells has been successfully demonstrated at several of the sites currently being decommissioned. Access to navigable waterways has allowed these large packages to be transported to the Barnwell, South Carolina and Hanford, Washington disposal sites with minimal overland travel. Intact disposal of the reactor vessel and internal components can provide savings in cost and worker exposure by eliminating the complex segmentation requirements, isolation of the GTCC material, and transport/storage of the resulting waste packages. Portland General Electric (PGE) was able to dispose of the Trojan reactor as an intact package (including the internals). However, its location on the Columbia River simplified the transportation analysis since:

- the reactor package could be secured to the transport vehicle for the entire journey, i.e., the package was not lifted during transport,
- there were no man-made or natural terrain features between the plant site and the disposal location that could produce a large drop, and
- transport speeds were very low, limited by the overland transport vehicle and the river barge.

As a member of the Northwest Compact, PGE had a site available for disposal of the package - the US Ecology facility in Washington State. The characteristics of this arid site proved favorable in demonstrating compliance with land disposal regulations.

It is not known whether this option will be available when Wolf Creek ceases operation. Future viability of this option will depend upon the ultimate location of the disposal site, as well as the disposal site licensee's ability to accept highly radioactive packages and effectively isolate them from the environment. Consequently, the study assumes the reactor vessel will require segmentation, as a bounding condition.

3.4.3 Primary System Components

In the DECON scenario, the reactor coolant system components are assumed to be decontaminated using chemical agents prior to the start of dismantling operations. This type of decontamination can be expected to have a significant ALARA impact, since in this scenario the removal work is done within the first few years of shutdown. In the SAFSTOR scenario, radionuclide decay is expected to provide the same benefit and, therefore, a chemical decontamination is not included.

The following discussion deals with the removal and disposition of the steam generators, but the techniques involved are also applicable to other large components, such as heat exchangers, component coolers, and the pressurizer. The steam generators' size and weight, as well as their location within the reactor building, will ultimately determine the removal strategy.

A trolley crane is set up for the removal of the generators. It can also be used to move portions of the steam generator cubicle walls and floor slabs from the reactor building to a location where they can be decontaminated and transported to the material handling area.

Interferences within the work area, such as grating, piping, and other components are removed to create sufficient laydown space for processing these large components.

The generators are rigged for removal, disconnected from the surrounding piping and supports, and maneuvered into the open area where they are lowered onto a dolly. Each generator is rotated into the horizontal position for extraction from the containment and placed onto a multi-wheeled vehicle for transport to an on-site processing and storage area.

The generators are disassembled on-site with the steam dome and lightly contaminated subassemblies designated for off-site recycling. The more highly contaminated tube sheet and tube bundle are packaged for direct disposal. The interior volume is filled with low-density cellular concrete for stabilization of the internal contamination.

Reactor coolant piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and transported by shielded van. The reactor coolant pumps and motors are lifted out intact, packaged, and transported for processing and/or disposal.

3.4.4 Main Turbine and Condenser

The main turbine is dismantled using conventional maintenance procedures. The turbine rotors and shafts are removed to a laydown area. The lower turbine casings are removed from their anchors by controlled demolition. The main condensers are also disassembled and moved to a laydown area. Material is then prepared for transportation to an off-site recycling facility where it is surveyed and designated for either decontamination or volume reduction, conventional disposal, or controlled disposal. Components are packaged and readied for transport in accordance with the intended disposition.

3.4.5 Transportation Methods

Contaminated piping, components, and structural material other than the highly activated reactor vessel and internal components will qualify as LSA-I, II or III or Surface Contaminated Object, SCO-I or II, as described in Title 49.[30] The contaminated material will be packaged in Industrial Packages (IP-1, IP-2, or IP-3, as defined in subpart 173.411)

for transport unless demonstrated to qualify as their own shipping containers. The reactor vessel and internal components are expected to be transported in accordance with 10 CFR Part 71, as Type B. It is conceivable that the reactor, due to its limited specific activity, could qualify as LSA II or III. However, the high radiation levels on the outer surface would require that additional shielding be incorporated within the packaging so as to attenuate the dose to levels acceptable for transport.

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major reactor components to be shipped under current transportation regulations and disposal requirements.

Transport of the highly activated metal, produced in the segmentation of the reactor vessel and internal components, will be by shielded truck cask. Cask shipments may exceed 95,000 pounds, including vessel segment(s), supplementary shielding, cask tie-downs, and tractor-trailer. The maximum level of activity per shipment assumed permissible was based upon the license limits of the available shielded transport casks. The segmentation scheme for the vessel and internal segments is designed to meet these limits.

The transport of large intact components (e.g., large heat exchangers and other oversized components) will be by a combination of truck, rail, and/or multi-wheeled transporter.

Transportation costs for Class A radioactive material requiring controlled disposal are based upon the mileage to the Energy*Solutions* facility in Clive, Utah. Transportation costs for the higher activity Class B and C radioactive material are based upon the mileage to the WCS facility in Andrews County, Texas. The transportation cost for the GTCC material is assumed to be contained within the disposal cost. Transportation costs for off-site waste processing are based upon the mileage to Oak Ridge, Tennessee. Truck transport costs are estimated using published tariffs from Tri-State Motor Transit.[31]

3.4.6 Low-Level Radioactive Waste Disposal

To the greatest extent practical, metallic material generated in the decontamination and dismantling processes is processed to reduce the

total cost of controlled disposal. Material meeting the regulatory and/or site release criterion, is released as scrap, requiring no further cost consideration. Conditioning (preparing the material to meet the waste acceptance criteria of the disposal site) and recovery of the waste stream is performed off site at a licensed processing center. Any material leaving the site is subject to a survey and release charge, at a minimum. The mass of radioactive waste generated during the various decommissioning activities at the site is shown on a line-item basis in the appendices and summarized in Section 5. The quantified waste summaries shown in these tables are consistent with 10 CFR Part 61 classifications. Commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations. The volumes are calculated based on the exterior package dimensions for containerized material or a specific calculation for components serving as their own waste containers.

The more highly activated reactor components will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

The cost to dispose of the lowest level waste and the majority of the material generated from the decontamination and dismantling activities is based upon the current cost for disposal at Energy*Solutions* facility in Clive, Utah. Disposal costs for the higher activity waste (Class B and C) were based upon preliminary and indicative rates for WCS's Andrews County facility.

3.4.7 Site Conditions Following Decommissioning

The NRC will terminate the site license when it determines that site remediation has been performed in accordance with the license termination plan, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release. The NRC's involvement in the decommissioning process will end at this point. Local building codes and state environmental regulations will dictate the next step in the decommissioning process, as well as the owner's own future plans for the site.

The estimates presented herein include the dismantling of the major structures to just below ground level, backfilling and the collapsing of below grade voids, and regrading such that the site upon which the power block and supplemental structures are located is transformed into a "grassy plain."

Concrete rubble generated from demolition activities is processed and made available as clean fill for the power block foundations. Additional fill is brought in to cap the power block excavations and to permit seeding for erosion control.

A significant amount of the below grade piping is located around the perimeter of the power block. The estimate includes a cost to excavate this area to an average depth of six feet so as to expose the piping, duct bank, conduit, and any near-surface grounding grid. The overburden is surveyed and stockpiled on site for future use in backfilling the below grade voids.

The existing electrical switchyard and access roads will remain in support of the electrical transmission and distribution system. Other structures that will remain are the main dam, cooling lake, makeup water discharge structure (west side of lake), makeup water screen house (located below the John Redmond Dam) and associated underground piping, the Eisenhower Learning Center, and a railroad spur running about 11.5 miles from the plant southeast to near Aliceville, Kansas, where it connects to a Union Pacific Railroad line.

The estimates do not assume the remediation of any significant volume of contaminated soil. Costs are included, however, for the remediation of the firing range, i.e., removal of soil containing lead residue. This assumption may be affected by continued plant operations and/or future regulatory actions, such as the development of site-specific release criteria.

3.5 ASSUMPTIONS

The following are the major assumptions made in the development of the estimates for decommissioning the site.

3.5.1 Estimating Basis

Decommissioning costs are reported in the year of projected expenditure; however, the values are provided in 2017 dollars. Costs are not inflated, escalated, or discounted over the periods of performance.

The estimates rely upon the physical plant inventory that was the basis for the 2014 analysis.

The study follows the principles of ALARA through the use of work duration adjustment factors. These factors address the impact of activities such as radiological protection instruction, mock-up training, and the use of respiratory protection and protective clothing. The factors lengthen a task's duration, increasing costs and lengthening the overall schedule. ALARA planning is considered in the costs for engineering and planning, and in the development of activity specifications and detailed procedures. Changes to worker exposure limits may impact the decommissioning cost and project schedule.

3.5.2 Labor Costs

WCNOC, as the operator, will continue to provide site operations support, including decommissioning program management, licensing, radiological protection, and site security. A Decommissioning Operations Contractor (DOC) will provide the supervisory staff needed to oversee the labor subcontractors, consultants, and specialty contractors needed to perform the work required for the decontamination and dismantling effort. The DOC will also provide the engineering services needed to develop activity specifications, detailed procedures, detailed activation analyses, and support field activities such as structural modifications.

Personnel costs are based upon average salary information provided by WCNOC. Overhead costs are included for site and corporate support, reduced commensurate with the staffing of the project.

The craft labor required to decontaminate and dismantle the nuclear station is acquired through standard site contracting practices. The current cost of labor at the site is used as an estimating basis.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel.

A profile of the staffing levels for decommissioning, including contractors and craft, is provided in Figures 3.1 and 3.2 for the DECON and SAFSTOR scenarios, respectively. Utility staffing levels will gradually decrease after completing the removal of physical systems. Staffing levels and management support will vary based upon the amount and type of decommissioning work. Craft manpower levels decrease after systems removal and structures decontamination and drop substantially during the license termination survey period. However, craft levels increase again during the site restoration period due to the work associated with structures demolition.

3.5.3 Design Conditions

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major NSSS components to be shipped under current transportation regulations and disposal requirements.

The curie contents of the vessel and internals at final shutdown are derived from those listed in NUREG/CR-3474.[32] Actual estimates are derived from the curie/gram values contained therein and adjusted for the different mass of the Wolf Creek components, projected operating life, and different periods of decay. Additional short-lived isotopes were derived from CR-0130[33] and CR-0672,[34] and benchmarked to the long-lived values from CR-3474.

The control elements are disposed of along with the spent fuel, i.e., there is no additional cost provided for their disposal.

Activation of the containment building structure is confined to the biological shield.

3.5.4 General

Transition Activities

Existing warehouses are cleared of non-essential material and remain for use by WCNOC and its subcontractors. The plant's operating staff performs the following activities at no additional cost or credit to the project during the transition period:

- Drain and collect fuel oils, lubricating oils, and transformer oils for recycle and/or sale.
- Drain and collect acids, caustics, and other chemical stores for recycle and/or sale.
- Process operating waste inventories (i.e., the estimates do not address the disposition of any legacy wastes; the disposal of operating wastes during this initial period is not considered a decommissioning expense).

Scrap and Salvage

The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. WCNOC will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that some buyers wanted equipment stripped down to very specific requirements before they would consider purchase. This required expensive rework after the equipment had been removed from its installed location. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall decommissioning expenses, this analysis does not attempt to quantify the value that an owner may realize based upon those efforts.

It is assumed, for purposes of this analysis, that any value received from the sale of scrap generated in the dismantling process would be more than offset by the on-site processing costs. The dismantling techniques assumed in the decommissioning estimates do not include the additional cost for size reduction and preparation to meet "furnace ready" conditions. For example, the recovery of copper from electrical cabling may require the removal and disposition of any contaminated insulation, an added expense. With a volatile market, the potential profit margin in scrap recovery is highly speculative, regardless of the ability to free release this material. This assumption is an implicit recognition of scrap value in the disposal of clean metallic waste at no additional cost to the project.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property is removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts are also made available for alternative use.

Energy

For estimating purposes, the plant is assumed to be de-energized, with the exception of those facilities associated with spent fuel storage. Replacement power costs are used to calculate the cost of energy consumed during decommissioning for tooling, lighting, ventilation, and essential services.

Emergency Planning

FEMA and state fees associated with emergency planning are assumed to continue for approximately 18 months following the cessation of operations. At this time, the fees are discontinued. The timing is based upon the anticipated condition of the spent fuel (i.e., the hottest spent fuel assemblies are assumed to be cool enough that no substantial Zircaloy oxidation and off-site event would occur with the loss of spent fuel pool water). State and local fees continue until all fuel has been removed from the site (approximately five and one-half years following the cessation of operations).

Insurance

Costs for continuing coverage (nuclear liability and property insurance) following cessation of plant operations and during decommissioning are included and based upon current operating premiums. Reductions in premiums, throughout the decommissioning process, are based upon the guidance provided in SECY-00-0145, "Integrated Rulemaking Plan for Nuclear Power Plant Decommissioning"[35] The NRC's financial protection requirements are based on various reactor (and spent fuel) configurations.

Taxes

Property tax payments are included for the land and those facilities that will continue to be used to support the decommissioning project. When the facilities are no longer needed, the taxes are reduced accordingly.

Site Modifications

The perimeter fence and in-plant security barriers will be moved, as appropriate, to conform to the Site Security Plan in force during the various stages of the project.

3.6 COST ESTIMATE SUMMARY

Schedules of expenditures are provided in Tables 3.1 and 3.2. The tables delineate the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal).

The cost elements are also assigned to one of three subcategories: "License Termination," "Spent Fuel Management," and "Site Restoration." The subcategory "License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). The cost reported for this subcategory is generally sufficient to terminate the station's operating license, recognizing that there may be some additional cost impact from spent fuel management. These costs are identified in Tables 3.1a and 3.2a.

The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). The basis for the ISFSI decommissioning cost that is included in both Appendices C and D is described in Section 3.4.1.

The "Spent Fuel Management" subcategory contains costs associated with the five and one-half years of post-shutdown pool and ISFSI operations, and the management of the spent fuel until such time that the transfer of all fuel from this facility to an off-site location is complete. These costs are identified in Tables 3.1b and 3.2b.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are removed to a depth of three feet and backfilled to conform to local grade. These costs are identified in Tables 3.1c and 3.2c.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligation determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, an owner may decide to remove non-contaminated structures early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support

activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As discussed in Section 3.4.1, while designated for disposal at the geologic repository along with the spent fuel, GTCC waste is still classified as low-level radioactive waste and, as such, included as a "License Termination" expense.

The estimates were developed and costs are presented in 2017 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the reactor or during the decommissioning period. The schedules are based upon the detailed activity costs reported in Appendices C and D, along with the timeline presented in Section 4.

TABLE 3.1
DECON ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	58,361	2,378	1,969	33	9,446	72,188
2046	79,873	21,825	3,615	14,402	27,684	147,398
2047	76,699	32,056	2,307	32,769	20,185	164,016
2048	72,060	23,138	2,066	21,513	14,659	133,436
2049	67,183	14,384	1,821	10,505	9,232	103,125
2050	58,152	13,450	1,560	11,115	9,239	93,516
2051	33,150	5,285	664	4,607	4,793	48,499
2052	18,938	10,854	277	4	1,885	31,959
2053	10,625	7,677	152	0	1,142	19,595
Total	475,042	131,047	14,431	94,948	98,265	813,733

Note: Columns may not add due to rounding

TABLE 3.1a
DECON ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	57,604	1,585	1,969	33	7,509	68,700
2046	77,006	17,414	3,615	14,402	25,472	137,908
2047	73,503	26,787	2,307	32,769	18,372	153,738
2048	68,660	17,316	2,066	21,513	12,841	122,396
2049	63,604	8,058	1,821	10,505	7,419	91,407
2050	55,274	9,065	1,560	11,115	7,982	84,997
2051	31,860	5,285	664	4,607	4,793	47,209
2052	4,201	248	68	4	308	4,829
2053	88	0	0	0	0	88
Total	431,800	85,759	14,069	94,948	84,697	711,273

Note: Columns may not add due to rounding

TABLE 3.1b
DECON ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	264	793	0	0	1,938	2,995
2046	1,460	4,380	0	0	2,212	8,053
2047	1,724	5,171	0	0	1,813	8,708
2048	1,911	5,733	0	0	1,818	9,461
2049	2,082	6,245	0	0	1,813	10,139
2050	1,840	4,329	0	0	1,257	7,425
2051	1,290	0	0	0	0	1,290
2052	180	0	0	0	0	180
2053	0	0	0	0	0	0
Total	10,751	26,651	0	0	10,850	48,251

Note: Columns may not add due to rounding

TABLE 3.1c
DECON ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	493	0	0	0	0	493
2046	1,407	30	0	0	0	1,437
2047	1,472	98	0	0	0	1,570
2048	1,489	89	0	0	0	1,579
2049	1,498	81	0	0	0	1,578
2050	1,038	56	0	0	0	1,094
2051	0	0	0	0	0	0
2052	14,558	10,606	210	0	1,577	26,950
2053	10,537	7,677	152	0	1,142	19,507
Total	32,491	18,637	361	0	2,719	54,208

Note: Columns may not add due to rounding

TABLE 3.2
SAFSTOR ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	50,301	1,936	1,969	33	9,446	63,686
2046	52,967	10,775	1,832	1,389	23,599	90,562
2047	28,085	6,228	486	15	6,065	40,878
2048	28,162	6,245	487	16	6,082	40,990
2049	28,085	6,228	486	15	6,065	40,878
2050	20,521	4,415	411	13	4,624	29,985
2051	3,437	322	243	7	1,370	5,378
2052	3,446	323	243	7	1,374	5,393
2053	3,437	322	243	7	1,370	5,378
2054	3,437	322	243	7	1,370	5,378
2055	3,437	322	243	7	1,370	5,378
2056	3,446	323	243	7	1,374	5,393
2057	3,437	322	243	7	1,370	5,378
2058	3,437	322	243	7	1,370	5,378
2059	3,437	322	243	7	1,370	5,378
2060	3,446	323	243	7	1,374	5,393
2061	3,437	322	243	7	1,370	5,378
2062	3,437	322	243	7	1,370	5,378
2063	3,437	322	243	7	1,370	5,378
2064	3,446	323	243	7	1,374	5,393
2065	3,437	322	243	7	1,370	5,378
2066	3,437	322	243	7	1,370	5,378
2067	3,437	322	243	7	1,370	5,378
2068	3,446	323	243	7	1,374	5,393
2069	3,437	322	243	7	1,370	5,378
2070	3,437	322	243	7	1,370	5,378
2071	3,437	322	243	7	1,370	5,378
2072	3,446	323	243	7	1,374	5,393
2073	3,437	322	243	7	1,370	5,378
2074	3,437	322	243	7	1,370	5,378
2075	3,437	322	243	7	1,370	5,378
2076	3,446	323	243	7	1,374	5,393
2077	3,437	322	243	7	1,370	5,378

TABLE 3.2 (continued)
SAFSTOR ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2078	3,437	322	243	7	1,370	5,378
2079	3,437	322	243	7	1,370	5,378
2080	3,446	323	243	7	1,374	5,393
2081	3,437	322	243	7	1,370	5,378
2082	3,437	322	243	7	1,370	5,378
2083	3,437	322	243	7	1,370	5,378
2084	3,446	323	243	7	1,374	5,393
2085	3,437	322	243	7	1,370	5,378
2086	3,437	322	243	7	1,370	5,378
2087	3,437	322	243	7	1,370	5,378
2088	3,446	323	243	7	1,374	5,393
2089	3,437	322	243	7	1,370	5,378
2090	3,437	322	243	7	1,370	5,378
2091	3,437	322	243	7	1,370	5,378
2092	3,446	323	243	7	1,374	5,393
2093	3,437	322	243	7	1,370	5,378
2094	3,437	322	243	7	1,370	5,378
2095	3,437	322	243	7	1,370	5,378
2096	3,446	323	243	7	1,374	5,393
2097	3,437	322	243	7	1,370	5,378
2098	8,030	526	530	10	1,416	10,512
2099	39,843	3,003	2,428	35	1,725	47,034
2100	51,668	21,348	2,352	19,715	11,194	106,277
2101	52,224	26,356	2,272	29,879	16,007	126,738
2102	43,514	7,481	1,821	10,054	5,614	68,485
2103	43,514	7,481	1,821	10,054	5,614	68,485
2104	36,028	4,171	1,047	4,233	3,422	48,900
2105	19,989	11,805	289	6	1,828	33,916
2106	11,872	9,571	164	0	1,237	22,843
Total	676,430	142,714	29,815	75,790	168,367	1,093,117

TABLE 3.2a
SAFSTOR ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	50,036	1,143	1,969	33	7,509	60,690
2046	50,641	6,213	1,758	1,389	21,375	81,375
2047	23,538	465	243	15	4,213	28,474
2048	23,602	467	243	16	4,224	28,552
2049	23,538	465	243	15	4,213	28,474
2050	17,370	421	243	13	3,340	21,387
2051	3,437	322	243	7	1,370	5,378
2052	3,446	323	243	7	1,374	5,393
2053	3,437	322	243	7	1,370	5,378
2054	3,437	322	243	7	1,370	5,378
2055	3,437	322	243	7	1,370	5,378
2056	3,446	323	243	7	1,374	5,393
2057	3,437	322	243	7	1,370	5,378
2058	3,437	322	243	7	1,370	5,378
2059	3,437	322	243	7	1,370	5,378
2060	3,446	323	243	7	1,374	5,393
2061	3,437	322	243	7	1,370	5,378
2062	3,437	322	243	7	1,370	5,378
2063	3,437	322	243	7	1,370	5,378
2064	3,446	323	243	7	1,374	5,393
2065	3,437	322	243	7	1,370	5,378
2066	3,437	322	243	7	1,370	5,378
2067	3,437	322	243	7	1,370	5,378
2068	3,446	323	243	7	1,374	5,393
2069	3,437	322	243	7	1,370	5,378
2070	3,437	322	243	7	1,370	5,378
2071	3,437	322	243	7	1,370	5,378
2072	3,446	323	243	7	1,374	5,393
2073	3,437	322	243	7	1,370	5,378
2074	3,437	322	243	7	1,370	5,378
2075	3,437	322	243	7	1,370	5,378
2076	3,446	323	243	7	1,374	5,393
2077	3,437	322	243	7	1,370	5,378

TABLE 3.2a (continued)
SAFSTOR ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2078	3,437	322	243	7	1,370	5,378
2079	3,437	322	243	7	1,370	5,378
2080	3,446	323	243	7	1,374	5,393
2081	3,437	322	243	7	1,370	5,378
2082	3,437	322	243	7	1,370	5,378
2083	3,437	322	243	7	1,370	5,378
2084	3,446	323	243	7	1,374	5,393
2085	3,437	322	243	7	1,370	5,378
2086	3,437	322	243	7	1,370	5,378
2087	3,437	322	243	7	1,370	5,378
2088	3,446	323	243	7	1,374	5,393
2089	3,437	322	243	7	1,370	5,378
2090	3,437	322	243	7	1,370	5,378
2091	3,437	322	243	7	1,370	5,378
2092	3,446	323	243	7	1,374	5,393
2093	3,437	322	243	7	1,370	5,378
2094	3,437	322	243	7	1,370	5,378
2095	3,437	322	243	7	1,370	5,378
2096	3,446	323	243	7	1,374	5,393
2097	3,437	322	243	7	1,370	5,378
2098	7,946	526	530	10	1,416	10,428
2099	39,068	3,003	2,428	35	1,725	46,259
2100	49,978	21,279	2,352	19,715	11,194	104,518
2101	50,548	26,248	2,272	29,879	16,007	124,954
2102	42,190	7,410	1,821	10,054	5,614	67,089
2103	42,190	7,410	1,821	10,054	5,614	67,089
2104	35,472	4,141	1,047	4,233	3,422	48,315
2105	6,309	1,835	92	6	346	8,588
2106	457	1,251	0	0	0	1,708
Total	624,509	97,424	28,482	75,790	154,641	980,846

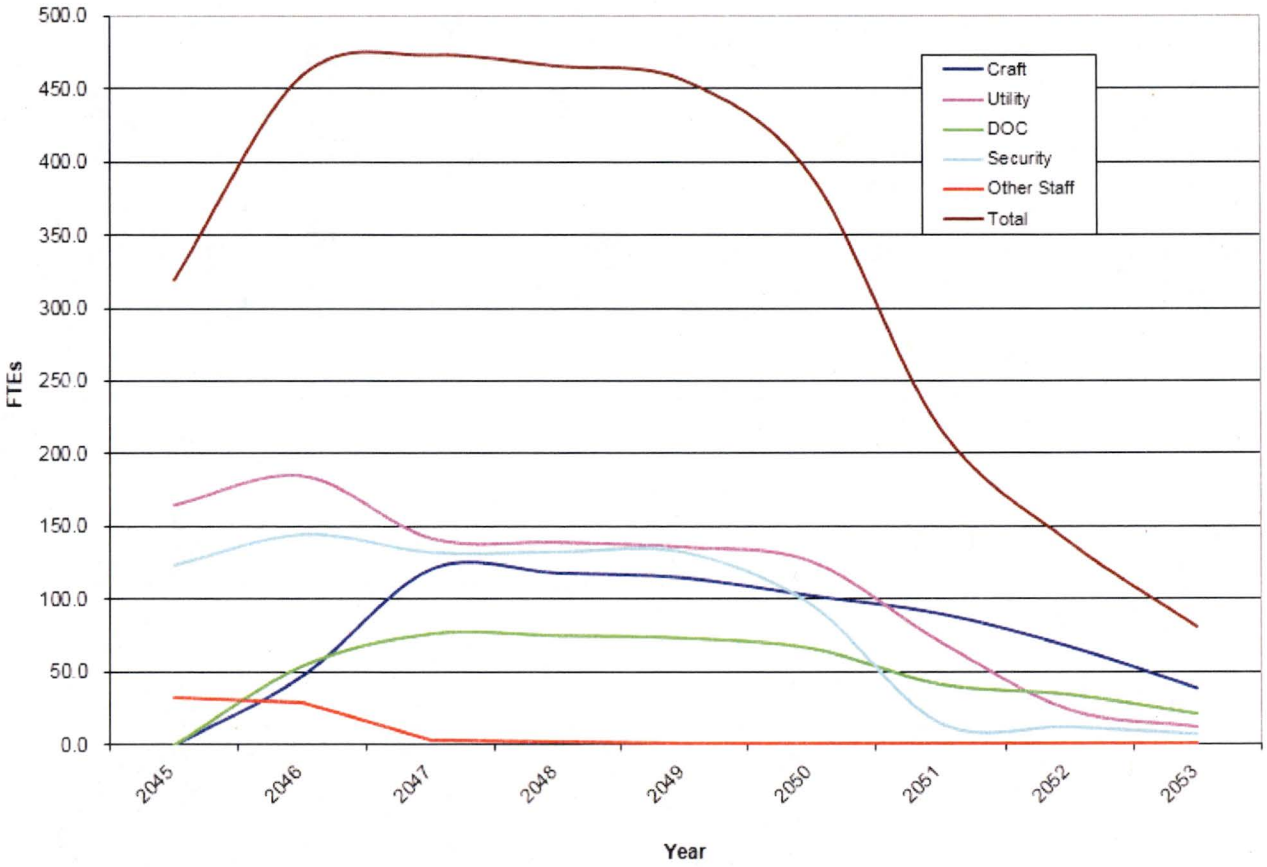
TABLE 3.2b
SAFSTOR ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	264	793	0	0	1,938	2,995
2046	2,327	4,562	75	0	2,224	9,187
2047	4,547	5,762	243	0	1,852	12,404
2048	4,560	5,778	243	0	1,857	12,438
2049	4,547	5,762	243	0	1,852	12,404
2050	3,152	3,994	168	0	1,284	8,598
2051-2106	0	0	0	0	0	0
Total	19,397	26,651	972	0	11,008	58,028

TABLE 3.2c
SAFSTOR ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2017 dollars)

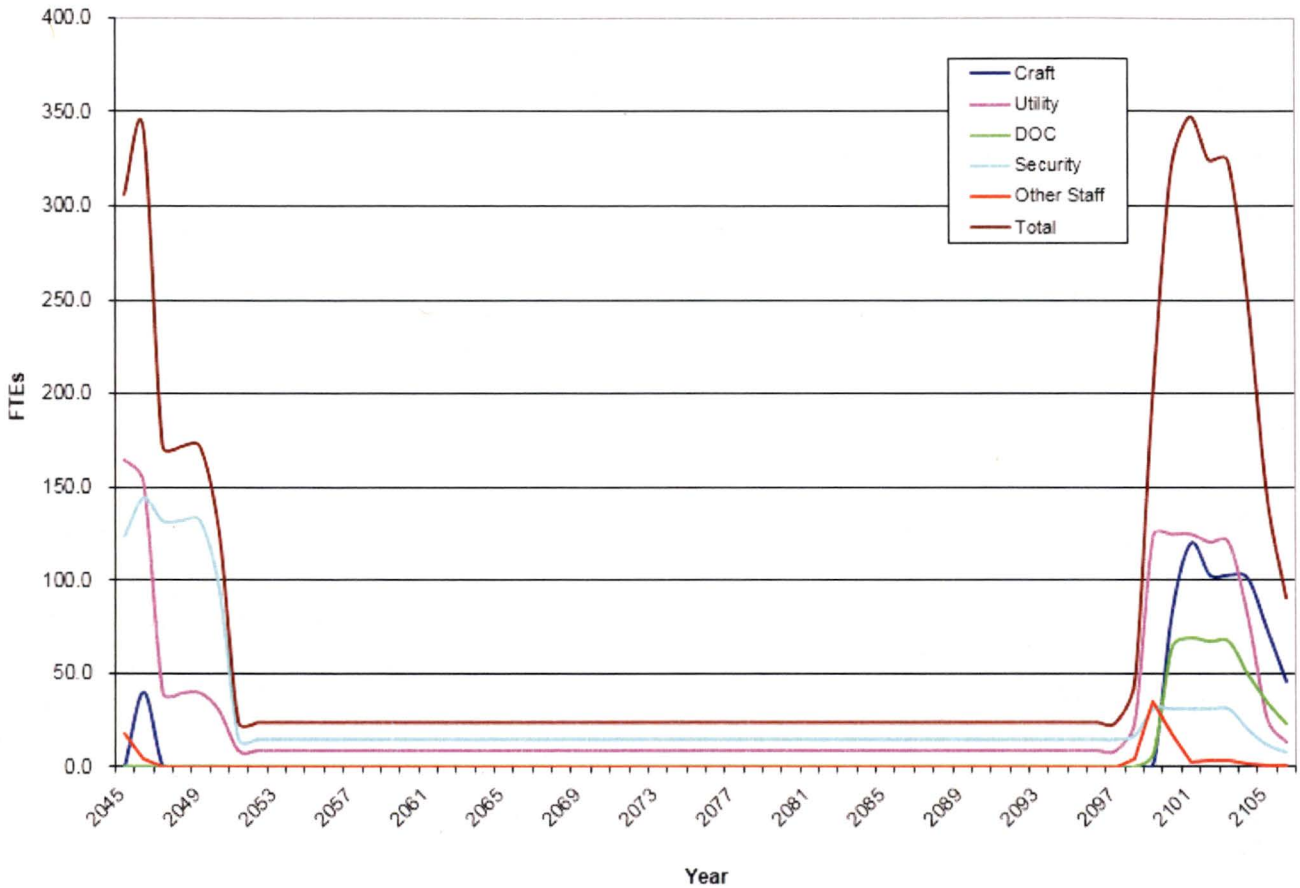
Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045-97	0	0	0	0	0	0
2098	84	0	0	0	0	84
2099	775	0	0	0	0	775
2100	1,690	69	0	0	0	1,759
2101	1,676	107	0	0	0	1,784
2102	1,325	71	0	0	0	1,396
2103	1,325	71	0	0	0	1,396
2104	555	30	0	0	0	585
2105	13,680	9,970	197	0	1,482	25,328
2106	11,415	8,319	164	0	1,237	21,135
Total	32,525	18,639	361	0	2,719	54,243

FIGURE 3.1
DECOMMISSIONING PERSONNEL LEVELS
DECON



Note that the labor hour basis of this chart was taken from Appendix C; however not all line items in Appendix C have labor hour values available (e.g. spent fuel canister loading estimates)

FIGURE 3.2
DECOMMISSIONING PERSONNEL LEVELS
SAFSTOR



Note that the labor hour basis of this chart was taken from Appendix D; however not all line items in Appendix D have labor hour values available (e.g. spent fuel canister loading estimates)

4. SCHEDULE ESTIMATE

The schedules for the decommissioning scenarios considered in this study follow the sequences presented in the AIF/NESP-036 study, with minor changes to reflect recent experience and site-specific constraints. In addition, the scheduling has been revised to reflect the spent fuel management plan described in Section 3.4.1.

A schedule or sequence of activities for the DECON alternative is presented in Figure 4.1. The scheduling sequence assumes that fuel is removed from the spent fuel pool within five and one-half years. The key activities listed in the schedule do not reflect a one-to-one correspondence with those activities in the cost tables, but reflect dividing some activities for clarity and combining others for convenience. The schedule was prepared using the "Microsoft Project Professional" computer software.[36]

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedule reflects the results of a precedence network developed for the site decommissioning activities, i.e., a PERT (Program Evaluation and Review Technique) Software Package. The work activity durations used in the precedence network reflect the actual man-hour estimates from the cost table, adjusted by stretching certain activities over their slack range and shifting the start and end dates of others. The following assumptions were made in the development of the decommissioning schedule:

- The fuel building is isolated until such time that all spent fuel has been transferred from the spent fuel pool to the DOE. Decontamination and dismantling of the storage pool is initiated once the transfer of spent fuel is complete (DECON option).
- All work (except vessel and internals removal) is performed during an 8-hour workday, 5 days per week, with no overtime. There are eleven paid holidays per year.
- Reactor and internals removal activities are performed by using separate crews for different activities working on different shifts, with a corresponding backshift charge for the second shift.
- Multiple crews work parallel activities to the maximum extent possible, consistent with optimum efficiency, adequate access for cutting, removal and laydown space, and with the stringent safety measures necessary during demolition of heavy components and structures.

- For plant systems removal, the systems with the longest removal durations in areas on the critical path are considered to determine the duration of the activity.

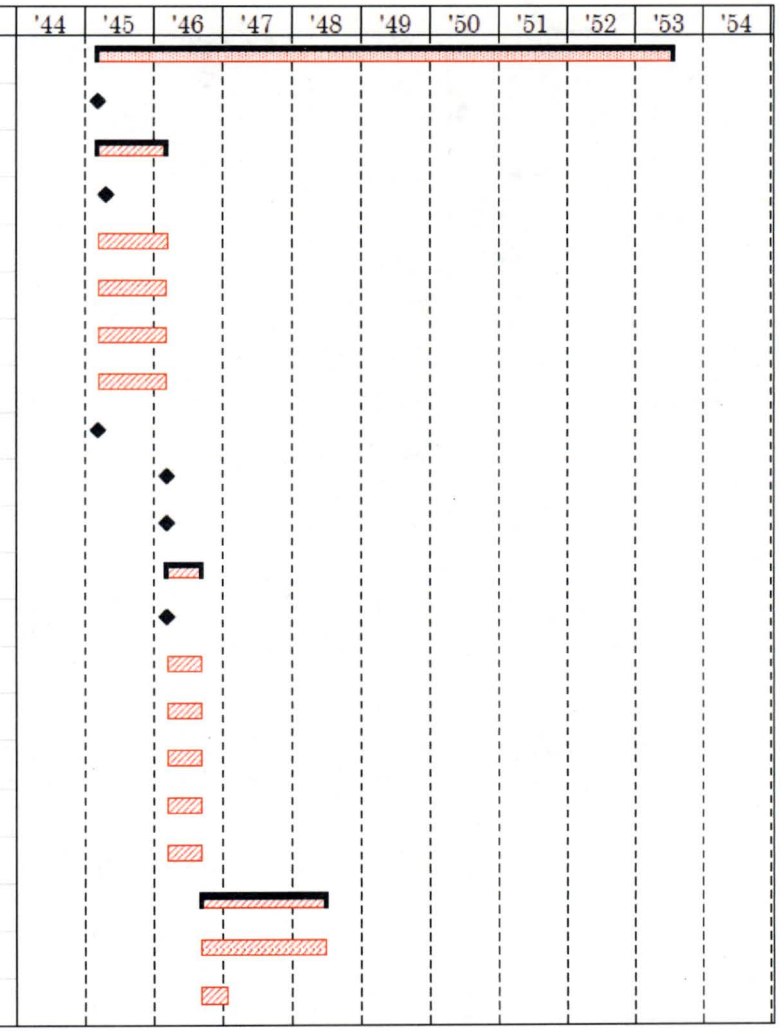
4.2 PROJECT SCHEDULE

The period-dependent costs presented in the detailed cost tables are based upon the durations developed in the schedules for decommissioning. Durations are established between several milestones in each project period; these durations are used to establish a critical path for the entire project. In turn, the critical path duration for each period is used as the basis for determining the period-dependent costs. A second critical path is shown for the spent fuel storage period, which determines the release of the fuel building for final decontamination.

Project timelines are provided in Figures 4.2 and 4.3 with milestone dates based on a 2045 shutdown date. The fuel pool is emptied approximately five and one-half years after shutdown. Deferred decommissioning in the SAFSTOR scenarios is assumed to commence so that the operating license is terminated within a 60-year period from the cessation of plant operations.

FIGURE 4.1
ACTIVITY SCHEDULE

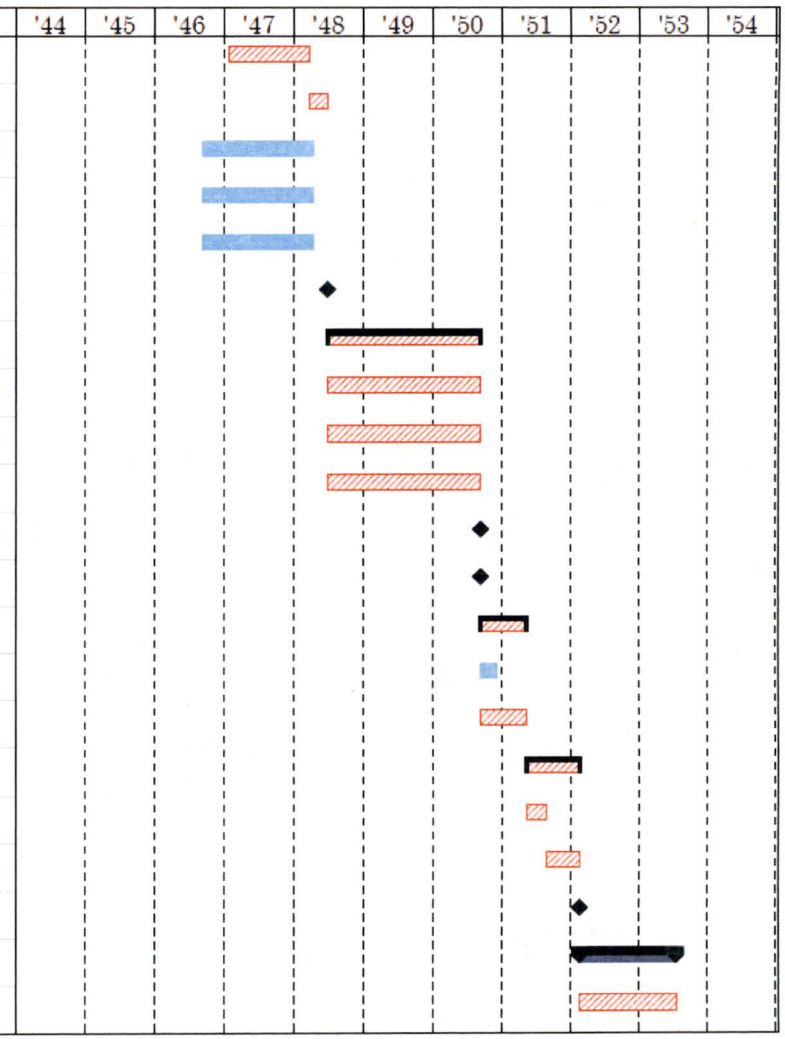
ID	Task Name
1	Wolf Creek Decon Project Schedule
2	Shutdown plant
3	Period 1a - Shutdown through transition
4	Certificate of permanent cessation of operations submitted
5	Fuel storage pool operations
6	Reconfigure plant
7	Prepare activity specifications
8	Perform site characterization
9	Written certificate of permanent removal of fuel submitted
10	PSDAR submitted
11	Site specific decommissioning cost estimate submitted
12	Period 1b - Decommissioning preparations
13	DOC staff mobilized
14	Fuel storage pool operations
15	Reconfigure plant (continued)
16	Prepare detailed work procedures
17	Decon NSSS
18	Isolate spent fuel pool
19	Period 2a - Large component removal
20	Fuel storage pool operations
21	Preparation for reactor vessel removal



Red text indicates critical path activities
Blue text indicates milestones

FIGURE 4.1
ACTIVITY SCHEDULE
(continued)

ID	Task Name
22	Reactor vessel & internals
23	Remaining large NSSS components disposition
24	Non-essential systems
25	Main turbine/generator
26	Main condenser
27	License termination plan submitted
28	Period 2b - Decontamination (wet fuel)
29	Fuel storage pool operations
30	Remove systems not supporting wet fuel storage
31	Decon buildings not supporting wet fuel storage
32	License termination plan approved
33	Fuel storage pool available for decommissioning
34	Period 2d - Decontamination following wet fuel storage
35	Remove remaining systems
36	Decon wet fuel storage area
37	Period 2f - Plant license termination
38	Final Site Survey
39	NRC review & approval
40	Part 50 license terminated
41	Period 3b - Site restoration
42	Building demolitions, backfill and landscaping



Red text indicates critical path activities
Blue text indicates milestones

FIGURE 4.2
DECOMMISSIONING TIMELINE
DECON ALTERNATIVE
(not to scale)

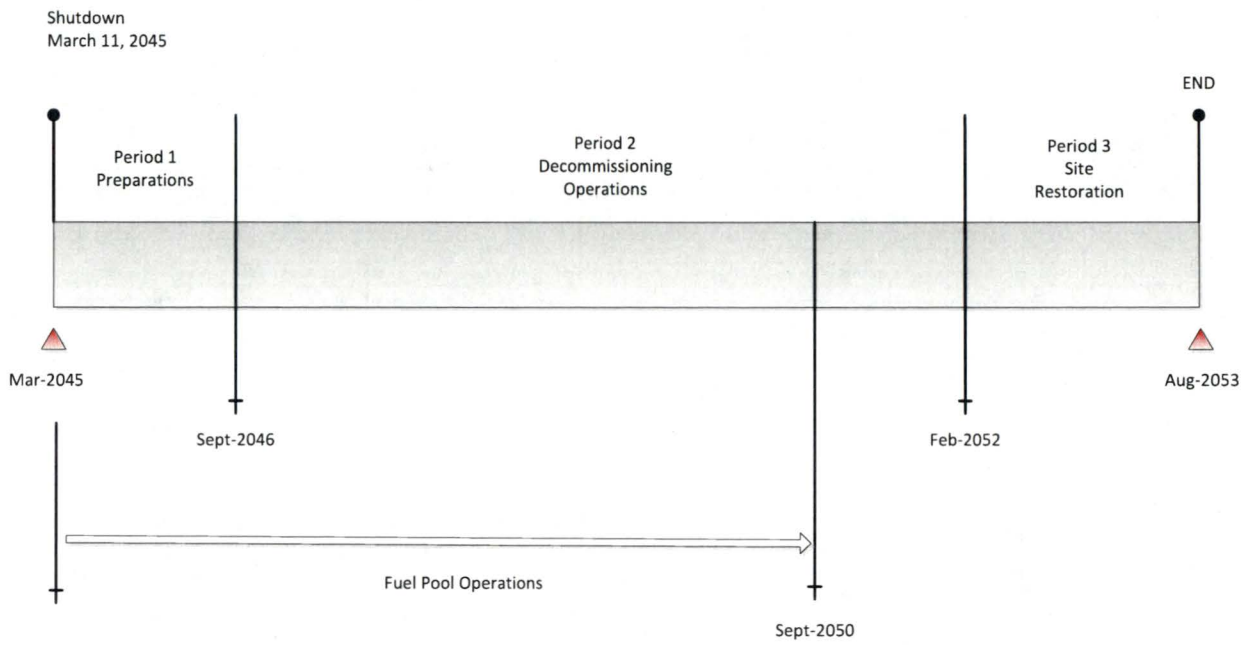
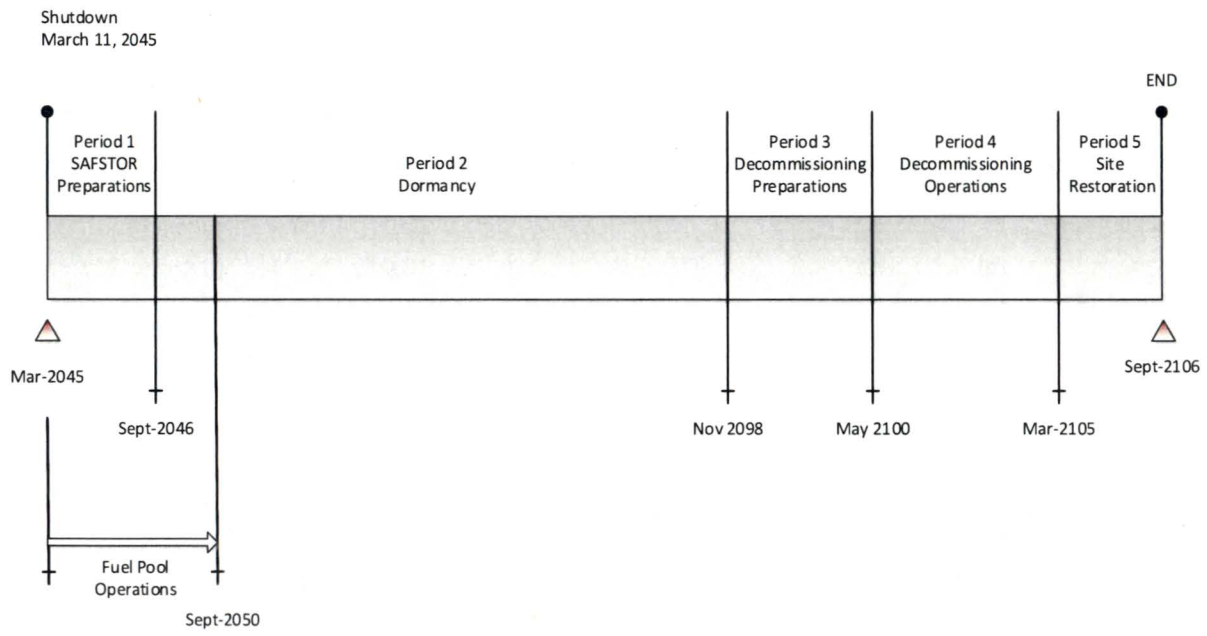


FIGURE 4.3
DECOMMISSIONING TIMELINE
SAFSTOR ALTERNATIVE
(not to scale)



5. RADIOACTIVE WASTES

The objectives of the decommissioning process are the removal of all radioactive material from the site that would restrict its future use and the termination of the NRC license. This currently requires the remediation of all radioactive material at the site in excess of applicable legal limits. Under the Atomic Energy Act,[37] the NRC is responsible for protecting the public from sources of ionizing radiation. Title 10 of the Code of Federal Regulations delineates the production, utilization, and disposal of radioactive materials and processes. In particular, Part 71 defines radioactive material as it pertains to transportation and Part 61 specifies its disposition.

Most of the materials being transported for controlled burial are categorized as Low Specific Activity (LSA) or Surface Contaminated Object (SCO) materials containing Type A quantities, as defined in 49 CFR Parts 173-178. Shipping containers are required to be Industrial Packages (IP-1, IP-2 or IP-3, as defined in 49 CFR §173.411). For this study, commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations.

The destinations for the various waste streams from decommissioning are identified in Figures 5.1 and 5.2. The volumes of radioactive waste generated during the various decommissioning activities at the site are shown on a line-item basis in Appendices C and D, and summarized in Tables 5.1 and 5.2. The quantified waste volume summaries shown in these tables are consistent with Part 61 classifications. The volumes are calculated based on the exterior dimensions for containerized material and on the displaced volume of components serving as their own waste containers.

The reactor vessel and internals are categorized as large quantity shipments and, accordingly, will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

No process system containing/handling radioactive substances at shutdown is presumed to meet material release criteria by decay alone (i.e., systems radioactive at shutdown will still be radioactive over the time period during which the decommissioning is accomplished, due to the presence of long-lived radionuclides).

While the dose rates decrease with time, radionuclides such as ^{137}Cs will still control the disposition requirements.

The waste material produced in the decontamination and dismantling of the nuclear station is primarily generated during Period 2 of DECON and Period 4 of SAFSTOR. Material that is considered potentially contaminated when removed from the radiological controlled area is sent to processing facilities in Tennessee for conditioning and disposal. Heavily contaminated components and activated materials are routed for controlled disposal. The disposal volumes reported in the tables reflect the savings resulting from reprocessing and recycling.

For purposes of constructing the estimates, the cost for disposal at the Energy*Solutions* facility was used as a proxy for future disposal facilities. Separate rates were used for containerized waste and large components, including the steam generators and reactor coolant pump motors. Demolition debris including miscellaneous steel, scaffolding, and concrete was disposed of at a bulk rate. The decommissioning waste stream also included resins and dry active waste.

Since Energy*Solutions* is not currently able to receive the more highly radioactive components generated in the decontamination and dismantling of the nuclear steam supply system, disposal costs for the Class B and C material were based preliminary and indicative rates for WCS's Andrews County disposal facility.

A small quantity of material generated during the decommissioning will not be considered suitable for near-surface disposal, and is assumed to be disposed of in a geologic repository, in a manner similar to that envisioned for spent fuel disposal. Such material, known as Greater-Than-Class-C or GTCC material, is estimated to require six spent fuel storage canisters (or the equivalent) to dispose of the most radioactive portions of the reactor vessel internals. The volume and weight reported in Tables 5.1 and 5.2 represent the packaged weight and volume of the spent fuel storage canisters.

FIGURE 5.1
RADIOACTIVE WASTE DISPOSITION

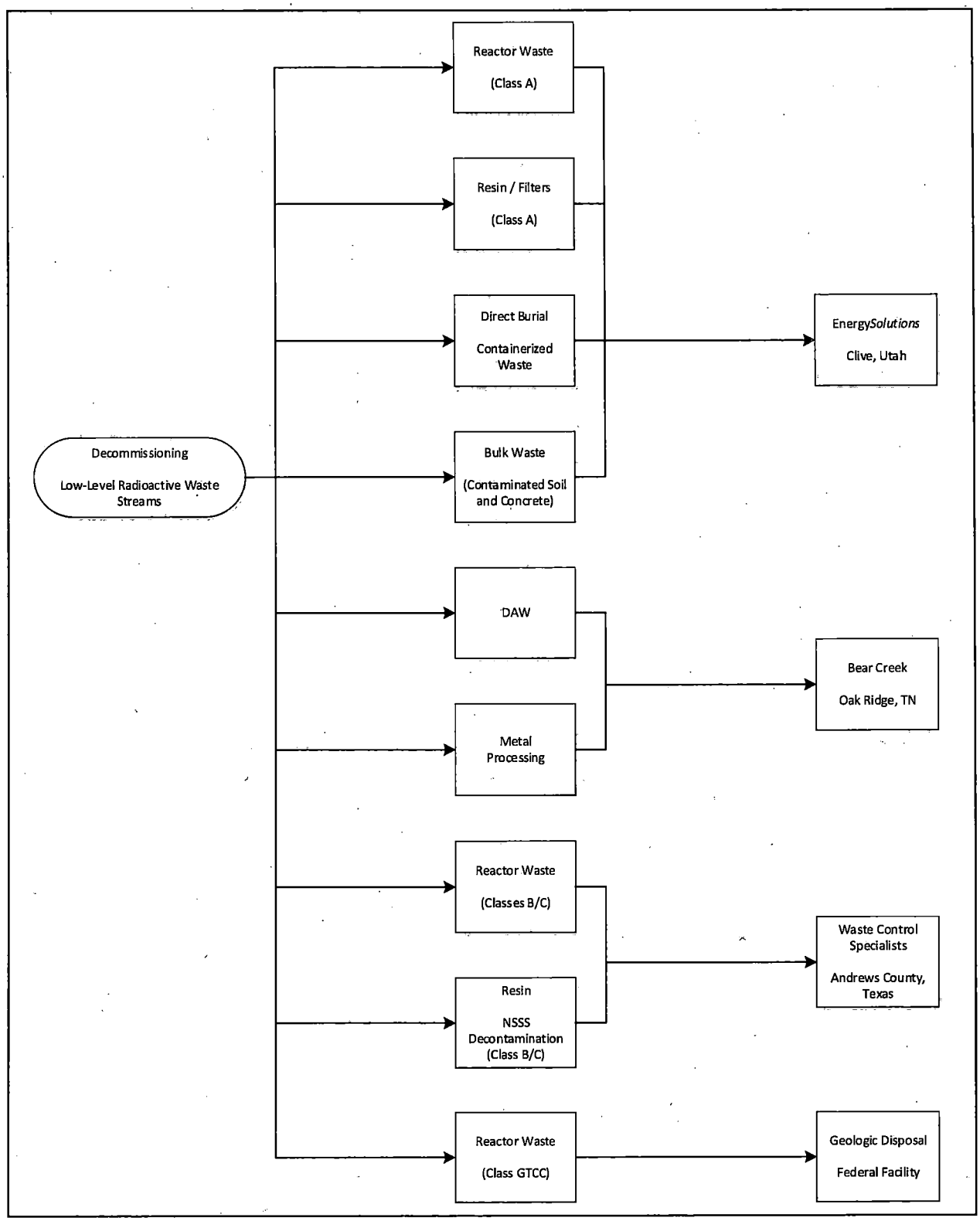


FIGURE 5.2
DECOMMISSIONING WASTE DESTINATIONS
RADIOLOGICAL

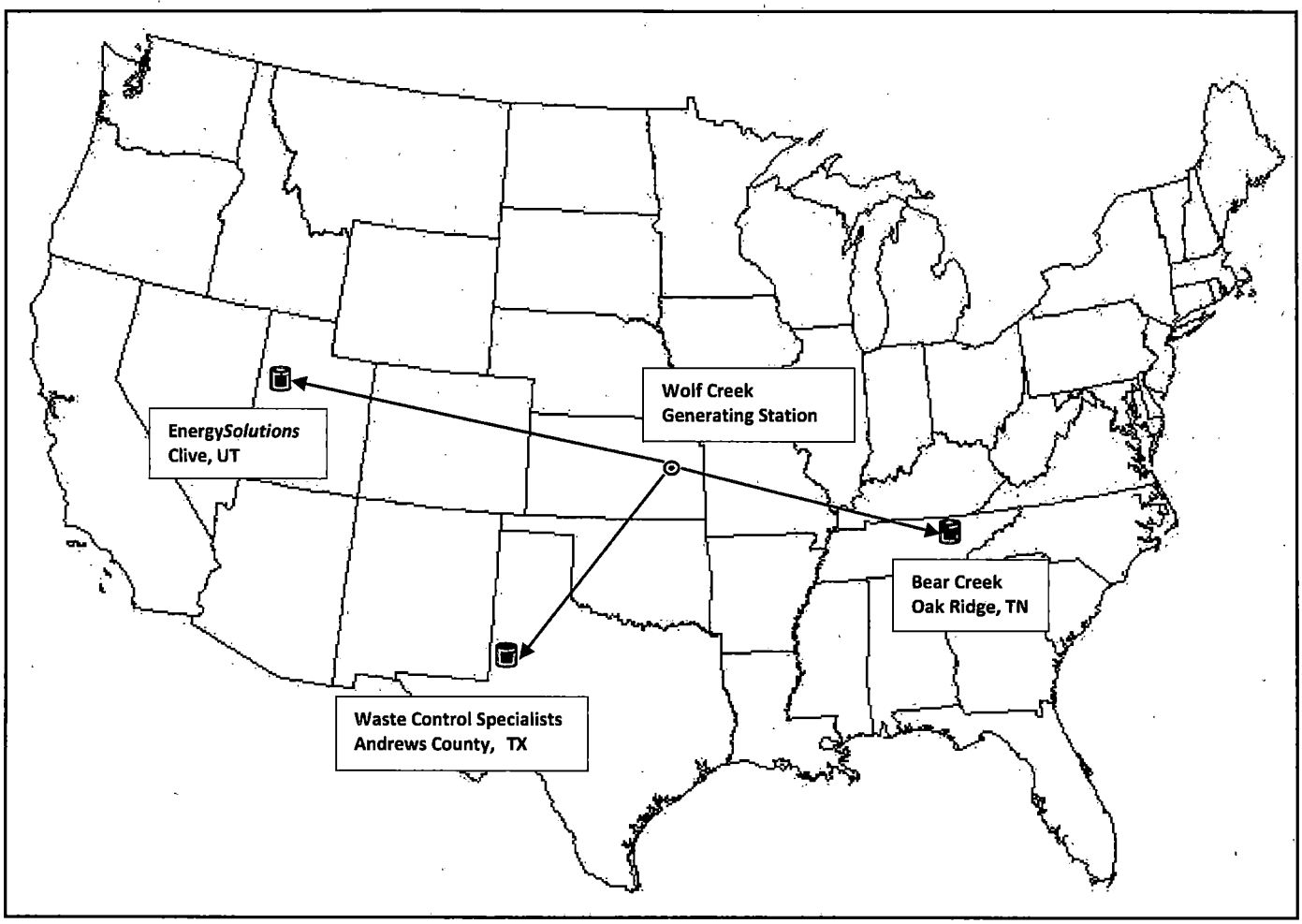


TABLE 5.1
DECON ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions*	A	187,840	11,878,919
	WCS	B	1,750	191,469
	WCS	C	393	47,411
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	2,217	433,180
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	254,732	9,940,690
Totals [2]			446,931	22,491,670

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.2
SAFSTOR ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions*	A	153,674	9,409,645
	WCS	B	501	50,254
	WCS	C	393	47,411
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	2,217	433,180
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	282,530	11,104,170
Totals [2]			439,314	21,044,660

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

6. RESULTS

The analysis to estimate the costs to decommission Wolf Creek relied upon the site-specific, technical information developed for a previous analysis prepared in 2014. While not an engineering study, the estimates provide the operator and the plant owners with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The estimates are based on numerous fundamental assumptions that consider current regulations, low-level radioactive waste disposal options, spent fuel management requirements, site restoration practices, and project contingencies. The estimates incorporate a minimum cooling period of approximately five and one-half years for the spent fuel that resides in the plant's wet storage pool when operations cease. During this period, it is assumed that the DOE will complete the transfer of the spent fuel from the site to a federal facility.

The cost projected to promptly decommission (DECON) Wolf Creek is estimated to be $813.7 million. The majority of this cost (approximately 87.4%) is associated with the physical decontamination and dismantling of the nuclear station so that the operating license can be terminated. Another 5.9% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 6.7% is for the demolition of the designated structures and limited restoration of the site.

The cost projected for deferred decommissioning (SAFSTOR) is estimated to be $1,093.1 million. The majority of this cost (approximately 89.7%) is associated with placing the station in storage, ongoing caretaking of the station during dormancy, and the eventual physical decontamination and dismantling of the nuclear station so that the operating license can be terminated. Another 5.3% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 5.0% is for the demolition of the designated structures and limited restoration of the site.

The primary cost contributors, identified in Tables 6.1 and 6.2, are either labor-related or associated with the management and disposition of the radioactive waste. Program management is the largest single contributor to the overall cost. The magnitude of the expense is a function of both the size of the organization required to manage the decommissioning, as well as the duration of the program. It is assumed, for purposes of this analysis, that WCNOC will oversee the decommissioning program, using a DOC to manage the decommissioning labor force and the associated subcontractors. The size and composition of the management organization varies with the decommissioning phase and associated site activities.

However, once the operating license is terminated, the staff is substantially reduced for the conventional demolition and restoration of the site (for the DECON alternative).

As described in this report, the spent fuel pool will remain operational for a minimum of five and one-half years following the cessation of operations. The pool will be isolated and an independent spent fuel island created. This will allow decommissioning operations to proceed in and around the pool area. Over the five and one-half year period, the spent fuel will be packaged into transportable canisters for loading into a DOE-provided transport cask.

The cost for waste disposal includes only those costs associated with the controlled disposition of the low-level radioactive waste generated from decontamination and dismantling activities, including plant equipment and components, structural material, filters, resins and dry-active waste. As described in Section 5, disposition of the low-level radioactive material requiring controlled disposal is at licensed facility (e.g., Energy*Solutions*' or equivalent). Highly activated components, requiring additional isolation from the environment (GTCC), are packaged for geologic disposal. The cost of geologic disposal is based upon a cost equivalent for spent fuel.

A significant portion of the metallic waste is designated for additional processing and treatment at an off-site facility. Processing reduces the volume of material requiring controlled disposal through such techniques and processes as survey and sorting, decontamination, and volume reduction. The material that cannot be unconditionally released is packaged for controlled disposal at one of the currently operating facilities. The cost identified in the summary tables for processing is all-inclusive, incorporating the ultimate disposition of the material.

Removal costs reflect the labor-intensive nature of the decommissioning process, as well as the management controls required to ensure a safe and successful program. Decontamination and packaging costs also have a large labor component that is based upon prevailing union wages. Non-radiological demolition is a natural extension of the decommissioning process. The methods employed in decontamination and dismantling are generally destructive and indiscriminate in inflicting collateral damage. With a work force mobilized to support decommissioning operations, non-radiological demolition can be an integrated activity and a logical expansion of the work being performed in the process of terminating the operating license. Prompt demolition reduces future liabilities and can be more cost effective than deferral, due to the deterioration of the facilities (and therefore the working conditions) with time.

The reported cost for transport includes the tariffs and surcharges associated with moving large components and/or overweight shielded casks overland, as well as the general expense, e.g., labor and fuel, of transporting material to the destinations identified in this report. For purposes of this analysis, material is primarily moved overland by truck.

Decontamination is used to reduce the plant's radiation fields and minimize worker exposure. Slightly contaminated material or material located within a contaminated area is sent to an off-site processing center, i.e., this analysis does not assume that contaminated plant components and equipment can be decontaminated for uncontrolled release in-situ. Centralized processing centers have proven to be a more economical means of handling the large volumes of material produced in the dismantling of a nuclear station.

License termination survey costs are associated with the labor intensive and complex activity of verifying that contamination has been removed from the site to the levels specified by the regulating agency. This process involves a systematic survey of all remaining plant surface areas and surrounding environs, sampling, isotopic analysis, and documentation of the findings. The status of any plant components and materials not removed in the decommissioning process will also require confirmation and will add to the expense of surveying the facilities alone.

The remaining costs include allocations for heavy equipment and temporary services, as well as for other expenses such as regulatory fees and the premiums for nuclear insurance. While site operating costs are greatly reduced following the final cessation of plant operations, certain administrative functions do need to be maintained either at a basic functional or regulatory level.

TABLE 6.1
DECON ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	16,486	2.0
Removal	120,128	14.8
Packaging	24,544	3.0
Transportation	12,533	1.5
Waste Disposal	84,171	10.3
Off-site Waste Processing	24,134	3.0
Program Management [1]	273,568	33.6
Security	115,889	14.2
Corporate Allocations	2,002	0.2
Spent Fuel Pool Isolation	13,445	1.7
Spent Fuel Management - Direct Costs [2]	46,385	5.7
Insurance and Regulatory Fees	19,065	2.3
Energy	14,431	1.8
Characterization and Licensing Surveys	24,313	3.0
Property Taxes	15,363	1.9
Miscellaneous Equipment	7,279	0.9
Total [3]	813,733	100.0

Cost Element	Total	Percentage
License Termination	711,273	87.4
Spent Fuel Management	48,251	5.9
Site Restoration	54,208	6.7
Total [3]	813,733	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging costs/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

TABLE 6.2
SAFSTOR ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	14,346	1.3
Removal	123,154	11.3
Packaging	19,286	1.8
Transportation	9,751	0.9
Waste Disposal	62,163	5.7
Off-site Waste Processing	26,984	2.5
Program Management [1]	366,223	33.5
Security	224,686	20.6
Corporate Allocations	3,292	0.3
Spent Fuel Pool Isolation	13,445	1.2
Spent Fuel Management - Direct Costs [2]	46,385	4.2
Insurance and Regulatory Fees	71,272	6.5
Energy	29,815	2.7
Characterization and Licensing Surveys	24,929	2.3
Property Taxes	33,724	3.1
Miscellaneous Equipment	23,661	2.2
Total [3]	1,093,117	100.0

Cost Element	Total	Percentage
License Termination	980,846	89.7
Spent Fuel Management	58,028	5.3
Site Restoration	54,243	5.0
Total [3]	1,093,117	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging costs/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

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APPENDIX A

UNIT COST FACTOR DEVELOPMENT

APPENDIX A
UNIT COST FACTOR DEVELOPMENT

Example: Unit Factor for Removal of Contaminated Heat Exchanger < 3,000 lbs.

1. SCOPE

Heat exchangers weighing < 3,000 lbs. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the waste processing area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration (minutes)	Critical Duration (minutes)*
a	Remove insulation	60	(b)
b	Mount pipe cutters	60	60
c	Install contamination controls	20	(b)
d	Disconnect inlet and outlet lines	60	60
e	Cap openings	20	(d)
f	Rig for removal	30	30
g	Unbolt from mounts	30	30
h	Remove contamination controls	15	15
i	Remove, wrap, send to waste processing area	60	60
	Totals (Activity/Critical)	355	255

Duration adjustment(s):	
+ Respiratory protection adjustment (50% of critical duration)	128
+ Radiation/ALARA adjustment (37% of critical duration)	95
Adjusted work duration	478
+ Protective clothing adjustment (30% of adjusted duration)	143
Productive work duration	621
+ Work break adjustment (8.33 % of productive duration)	52
Total work duration (minutes)	673

***** Total duration = 11.217 hr *****

* alpha designators indicate activities that can be performed in parallel

APPENDIX A
(continued)

3. LABOR REQUIRED

Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	3.00	11.217	$20.56	$691.86
Craftsmen	2.00	11.217	$37.39	$838.81
Foreman	1.00	11.217	$41.07	$460.68
General Foreman	0.25	11.217	$44.42	$124.56
Fire Watch	0.05	11.217	$20.56	$11.53
Health Physics Technician	1.00	11.217	$48.84	$547.84
Total Labor Cost				$2,675.28

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	none
Consumables/Materials Costs	
• Universal Polypropylene Sorbent 50 @ $0.64/sq ft [1]	$32.00
• Tarpaulin, oil resistant, fire retardant 50 @ $0.47/sq ft [2]	$23.50
• Gas torch consumables 1 @ $21.17 x 1 /hr [3]	$21.17
Subtotal cost of equipment and materials	$76.67
Overhead & profit on equipment and materials @ 18.50 %	$14.18
Total costs, equipment & material	$90.85

TOTAL COST:

Removal of contaminated heat exchanger <3000 pounds:	**$2,766.13**
Total labor cost:	$2,675.28
Total equipment/material costs:	$90.85
Total craft labor man-hours required per unit:	81.88

5. NOTES AND REFERENCES

- Work difficulty factors were developed in conjunction with the Atomic Industrial Forum's (now NEI) program to standardize nuclear decommissioning cost estimates and are delineated in Volume 1, Chapter 5 of the "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

- References for equipment & consumables costs:

  1. www.mcmaster.com online catalog, McMaster Carr Spill Control (7193T88)
  2. RSMeans (2017) Division 01 56, Section 13.60-0600, page 23
  3. RSMeans (2017) Division 01 54 33, Section 40-6360, page 718

- Material and consumable costs were adjusted using the regional indices for Emporia, Kansas.

APPENDIX B

UNIT COST FACTOR LISTING
(DECON: Power Block Structures Only)

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean instrument and sampling tubing, $/linear foot	0.26
Removal of clean pipe 0.25 to 2 inches diameter, $/linear foot	2.66
Removal of clean pipe >2 to 4 inches diameter, $/linear foot	3.99
Removal of clean pipe >4 to 8 inches diameter, $/linear foot	8.27
Removal of clean pipe >8 to 14 inches diameter, $/linear foot	15.35
Removal of clean pipe >14 to 20 inches diameter, $/linear foot	20.19
Removal of clean pipe >20 to 36 inches diameter, $/linear foot	29.64
Removal of clean pipe >36 inches diameter, $/linear foot	35.12
Removal of clean valve >2 to 4 inches	54.75
Removal of clean valve >4 to 8 inches	82.70
Removal of clean valve >8 to 14 inches	153.51
Removal of clean valve >14 to 20 inches	201.85
Removal of clean valve >20 to 36 inches	296.44
Removal of clean valve >36 inches	351.19
Removal of clean pipe hanger for small bore piping	21.27
Removal of clean pipe hanger for large bore piping	66.80
Removal of clean pump, <300 pound	144.29
Removal of clean pump, 300-1000 pound	405.30
Removal of clean pump, 1000-10,000 pound	1,556.09
Removal of clean pump, >10,000 pound	3,026.06
Removal of clean pump motor, 300-1000 pound	165.70
Removal of clean pump motor, 1000-10,000 pound	641.11
Removal of clean pump motor, >10,000 pound	1,442.51
Removal of clean heat exchanger <3000 pound	846.90
Removal of clean heat exchanger >3000 pound	2,154.97
Removal of clean feedwater heater/deaerator	5,994.85
Removal of clean moisture separator/reheater	12,217.99
Removal of clean tank, <300 gallons	185.04
Removal of clean tank, 300-3000 gallon	574.34
Removal of clean tank, >3000 gallons, $/square foot surface area	5.04

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean electrical equipment, <300 pound	74.99
Removal of clean electrical equipment, 300-1000 pound	269.78
Removal of clean electrical equipment, 1000-10,000 pound	539.55
Removal of clean electrical equipment, >10,000 pound	1,310.99
Removal of clean electrical transformer < 30 tons	910.47
Removal of clean electrical transformer > 30 tons	2,621.97
Removal of clean standby diesel generator, <100 kW	929.96
Removal of clean standby diesel generator, 100 kW to 1 MW	2,075.72
Removal of clean standby diesel generator, >1 MW	4,297.17
Removal of clean electrical cable tray, $/linear foot	7.28
Removal of clean electrical conduit, $/linear foot	3.20
Removal of clean mechanical equipment, <300 pound	74.99
Removal of clean mechanical equipment, 300-1000 pound	269.78
Removal of clean mechanical equipment, 1000-10,000 pound	539.55
Removal of clean mechanical equipment, >10,000 pound	1,310.99
Removal of clean HVAC equipment, <300 pound	90.68
Removal of clean HVAC equipment, 300-1000 pound	324.16
Removal of clean HVAC equipment, 1000-10,000 pound	646.04
Removal of clean HVAC equipment, >10,000 pound	1,310.99
Removal of clean HVAC ductwork, $/pound	0.27
Removal of contaminated instrument and sampling tubing, $/linear foot	1.00
Removal of contaminated pipe 0.25 to 2 inches diameter, $/linear foot	16.21
Removal of contaminated pipe >2 to 4 inches diameter, $/linear foot	25.54
Removal of contaminated pipe >4 to 8 inches diameter, $/linear foot	41.86
Removal of contaminated pipe >8 to 14 inches diameter, $/linear foot	77.54
Removal of contaminated pipe >14 to 20 inches diameter, $/linear foot	91.96
Removal of contaminated pipe >20 to 36 inches diameter, $/linear foot	124.55
Removal of contaminated pipe >36 inches diameter, $/linear foot	145.84
Removal of contaminated valve >2 to 4 inches	306.15
Removal of contaminated valve >4 to 8 inches	361.56

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated valve >8 to 14 inches	709.67
Removal of contaminated valve >14 to 20 inches	894.66
Removal of contaminated valve >20 to 36 inches	1,179.75
Removal of contaminated valve >36 inches	1,392.59
Removal of contaminated pipe hanger for small bore piping	101.80
Removal of contaminated pipe hanger for large bore piping	319.02
Removal of contaminated pump, <300 pound	652.86
Removal of contaminated pump, 300-1000 pound	1,494.51
Removal of contaminated pump, 1000-10,000 pound	4,475.05
Removal of contaminated pump, >10,000 pound	10,895.28
Removal of contaminated pump motor, 300-1000 pound	672.15
Removal of contaminated pump motor, 1000-10,000 pound	1,859.76
Removal of contaminated pump motor, >10,000 pound	4,175.77
Removal of contaminated heat exchanger <3000 pound	2,766.13
Removal of contaminated heat exchanger >3000 pound	8,143.01
Removal of contaminated tank, <300 gallons	1,094.05
Removal of contaminated tank, >300 gallons, $/square foot	20.31
Removal of contaminated electrical equipment, <300 pound	484.52
Removal of contaminated electrical equipment, 300-1000 pound	1,187.87
Removal of contaminated electrical equipment, 1000-10,000 pound	2,290.07
Removal of contaminated electrical equipment, >10,000 pound	4,544.55
Removal of contaminated electrical cable tray, $/linear foot	23.53
Removal of contaminated electrical conduit, $/linear foot	12.77
Removal of contaminated mechanical equipment, <300 pound	538.22
Removal of contaminated mechanical equipment, 300-1000 pound	1,308.86
Removal of contaminated mechanical equipment, 1000-10,000 pound	2,519.06
Removal of contaminated mechanical equipment, >10,000 pound	4,544.55
Removal of contaminated HVAC equipment, <300 pound	538.22
Removal of contaminated HVAC equipment, 300-1000 pound	1,308.86
Removal of contaminated HVAC equipment, 1000-10,000 pound	2,519.06

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated HVAC equipment, >10,000 pound	4,544.55
Removal of contaminated HVAC ductwork, $/pound	1.60
Removal/plasma arc cut of contaminated thin metal components, $/linear in.	2.51
Additional decontamination of surface by washing, $/square foot	5.25
Additional decontamination of surfaces by hydrolasing, $/square foot	24.42
Decontamination rig hook up and flush, $/ 250 foot length	4,477.76
Chemical flush of components/systems, $/gallon	21.64
Removal of clean standard reinforced concrete, $/cubic yard	66.27
Removal of grade slab concrete, $/cubic yard	75.32
Removal of clean concrete floors, $/cubic yard	307.36
Removal of sections of clean concrete floors, $/cubic yard	873.10
Removal of clean heavily rein concrete w/#9 rebar, $/cubic yard	95.43
Removal of contaminated heavily rein concrete w/#9 rebar, $/cubic yard	1,621.76
Removal of clean heavily rein concrete w/#18 rebar, $/cubic yard	129.29
Removal of contaminated heavily rein concrete w/#18 rebar, $/cubic yard	2,141.37
Removal heavily rein concrete w/#18 rebar & steel embedments, $/cubic yard	355.85
Removal of below-grade suspended floors, $/cubic yard	181.13
Removal of clean monolithic concrete structures, $/cubic yard	680.04
Removal of contaminated monolithic concrete structures, $/cubic yard	1,603.30
Removal of clean foundation concrete, $/cubic yard	539.47
Removal of contaminated foundation concrete, $/cubic yard	1,494.90
Explosive demolition of bulk concrete, $/cubic yard	39.35
Removal of clean hollow masonry block wall, $/cubic yard	23.17
Removal of contaminated hollow masonry block wall, $/cubic yard	60.60
Removal of clean solid masonry block wall, $/cubic yard	23.17
Removal of contaminated solid masonry block wall, $/cubic yard	60.60
Backfill of below-grade voids, $/cubic yard	31.73
Removal of subterranean tunnels/voids, $/linear foot	82.06
Placement of concrete for below-grade voids, $/cubic yard	146.85
Excavation of clean material, $/cubic yard	2.81

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Excavation of contaminated material, $/cubic yard	35.81
Removal of clean concrete rubble (tipping fee included), $/cubic yard	24.27
Removal of contaminated concrete rubble, $/cubic yard	22.94
Removal of building by volume, $/cubic foot	0.26
Removal of clean building metal siding, $/square foot	0.93
Removal of contaminated building metal siding, $/square foot	3.46
Removal of standard asphalt roofing, $/square foot	1.21
Removal of transite panels, $/square foot	1.49
Scarifying contaminated concrete surfaces (drill & spall), $/square foot	10.15
Scabbling contaminated concrete floors, $/square foot	5.60
Scabbling contaminated concrete walls, $/square foot	14.25
Scabbling contaminated ceilings, $/square foot	48.40
Scabbling structural steel, $/square foot	4.67
Removal of clean overhead crane/monorail < 10 ton capacity	394.64
Removal of contaminated overhead crane/monorail < 10 ton capacity	1,242.95
Removal of clean overhead crane/monorail >10-50 ton capacity	947.13
Removal of contaminated overhead crane/monorail >10-50 ton capacity	2,982.57
Removal of polar crane > 50 ton capacity	4,027.16
Removal of gantry crane > 50 ton capacity	16,387.31
Removal of structural steel, $/pound	0.14
Removal of clean steel floor grating, $/square foot	3.29
Removal of contaminated steel floor grating, $/square foot	10.07
Removal of clean free standing steel liner, $/square foot	7.56
Removal of contaminated free standing steel liner, $/square foot	23.55
Removal of clean concrete-anchored steel liner, $/square foot	3.78
Removal of contaminated concrete-anchored steel liner, $/square foot	27.49
Placement of scaffolding in clean areas, $/square foot	14.44
Placement of scaffolding in contaminated areas, $/square foot	21.21
Landscaping with topsoil, $/acre	24,013.40
Cost of CPC B-88 LSA box & preparation for use	2,083.45

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Cost of CPC B-25 LSA box & preparation for use	1,958.03
Cost of CPC B-12V 12 gauge LSA box & preparation for use	1,540.78
Cost of CPC B-144 LSA box & preparation for use	10,871.54
Cost of LSA drum & preparation for use	194.02
Cost of cask liner for CNSI 8 120A cask (resins)	12,196.03
Cost of cask liner for CNSI 8 120A cask (filters)	8,614.99
Decontamination of surfaces with vacuuming, $/square foot	0.59

APPENDIX C

DETAILED COST ANALYSIS

DECON

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	362	54	417	417	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	584	88	672	672	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	575	86	661	595	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	487	73	560	504	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	830	124	954	954	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	760	114	874	874	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	365	55	419	419	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	187	28	215	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	365	55	419	210	-	210	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	105	16	121	60	-	60	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,421	663	5,084	4,477	-	607	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	281	42	323	323	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	188	188	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	165	165	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,735	2,210	16,945	16,338	-	607	-	-	-	-	-	-	-	78,157
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,754	375	4,130	4,130	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,274	227	2,502	2,502	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	615	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	3	-	33	-	10	59	59	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	2,111	317	2,428	2,428	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,225	122	1,347	-	1,347	-	-	-	-	-	-	-	-	-
1a.4.9	INPO Fees	-	-	-	-	-	-	333	50	383	383	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	16	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate Allocations	-	-	-	-	-	-	357	54	411	411	-	-	-	-	-	-	-	-	-	-
1a.4.13	NEI Annual Fees	-	-	-	-	-	-	530	79	609	609	-	-	-	-	-	-	-	-	-	-
1a.4.14	Security Staff Cost	-	-	-	-	-	-	19,401	2,910	22,311	22,311	-	-	-	-	-	-	-	-	-	316,295
1a.4.15	Utility Staff Cost	-	-	-	-	-	-	28,719	4,308	33,027	33,027	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	3	-	33	60,721	8,914	70,766	68,377	2,389	-	-	610	-	-	-	12,190	20	738,535
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	3	-	33	76,590	11,294	89,016	84,715	3,694	607	-	610	-	-	-	12,190	20	816,691

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	553	83	636	573	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	292	44	336	336	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	181	45	-	136	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	424	64	488	488	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	140	21	161	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	60	60	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	140	21	161	161	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	134	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,885	583	4,468	3,628	-	840	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	721	-	-	-	-	-	-	361	1,082	1,082	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	721	-	-	-	-	-	3,885	943	5,550	4,710	-	840	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	2,984	895	3,880	3,880	-	-	-	-	-	-	-	-	19,100	7,852
1b.2.3	Misc/Hazardous Waste	-	-	76	20	16	-	-	13	125	125	-	-	2,151	-	-	-	-	137,800	740	-
1b.2	Subtotal Period 1b Additional Costs	-	-	76	20	16	-	14,676	2,662	17,449	17,449	-	-	2,151	-	-	-	-	137,800	19,840	7,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	45	-	29	70	-	129	-	68	341	341	-	-	-	283	-	-	-	16,989	55	-
1b.3.4	Process decommissioning chemical flush waste	2	-	77	278	-	3,307	-	877	4,542	4,542	-	-	-	-	788	-	-	83,917	147	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	2,015	-	-	-	-	-	-	302	2,317	2,317	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	3,025	454	3,478	-	3,478	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	3,034	1,202	106	348	-	3,437	4,347	2,226	14,700	11,222	3,478	-	-	283	788	-	-	100,906	203	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	36	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,893	189	2,082	2,082	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,147	115	1,261	1,261	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	295	-	-	-	-	-	74	369	369	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	19	-	6	35	35	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	2,129	319	2,448	2,448	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	618	62	679	-	679	-	-	-	-	-	-	-	-	-
1b.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	405	61	465	-	465	-	-	-	-	-	-	-	-	-
1b.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.12	Corporate Allocations	-	-	-	-	-	-	181	27	208	208	-	-	-	-	-	-	-	-	-	-
1b.4.13	NEI Annual Fees	-	-	-	-	-	-	267	40	307	307	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	9,577	1,437	11,014	11,014	-	-	-	-	-	-	-	-	-	156,018
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,350	803	6,153	6,153	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	14,551	2,183	16,733	16,733	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	36	581	8	2	-	19	36,491	5,406	42,543	41,339	1,204	-	-	360	-	-	-	7,197	12	433,883
1b.0	TOTAL PERIOD 1b COST	3,791	1,783	189	370	16	3,456	59,399	11,238	80,243	74,719	4,683	840	2,151	643	788	-	-	245,903	21,120	474,978
PERIOD 1 TOTALS		3,791	2,865	202	373	16	3,489	135,989	22,532	169,259	159,435	8,376	1,448	2,151	1,253	788	-	-	258,093	21,140	1,291,669

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	129	140	42	49	-	542	-	247	1,149	1,149	-	-	-	2,046	-	-	-	142,726	6,863	-
2a.1.1.2	Pressurizer Relief Tank	22	18	12	14	-	153	-	57	276	276	-	-	-	578	-	-	-	40,338	1,077	-
2a.1.1.3	Reactor Coolant Pumps & Motors	72	74	123	213	-	1,061	-	364	1,906	1,906	-	-	-	3,386	-	-	-	816,140	4,188	100
2a.1.1.4	Pressurizer	35	37	602	159	-	1,171	-	404	2,407	2,407	-	-	-	3,739	-	-	-	293,734	2,534	1,875
2a.1.1.5	Steam Generators	274	5,183	3,875	3,165	2,688	7,273	-	4,516	26,974	26,974	-	-	40,845	23,217	-	-	-	3,577,181	30,060	5,750
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	109	202	256	53	-	639	-	298	1,557	1,557	-	-	-	4,534	-	-	-	168,041	8,136	-
2a.1.1.7	Reactor Vessel Internals	98	6,706	9,397	1,492	-	14,843	396	15,282	48,214	48,214	-	-	-	1,878	963	393	-	329,968	34,307	1,531
2a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	11,615	-	1,742	13,357	13,357	-	-	-	-	-	-	2,217	433,180	-	-
2a.1.1.9	Reactor Vessel	78	8,230	2,820	1,180	-	4,491	396	9,516	26,711	26,711	-	-	-	13,554	-	-	-	972,836	34,307	1,531
2a.1.1	Totals	817	20,590	17,125	6,325	2,688	41,788	793	32,426	122,551	122,551	-	-	40,845	52,932	963	393	2,217	6,774,144	121,472	10,786
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	336	419	75	619	615	-	384	2,449	2,449	-	-	4,844	2,698	-	-	-	462,027	9,734	-
2a.1.3	Main Condensers	-	936	241	85	738	776	-	576	3,353	3,353	-	-	7,701	3,216	-	-	-	550,847	27,762	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	443	-	-	-	-	-	66	510	510	-	-	-	-	-	-	-	-	4,871	-
2a.1.4.2	Auxiliary	-	229	-	-	-	-	-	34	264	264	-	-	-	-	-	-	-	-	2,194	-
2a.1.4.3	Hot Machine Shop	-	1	-	-	-	-	-	0	1	1	-	-	-	-	-	-	-	-	7	-
2a.1.4.4	Radwaste	-	44	-	-	-	-	-	7	51	51	-	-	-	-	-	-	-	-	387	-
2a.1.4.5	Fuel Building	-	97	-	-	-	-	-	15	112	112	-	-	-	-	-	-	-	-	773	-
2a.1.4	Totals	-	815	-	-	-	-	-	122	937	937	-	-	-	-	-	-	-	-	8,233	-
Disposal of Plant Systems																					
2a.1.5.1	AB - Main Steam	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,833	-
2a.1.5.2	AB - Main Steam RCA	-	60	4	11	186	-	-	45	305	305	-	-	2,156	-	-	-	-	87,550	1,515	-
2a.1.5.3	AC - Main Turbine	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,641	-
2a.1.5.4	AD - Condensate	-	181	-	-	-	-	-	27	208	-	-	208	-	-	-	-	-	-	6,144	-
2a.1.5.5	AE - Feedwater	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	4,271	-
2a.1.5.6	AF - Feedwater Htr Extretion, Drn & Vnt	-	152	-	-	-	-	-	23	175	-	-	175	-	-	-	-	-	-	6,352	-
2a.1.5.7	AK - Condensate Demineralizer	-	56	-	-	-	-	-	8	65	-	-	65	-	-	-	-	-	-	1,944	-
2a.1.5.8	AL - Auxiliary Feedwater	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	1,174	-
2a.1.5.9	AL-Auxiliary Feedwater Surge Tanks	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	72	-
2a.1.5.10	AQ - Condensate & Feedwater Chem Additn	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	468	-
2a.1.5.11	AX - Acid Feed	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	754	-
2a.1.5.12	Auxiliary Bldg Non-System Specific	-	85	7	6	41	68	-	46	253	253	-	-	474	282	-	-	-	37,164	2,282	-
2a.1.5.13	Auxiliary Bldg Non-System Specific RCA	-	537	13	38	660	-	-	240	1,487	1,487	-	-	7,629	-	-	-	-	309,812	13,471	-
2a.1.5.14	BL - Reactor Makeup Water	-	223	23	21	167	207	-	138	779	779	-	-	1,928	850	-	-	-	132,796	5,872	-
2a.1.5.15	BM - Steam Generator Blowdown	-	452	8	26	446	-	-	185	1,118	1,118	-	-	5,160	-	-	-	-	209,560	11,982	-
2a.1.5.16	CA - Steam Seal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	455	-
2a.1.5.17	CB - Main Turbine Lube Oil	-	38	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	1,207	-
2a.1.5.18	CC - Generator Hydrogen & CO2	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	198	-
2a.1.5.19	CD - Generator Seal Oil	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	287	-
2a.1.5.20	CE - Stator Cooling Water	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	241	-
2a.1.5.21	CF - Lube Oil Strg, Xfer & Purification	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	812	-
2a.1.5.22	CG - Condenser Air Removal	-	19	-	-	-	-	-	3	22	-	-	22	-	-	-	-	-	-	657	-
2a.1.5.23	CH - Main Turbine Control Oil	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,219	-
2a.1.5.24	CL - Chlorination	-	17	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	569	-
2a.1.5.25	CO - Carbon Dioxide	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	121	-
2a.1.5.26	CW - Circulating Water	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	7,858	-
2a.1.5.27	CZ - Caustic Acid	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	111	-
2a.1.5.28	DA - Circulating Water System	-	223	-	-	-	-	-	33	256	-	-	256	-	-	-	-	-	-	7,953	-
2a.1.5.29	DM - Equipment Drains	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	1,223	-
2a.1.5.30	DM - Equipment Drains RCA	-	111	26	77	1,336	-	-	242	1,793	1,793	-	-	15,445	-	-	-	-	627,223	2,840	-
2a.1.5.31	EG - Component Cooling Water RCA	-	557	24	70	1,225	-	-	336	2,213	2,213	-	-	14,161	-	-	-	-	575,071	13,646	-
2a.1.5.32	EJ - Residual Heat Removal	-	287	58	46	236	585	-	266	1,477	1,477	-	-	2,727	2,411	-	-	-	264,564	7,897	-
2a.1.5.33	EM - High Pressure Coolant Injection	-	240	18	15	109	158	-	120	660	660	-	-	1,260	648	-	-	-	92,828	6,201	-
2a.1.5.34	EN - Containment Spray	-	170	5	15	262	-	-	84	536	536	-	-	3,026	-	-	-	-	122,874	4,134	-
2a.1.5.35	FB - Auxiliary Steam	-	60	-	-	-	-	-	9	69	-	-	69	-	-	-	-	-	-	2,106	-
2a.1.5.36	FB - Auxiliary Steam RCA	-	66	1	4	71	-	-	28	169	169	-	-	816	-	-	-	-	33,148	1,537	-
2a.1.5.37	FC - Auxiliary Turbines	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,301	-
2a.1.5.38	FE - Auxiliary Steam Chemical Addition	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	105	-
2a.1.5.39	GE - Turbine Bldg HVAC	-	86	-	-	-	-	-	13	99	-	-	99	-	-	-	-	-	-	3,189	-
2a.1.5.40	GF - Miscellaneous Building HVAC	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	987	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2a.1.5.41	GS - Containment Hydrogen Control	-	58	4	5	57	26	-	31	180	180	-	-	658	104	-	-	-	33,502	1,559	-
2a.1.5.42	HF - Secondary Liquid Waste	547	741	85	73	535	780	-	754	3,515	3,515	-	-	6,186	3,203	-	-	-	456,359	31,896	-
2a.1.5.43	HY - Hydrogen	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	223	-
2a.1.5.44	KH - Service Gas	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	644	-
2a.1.5.45	LE - Oily Waste	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,575	-
2a.1.5.46	LE - Oily Waste RCA	-	153	3	9	149	-	-	62	376	376	-	-	1,718	-	-	-	-	69,785	3,518	-
2a.1.5.47	NT - Nitrogen	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	149	-
2a.1.5.48	OX - Oxygen	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	171	-
2a.1.5.49	SW - Screen Wash	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	635	-
2a.1.5.50	Turbine Bldg Non-System Specific	-	471	-	-	-	-	-	71	542	-	-	542	-	-	-	-	-	-	15,405	-
2a.1.5.51	VH - Circ Water & Makeup Water Scrnhs	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	272	-
2a.1.5.52	VV - Misc Bldg HVAC	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	148	-
2a.1.5.53	WG - Gland Water & Motor Cooling Water	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	593	-
2a.1.5.54	WL - Cooling Lake Makeup & Blowdown	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	745	-
2a.1.5	Totals	547	6,171	279	414	5,479	1,823	-	2,941	17,656	14,861	-	2,794	63,344	7,498	-	-	-	3,052,234	192,162	-
2a.1.6	Scaffolding in support of decommissioning	-	1,035	29	8	116	26	-	287	1,500	1,500	-	-	1,206	106	-	-	-	61,032	36,964	-
2a.1	Subtotal Period 2a Activity Costs	1,364	29,884	18,094	6,907	9,640	45,029	793	36,736	148,446	145,651	-	2,794	117,940	66,450	963	393	2,217	10,900,280	396,325	10,786
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,827	548	2,376	2,376	-	-	-	-	-	-	-	-	37,415	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	1,827	548	2,376	2,376	-	-	-	-	-	-	-	-	37,415	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	161	-	105	257	-	474	-	248	1,246	1,246	-	-	-	1,037	-	-	-	62,244	202	-
2a.3.2	Process decommissioning chemical flush waste	1	-	26	94	-	216	-	71	408	408	-	-	-	266	-	-	-	28,388	50	-
2a.3.3	Small tool allowance	-	278	-	-	-	-	-	42	319	287	-	32	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	10,792	1,619	12,411	-	12,411	-	-	-	-	-	-	-	-	-
2a.3.5	On-site survey and release of 115.8 tons clean metallic waste	-	-	-	-	-	-	165	16	181	181	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	162	278	131	351	-	691	10,956	1,996	14,565	2,122	12,411	32	-	1,304	-	-	-	90,632	252	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	127	-	-	-	-	-	-	32	159	159	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,248	125	1,373	1,373	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	4,094	409	4,503	4,503	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	3,021	-	-	-	-	-	755	3,777	3,777	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,952	-	-	-	-	-	593	4,545	4,545	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	140	35	-	347	-	106	629	629	-	-	-	6,453	-	-	-	129,051	210	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	3,610	542	4,152	4,152	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	1,042	104	1,146	1,146	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,262	126	1,388	-	1,388	-	-	-	-	-	-	-	-	-
2a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	1,445	217	1,661	-	1,661	-	-	-	-	-	-	-	-	-
2a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	186	28	214	-	214	-	-	-	-	-	-	-	-	-
2a.4.12	Corporate Allocations	-	-	-	-	-	-	448	67	516	516	-	-	-	-	-	-	-	-	-	-
2a.4.13	NEI Annual Fees	-	-	-	-	-	-	953	143	1,096	1,096	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	30,401	4,560	34,961	34,961	-	-	-	-	-	-	-	-	-	493,870
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	23,034	3,455	26,490	26,490	-	-	-	-	-	-	-	-	-	284,544
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	37,595	5,639	43,234	43,234	-	-	-	-	-	-	-	-	-	529,776
2a.4	Subtotal Period 2a Period-Dependent Costs	127	6,974	140	35	-	347	105,318	16,901	129,842	126,579	3,263	-	-	6,453	-	-	-	129,051	210	1,308,190
2a.0	TOTAL PERIOD 2a COST	1,652	37,135	18,365	7,293	9,640	46,067	118,894	56,182	295,229	276,729	15,674	2,826	117,940	74,207	963	393	2,217	11,119,970	434,203	1,318,976
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	AN - Demineralized Wtr Storage & xfer	-	45	-	-	-	-	-	7	51	-	-	51	-	-	-	-	-	-	1,548	-
2b.1.1.2	AN - Demineralized Wtr Strg & xfer RCA	-	15	0	1	10	-	-	5	32	32	-	-	120	-	-	-	-	4,855	334	-
2b.1.1.3	AP - Condensate Storage & Transfer	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,660	-
2b.1.1.4	BB - Reactor Coolant	-	226	38	31	151	404	-	189	1,038	1,038	-	-	1,746	1,669	-	-	-	177,118	6,412	-
2b.1.1.5	BG - Chemical & Volume Control	726	721	121	90	424	1,197	-	932	4,210	4,210	-	-	4,899	4,925	-	-	-	513,906	27,846	-
2b.1.1.6	BN - Borated Refueling Water Storage	-	247	20	34	477	129	-	173	1,080	1,080	-	-	5,512	533	-	-	-	257,802	6,939	-
2b.1.1.7	Control Bldg Non-System Specific	-	139	4	11	185	-	-	64	402	402	-	-	2,139	-	-	-	-	86,849	3,413	-
2b.1.1.8	Control Bldg Non-System Specific Cln	-	988	-	-	-	-	-	148	1,137	-	-	1,137	-	-	-	-	-	-	29,076	-
2b.1.1.9	DO - Diesel Oil	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	48	-
2b.1.1.10	EA - Service Water	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,592	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial 7 Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.11	EB - Closed Cooling Water	-	36	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,267	-
2b.1.1.12	EF - Essential Service Water	-	108	-	-	-	-	-	16	124	-	-	124	-	-	-	-	-	-	3,800	-
2b.1.1.13	EF - Essential Service Water RCA	-	70	2	7	123	-	-	37	240	240	-	-	1,427	-	-	-	-	57,959	1,734	-
2b.1.1.14	EP - Accumulator Safety Injection	-	124	10	12	136	69	-	71	422	422	-	-	1,568	283	-	-	-	81,940	3,246	-
2b.1.1.15	FA - Auxiliary Steam Generator	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	521	-
2b.1.1.16	FO - Fuel Oil	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	486	-
2b.1.1.17	FP - Fire Protection	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	3,826	-
2b.1.1.18	FP - Fire Protection RCA	-	150	8	22	389	-	-	100	669	669	-	-	4,492	-	-	-	-	182,411	3,541	-
2b.1.1.19	GA - Plant Heating	-	55	-	-	-	-	-	8	63	-	-	63	-	-	-	-	-	-	1,912	-
2b.1.1.20	GA - Plant Heating RCA	-	92	1	4	64	-	-	33	194	194	-	-	746	-	-	-	-	30,275	2,072	-
2b.1.1.21	GB - Central Chilled Water	-	52	-	-	-	-	-	8	59	-	-	59	-	-	-	-	-	-	1,803	-
2b.1.1.22	GB - Central Chilled Water RCA	-	21	0	1	16	-	-	8	47	47	-	-	187	-	-	-	-	7,591	482	-
2b.1.1.23	GD - Esstl Srvc Wtr Pumphs Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	284	-
2b.1.1.24	GH - Radwaste Building HVAC	-	145	6	13	210	24	-	76	474	474	-	-	2,425	98	-	-	-	104,702	3,455	-
2b.1.1.25	GK - Control Building HVAC	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	3,959	-
2b.1.1.26	GL - Auxiliary Building HVAC	-	363	13	28	438	55	-	176	1,073	1,073	-	-	5,064	228	-	-	-	220,197	8,491	-
2b.1.1.27	GM - Diesel Generator Building HVAC	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	695	-
2b.1.1.28	GN - Containment Cooling	-	392	26	45	636	156	-	242	1,495	1,495	-	-	7,354	643	-	-	-	339,572	9,502	-
2b.1.1.29	GP - Containmnt Integratd Leak Rate Test	-	30	1	3	50	-	-	16	100	100	-	-	580	-	-	-	-	23,570	750	-
2b.1.1.30	GR - Containment Atmospheric Control	-	14	3	6	94	10	-	21	148	148	-	-	1,086	41	-	-	-	46,686	392	-
2b.1.1.31	GT - Containment Purge HVAC	-	92	7	12	168	41	-	61	382	382	-	-	1,948	170	-	-	-	89,946	2,259	-
2b.1.1.32	HA - Gaseous Radwaste	-	278	23	23	241	164	-	152	882	882	-	-	2,782	666	-	-	-	156,216	7,037	-
2b.1.1.33	HB - Liquid Radwaste	584	657	77	64	480	670	-	713	3,244	3,244	-	-	5,544	2,742	-	-	-	401,460	30,762	-
2b.1.1.34	HC - Solid Radwaste	-	369	52	41	241	505	-	266	1,474	1,474	-	-	2,781	2,076	-	-	-	245,800	9,589	-
2b.1.1.35	HD - Decontamination	-	78	6	7	85	42	-	44	262	262	-	-	983	171	-	-	-	50,973	2,051	-
2b.1.1.36	HE - Boron Recycle	297	383	38	32	225	344	-	373	1,691	1,691	-	-	2,600	1,411	-	-	-	196,130	16,660	-
2b.1.1.37	JE - Emergency Fuel Oil	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	1,260	-
2b.1.1.38	KA - Compressed Air and Instrument	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	6,089	-
2b.1.1.39	KB - Breathing Air	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	1,075	-
2b.1.1.40	KC - Fire Protection	-	262	-	-	-	-	-	39	301	-	-	301	-	-	-	-	-	-	9,256	-
2b.1.1.41	KC - Fire Protection RCA	-	271	10	30	514	-	-	150	975	975	-	-	5,944	-	-	-	-	241,384	6,383	-
2b.1.1.42	KD - Domestic Water	-	50	-	-	-	-	-	7	57	-	-	57	-	-	-	-	-	-	1,708	-
2b.1.1.43	KE - Fuel Hndlg & Strg Reactor Vssl Serv	-	14	4	5	57	38	-	23	141	141	-	-	661	158	-	-	-	36,889	375	-
2b.1.1.44	KJ - Standby Diesel Engine	-	208	-	-	-	-	-	31	239	-	-	239	-	-	-	-	-	-	6,749	-
2b.1.1.45	LA - Sanitary Drains	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	290	-
2b.1.1.46	LA - Sanitary Drains RCA	-	21	0	1	24	-	-	9	55	55	-	-	272	-	-	-	-	11,053	422	-
2b.1.1.47	LB - Roof Drains	-	37	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,276	-
2b.1.1.48	LB - Roof Drains RCA	-	113	4	11	185	-	-	58	371	371	-	-	2,139	-	-	-	-	86,858	2,694	-
2b.1.1.49	LC - Yard Drains	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	96	-
2b.1.1.50	LD - Chemical & Detergent Waste	54	91	6	5	44	51	-	70	321	321	-	-	504	211	-	-	-	33,951	3,490	-
2b.1.1.51	LF - Floor & Equipment Drains	-	1,129	129	94	323	1,386	-	704	3,766	3,766	-	-	3,739	5,724	-	-	-	516,484	29,320	-
2b.1.1.52	RM - Process Sampling & Analysis	-	100	8	7	57	60	-	50	283	283	-	-	661	240	-	-	-	42,525	2,774	-
2b.1.1.53	Radwaste Bldg Non-System Specific	-	139	11	10	61	120	-	77	418	418	-	-	705	497	-	-	-	60,190	3,653	-
2b.1.1.54	Radwaste Bldg Non-System Specific RCA	-	893	22	63	1,097	-	-	400	2,475	2,475	-	-	12,684	-	-	-	-	515,103	21,919	-
2b.1.1.55	Reactor Bldg Non-System Specific	-	71	4	4	23	45	-	33	180	180	-	-	269	186	-	-	-	22,727	1,760	-
2b.1.1.56	Reactor Bldg Non-System Specific RCA	-	460	8	24	412	-	-	181	1,086	1,086	-	-	4,768	-	-	-	-	193,612	10,425	-
2b.1.1.57	SBO Diesel Generator	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,610	-
2b.1.1.58	SJ - Nuclear Sampling	-	57	6	5	37	46	-	32	182	182	-	-	423	184	-	-	-	29,191	1,620	-
2b.1.1.59	ST - Sewage Treatment	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	2,316	-
2b.1.1.60	SZ - Service Air	-	54	-	-	-	-	-	8	62	-	-	62	-	-	-	-	-	-	1,892	-
2b.1.1.61	VA - I&C Shop HVAC	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	155	-
2b.1.1.62	VB - I&C Shop Computer Room HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	106	-
2b.1.1.63	VC - Health Physics Computer Room HVAC	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	208	-
2b.1.1.64	VJ - Shop Bldg Machine Shop Area Vent	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	57	-
2b.1.1.65	VL - Shop Building HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	101	-
2b.1.1.66	VS - Admin Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	262	-
2b.1.1.67	VT - Tech Support Building HVAC	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	87	-
2b.1.1.68	VW - Waste Water Treatment Ventilation	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	52	-
2b.1.1.69	WD - Domestic Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	870	-
2b.1.1.70	WM - Makeup Demineralizer	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,929	-
2b.1.1.71	WS - Plant Services Water	-	93	-	-	-	-	-	14	107	-	-	107	-	-	-	-	-	-	3,297	-
2b.1.1.72	WS - Plant Services Water RCA	-	29	3	9	159	-	-	33	233	233	-	-	1,838	-	-	-	-	74,625	782	-
2b.1.1.73	WT - Waste Water Treatment	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	769	-
2b.1.1.74	WZ - Radioactive Liquid Waste	-	36	6	4	10	62	-	27	145	145	-	-	120	258	-	-	-	21,303	879	-
2b.1.1.75	Yard Non-System Specific	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	603	-
2b.1.1	Totals	1,661	11,052	679	758	7,846	5,617	-	6,054	33,668	30,191	-	3,477	90,709	23,114	-	-	-	5,161,856	333,052	-
2b.1.2	Scaffolding in support of decommissioning	-	1,294	36	10	145	32	-	358	1,875	1,875	-	-	1,508	133	-	-	-	76,290	46,205	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	885	837	54	202	515	1,640	-	1,175	5,308	5,308	-	-	5,955	17,517	-	-	-	997,209	44,353	-
2b.1.3.2	Auxiliary	463	302	24	93	189	250	-	414	1,735	1,735	-	-	2,185	6,943	-	-	-	417,552	19,560	-
2b.1.3.3	Communication Corridor - Contaminated	10	5	0	2	1	5	-	8	33	33	-	-	17	152	-	-	-	7,854	395	-
2b.1.3.4	Hot Machine Shop	13	10	1	2	-	6	-	11	43	43	-	-	-	188	-	-	-	8,892	597	-
2b.1.3.5	RWST Foundation Decon	-	7	1	4	-	11	-	5	28	28	-	-	-	335	-	-	-	15,840	108	-
2b.1.3.6	Radwaste	246	144	12	48	73	130	-	211	865	865	-	-	844	3,681	-	-	-	208,617	10,005	-
2b.1.3.7	Radwaste Drum Storage	28	15	1	5	6	14	-	23	92	92	-	-	66	413	-	-	-	22,243	1,093	-
2b.1.3.8	Radwaste Storage Building	71	32	3	13	-	37	-	55	210	210	-	-	-	1,090	-	-	-	51,480	2,634	-
2b.1.3	Totals	1,715	1,353	96	369	784	2,094	-	1,902	8,314	8,314	-	-	9,068	30,319	-	-	-	1,729,687	78,745	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	479	72	551	551	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	3,377	13,699	811	1,137	8,775	7,743	479	8,386	44,407	40,930	-	3,477	101,284	53,566	-	-	-	6,967,833	458,002	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,236	671	2,907	2,907	-	-	-	-	-	-	-	-	45,787	-
2b.2.2	Operational Equipment	-	-	19	49	624	-	-	103	794	794	-	-	11,710	-	-	-	-	292,750	32	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	49	624	-	2,236	774	3,701	3,701	-	-	11,710	-	-	-	-	292,750	45,819	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	190	-	128	311	-	575	-	299	1,504	1,504	-	-	-	1,258	-	-	-	75,490	245	-
2b.3.2	Process decommissioning chemical flush waste	4	-	145	524	-	1,203	-	396	2,271	2,271	-	-	-	1,481	-	-	-	157,863	277	-
2b.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	289	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	15,949	2,392	18,342	-	18,342	-	-	-	-	-	-	-	-	-
2b.3.5	On-site survey and release of 44.30 tons clean metallic waste	-	-	-	-	-	-	63	6	69	69	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	195	251	272	835	-	1,778	16,012	3,131	22,474	4,133	18,342	-	-	2,740	-	-	-	233,353	523	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,600	-	-	-	-	-	-	400	2,000	2,000	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,527	153	1,680	1,680	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	5,010	501	5,511	5,511	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	3,553	-	-	-	-	-	888	4,442	4,442	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,973	-	-	-	-	-	746	5,719	5,719	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	139	35	-	344	-	105	622	622	-	-	-	6,385	-	-	-	127,708	208	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	3,488	523	4,011	4,011	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,275	128	1,403	1,403	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,544	154	1,698	-	1,698	-	-	-	-	-	-	-	-	-
2b.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	1,768	265	2,033	-	2,033	-	-	-	-	-	-	-	-	-
2b.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	446	67	513	513	-	-	-	-	-	-	-	-	-	-
2b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	227	34	262	-	262	-	-	-	-	-	-	-	-	-
2b.4.13	Corporate Allocations	-	-	-	-	-	-	526	79	604	604	-	-	-	-	-	-	-	-	-	-
2b.4.14	NEI Annual Fees	-	-	-	-	-	-	1,166	175	1,341	1,341	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	37,203	5,580	42,783	42,783	-	-	-	-	-	-	-	-	-	604,370
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,105	4,066	31,171	31,171	-	-	-	-	-	-	-	-	-	334,464
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	44,158	6,624	50,782	50,782	-	-	-	-	-	-	-	-	-	620,820
2b.4	Subtotal Period 2b Period-Dependent Costs	1,600	8,527	139	35	-	344	125,443	20,488	156,575	152,582	3,993	-	-	6,385	-	-	-	127,708	208	1,559,655
2b.0	TOTAL PERIOD 2b COST	5,171	22,477	1,241	2,056	9,399	9,865	144,171	32,779	227,158	201,346	22,335	3,477	112,994	62,691	-	-	-	7,621,644	504,552	1,563,751
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	521	50	281	83	-	1,509	-	691	3,134	3,134	-	-	-	6,250	-	-	-	397,077	1,722	-
Disposal of Plant Systems																					
2d.1.2.1	EC - Fuel Pool Cooling & Cleanup	-	305	28	27	225	264	-	183	1,033	1,033	-	-	2,600	1,088	-	-	-	175,058	8,041	-
2d.1.2.2	Fuel Bldg Non-System Specific	-	37	3	2	15	29	-	19	106	106	-	-	170	120	-	-	-	14,568	954	-
2d.1.2.3	Fuel Bldg Non-System Specific RCA	-	245	5	16	277	-	-	106	649	649	-	-	3,200	-	-	-	-	129,974	5,859	-
2d.1.2.4	Fuel Building Fire Protection	-	119	5	15	254	-	-	71	463	463	-	-	2,941	-	-	-	-	119,444	2,802	-
2d.1.2.5	GG - Fuel Building HVAC	-	199	9	21	323	38	-	112	701	701	-	-	3,729	155	-	-	-	161,297	4,673	-
2d.1.2	Totals	-	906	51	81	1,093	331	-	490	2,953	2,953	-	-	12,641	1,364	-	-	-	600,340	22,329	-
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Building	569	611	12	34	234	85	-	500	2,046	2,046	-	-	2,705	1,864	-	-	-	199,762	31,564	-
2d.1.3	Totals	569	611	12	34	234	85	-	500	2,046	2,046	-	-	2,705	1,864	-	-	-	199,762	31,564	-
2d.1.4	Scaffolding in support of decommissioning	-	259	7	2	29	6	-	72	375	375	-	-	302	27	-	-	-	15,258	9,241	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
2d.1	Subtotal Period 2d Activity Costs	1,090	1,826	351	200	1,356	1,931	-	1,753	8,507	8,507	-	-	15,647	9,505	-	-	-	1,212,437	64,856	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,340	402	1,742	1,742	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	684	205	890	890	-	-	-	-	-	-	-	-	14,009	-
2d.2.3	Excavation of Underground Services	-	2,001	-	-	-	-	907	636	3,545	3,545	-	-	-	-	-	-	-	-	15,949	-
2d.2.4	License Termination ISFSI	-	155	205	500	-	2,529	1,964	1,338	6,691	6,691	-	-	-	36,660	-	-	-	1,893,161	5,152	10,496
2d.2	Subtotal Period 2d Additional Costs	-	2,156	205	500	-	2,529	4,895	2,582	12,867	12,867	-	-	-	36,660	-	-	-	1,893,161	35,110	22,976
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	86	-	58	141	-	261	-	135	681	681	-	-	-	571	-	-	-	34,248	111	-
2d.3.3	Small tool allowance	-	54	-	-	-	-	-	8	62	62	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	45	575	128	-	139	1,030	1,030	-	-	6,000	529	-	-	-	303,608	147	-
2d.3	Subtotal Period 2d Collateral Costs	86	54	201	187	575	389	-	282	1,773	1,773	-	-	6,000	1,100	-	-	-	337,856	258	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	229	-	-	-	-	-	-	57	286	286	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	467	47	514	514	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	447	45	492	492	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	760	-	-	-	-	-	190	950	950	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,522	-	-	-	-	-	228	1,750	1,750	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	45	11	-	111	-	34	201	201	-	-	-	2,065	-	-	-	41,306	67	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	569	85	655	655	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	330	33	363	363	-	-	-	-	-	-	-	-	-	-
2d.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	273	41	314	314	-	-	-	-	-	-	-	-	-	-
2d.4.10	Corporate Allocations	-	-	-	-	-	-	112	17	129	129	-	-	-	-	-	-	-	-	-	-
2d.4.11	Security Staff Cost	-	-	-	-	-	-	1,558	234	1,791	1,791	-	-	-	-	-	-	-	-	-	43,808
2d.4.12	DOC Staff Cost	-	-	-	-	-	-	5,766	865	6,631	6,631	-	-	-	-	-	-	-	-	-	70,093
2d.4.13	Utility Staff Cost	-	-	-	-	-	-	9,719	1,458	11,177	10,305	872	-	-	-	-	-	-	-	-	132,476
2d.4	Subtotal Period 2d Period-Dependent Costs	229	2,282	45	11	-	111	19,241	3,333	25,252	24,380	872	-	-	2,065	-	-	-	41,306	67	246,377
2d.0	TOTAL PERIOD 2d COST	1,405	6,317	802	897	1,931	4,960	24,136	7,950	48,399	47,527	872	-	21,647	49,330	-	-	-	3,484,760	100,291	269,353
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	536	54	589	589	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	513	51	564	564	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	768	-	-	-	-	-	192	960	960	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	19	-	6	35	35	-	-	-	360	-	-	-	7,203	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	431	43	474	474	-	-	-	-	-	-	-	-	-	-
2f.4.7	Corporate Allocations	-	-	-	-	-	-	65	10	74	74	-	-	-	-	-	-	-	-	-	-
2f.4.8	Security Staff Cost	-	-	-	-	-	-	900	135	1,036	1,036	-	-	-	-	-	-	-	-	-	19,284
2f.4.9	DOC Staff Cost	-	-	-	-	-	-	5,038	756	5,794	5,794	-	-	-	-	-	-	-	-	-	58,656
2f.4.10	Utility Staff Cost	-	-	-	-	-	-	6,051	908	6,959	5,963	995	-	-	-	-	-	-	-	-	76,333
2f.4	Subtotal Period 2f Period-Dependent Costs	-	768	8	2	-	19	13,859	2,203	16,859	15,864	995	-	-	360	-	-	-	7,203	12	154,273
2f.0	TOTAL PERIOD 2f COST	-	768	8	2	-	19	21,830	4,396	27,023	26,028	995	-	-	360	-	-	-	7,203	152,831	160,513
PERIOD 2 TOTALS		8,228	66,697	20,416	10,249	20,970	60,910	309,031	101,306	597,808	551,629	39,875	6,303	252,581	186,588	963	393	2,217	22,233,570	1,191,877	3,312,693

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	2,518	-	-	-	-	-	378	2,896	-	-	2,896	-	-	-	-	-	-	27,724	-
3b.1.1.2	Access Vaults	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	59	-
3b.1.1.3	Administration	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,724	-
3b.1.1.4	Auxiliary	-	2,063	-	-	-	-	-	309	2,373	-	-	2,373	-	-	-	-	-	-	19,753	-
3b.1.1.5	Auxiliary Boiler	-	16	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	248	-
3b.1.1.6	Chemical Addition Structure	-	33	-	-	-	-	-	5	37	-	-	37	-	-	-	-	-	-	469	-
3b.1.1.7	Circ Water Pump Enclosure	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	164	-
3b.1.1.8	Circ Water Travel Screen Enclosure	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	160	-
3b.1.1.9	Circulating Water Discharge Structure	-	90	-	-	-	-	-	13	103	-	-	103	-	-	-	-	-	-	542	-
3b.1.1.10	Circulating Water Intake & Screenhouse	-	83	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	683	-
3b.1.1.11	Communication Corridor - Clean	-	683	-	-	-	-	-	102	785	-	-	785	-	-	-	-	-	-	8,280	-
3b.1.1.12	Communication Corridor - Contaminated	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	184	-
3b.1.1.13	Covered Walkways	-	11	-	-	-	-	-	2	12	-	-	12	-	-	-	-	-	-	242	-
3b.1.1.14	Diesel Generator	-	239	-	-	-	-	-	36	274	-	-	274	-	-	-	-	-	-	2,185	-
3b.1.1.15	E.S.W.S. Pumphouse	-	124	-	-	-	-	-	19	143	-	-	143	-	-	-	-	-	-	801	-
3b.1.1.16	ESWS Valve House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	42	-
3b.1.1.17	FLEX Building No. 1 & 2	-	347	-	-	-	-	-	52	399	-	-	399	-	-	-	-	-	-	2,880	-
3b.1.1.18	GOB - Administration Building	-	193	-	-	-	-	-	29	222	-	-	222	-	-	-	-	-	-	2,962	-
3b.1.1.19	Hot Machine Shop	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	243	-
3b.1.1.20	M.M.O. Building	-	225	-	-	-	-	-	34	259	-	-	259	-	-	-	-	-	-	2,389	-
3b.1.1.21	Material Center West	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,379	-
3b.1.1.22	Misc Structures and Additions	-	57	-	-	-	-	-	9	66	-	-	66	-	-	-	-	-	-	910	-
3b.1.1.23	Miscellaneous Site Foundations	-	204	-	-	-	-	-	31	234	-	-	234	-	-	-	-	-	-	1,242	-
3b.1.1.24	Miscellaneous Site Structures	-	1,284	-	-	-	-	-	193	1,477	-	-	1,477	-	-	-	-	-	-	13,693	-
3b.1.1.25	New Covered Walkway	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	79	-
3b.1.1.26	Oil Separator and Waste Tank	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	8	-
3b.1.1.27	Radwaste	-	864	-	-	-	-	-	130	993	-	-	993	-	-	-	-	-	-	8,111	-
3b.1.1.28	Radwaste Drum Storage	-	126	-	-	-	-	-	19	144	-	-	144	-	-	-	-	-	-	1,504	-
3b.1.1.29	Radwaste Storage Building	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	1,028	-
3b.1.1.30	SBO Diesel Generator	-	240	-	-	-	-	-	36	276	-	-	276	-	-	-	-	-	-	3,079	-
3b.1.1.31	Security Main Gate North	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	1,123	-
3b.1.1.32	Security Additions	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	405	-
3b.1.1.33	Security/Guardhouse	-	30	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	342	-
3b.1.1.34	Site Diesel Generator	-	2	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	18	-
3b.1.1.35	Support Complex	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	389	-
3b.1.1.36	Turbine Building	-	2,393	-	-	-	-	-	359	2,752	-	-	2,752	-	-	-	-	-	-	47,184	-
3b.1.1.37	Turbine Pedestal	-	478	-	-	-	-	-	72	549	-	-	549	-	-	-	-	-	-	2,934	-
3b.1.1.38	Waste Water Treatment	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	172	-
3b.1.1.39	Water Treatment Building North (Z110)	-	48	-	-	-	-	-	7	55	-	-	55	-	-	-	-	-	-	608	-
3b.1.1.40	Fuel Building	-	909	-	-	-	-	-	136	1,045	-	-	1,045	-	-	-	-	-	-	7,983	-
3b.1.1	Totals	-	13,727	-	-	-	-	-	2,059	15,787	-	-	15,787	-	-	-	-	-	-	163,924	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	948	-	-	-	-	-	142	1,090	-	-	1,090	-	-	-	-	-	-	5,352	-
3b.1.3	Grade & landscape site	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	512	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	14,776	-	-	-	-	182	2,244	17,202	210	-	16,992	-	-	-	-	-	-	169,788	1,560
Period 3b Additional Costs																					
3b.2.1	Concrete Crushing	-	880	-	-	-	-	11	134	1,025	-	-	1,025	-	-	-	-	-	-	4,585	-
3b.2.2	Circulating Water Intake Cofferdam	-	308	-	-	-	-	-	46	354	-	-	354	-	-	-	-	-	-	2,584	-
3b.2.3	E.S.W.S. Pumphouse Cofferdam	-	404	-	-	-	-	-	61	465	-	-	465	-	-	-	-	-	-	3,652	-
3b.2.4	Construction Debris	-	-	-	-	-	-	1,730	260	1,990	-	-	1,990	-	-	-	-	-	-	-	-
3b.2.5	Site Restoration ISFSI	-	462	-	-	-	-	111	86	659	-	-	659	-	-	-	-	-	-	4,099	160
3b.2.6	Firing Range Closure	-	-	-	-	-	-	692	104	796	-	-	796	-	-	-	-	-	-	-	-
3b.2	Subtotal Period 3b Additional Costs	-	2,055	-	-	-	-	2,544	690	5,289	-	-	5,289	-	-	-	-	-	-	14,821	160
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	105	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	105	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	-	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs																					
3b.4.2	Property taxes	-	-	-	-	-	-	482	48	530	-	-	530	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	4,679	-	-	-	-	-	702	5,381	-	-	5,381	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	314	47	361	-	-	361	-	-	-	-	-	-	-	-
3b.4.5	Corporate Allocations	-	-	-	-	-	-	51	8	59	-	-	59	-	-	-	-	-	-	-	-
3b.4.6	Security Staff Cost	-	-	-	-	-	-	1,734	260	1,994	-	-	1,994	-	-	-	-	-	-	-	37,132
3b.4.7	DOC Staff Cost	-	-	-	-	-	-	9,107	1,366	10,473	-	-	10,473	-	-	-	-	-	-	-	105,208
3b.4.8	Utility Staff Cost	-	-	-	-	-	-	4,573	686	5,259	-	-	5,259	-	-	-	-	-	-	-	60,340
3b.4	Subtotal Period 3b Period-Dependent Costs	-	4,679	-	-	-	-	16,260	3,117	24,056	-	-	24,056	-	-	-	-	-	-	-	202,680
3b.0	TOTAL PERIOD 3b COST	-	21,614	-	-	-	-	18,987	6,066	46,667	210	-	46,457	-	-	-	-	-	-	184,609	204,400
PERIOD 3 TOTALS		-	21,614	-	-	-	-	18,987	6,066	46,667	210	-	46,457	-	-	-	-	-	-	184,609	204,400
TOTAL COST TO DECOMMISSION		12,020	91,177	20,618	10,622	20,986	64,399	464,007	129,904	813,733	711,273	48,251	54,208	254,732	187,840	1,750	393	2,217	22,491,670	1,397,626	4,808,663

TOTAL COST TO DECOMMISSION WITH 19% CONTINGENCY:	$813,733	thousands of 2017 dollars
TOTAL NRC LICENSE TERMINATION COST IS 87.41% OR:	$711,273	thousands of 2017 dollars
SPENT FUEL MANAGEMENT COST IS 5.93% OR:	$48,251	thousands of 2017 dollars
NON-NUCLEAR DEMOLITION COST IS 6.66% OR:	$54,208	thousands of 2017 dollars
TOTAL LOW-LEVEL RADIOACTIVE RADWASTE VOLUME BURIED (EXCLUDING GTCC):	189,983	cubic feet
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED	2,217	cubic feet
TOTAL SCRAP METAL REMOVED:	69,384	tons
TOTAL CRAFT LABOR REQUIREMENTS:	1,397,626	man-hours

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX D

DETAILED COST ANALYSIS

SAFSTOR

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	380	114	494	494	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	175	26	202	202	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	362	54	417	417	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	584	88	672	672	-	-	-	-	-	-	-	-	-	5,000
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	575	86	661	661	-	-	-	-	-	-	-	-	-	4,920
1a.1.18.2	Plant systems	-	-	-	-	-	-	487	73	560	560	-	-	-	-	-	-	-	-	-	4,167
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	365	55	419	419	-	-	-	-	-	-	-	-	-	3,120
1a.1.18.4	Waste management	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.18	Total	-	-	-	-	-	-	1,894	284	2,178	2,178	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	138	21	159	159	-	-	-	-	-	-	-	-	-	1,183
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	140	21	161	161	-	-	-	-	-	-	-	-	-	1,200
1a.1.19	Total	-	-	-	-	-	-	279	42	320	320	-	-	-	-	-	-	-	-	-	2,383
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	12	2	13	13	-	-	-	-	-	-	-	-	-	100
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,568	892	6,461	6,461	-	-	-	-	-	-	-	-	-	44,390
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Transfer (ISFSI to DOE)	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,754	375	4,130	4,130	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,274	227	2,502	2,502	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	3	-	33	-	10	59	59	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	2,111	317	2,428	2,428	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,225	122	1,347	-	1,347	-	-	-	-	-	-	-	-	-
1a.4.9	INPO Fees	-	-	-	-	-	-	333	50	383	383	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate Allocations	-	-	-	-	-	-	357	54	411	411	-	-	-	-	-	-	-	-	-	-
1a.4.13	NEI Annual Fees	-	-	-	-	-	-	530	79	609	609	-	-	-	-	-	-	-	-	-	-
1a.4.14	Security Staff Cost	-	-	-	-	-	-	19,401	2,910	22,311	22,311	-	-	-	-	-	-	-	-	-	316,295
1a.4.15	Utility Staff Cost	-	-	-	-	-	-	28,719	4,308	33,027	33,027	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	3	-	33	60,721	8,914	70,766	68,377	2,389	-	-	610	-	-	-	12,190	20	738,535
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	3	-	33	67,423	9,976	78,531	74,838	3,694	-	-	610	-	-	-	12,190	20	782,925

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities.																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	872	-	-	-	-	-	-	436	1,308	1,308	-	-	-	-	-	-	-	-	24,102	-
1b.1.1.2	Auxiliary	436	-	-	-	-	-	-	218	653	653	-	-	-	-	-	-	-	-	12,527	-
1b.1.1.3	Communication Corridor - Contaminated	10	-	-	-	-	-	-	5	14	14	-	-	-	-	-	-	-	-	276	-
1b.1.1.4	Fuel Building	562	-	-	-	-	-	-	281	842	842	-	-	-	-	-	-	-	-	14,371	-
1b.1.1.5	Hot Machine Shop	12	-	-	-	-	-	-	6	18	18	-	-	-	-	-	-	-	-	344	-
1b.1.1.6	Radwaste	232	-	-	-	-	-	-	116	348	348	-	-	-	-	-	-	-	-	6,671	-
1b.1.1.7	Radwaste Drum Storage	26	-	-	-	-	-	-	13	39	39	-	-	-	-	-	-	-	-	750	-
1b.1.1.8	Radwaste Storage Building	61	-	-	-	-	-	-	30	91	91	-	-	-	-	-	-	-	-	1,690	-
1b.1.1	Totals	2,209	-	-	-	-	-	-	1,105	3,314	3,314	-	-	-	-	-	-	-	-	60,731	-
1b.1	Subtotal Period 1b Activity Costs	2,209	-	-	-	-	-	-	1,105	3,314	3,314	-	-	-	-	-	-	-	-	60,731	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	172	-	110	269	-	497	-	262	1,310	1,310	-	-	-	1,086	-	-	-	65,189	212	-
1b.3.4	Small tool allowance	-	35	-	-	-	-	-	5	40	40	-	-	-	-	-	-	-	-	-	-
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,512	227	1,739	-	1,739	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,145	35	110	269	-	497	1,512	640	4,208	2,469	1,739	-	-	1,086	-	-	-	65,189	212	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,502	-	-	-	-	-	-	376	1,878	1,878	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	946	95	1,041	1,041	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	573	57	631	631	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	421	-	-	-	-	-	105	526	526	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	16	4	-	40	-	12	73	73	-	-	-	753	-	-	-	15,052	25	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	532	80	612	612	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	309	31	340	-	340	-	-	-	-	-	-	-	-	-
1b.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.11	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.12	Corporate Allocations	-	-	-	-	-	-	90	14	104	104	-	-	-	-	-	-	-	-	-	-
1b.4.13	NEI Annual Fees	-	-	-	-	-	-	134	20	154	154	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	4,792	719	5,511	5,511	-	-	-	-	-	-	-	-	-	78,063
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	7,239	1,086	8,325	8,325	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	1,502	564	16	4	-	40	15,005	2,666	19,797	19,195	602	-	-	753	-	-	-	15,052	25	184,491
1b.0	TOTAL PERIOD 1b COST	4,856	599	127	273	-	537	16,517	4,410	27,319	24,978	2,341	-	-	1,839	-	-	-	80,241	60,968	184,491
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	394	-	-	-	-	-	59	453	453	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	26	-	-	-	-	-	4	30	30	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	14,124	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	68	10	78	78	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	420	-	-	-	-	801	293	1,515	1,515	-	-	-	-	-	-	-	-	17,824	583
Period 1c Additional Costs																					
1c.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1c.2.2	Misc/Hazardous Waste	-	-	76	20	16	-	-	13	125	125	-	-	2,151	-	-	-	-	137,800	740	-
1c.2	Subtotal Period 1c Additional Costs	-	-	76	20	16	-	11,691	1,767	13,570	13,570	-	-	2,151	-	-	-	-	137,800	740	-
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	187	-	120	293	-	541	-	285	1,425	1,425	-	-	-	1,183	-	-	-	70,966	231	-
1c.3.3	Small tool allowance	-	2	-	-	-	-	-	0	3	3	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,512	227	1,739	-	1,739	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	187	2	120	293	-	541	1,512	512	3,167	1,428	1,739	-	-	1,183	-	-	-	70,966	231	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	946	95	1,041	1,041	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	573	57	631	631	-	-	-	-	-	-	-	-	-	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 1c Period-Dependent Costs (continued)																					
1c.4.3	Health physics supplies	-	220	-	-	-	-	-	55	275	275	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	8	-	3	15	15	-	-	-	154	-	-	-	3,073	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	532	80	612	612	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	309	31	340	-	340	-	-	-	-	-	-	-	-	-
1c.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1c.4.11	Corporate Allocations	-	-	-	-	-	-	90	14	104	104	-	-	-	-	-	-	-	-	-	-
1c.4.12	NEI Annual Fees	-	-	-	-	-	-	134	20	154	154	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	4,785	718	5,503	5,503	-	-	-	-	-	-	-	-	-	77,954
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	7,239	1,086	8,325	8,325	-	-	-	-	-	-	-	-	-	106,428
1c.4	Subtotal Period 1c Period-Dependent Costs	-	363	3	1	-	8	14,998	2,229	17,602	17,000	602	-	-	154	-	-	-	3,073	5	184,382
1c.0	TOTAL PERIOD 1c COST	187	785	199	313	16	549	29,003	4,801	35,854	33,512	2,341	-	2,151	1,336	-	-	-	211,838	18,799	184,965
PERIOD 1 TOTALS		5,043	2,467	339	590	16	1,119	112,943	19,187	141,704	133,328	8,376	-	2,151	3,785	-	-	-	304,269	79,787	1,152,381
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	408	61	469	469	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	564	141	705	706	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	973	202	1,175	1,175	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	26,741	4,011	30,752	-	30,752	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	26,741	4,011	30,752	-	30,752	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,775	277	3,052	3,052	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	9,104	910	10,014	10,014	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	828	-	-	-	-	-	207	1,034	1,034	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	20	5	-	50	-	15	90	90	-	-	-	921	-	-	-	18,419	30	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,690	254	1,944	972	972	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	1,027	103	1,130	1,130	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,806	281	3,086	-	3,086	-	-	-	-	-	-	-	-	-
2a.4.8	Spent Fuel Pool O&M	-	-	-	-	-	-	3,212	482	3,694	-	3,694	-	-	-	-	-	-	-	-	-
2a.4.9	ISFSI Operating Costs	-	-	-	-	-	-	413	62	475	-	475	-	-	-	-	-	-	-	-	-
2a.4.10	Corporate Allocations	-	-	-	-	-	-	278	42	320	162	158	-	-	-	-	-	-	-	-	-
2a.4.11	NEI Annual Fees	-	-	-	-	-	-	2,119	318	2,437	2,437	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	67,604	10,141	77,744	72,380	5,364	-	-	-	-	-	-	-	-	1,098,240
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	23,197	3,480	26,677	21,528	5,149	-	-	-	-	-	-	-	-	328,865
2a.4	Subtotal Period 2a Period-Dependent Costs	-	828	20	5	-	50	114,226	16,570	131,698	112,799	18,899	-	-	921	-	-	-	18,419	30	1,427,105
2a.0	TOTAL PERIOD 2a COST	-	828	20	5	-	50	141,940	20,784	163,625	113,974	49,651	-	-	921	-	-	-	18,419	30	1,427,105
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	4,914	737	5,652	5,652	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	6,798	1,700	8,498	8,498	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	11,713	2,437	14,150	14,150	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	32,234	3,223	35,457	35,457	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	15,605	1,561	17,166	17,166	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	4,548	-	-	-	-	-	1,137	5,685	5,685	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	107	27	-	264	-	81	478	478	-	-	-	4,907	-	-	-	98,142	160	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	10,178	1,527	11,705	11,705	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	10,722	1,072	11,795	11,795	-	-	-	-	-	-	-	-	-	-
2c.4.7	Corporate Allocations	-	-	-	-	-	-	743	111	854	854	-	-	-	-	-	-	-	-	-	-
2c.4.8	Security Staff Cost	-	-	-	-	-	-	83,336	12,500	95,837	95,837	-	-	-	-	-	-	-	-	-	1,504,097

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2c Period-Dependent Costs (continued)																					
2c.4.9	Utility Staff Cost	-	-	-	-	-	-	57,514	8,627	66,141	66,141	-	-	-	-	-	-	-	-	-	877,390
2c.4	Subtotal Period 2c Period-Dependent Costs	-	4,548	107	27	-	264	210,333	29,839	245,117	245,117	-	-	-	4,907	-	-	-	98,142	160	2,381,486
2c.0	TOTAL PERIOD 2c COST	-	4,548	107	27	-	264	222,046	32,276	259,267	259,267	-	-	-	4,907	-	-	-	98,142	160	2,381,486
PERIOD 2 TOTALS		-	5,375	127	32	-	314	363,985	53,060	422,893	373,241	49,651	-	-	5,828	-	-	-	116,561	190	3,808,591
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									n											
3a.1.4	End product description	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	362	54	417	417	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	584	88	672	672	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	861	129	991	892	-	99	-	-	-	-	-	-	-	7,370
3a.1.9.2	Plant systems	-	-	-	-	-	-	487	73	560	504	-	56	-	-	-	-	-	-	-	4,167
3a.1.9.3	Reactor internals	-	-	-	-	-	-	830	124	954	954	-	-	-	-	-	-	-	-	-	7,100
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	760	114	874	874	-	-	-	-	-	-	-	-	-	6,500
3a.1.9.5	Biological shield	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	500
3a.1.9.6	Steam generators	-	-	-	-	-	-	365	55	419	419	-	-	-	-	-	-	-	-	-	3,120
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	187	28	215	108	-	108	-	-	-	-	-	-	-	1,600
3a.1.9.8	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.9	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.10	Plant structures & buildings	-	-	-	-	-	-	365	55	419	210	-	210	-	-	-	-	-	-	-	3,120
3a.1.9.11	Waste management	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
3a.1.9.12	Facility & site closeout	-	-	-	-	-	-	105	16	121	60	-	60	-	-	-	-	-	-	-	900
3a.1.9	Total	-	-	-	-	-	-	4,649	697	5,346	4,706	-	640	-	-	-	-	-	-	-	39,777
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	281	42	323	323	-	-	-	-	-	-	-	-	-	2,400
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	164	25	188	188	-	-	-	-	-	-	-	-	-	1,400
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	144	22	165	165	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	13,619	2,043	15,662	15,021	-	640	-	-	-	-	-	-	-	68,607
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	669	67	736	736	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	324	32	356	356	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	450	-	-	-	-	-	113	563	563	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	3	-	28	-	8	50	50	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	2,111	317	2,428	2,428	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	341	34	376	376	-	-	-	-	-	-	-	-	-	-
3a.4.8	Corporate Allocations	-	-	-	-	-	-	218	33	251	251	-	-	-	-	-	-	-	-	-	-
3a.4.9	Security Staff Cost	-	-	-	-	-	-	2,311	347	2,658	2,658	-	-	-	-	-	-	-	-	-	65,000
3a.4.10	Utility Staff Cost	-	-	-	-	-	-	17,990	2,699	20,689	20,689	-	-	-	-	-	-	-	-	-	257,920
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,018	11	3	-	28	23,965	3,734	28,758	28,758	-	-	-	514	-	-	-	10,287	17	322,920
3a.0	TOTAL PERIOD 3a COST	-	1,018	11	3	-	28	37,583	5,777	44,420	43,779	-	640	-	514	-	-	-	10,287	17	391,527
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	553	83	636	573	-	64	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	292	44	336	336	-	-	-	-	-	-	-	-	-	2,500
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	158	24	181	45	-	136	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	424	64	488	488	-	-	-	-	-	-	-	-	-	3,630

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Detailed Work Procedures (continued)																					
3b.1.1.8	Facility closeout	-	-	-	-	-	-	140	21	161	81	-	81	-	-	-	-	-	-	-	1,200
3b.1.1.9	Missile shields	-	-	-	-	-	-	53	8	60	60	-	-	-	-	-	-	-	-	-	450
3b.1.1.10	Biological shield	-	-	-	-	-	-	140	21	161	161	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.11	Steam generators	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	117	18	134	67	-	67	-	-	-	-	-	-	-	1,000
3b.1.1.13	Main Turbine	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
3b.1.1.14	Main Condensers	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
3b.1.1.16	Reactor building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	3,769	565	4,334	3,494	-	840	-	-	-	-	-	-	-	32,243
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	3,769	565	4,334	3,494	-	840	-	-	-	-	-	-	-	32,243
Period 3b Additional Costs																					
3b.2.1	Site Characterization	-	-	-	-	-	-	2,984	895	3,880	3,880	-	-	-	-	-	-	-	-	19,100	7,852
3b.2	Subtotal Period 3b Additional Costs	-	-	-	-	-	-	2,984	895	3,880	3,880	-	-	-	-	-	-	-	-	19,100	7,852
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,323	524	4,020	4,020	-	-	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	36	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	349	35	384	384	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	163	16	180	180	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	250	-	-	-	-	-	63	313	313	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	16	-	5	29	29	-	-	-	293	-	-	-	5,866	10	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	1,064	160	1,224	1,224	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	172	17	189	189	-	-	-	-	-	-	-	-	-	-
3b.4.9	Corporate Allocations	-	-	-	-	-	-	110	17	127	127	-	-	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	1,165	175	1,340	1,340	-	-	-	-	-	-	-	-	-	32,767
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	4,865	730	5,595	5,595	-	-	-	-	-	-	-	-	-	58,719
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	9,069	1,360	10,429	10,429	-	-	-	-	-	-	-	-	-	130,020
3b.4	Subtotal Period 3b Period-Dependent Costs	36	536	6	2	-	16	16,958	2,629	20,182	20,182	-	-	-	293	-	-	-	5,866	10	221,506
3b.0	TOTAL PERIOD 3b COST	1,008	1,736	6	2	-	16	25,034	4,614	32,416	31,575	-	840	-	293	-	-	-	5,866	19,110	261,601
PERIOD 3 TOTALS		1,008	2,754	18	4	-	43	62,617	10,391	76,835	75,355	-	1,481	-	808	-	-	-	16,153	19,126	653,128
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	25	129	42	28	137	271	-	142	775	775	-	-	967	1,023	-	-	-	135,750	3,982	-
4a.1.1.2	Pressurizer Relief Tank	4	16	12	8	39	77	-	34	190	190	-	-	273	289	-	-	-	38,367	602	-
4a.1.1.3	Reactor Coolant Pumps & Motors	16	65	62	199	-	1,061	-	326	1,728	1,728	-	-	-	3,386	-	-	-	816,140	2,700	80
4a.1.1.4	Pressurizer	7	37	420	147	-	1,171	-	370	2,152	2,152	-	-	-	3,739	-	-	-	241,053	1,539	1,500
4a.1.1.5	Steam Generators	54	5,183	2,904	3,116	2,688	7,063	-	4,249	25,257	25,257	-	-	40,845	22,546	-	-	-	3,356,336	22,021	4,500
4a.1.1.6	CRDMs/ICIs/Service Structure Removal	21	178	248	37	97	439	-	210	1,230	1,230	-	-	1,227	3,012	-	-	-	160,939	5,371	-
4a.1.1.7	Reactor Vessel Internals	87	6,283	7,575	1,270	-	10,290	337	12,163	38,006	38,006	-	-	-	2,504	501	393	-	329,177	28,573	1,301
4a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	11,615	-	1,742	13,357	13,357	-	-	-	-	-	-	2,217	433,180	-	-
4a.1.1.9	Reactor Vessel	-	7,807	2,219	496	-	4,897	337	9,033	24,788	24,788	-	-	-	15,631	-	-	-	979,036	28,573	1,301
4a.1.1	Totals	215	19,699	13,483	5,301	2,960	36,883	674	28,268	107,483	107,483	-	-	43,312	52,130	501	393	2,217	6,489,979	93,362	8,683
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	297	283	37	652	-	-	206	1,475	1,475	-	-	5,099	-	-	-	-	305,952	8,585	-
4a.1.3	Main Condensers	-	842	176	45	777	-	-	351	2,191	2,191	-	-	8,106	-	-	-	-	364,767	24,802	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	443	-	-	-	-	-	66	510	510	-	-	-	-	-	-	-	-	4,871	-
4a.1.4.2	Auxiliary	-	229	-	-	-	-	-	34	264	264	-	-	-	-	-	-	-	-	2,194	-
4a.1.4.3	Fuel Building	-	97	-	-	-	-	-	15	112	112	-	-	-	-	-	-	-	-	773	-
4a.1.4.4	Hot Machine Shop	-	1	-	-	-	-	-	0	1	1	-	-	-	-	-	-	-	-	7	-
4a.1.4.5	Radwaste	-	44	-	-	-	-	-	7	51	51	-	-	-	-	-	-	-	-	387	-
4a.1.4	Totals	-	815	-	-	-	-	-	122	937	937	-	-	-	-	-	-	-	-	8,233	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems																					
4a.1.5.1	AB - Main Steam	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,833	-
4a.1.5.2	AB - Main Steam RCA	-	60	4	11	186	-	-	45	305	305	-	-	2,156	-	-	-	-	87,550	1,515	-
4a.1.5.3	AC - Main Turbine	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,641	-
4a.1.5.4	AD - Condensate	-	181	-	-	-	-	-	27	208	-	-	208	-	-	-	-	-	-	6,144	-
4a.1.5.5	AE - Feedwater	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	4,271	-
4a.1.5.6	AF - Feedwater Hter Extrction, Drn & Vnt	-	152	-	-	-	-	-	23	175	-	-	175	-	-	-	-	-	-	5,352	-
4a.1.5.7	AK - Condensate Demineralizer	-	56	-	-	-	-	-	8	65	-	-	65	-	-	-	-	-	-	1,944	-
4a.1.5.8	AL - Auxiliary Feedwater	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	1,174	-
4a.1.5.9	AL-Auxiliary Feedwater Surge Tanks	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	87	-
4a.1.5.10	AQ - Condensate & Feedwater Chem Additn	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	468	-
4a.1.5.11	AX - Acid Feed	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	754	-
4a.1.5.12	Auxiliary Bldg Non-System Specific	-	77	2	5	71	8	-	33	195	195	-	-	824	31	-	-	-	35,454	2,031	-
4a.1.5.13	Auxiliary Bldg Non-System Specific RCA	-	537	13	38	660	-	-	240	1,487	1,487	-	-	7,629	-	-	-	-	309,812	13,471	-
4a.1.5.14	BL - Reactor Makeup Water	-	203	15	18	219	102	-	113	670	670	-	-	2,529	418	-	-	-	129,620	5,227	-
4a.1.5.15	BM - Steam Generator Blowdown	-	413	8	26	446	-	-	175	1,069	1,069	-	-	5,160	-	-	-	-	209,560	10,703	-
4a.1.5.16	CA - Steam Seal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	455	-
4a.1.5.17	CB - Main Turbine Lube Oil	-	38	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	1,207	-
4a.1.5.18	CC - Generator Hydrogen & CO2	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	198	-
4a.1.5.19	CD - Generator Seal Oil	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	287	-
4a.1.5.20	CE - Stator Cooling Water	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	241	-
4a.1.5.21	CF - Lube Oil Strg, Xfer & Purification	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	812	-
4a.1.5.22	CG - Condenser Air Removal	-	19	-	-	-	-	-	3	22	-	-	22	-	-	-	-	-	-	657	-
4a.1.5.23	CH - Main Turbine Control Oil	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,219	-
4a.1.5.24	CL - Chlorination	-	17	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	569	-
4a.1.5.25	CO - Carbon Dioxide	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	121	-
4a.1.5.26	CW - Circulating Water	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	7,858	-
4a.1.5.27	CZ - Caustic Acid	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	111	-
4a.1.5.28	DA - Circulating Water System	-	223	-	-	-	-	-	33	256	-	-	256	-	-	-	-	-	-	7,953	-
4a.1.5.29	DM - Equipment Drains	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	1,223	-
4a.1.5.30	DM - Equipment Drains RCA	-	111	26	77	1,336	-	-	242	1,793	1,793	-	-	15,445	-	-	-	-	627,223	2,840	-
4a.1.5.31	EG - Component Cooling Water RCA	-	557	24	70	1,225	-	-	336	2,213	2,213	-	-	14,161	-	-	-	-	575,071	13,646	-
4a.1.5.32	EJ - Residual Heat Removal	-	261	33	38	386	283	-	203	1,203	1,203	-	-	4,461	1,166	-	-	-	255,554	7,018	-
4a.1.5.33	EM - High Pressure Coolant Injection	-	220	4	11	187	-	-	85	506	506	-	-	2,159	-	-	-	-	87,663	5,527	-
4a.1.5.34	EN - Containment Spray	-	170	5	15	262	-	-	84	536	536	-	-	3,026	-	-	-	-	122,874	4,134	-
4a.1.5.35	FB - Auxiliary Steam	-	60	-	-	-	-	-	9	69	-	-	69	-	-	-	-	-	-	2,106	-
4a.1.5.36	FB - Auxiliary Steam RCA	-	66	1	4	71	-	-	28	169	169	-	-	816	-	-	-	-	33,148	1,537	-
4a.1.5.37	FC - Auxiliary Turbines	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,301	-
4a.1.5.38	FE - Auxiliary Steam Chemical Addition	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	105	-
4a.1.5.39	GE - Turbine Bldg HVAC	-	86	-	-	-	-	-	13	99	-	-	99	-	-	-	-	-	-	3,189	-
4a.1.5.40	GF - Miscellaneous Building HVAC	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	987	-
4a.1.5.41	GS - Containment Hydrogen Control	-	53	1	4	69	-	-	24	152	152	-	-	801	-	-	-	-	32,539	1,395	-
4a.1.5.42	HF - Secondary Liquid Waste	-	677	52	63	729	387	-	390	2,298	2,298	-	-	8,431	1,588	-	-	-	444,251	17,832	-
4a.1.5.43	HY - Hydrogen	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	223	-
4a.1.5.44	KH - Service Gas	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	644	-
4a.1.5.45	LE - Oily Waste	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,575	-
4a.1.5.46	LE - Oily Waste RCA	-	153	3	9	149	-	-	62	376	376	-	-	1,718	-	-	-	-	69,785	3,618	-
4a.1.5.47	NT - Nitrogen	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	149	-
4a.1.5.48	OX - Oxygen	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	171	-
4a.1.5.49	SW - Screen Wash	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	635	-
4a.1.5.50	Turbine Bldg Non-System Specific	-	471	-	-	-	-	-	71	542	-	-	542	-	-	-	-	-	-	15,405	-
4a.1.5.51	VH - Circ Water & Makeup Water Scrnbs	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	272	-
4a.1.5.52	VV - Misc Bldg HVAC	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	148	-
4a.1.5.53	WG - Gland Water & Motor Cooling Water	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	593	-
4a.1.5.54	WL - Cooling Lake Makeup & Blowdown	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	745	-
4a.1.5	Totals	-	5,989	191	387	5,996	779	-	2,426	15,768	12,973	-	2,795	69,317	3,203	-	-	-	3,020,102	174,218	-
4a.1.6	Scaffolding in support of decommissioning	-	947	29	8	116	26	-	265	1,390	1,390	-	-	1,206	106	-	-	-	61,032	33,925	-
4a.1	Subtotal Period 4a Activity Costs	215	28,590	14,162	5,778	10,501	37,688	674	31,638	129,245	126,450	-	2,795	127,040	55,440	501	393	2,217	10,241,830	343,124	8,683
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,580	474	2,054	2,054	-	-	-	-	-	-	-	-	32,347	-
4a.2	Subtotal Period 4a Additional Costs	-	-	-	-	-	-	1,580	474	2,054	2,054	-	-	-	-	-	-	-	-	32,347	-
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	5	-	8	19	-	36	-	15	82	82	-	-	-	78	-	-	-	4,664	15	-
4a.3.3	Small tool allowance	-	236	-	-	-	-	-	35	271	244	-	27	-	-	-	-	-	-	-	-
4a.3.4	On-site survey and release of 116.8 tons clean metallic waste	-	-	-	-	-	-	166	17	182	182	-	-	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	5	236	8	19	-	36	166	67	536	509	-	27	-	78	-	-	-	4,664	15	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	110	-	-	-	-	-	-	27	137	137	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	1,079	108	1,187	1,187	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	504	50	554	554	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	2,583	-	-	-	-	-	646	3,229	3,229	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	3,417	-	-	-	-	-	513	3,929	3,929	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	115	29	-	284	-	87	513	513	-	-	-	5,271	-	-	-	105,415	172	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	3,121	468	3,590	3,590	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	867	87	954	954	-	-	-	-	-	-	-	-	-	-
4a.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	630	94	724	724	-	-	-	-	-	-	-	-	-	-
4a.4.10	Corporate Allocations	-	-	-	-	-	-	343	51	394	394	-	-	-	-	-	-	-	-	-	-
4a.4.11	Security Staff Cost	-	-	-	-	-	-	3,596	539	4,136	4,136	-	-	-	-	-	-	-	-	-	101,151
4a.4.12	DOC Staff Cost	-	-	-	-	-	-	17,745	2,662	20,407	20,407	-	-	-	-	-	-	-	-	-	223,341
4a.4.13	Utility Staff Cost	-	-	-	-	-	-	28,338	4,251	32,589	32,589	-	-	-	-	-	-	-	-	-	404,603
4a.4	Subtotal Period 4a Period-Dependent Costs	110	6,000	115	29	-	284	56,223	9,583	72,343	72,343	-	-	-	5,271	-	-	-	105,415	172	729,094
4a.0	TOTAL PERIOD 4a COST	329	34,826	14,284	5,826	10,501	38,007	58,643	41,762	204,177	201,355	-	2,822	127,040	60,788	501	393	2,217	10,351,910	375,658	737,777
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	475	50	281	83	-	1,509	-	668	3,065	3,065	-	-	-	6,250	-	-	-	397,077	1,722	-
Disposal of Plant Systems																					
4b.1.2.1	AN - Demineralized Wtr Storage & xfer	-	45	-	-	-	-	-	7	51	-	-	51	-	-	-	-	-	-	1,648	-
4b.1.2.2	AN - Demineralized Wtr Strg & xfer RCA	-	15	0	1	10	-	-	5	32	32	-	-	120	-	-	-	-	4,855	334	-
4b.1.2.3	AP - Condensate Storage & Transfer	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,660	-
4b.1.2.4	BB - Reactor Coolant	-	205	28	27	217	271	-	158	907	907	-	-	2,511	1,121	-	-	-	173,293	5,731	-
4b.1.2.5	BG - Chemical & Volume Control	-	661	74	75	705	630	-	447	2,592	2,592	-	-	8,155	2,686	-	-	-	496,849	17,005	-
4b.1.2.6	BN - Borated Refueling Water Storage	-	222	10	31	541	-	-	142	946	946	-	-	6,255	-	-	-	-	254,024	6,161	-
4b.1.2.7	Control Bldg Non-System Specific	-	139	4	11	185	-	-	64	402	402	-	-	2,139	-	-	-	-	86,849	3,413	-
4b.1.2.8	Control Bldg Non-System Specific Cln	-	988	-	-	-	-	-	148	1,137	-	-	1,137	-	-	-	-	-	-	29,076	-
4b.1.2.9	DO - Diesel Oil	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	48	-
4b.1.2.10	EA - Service Water	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,592	-
4b.1.2.11	EB - Closed Cooling Water	-	36	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,267	-
4b.1.2.12	EC - Fuel Pool Cooling & Cleanup	-	279	7	20	356	-	-	127	789	789	-	-	4,115	-	-	-	-	167,129	7,154	-
4b.1.2.13	EF - Essential Service Water	-	108	-	-	-	-	-	16	124	-	-	124	-	-	-	-	-	-	3,800	-
4b.1.2.14	EF - Essential Service Water RCA	-	70	2	7	123	-	-	37	240	240	-	-	1,427	-	-	-	-	57,959	1,734	-
4b.1.2.15	EP - Accumulator Safety Injection	-	113	3	10	169	-	-	56	351	351	-	-	1,958	-	-	-	-	79,502	2,904	-
4b.1.2.16	FA - Auxiliary Steam Generator	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	521	-
4b.1.2.17	FO - Fuel Oil	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	486	-
4b.1.2.18	FP - Fire Protection	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	3,826	-
4b.1.2.19	FP - Fire Protection RCA	-	150	8	22	389	-	-	100	669	669	-	-	4,492	-	-	-	-	182,411	3,541	-
4b.1.2.20	Fuel Bldg Non-System Specific	-	34	1	2	28	3	-	14	81	81	-	-	322	12	-	-	-	13,829	850	-
4b.1.2.21	Fuel Bldg Non-System Specific RCA	-	245	5	16	277	-	-	106	649	649	-	-	3,200	-	-	-	-	129,974	5,859	-
4b.1.2.22	Fuel Building Fire Protection	-	119	5	15	254	-	-	71	463	463	-	-	2,941	-	-	-	-	119,444	2,802	-
4b.1.2.23	GA - Plant Heating	-	55	-	-	-	-	-	8	63	-	-	63	-	-	-	-	-	-	1,912	-
4b.1.2.24	GA - Plant Heating RCA	-	92	1	4	64	-	-	33	194	194	-	-	746	-	-	-	-	30,275	2,072	-
4b.1.2.25	GB - Central Chilled Water	-	52	-	-	-	-	-	8	59	-	-	59	-	-	-	-	-	-	1,803	-
4b.1.2.26	GB - Central Chilled Water RCA	-	21	0	1	16	-	-	8	47	47	-	-	187	-	-	-	-	7,591	482	-
4b.1.2.27	GD - Essl Srvc Wtr Pumpha Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	284	-
4b.1.2.28	GG - Fuel Building HVAC	-	183	6	20	341	-	-	100	650	650	-	-	3,945	-	-	-	-	160,195	4,052	-
4b.1.2.29	GH - Radwaste Building HVAC	-	133	4	13	222	-	-	69	440	440	-	-	2,561	-	-	-	-	104,012	3,004	-
4b.1.2.30	GK - Control Building HVAC	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	3,959	-
4b.1.2.31	GL - Auxiliary Building HVAC	-	332	9	27	465	-	-	158	991	991	-	-	5,381	-	-	-	-	218,514	7,364	-
4b.1.2.32	GM - Diesel Generator Building HVAC	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	695	-
4b.1.2.33	GN - Containment Cooling	-	359	14	41	714	-	-	204	1,331	1,331	-	-	8,250	-	-	-	-	335,052	8,317	-
4b.1.2.34	GP - Containmnt Integratd Leak Rate Test	-	30	1	3	50	-	-	16	100	100	-	-	580	-	-	-	-	23,670	760	-
4b.1.2.35	GR - Containment Atmospheric Control	-	13	2	6	99	-	-	19	138	138	-	-	1,143	-	-	-	-	46,407	350	-
4b.1.2.36	GT - Containment Purge HVAC	-	84	4	11	189	-	-	51	339	339	-	-	2,185	-	-	-	-	88,746	1,973	-
4b.1.2.37	HA - Gaseous Radwaste	-	256	6	18	320	-	-	115	716	716	-	-	3,699	-	-	-	-	150,219	6,296	-
4b.1.2.38	HB - Liquid Radwaste	-	602	50	56	635	356	-	348	2,047	2,047	-	-	7,343	1,450	-	-	-	391,794	15,380	-
4b.1.2.39	HC - Solid Radwaste	-	339	35	36	345	295	-	219	1,269	1,269	-	-	3,986	1,211	-	-	-	239,489	8,570	-
4b.1.2.40	HD - Decontamination	-	71	2	6	106	-	-	35	219	219	-	-	1,220	-	-	-	-	49,558	1,828	-
4b.1.2.41	HE - Boron Recycle	-	351	25	28	299	194	-	188	1,086	1,086	-	-	3,460	794	-	-	-	191,531	8,970	-
4b.1.2.42	JE - Emergency Fuel Oil	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	1,260	-
4b.1.2.43	KA - Compressed Air and Instrument	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	6,089	-
4b.1.2.44	KB - Breathing Air	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	1,075	-
4b.1.2.45	KC - Fire Protection	-	262	-	-	-	-	-	39	301	-	-	301	-	-	-	-	-	-	9,256	-
4b.1.2.46	KC - Fire Protection RCA	-	271	10	30	514	-	-	150	975	975	-	-	5,944	-	-	-	-	241,384	6,383	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4b.1.2.47	KD - Domestic Water	-	50	-	-	-	-	-	7	57	-	-	57	-	-	-	-	-	-	1,708	-
4b.1.2.48	KE - Fuel Hndlg & Strg Reactor Vssl Serv	-	12	1	4	76	-	-	15	110	110	-	-	882	-	-	-	-	35,813	332	-
4b.1.2.49	KJ - Standby Diesel Engine	-	208	-	-	-	-	-	31	239	-	-	239	-	-	-	-	-	-	6,749	-
4b.1.2.50	LA - Sanitary Drains	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	290	-
4b.1.2.51	LA - Sanitary Drains RCA	-	21	0	1	24	-	-	9	55	55	-	-	272	-	-	-	-	11,053	422	-
4b.1.2.52	LB - Roof Drains	-	37	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,276	-
4b.1.2.53	LB - Roof Drains RCA	-	113	4	11	185	-	-	58	371	371	-	-	2,139	-	-	-	-	86,858	2,694	-
4b.1.2.54	LC - Yard Drains	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	96	-
4b.1.2.55	LD - Chemical & Detergent Waste	-	83	1	4	69	-	-	32	190	190	-	-	797	-	-	-	-	32,369	2,139	-
4b.1.2.56	LF - Floor & Equipment Drains	-	1,036	88	81	576	878	-	586	3,245	3,245	-	-	6,660	3,627	-	-	-	501,387	26,164	-
4b.1.2.57	RM - Process Sampling & Analysis	-	90	2	5	86	-	-	36	219	219	-	-	990	-	-	-	-	40,200	2,450	-
4b.1.2.58	Radwaste Bldg Non-System Specific	-	126	3	7	115	12	-	53	317	317	-	-	1,329	50	-	-	-	57,145	3,253	-
4b.1.2.59	Radwaste Bldg Non-System Specific RCA	-	893	22	63	1,097	-	-	400	2,475	2,475	-	-	12,684	-	-	-	-	515,103	21,919	-
4b.1.2.60	Reactor Bldg Non-System Specific	-	65	1	3	43	5	-	24	141	141	-	-	502	19	-	-	-	21,090	1,569	-
4b.1.2.61	Reactor Bldg Non-System Specific RCA	-	460	8	24	412	-	-	181	1,086	1,086	-	-	4,768	-	-	-	-	193,612	10,425	-
4b.1.2.62	SBO Diesel Generator	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,610	-
4b.1.2.63	SJ - Nuclear Sampling	-	51	1	3	59	-	-	22	136	136	-	-	677	-	-	-	-	27,501	1,430	-
4b.1.2.64	ST - Sewage Treatment	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	2,316	-
4b.1.2.65	SZ - Service Air	-	54	-	-	-	-	-	8	62	-	-	62	-	-	-	-	-	-	1,892	-
4b.1.2.66	VA - I&C Shop HVAC	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	155	-
4b.1.2.67	VB - I&C Shop Computer Room HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	106	-
4b.1.2.68	VC - Health Physics Computer Room HVAC	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	208	-
4b.1.2.69	VJ - Shop Bldg Machine Shop Area Vent	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	57	-
4b.1.2.70	VL - Shop Building HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	101	-
4b.1.2.71	VS - Admin Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	262	-
4b.1.2.72	VT - Tech Support Building HVAC	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	87	-
4b.1.2.73	VW - Waste Water Treatment Ventilation	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	52	-
4b.1.2.74	WD - Domestic Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	870	-
4b.1.2.75	WM - Makeup Demineralizer	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,929	-
4b.1.2.76	WS - Plant Services Water	-	93	-	-	-	-	-	14	107	-	-	107	-	-	-	-	-	-	3,297	-
4b.1.2.77	WS - Plant Services Water RCA	-	29	3	9	159	-	-	33	233	233	-	-	1,838	-	-	-	-	74,625	782	-
4b.1.2.78	WT - Waste Water Treatment	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	769	-
4b.1.2.79	WZ - Radioactive Liquid Waste	-	32	4	3	21	40	-	22	124	124	-	-	247	167	-	-	-	20,647	783	-
4b.1.2.80	Yard Non-System Specific	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	603	-
4b.1.2	Totals	-	11,425	456	753	10,557	2,683	-	4,967	30,840	27,363	-	3,477	122,048	11,036	-	-	-	5,662,357	307,229	-
4b.1.3	Scaffolding in support of decommissioning	-	1,421	43	12	173	39	-	397	2,085	2,085	-	-	1,809	160	-	-	-	91,548	50,887	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	797	692	51	186	515	494	-	805	3,541	3,541	-	-	5,955	13,318	-	-	-	874,477	38,225	-
4b.1.4.2	Auxiliary	410	180	15	52	189	135	-	321	1,301	1,301	-	-	2,185	3,518	-	-	-	255,780	15,363	-
4b.1.4.3	Communication Corridor - Contaminated	9	3	0	1	1	3	-	6	23	23	-	-	17	76	-	-	-	4,296	306	-
4b.1.4.4	Fuel Building	508	516	10	24	234	55	-	437	1,784	1,784	-	-	2,705	984	-	-	-	158,200	27,457	-
4b.1.4.5	Hot Machine Shop	11	5	0	1	-	3	-	8	28	28	-	-	-	94	-	-	-	4,446	421	-
4b.1.4.6	RWST Foundation Decon	-	3	0	2	-	6	-	3	14	14	-	-	-	168	-	-	-	7,920	48	-
4b.1.4.7	Radwaste	218	81	7	26	73	69	-	162	636	636	-	-	844	1,857	-	-	-	122,469	7,815	-
4b.1.4.8	Radwaste Drum Storage	25	8	1	3	6	7	-	17	67	67	-	-	66	208	-	-	-	12,565	850	-
4b.1.4.9	Radwaste Storage Building	62	14	1	7	-	18	-	41	144	144	-	-	-	545	-	-	-	25,740	2,013	-
4b.1.4	Totals	2,041	1,501	86	301	1,018	790	-	1,800	7,538	7,538	-	-	11,773	20,770	-	-	-	1,465,893	92,498	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	479	72	551	551	-	-	-	-	-	-	-	-	-	4,096
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	2,516	14,397	865	1,149	11,749	5,020	479	7,903	44,079	40,602	-	3,477	135,630	38,216	-	-	-	7,616,876	452,336	4,096
Period 4b Additional Costs																					
4b.2.1	Final Survey Program Management	-	-	-	-	-	-	1,340	402	1,742	1,742	-	-	-	-	-	-	-	-	-	12,480
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,528	759	3,287	3,287	-	-	-	-	-	-	-	-	51,767	-
4b.2.3	Operational Equipment	-	-	19	49	624	-	-	103	794	794	-	-	11,710	-	-	-	-	292,750	32	-
4b.2.4	License Termination ISFSI	-	155	205	500	-	2,529	1,964	1,338	6,691	6,691	-	-	-	36,660	-	-	-	1,893,161	5,152	10,496
4b.2	Subtotal Period 4b Additional Costs	-	155	224	549	624	2,529	5,833	2,601	12,514	12,514	-	-	11,710	36,660	-	-	-	2,185,911	56,950	22,976
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	12	-	21	51	-	93	-	39	216	216	-	-	-	204	-	-	-	12,264	40	-
4b.3.3	Small tool allowance	-	257	-	-	-	-	-	39	295	295	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	143	45	575	128	-	139	1,030	1,030	-	-	6,000	529	-	-	-	303,608	147	-
4b.3.5	On-site survey and release of 44.30 tons clean metallic waste	-	-	-	-	-	-	63	6	69	69	-	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	12	257	163	96	575	221	63	223	1,611	1,611	-	-	6,000	733	-	-	-	315,872	187	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
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Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,660	-	-	-	-	-	-	415	2,075	2,075	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	1,726	173	1,899	1,899	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	806	81	887	887	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	3,679	-	-	-	-	-	920	4,599	4,599	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	6,623	-	-	-	-	-	843	6,466	6,466	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	141	35	-	349	-	107	633	633	-	-	-	6,495	-	-	-	129,908	212	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	3,944	592	4,535	4,535	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	1,388	139	1,527	1,527	-	-	-	-	-	-	-	-	-	-
4b.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	1,008	151	1,159	1,159	-	-	-	-	-	-	-	-	-	-
4b.4.10	Corporate Allocations	-	-	-	-	-	-	517	78	595	595	-	-	-	-	-	-	-	-	-	-
4b.4.11	Security Staff Cost	-	-	-	-	-	-	5,755	863	6,618	6,618	-	-	-	-	-	-	-	-	-	161,877
4b.4.12	DOC Staff Cost	-	-	-	-	-	-	27,705	4,156	31,861	31,861	-	-	-	-	-	-	-	-	-	347,064
4b.4.13	Utility Staff Cost	-	-	-	-	-	-	43,042	6,456	49,498	49,498	-	-	-	-	-	-	-	-	-	611,247
4b.4	Subtotal Period 4b Period-Dependent Costs	1,660	9,302	141	35	-	349	85,891	14,973	112,352	112,352	-	-	-	6,495	-	-	-	129,908	212	1,120,187
4b.0	TOTAL PERIOD 4b COST	4,189	24,111	1,394	1,829	12,948	8,120	92,266	25,701	170,556	167,079	-	3,477	153,340	82,105	-	-	-	10,248,570	509,684	1,147,259
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	Final Site survey	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	536	54	589	589	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	250	25	275	275	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	768	-	-	-	-	-	192	960	960	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	8	2	-	19	-	6	35	35	-	-	-	360	-	-	-	7,203	12	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	431	43	474	474	-	-	-	-	-	-	-	-	-	-
4f.4.7	Corporate Allocations	-	-	-	-	-	-	65	10	74	74	-	-	-	-	-	-	-	-	-	-
4f.4.8	Security Staff Cost	-	-	-	-	-	-	900	135	1,036	1,036	-	-	-	-	-	-	-	-	-	19,284
4f.4.9	DOC Staff Cost	-	-	-	-	-	-	5,038	756	5,794	5,794	-	-	-	-	-	-	-	-	-	58,656
4f.4.10	Utility Staff Cost	-	-	-	-	-	-	6,051	908	6,959	6,959	-	-	-	-	-	-	-	-	-	76,333
4f.4	Subtotal Period 4f Period-Dependent Costs	-	768	8	2	-	19	13,597	2,177	16,571	16,571	-	-	-	360	-	-	-	7,203	12	154,273
4f.0	TOTAL PERIOD 4f COST	-	768	8	2	-	19	21,568	4,369	26,734	26,734	-	-	-	360	-	-	-	7,203	152,831	160,513
PERIOD 4 TOTALS		4,518	59,704	15,686	7,657	23,448	46,146	172,476	71,832	401,467	395,168	-	6,299	280,380	143,253	501	393	2,217	20,607,680	1,038,173	2,045,549
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	2,518	-	-	-	-	-	378	2,896	-	-	2,896	-	-	-	-	-	-	27,724	-
5b.1.1.2	Access Vaults	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	59	-
5b.1.1.3	Administration	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,724	-
5b.1.1.4	Auxiliary	-	2,063	-	-	-	-	-	309	2,373	-	-	2,373	-	-	-	-	-	-	19,753	-
5b.1.1.5	Auxiliary Boiler	-	16	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	248	-
5b.1.1.6	Chemical Addition Structure	-	33	-	-	-	-	-	5	37	-	-	37	-	-	-	-	-	-	469	-
5b.1.1.7	Circ Water Pump Enclosure	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	164	-
5b.1.1.8	Circ Water Travel Screen Enclosure	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	160	-
5b.1.1.9	Circulating Water Discharge Structure	-	90	-	-	-	-	-	13	103	-	-	103	-	-	-	-	-	-	542	-
5b.1.1.10	Circulating Water Intake & Screenhouse	-	83	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	683	-
5b.1.1.11	Communication Corridor - Clean	-	683	-	-	-	-	-	102	785	-	-	785	-	-	-	-	-	-	8,280	-
5b.1.1.12	Communication Corridor - Contaminated	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	184	-
5b.1.1.13	Covered Walkways	-	11	-	-	-	-	-	2	12	-	-	12	-	-	-	-	-	-	242	-
5b.1.1.14	Diesel Generator	-	239	-	-	-	-	-	36	274	-	-	274	-	-	-	-	-	-	2,185	-
5b.1.1.15	E.S.W.S. Pumphouse	-	124	-	-	-	-	-	19	143	-	-	143	-	-	-	-	-	-	801	-

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Wolf Creek Generating Station
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Demolition of Remaining Site Buildings (continued)																					
5b.1.1.16	ESWS Valve House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	42	-
5b.1.1.17	FLEX Building NO. 1 & 2	-	347	-	-	-	-	-	52	399	-	-	399	-	-	-	-	-	-	2,880	-
5b.1.1.18	Fuel Building	-	909	-	-	-	-	-	136	1,045	-	-	1,045	-	-	-	-	-	-	7,983	-
5b.1.1.19	GOB - Administration Building	-	193	-	-	-	-	-	29	222	-	-	222	-	-	-	-	-	-	2,962	-
5b.1.1.20	Hot Machine Shop	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	243	-
5b.1.1.21	M.M.O. Building	-	225	-	-	-	-	-	34	259	-	-	259	-	-	-	-	-	-	2,389	-
5b.1.1.22	Material Center West	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,379	-
5b.1.1.23	Misc Structures and Additions	-	57	-	-	-	-	-	9	66	-	-	66	-	-	-	-	-	-	910	-
5b.1.1.24	Miscellaneous Site Foundations	-	204	-	-	-	-	-	31	234	-	-	234	-	-	-	-	-	-	1,242	-
5b.1.1.25	Miscellaneous Site Structures	-	1,284	-	-	-	-	-	193	1,477	-	-	1,477	-	-	-	-	-	-	13,693	-
5b.1.1.26	New Covered Walkway	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	79	-
5b.1.1.27	Oil Separator and Waste Tank	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	8	-
5b.1.1.28	Radwaste	-	864	-	-	-	-	-	130	993	-	-	993	-	-	-	-	-	-	8,111	-
5b.1.1.29	Radwaste Drum Storage	-	126	-	-	-	-	-	19	144	-	-	144	-	-	-	-	-	-	1,504	-
5b.1.1.30	Radwaste Storage Building	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	1,028	-
5b.1.1.31	SBO Diesel Generator	-	240	-	-	-	-	-	36	276	-	-	276	-	-	-	-	-	-	3,079	-
5b.1.1.32	Security Main Gate North	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	1,123	-
5b.1.1.33	Security Additions	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	405	-
5b.1.1.34	Security/Guardhouse	-	30	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	342	-
5b.1.1.35	Site Diesel Generator	-	2	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	18	-
5b.1.1.36	Support Complex	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	389	-
5b.1.1.37	Turbine Building	-	2,393	-	-	-	-	-	359	2,752	-	-	2,752	-	-	-	-	-	-	47,184	-
5b.1.1.38	Turbine Pedestal	-	478	-	-	-	-	-	72	549	-	-	549	-	-	-	-	-	-	2,934	-
5b.1.1.39	Waste Water Treatment	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	172	-
5b.1.1.40	Water Treatment Building North (Z110)	-	48	-	-	-	-	-	7	55	-	-	55	-	-	-	-	-	-	608	-
5b.1.1	Totals	-	13,727	-	-	-	-	-	2,059	15,787	-	-	15,787	-	-	-	-	-	-	163,924	-
Site Closeout Activities																					
5b.1.2	Remove Rubble	-	948	-	-	-	-	-	142	1,090	-	-	1,090	-	-	-	-	-	-	5,352	-
5b.1.3	Grade & landscape site	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	512	-
5b.1.4	Final report to NRC	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	14,776	-	-	-	-	182	2,244	17,202	210	-	16,992	-	-	-	-	-	-	169,788	1,560
Period 5b Additional Costs																					
5b.2.1	Concrete Crushing	-	880	-	-	-	-	11	134	1,025	-	-	1,025	-	-	-	-	-	-	4,585	-
5b.2.2	Circulating Water Intake Cofferdam	-	308	-	-	-	-	-	46	354	-	-	354	-	-	-	-	-	-	2,584	-
5b.2.3	E.S.W.S. Pumphouse Cofferdam	-	404	-	-	-	-	-	61	465	-	-	465	-	-	-	-	-	-	3,552	-
5b.2.4	Excavation of Underground Services	-	2,001	-	-	-	-	907	636	3,545	3,545	-	-	-	-	-	-	-	-	15,949	-
5b.2.5	Construction Debris	-	-	-	-	-	-	1,730	260	1,990	-	-	1,990	-	-	-	-	-	-	-	-
5b.2.6	Site Restoration ISFSI	-	462	-	-	-	-	111	86	659	-	-	659	-	-	-	-	-	-	4,099	160
5b.2.7	Firing Range Closure	-	-	-	-	-	-	692	104	796	-	-	796	-	-	-	-	-	-	-	-
5b.2	Subtotal Period 5b Additional Costs	-	4,056	-	-	-	-	3,451	1,326	8,833	3,545	-	5,289	-	-	-	-	-	-	30,770	160
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	110	-	-	-	-	-	17	127	-	-	127	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	110	-	-	-	-	-	17	127	-	-	127	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	482	48	530	-	-	530	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	4,679	-	-	-	-	-	702	5,381	-	-	5,381	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	314	47	361	-	-	361	-	-	-	-	-	-	-	-
5b.4.5	Corporate Allocations	-	-	-	-	-	-	51	8	59	-	-	59	-	-	-	-	-	-	-	-
5b.4.6	Security Staff Cost	-	-	-	-	-	-	1,734	260	1,994	-	-	1,994	-	-	-	-	-	-	-	37,132
5b.4.7	DOC Staff Cost	-	-	-	-	-	-	9,107	1,366	10,473	-	-	10,473	-	-	-	-	-	-	-	105,208
5b.4.8	Utility Staff Cost	-	-	-	-	-	-	4,573	686	5,259	-	-	5,259	-	-	-	-	-	-	-	60,340
5b.4	Subtotal Period 5b Period-Dependent Costs	-	4,679	-	-	-	-	16,260	3,117	24,056	-	-	24,056	-	-	-	-	-	-	-	202,680
5b.0	TOTAL PERIOD 5b COST	-	23,621	-	-	-	-	19,894	6,703	50,218	3,754	-	46,464	-	-	-	-	-	-	200,558	204,400
PERIOD 5 TOTALS		-	23,621	-	-	-	-	19,894	6,703	50,218	3,754	-	46,464	-	-	-	-	-	-	200,558	204,400
TOTAL COST TO DECOMMISSION		10,570	93,922	16,170	8,282	23,465	47,622	731,915	161,173	1,093,117	980,846	58,028	54,243	282,530	153,674	501	393	2,217	21,044,660	1,337,834	7,864,049

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours

TOTAL COST TO DECOMMISSION WITH 17.29% CONTINGENCY:	$1,093,117	thousands of 2017 dollars
TOTAL NRC LICENSE TERMINATION COST IS 89.73% OR:	$980,846	thousands of 2017 dollars
SPENT FUEL MANAGEMENT COST IS 5.31% OR:	$58,028	thousands of 2017 dollars
NON-NUCLEAR DEMOLITION COST IS 4.96% OR:	$54,243	thousands of 2017 dollars
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	154,567	cubic feet
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	2,217	cubic feet
TOTAL SCRAP METAL REMOVED:	69,526	tons
TOTAL CRAFT LABOR REQUIREMENTS:	1,337,834	man-hours

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
n - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX E

COST SENSITIVITY OF LONG-TERM, ON-SITE SPENT FUEL STORAGE

APPENDIX E

COST SENSITIVITY OF LONG-TERM, ON-SITE SPENT FUEL STORAGE

Introduction

As discussed in the last Decommissioning Cost Analysis for Wolf Creek issued in August 2014, developments in the area of spent nuclear fuel disposal suggest a possibility that the federal government may not have removed all of Wolf Creek's spent nuclear fuel and high-level radioactive waste (hereafter, simply "spent fuel") from the station by the time the plant has been decommissioned. There still is much uncertainty in this area. However, WCNOC asked TLG to consider that possibility, to make some assumptions regarding potential effects of the government's delayed removal of spent fuel from Wolf Creek, and to conduct a cost sensitivity analysis reflecting those assumptions. The following discussion is the result of that analysis. Because the assumptions used in this Appendix E analysis are so speculative at this point, the hypothetical cost effects shown here have not been included in the overall updated cost estimate in this report.

Congress passed the "Nuclear Waste Policy Act"[1] (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 Department of Energy (DOE). The NWPA provided that DOE would enter into contracts with generators in which DOE would promise to take the generator's spent fuel and high-level radioactive waste and the generators would pay the cost of the disposition services for that material. The NWPA, along with the individual contracts with the generators, specified that the DOE was to begin accepting spent fuel by January 31, 1998.

Since the original legislation, the DOE has announced several delays in the program schedule. By January 1998, the DOE had failed to accept any spent fuel or high level waste, as required by the NWPA and its contracts. Delays continue and, as a result, generators are no closer to shipping spent fuel today than in 1998.

Politically, the country is at an impasse on high-level waste disposal. The current administration has cut the budget for the geological repository program while promising to "conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle ... make recommendations for a new plan."[2] Towards this goal,

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1 "Nuclear Waste Policy Act of 1982 and Amendments," DOE's Office of Civilian Radioactive Management, 1982

2 Charter of the Blue Ribbon Commission on America's Nuclear Future, "Objectives and Scope of

the 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."[3]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of 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[4]
- "[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."[5]

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..."[6] This document states: "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

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Activities," http://www.brc.gov/index.php?q=page/charter

3 Ibid.

4 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," http://www.brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf, p. 32, January 2012

5 Ibid., p.27

6 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."

Completion of the decommissioning process (release of the entire site for unrestricted use) is highly dependent upon the DOE's ability to remove spent fuel from the site in a timely manner. DOE's repository program is currently based upon the premise that spent fuel allocations would be accepted for disposal from the nation's commercial nuclear plants, with limited exceptions, in the order in which it was discharged from the reactor (i.e., establishing a national "queue"). Even if spent fuel could be transferred to a federal facility for interim storage (in the absence of a permanent disposal facility), the nature of the queue would be expected to result in a long backlog of spent fuel at each site. Under the current system, as can be seen at sites where reactors have been decommissioned, the owner(s) can anticipate several decades of continuing, on-site storage of the spent fuel before the transfer could be expected to be complete.

It should be noted that the cost to dispose of the spent fuel generated from plant operations is not reflected within the estimates. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, until recently, the disposal cost was being financed by a 1 mill/kWhr surcharge on nuclear generated energy delivered to customers, the fee being paid into the DOE's waste fund during operations. The D.C. Circuit ruling on November 19, 2013, ordered the DOE to submit a proposal to Congress to suspend the Nuclear Waste Fund fee "until such time as either the Secretary chooses to comply with the Act as it is currently written, or until Congress enacts an alternative waste management plan". The fee was reduced to 0.0mill/kWh as of May 16, 2014. The fee is expected to be reinstated in the future.

Nonetheless, the NRC requires licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title to the fuel is transferred to the Secretary of Energy.[7] The post-shutdown costs incurred to satisfy this requirement are described below.

Base Analyses

The estimates described in the main report (and detailed in Appendix C and D) are based in general upon 1) a 2025 start date for DOE initiating transfer of commercial spent fuel to a federal facility, and 2) a 2032 start date for the transfer of spent fuel from the Wolf Creek site based on an "oldest fuel first" priority, and the DOE

7 U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

achieving an annual rate of transfer (3,000 metric tons of uranium per year) as reflected in DOE's latest Acceptance Priority Ranking and Annual Capacity Report.[8]

The assumed 2025 DOE start date is nominally based on the last position stated by the DOE. More importantly, the estimates assume that the DOE would give priority to fuel at shutdown sites,[9] i.e., it assumed that Congress would "(1)...direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process."[10]

Under this scenario, once Wolf Creek permanently ceases operation, DOE would expedite the removal of spent fuel from the site. The cost estimates described in the main body of this report assumed that:

- The spent fuel pool would be at capacity following the final core off-load and contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core
- DOE would give priority to the spent fuel stored in the pool
- The spent fuel pool would be emptied within the first five and one-half years following plant shutdown.[11] This would allow decommissioning to be completed and the site released for unrestricted use within a relatively short time (see Figure 4.2) or placed into long-term storage without the need of maintaining/operating a spent fuel storage facility

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8 "Acceptance Priority Ranking and Annual Capacity Report," U.S. DOE, Office of Civilian Radioactive Waste Management, DOE/RW-0567, July 2004

9 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," http://www.brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf, p. 42, January 2012: "[A]ccepting spent fuel according to the OFF 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."

10 "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

11 It is assumed that the five and one-half years provides the necessary cooling for the final core to meet transport requirements for decay heat

- The DOE is assumed to use its Transport, Aging and Disposal canister to empty the wet storage pool.[12] The canisters would be provided to WCNOC at no cost, however, Wolf Creek staff/or contractors would load, seal and transfer the multi-purpose canisters into a DOE-provided transport cask.
- Once the pool is emptied, the DOE would remove the spent fuel stored at the Wolf Creek Independent Spent Fuel Storage Installation (ISFSI). The current analysis assumes that 592 assemblies would be placed in dry storage during plant operations (i.e., maintain full core off-load capability in the spent fuel pool); 16 equivalent dry storage system modules.
- The ISFSI would be decommissioned in conjunction with the dismantling of the adjacent power block structures.
- Greater-than-Class C (GTCC)[13] material would be transferred directly to the DOE following the segmentation of the reactor internals.

Alternative Analysis

In 2008, the DOE issued a report to Congress in which it concluded that it did not have authority, under present law, to accept spent nuclear fuel for interim storage from decommissioned commercial nuclear power reactor sites.[14] It also concluded that legislation would be required that would eliminate the limitations in the Nuclear Waste Policy Act of 1982, as amended, on taking commercial spent nuclear fuel for interim storage prior to the opening of the Yucca Mountain repository.

For illustrative purposes only, this alternative analysis examines the impact of the status quo (i.e., the queue), on decommissioning and the resulting cost for long-term, on-site storage of the spent fuel generated during plant operations.[15] Under this scenario:

- DOE pickup of spent fuel would continue beyond the cessation of plant operations at the rates published for the Kansas Gas and Electric Company in the latest Acceptance Priority Ranking and Annual Capacity Report

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12 "Transport, Aging and Disposal Canister System Performance Specification," U.S. DOE, Civilian Radioactive Waste Management System, DOC ID: WMO-TADCS-000001, Rev.1, March 2008

13 U.S. Code of Federal Regulations, Title 10, Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste"

14 "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

15 This analysis does not consider that the cost incurred would most likely be reimbursable as a result of DOE's breach of contract due to it non-performance

- Pickup of spent fuel beyond the last published date would be based upon the plant average of the previous ten years
- The residual inventory in the spent fuel pool after the five and one-half years of cooling would be transferred to the ISFSI
- Wolf Creek would utilize a dry storage system that can accommodate 37 assemblies per module
- The ISFSI would be expanded to accommodate the additional dry fuel storage modules needed to empty the spent fuel pool and the GTCC generated during the decommissioning (on the premise that the GTCC would not be accepted by the DOE until after the transfer of the spent fuel was completed)[16]
- WCNOC would operate the ISFSI and manage the spent fuel until such time that the DOE could complete the transfer to an off-site facility
- The DOE would accept the multi-purpose canister without the need for repackaging the assemblies, i.e., the DOE transport cask could accommodate the multi-purpose canister without modification
- WCNOC staff or WCNOC contracted staff would transfer the multi- purpose canister into the DOE-provided transport cask
- The concrete storage overpack and ISFSI pad would be decommissioned once the transfer is completed (2074)

The impact of these assumptions, as compared to the Base Analysis, is summarized as follows.

	Base Case	Alternative
Spent fuel pool inventory at shutdown (assemblies)	1,771	1,771
ISFSI inventory at shutdown (assemblies)	592	592
Spent fuel transferred to the DOE during plant ops	1,009	1,009
Spent fuel transferred to the DOE from pool during decommissioning (assemblies)	1,771	337
Spent fuel transferred to the ISFSI for interim storage within 5½ years after shutdown (assemblies)	0	1,434
Number of additional dry-storage modules need to support decommissioning (excluding GTCC)	0	39
Transfer of Spent Fuel to DOE Complete (year)	2050	2074

16 GTCC is assumed to be disposed of as it is generated in the base analysis, avoiding the need for interim storage

In essence, spent fuel is on site for additional 21 years after plant decommissioning (completion of site restoration), during which time WCNOC maintains and operates the ISFSI under a General (10 CFR Part 50) or Site-Specific (Part 72) license.

The alternative estimate is based upon a nominal value of $1.0 million for the capital cost of a dry storage module and an associated loading cost and transfer cost of $300,000 (from the wet pool to the ISFSI). A unit cost of $150,000 (one half the wet loading cost) was used for transferring the multipurpose canisters from the concrete overpacks at the ISFSI into the DOE-provided transport cask. All such numbers are based on comparative data. The alternative estimate does not include any costs for expanding the 16 cask-capacity ISFSI pad to the 60 casks capacity required for the alternative estimate.

The cost of operating an ISFSI, once decommissioning is complete, is shown in the following schedule, particularly in the years 2054 through 2074 following the decommissioning of Wolf Creek. Annual expenditures include the costs for:

- Periodic Spent Fuel Transfer
- Nuclear Insurance
- Property Taxes
- NRC ISFSI Licensing Fees and Oversight Costs
- Emergency Planning Fees
- ISFSI Operating Costs (maintenance budget, including energy, lighting, and remote surveillance systems)
- Security Staff (full time, round-the-clock)
- WCNOC Staff (for ISFSI operations, maintenance, and fuel transfer activities)

The schedule of expenditure in the following table delineates the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal). Costs are reported in 2017 dollars and are not inflated, escalated, or discounted over the period of expenditure.

Since it is assumed that the DOE would not accept GTCC waste prior to completing the transfer of spent fuel, the cost of GTCC disposal is shown in the final year of ISFSI operation (2074). This same cost is included during the decommissioning phase in the base analyses (e.g., in Table 3.1, during years 2046-2048 for the DECON alternative).

While this analysis attempts to capture the cost for long-term spent fuel management at the Wolf Creek site, under the scenario outlined above, it is WCNOC's position that

the DOE has a contractual obligation to accept Wolf Creek's fuel earlier than the projections set out above consistent with its contract commitments. No assumption made in this analysis should be interpreted to be inconsistent with this claim.

TABLE E
DECON ALTERNATIVE WITH LONG-TERM SPENT FUEL MANAGEMENT
SCHEDULE OF TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	58,996	4,282	1,969	33	9,446	74,727
2046	82,734	30,407	3,615	14,402	25,407	156,565
2047	78,739	38,176	2,307	32,769	12,765	164,756
2048	73,774	28,281	2,066	21,513	10,999	136,633
2049	68,573	18,553	1,821	10,505	9,232	108,683
2050	61,728	15,396	1,560	9,676	8,297	96,657
2051	43,584	5,662	664	2,885	4,615	57,409
2052	25,088	12,930	277	4	4,163	42,464
2053	16,174	9,051	179	0	3,750	29,154
2054	6,034	298	73	0	2,961	9,366
2055	6,034	298	73	0	2,961	9,366
2056	6,051	299	73	0	2,969	9,392
2057	6,034	298	73	0	2,961	9,366
2058	6,034	298	73	0	2,961	9,366
2059	6,034	298	73	0	2,961	9,366
2060	6,051	299	73	0	2,969	9,392
2061	6,034	298	73	0	2,961	9,366
2062	6,034	298	73	0	2,961	9,366
2063	6,034	298	73	0	2,961	9,366
2064	6,051	299	73	0	2,969	9,392
2065	6,034	298	73	0	2,961	9,366
2066	6,034	298	73	0	2,961	9,366
2067	6,034	298	73	0	2,961	9,366
2068	6,051	299	73	0	2,969	9,392
2069	6,034	298	73	0	2,961	9,366
2070	6,034	298	73	0	2,961	9,366
2071	6,034	298	73	0	2,961	9,366
2072	6,051	299	73	0	2,969	9,392
2073	6,034	298	73	0	2,961	9,366
2074	5,874	1,249	76	444	16,582	24,225
2075	2,636	1,130	58	2,717	3,081	9,621

TABLE E (continued)
DECON ALTERNATIVE WITH LONG-TERM SPENT FUEL MANAGEMENT
SCHEDULE OF TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
Total	638,669	171,087	16,049	94,948	167,591	1,088,344

Schedule B

2017 Funding Analysis

KANSAS CITY POWER & LIGHT COMPANY

WOLF CREEK DECOMMISSIONING TRUST ANALYSIS

MISSOURI JURISDICTION - QUALIFIED TAXABLE TRUST

DECOMMISSIONING COST ASSUMPTIONS

2017 Decom Cost Est	$ 813,733,000
Cost Escalation Rate	3.16%
KCPL Share	47.00%
Future Juris Allocation Factor	52.96%
Wtd Historical/Future Alloc Factor	55.72%

DECOMMISSIONING TRUST FUND EARNINGS ASSUMPTIONS

TRUST FUND MANAGEMENT FEE	
Missouri Avg Fund Balance	$ 280,589,325
Missouri Annual Fixed Fee	31,778
Fixed Fee %	0.01%
FI Fee and Fixed Fee%	0.22%
Equity Fee and Fixed Fee	0.11%

DECOMMISSIONING TRUST FUND CASH FLOWS

NET AFTER-TAX MARKET VALUE		
June 30, 2017 Market Value	145,422,472	
2017 Remaining Deposits	640,632	
Market Value Incl Remaining Deposit		146,063,104
Unrealized Net Gain	46,403,573	
Effective Tax Rate	20.00%	
Tax on Unrealized Net Gain		9,280,715
Net After-Tax Market Value		136,782,390

Annual Accrual Escalation	0.00%

Year	2017 Wolf Creek Decom Cost	Escalated Wolf Creek Decom Cost	KCPL Missouri Decom Cost
2017	$ -	$ -	$ -
2018	$ -	$ -	$ -
2019	$ -	$ -	$ -
2020	$ -	$ -	$ -
2021	$ -	$ -	$ -
2022	$ -	$ -	$ -
2023	$ -	$ -	$ -
2024	$ -	$ -	$ -
2025	$ -	$ -	$ -
2026	$ -	$ -	$ -
2027	$ -	$ -	$ -
2028	$ -	$ -	$ -
2029	$ -	$ -	$ -
2030	$ -	$ -	$ -
2031	$ -	$ -	$ -
2032	$ -	$ -	$ -
2033	$ -	$ -	$ -
2034	$ -	$ -	$ -
2035	$ -	$ -	$ -
2036	$ -	$ -	$ -
2037	$ -	$ -	$ -
2038	$ -	$ -	$ -
2039	$ -	$ -	$ -
2040	$ -	$ -	$ -
2041	$ -	$ -	$ -
2042	$ -	$ -	$ -
2043	$ -	$ -	$ -
2044	$ -	$ -	$ -
2045	$ 72,188,000	$ 172,497,318	$ 45,171,096
2046	$ 147,398,000	$ 363,345,898	$ 95,147,754
2047	$ 164,016,000	$ 417,086,584	$ 109,220,586
2048	$ 133,436,000	$ 350,045,382	$ 91,664,808
2049	$ 103,125,000	$ 279,078,662	$ 73,081,073
2050	$ 93,516,000	$ 261,071,778	$ 68,365,691
2051	$ 48,499,000	$ 139,674,820	$ 36,576,016
2052	$ 31,959,000	$ 94,948,881	$ 24,863,836
2053	$ 19,596,000	$ 60,058,632	$ 15,727,284
	$ 813,733,000	$ 2,137,807,955	$ 559,818,143
KCP&L %	47.0%	47.0%	
KCP&L Share	$ 382,454,510	$ 1,004,769,739	
		55.7161%	
MO Jurisdictional Share —>		$ 559,818,143	

	US T-Bills	Fixed Income	Inter-national	Small Stocks	Lrg Corp Stocks	Weighted After-Tax Earnings
Pre-tax Returns	3.00%	3.80%	8.96%	8.78%	8.51%	
Effective Tax Rate	20.0%	20.0%	20.0%	20.0%	20.0%	
Earnings After Fees & Taxes	2.22%	2.86%	7.08%	6.94%	6.72%	
Year	Investment Mix					
2017	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2018	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2019	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2020	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2021	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2022	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2023	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2024	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2025	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2026	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2027	0.0%	35.0%	15.0%	18.0%	32.0%	5.46%
2028	2.8%	35.8%	14.2%	17.0%	30.2%	5.30%
2029	5.6%	36.7%	13.3%	16.0%	28.4%	5.14%
2030	8.3%	37.5%	12.5%	15.0%	26.7%	4.98%
2031	11.1%	38.3%	11.7%	14.0%	24.9%	4.81%
2032	13.9%	39.2%	10.8%	13.0%	23.1%	4.65%
2033	16.7%	40.0%	10.0%	12.0%	21.3%	4.49%
2034	19.4%	40.8%	9.2%	11.0%	19.6%	4.33%
2035	22.2%	41.7%	8.3%	10.0%	17.8%	4.17%
2036	25.0%	42.5%	7.5%	9.0%	16.0%	4.00%
2037	27.8%	43.3%	6.7%	8.0%	14.2%	3.84%
2038	30.6%	44.2%	5.8%	7.0%	12.4%	3.68%
2039	33.3%	45.0%	5.0%	6.0%	10.7%	3.52%
2040	36.1%	45.8%	4.2%	5.0%	8.9%	3.35%
2041	38.9%	46.7%	3.3%	4.0%	7.1%	3.19%
2042	41.7%	47.5%	2.5%	3.0%	5.3%	3.03%
2043	44.4%	48.3%	1.7%	2.0%	3.6%	2.87%
2044	47.2%	49.2%	0.8%	1.0%	1.8%	2.71%
2045	50.0%	50.0%	0.0%	0.0%	0.0%	2.54%
2046	52.8%	50.8%	-0.8%	-1.0%	-1.8%	2.38%
2047	55.6%	51.7%	-1.7%	-2.0%	-3.6%	2.22%
2048	61.8%	45.4%	-1.7%	-2.0%	-3.6%	2.18%
2049	68.1%	39.2%	-1.7%	-2.0%	-3.6%	2.14%
2050	74.3%	32.9%	-1.7%	-2.0%	-3.6%	2.10%
2051	80.6%	26.7%	-1.7%	-2.0%	-3.6%	2.06%
2052	86.8%	20.4%	-1.7%	-2.0%	-3.6%	2.02%
2053	100.0%	0.0%	0.0%	0.0%	0.0%	2.22%
2027	0.00%	35.00%	15.00%	18.00%	32.00%	100%
	-2.78%	-0.83%	0.83%	1.00%	1.78%	
2045	50.00%	50.00%	0.00%	0.00%	0.00%	100%
	-6.25%	6.25%	0.00%	0.00%	0.00%	
2053	100.00%	0.00%	0.00%	0.00%	0.00%	100%

Year	Trust Fund Contribution	Trust Fund Expenditure	Earnings After Fees & Taxes	Trust Fund Balance
2017	$ 1,281,264	$ -		$ 136,782,390
2018	$ 1,281,264	$ -	$ 7,499,055	$ 145,562,708
2019	$ 1,281,264	$ -	$ 7,978,748	$ 154,822,720
2020	$ 1,281,264	$ -	$ 8,484,648	$ 164,588,633
2021	$ 1,281,264	$ -	$ 9,018,187	$ 174,888,084
2022	$ 1,281,264	$ -	$ 9,580,875	$ 185,750,224
2023	$ 1,281,264	$ -	$ 10,174,304	$ 197,205,792
2024	$ 1,281,264	$ -	$ 10,800,154	$ 209,287,210
2025	$ 1,281,264	$ -	$ 11,460,196	$ 222,028,670
2026	$ 1,281,264	$ -	$ 12,156,298	$ 235,466,232
2027	$ 1,281,264	$ -	$ 12,890,429	$ 249,637,925
2028	$ 1,281,264	$ -	$ 13,259,021	$ 264,178,210
2029	$ 1,281,264	$ -	$ 13,600,586	$ 279,060,060
2030	$ 1,281,264	$ -	$ 13,911,987	$ 294,253,311
2031	$ 1,281,264	$ -	$ 14,190,109	$ 309,724,684
2032	$ 1,281,264	$ -	$ 14,431,888	$ 325,437,836
2033	$ 1,281,264	$ -	$ 14,634,341	$ 341,353,441
2034	$ 1,281,264	$ -	$ 14,794,587	$ 357,429,292
2035	$ 1,281,264	$ -	$ 14,909,885	$ 373,620,440
2036	$ 1,281,264	$ -	$ 14,977,654	$ 389,879,358
2037	$ 1,281,264	$ -	$ 14,995,508	$ 406,156,130
2038	$ 1,281,264	$ -	$ 14,961,281	$ 422,398,675
2039	$ 1,281,264	$ -	$ 14,873,054	$ 438,552,994
2040	$ 1,281,264	$ -	$ 14,729,183	$ 454,563,440
2041	$ 1,281,264	$ -	$ 14,528,319	$ 470,373,023
2042	$ 1,281,264	$ -	$ 14,269,435	$ 485,923,722
2043	$ 1,281,264	$ -	$ 13,951,845	$ 501,156,831
2044	$ 1,281,264	$ -	$ 13,575,220	$ 516,013,314
2045	$ 320,316	$ (45,171,096)	$ 12,699,502	$ 483,862,037
2046	$ -	$ (95,147,754)	$ 10,674,870	$ 399,389,152
2047	$ -	$ (109,220,586)	$ 7,955,872	$ 298,124,438
2048	$ -	$ (91,664,808)	$ 5,748,792	$ 212,208,422
2049	$ -	$ (73,081,073)	$ 3,954,111	$ 143,081,460
2050	$ -	$ (68,365,691)	$ 2,465,903	$ 77,181,672
2051	$ -	$ (36,576,016)	$ 1,307,161	$ 41,912,817
2052	$ -	$ (24,863,836)	$ 658,177	$ 17,707,158
2053	$ -	$ (15,727,284)	$ 262,642	$ 2,242,516
			Surplus/(Deficit)	0.40%

Annual NRC Certification Update
(5 pages)

Utility Decommissioning Tax Group

MEMORANDUM

February 20, 2019

ANNUAL NRC CERTIFICATION UPDATE

Each year, we provide information necessary for a nuclear licensee to update the "minimum financial assurance amount" for decommissioning a nuclear unit, as required by the Nuclear Regulatory Commission (NRC). This briefing paper includes certain background information concerning this requirement of the NRC as well as the data necessary for a licensee to calculate the minimum financial assurance amount in current dollars. Please note that burial costs for 2019 increased from 2018.

Background

The NRC requires every licensee of a nuclear unit to certify that financial assurance for decommissioning a nuclear unit will be provided in the minimum financial assurance amount prescribed by the regulations of the NRC. See 10 C.F.R. §§ 50.33(k) and 50.75. Typically, a licensee certifies to the NRC that it will make annual, levelized contributions to an external trust fund which, over the remaining license period for the nuclear unit, will accumulate a sum equal to the minimum financial assurance amount.

Each licensee must adjust the minimum financial assurance amount annually to reflect inflation in the estimated costs of decommissioning. See 10 C.F.R. § 50.75(b). In addition, the licensee must adjust its future contributions to the external decommissioning fund to approximate pro rata contributions, over the remaining license term, of the escalated minimum financial assurance amount remaining to be accumulated. See NRC Regulatory Guide 1.159, Revision 2, section 2.2.8. Adjustments to the pro rata contributions may be made to coincide with ratemaking proceedings before a public service commission or to reflect the schedule of ruling amounts issued by the Internal Revenue Service under section 468A of the Internal Revenue Code for a qualified nuclear decommissioning fund. See NRC Regulatory Guide 1.159, Revision 2, section 2.1.5. Such adjustments, in any event, should be made at least once every two years for licensees who are not rate-regulated, or at least once every five years for rate-regulated licensees. Id.[1]

The computation of the adjusted minimum financial assurance amount is made by reference to: (1) a formula for determining a base amount expressed in January 1986 dollars; and (2) an adjustment factor to escalate the base amount to reflect current dollars. See 10 C.F.R. § 50.75(c). The base amount in 1986 dollars is $105 million and $135 million, respectively, for a pressurized water reactor (PWR) and a boiling water reactor (BWR), assuming each has greater than 3,400 MWt. See 10 C.F.R. § 50.75(c)(1). The adjustment factor must be

> at least equal to 0.65L + 0.13 E + 0.22 B . . . where L and E are escalation factors for labor and energy, respectively, and are to be taken from regional data of U.S. Department of Labor Bureau of Labor Statistics and B is an escalation factor for waste burial and is to be taken from NRC report NUREG-1307, "Report on Waste Burial Charges."

See 10 C.F.R. § 50.75(c)(2).

Reporting Requirements

Pursuant to the NRC rules, a licensee is required to file a report with the NRC on the status of its decommissioning funding at least every two years. See 10 C.F.R. § 50.75(f)(1). Annual reporting is required for a plant that is within five years of the projected end of its operation, or where conditions have changed such that it will close within five years, or already has closed. Id. The information in the report must include (1) the amount of decommissioning funds estimated to be required pursuant to 10 C.F.R. § 50.75(b) and (c); (2) the amount accumulated to the end of the calendar year preceding the date of the report; (3) a schedule of the annual amounts remaining to be collected; (4) the assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections; (5) any contract the licensee is relying upon pursuant to 10 C.F.R. § 50.75(e)(1)(v) for collections of decommissioning monies from customers; (6) any modifications to the method of providing financial assurance since the last submitted report; and (7) any material changes to the decommissioning trust agreement(s). Id.

---

[1] Previously, NRC Regulatory Guide 1.159, Revision 1, dated October 2003, provided that rate-regulated licensees should make adjustments at least every six years.

Escalation Factors

In anticipation of the March 31, 2019 reporting deadline on the status of decommissioning funding, we have calculated the current escalation factors as follows:

LABOR		ENERGY		BURIAL	PWR	BWR
Northeast	2.95	PWR	2.365	Washington		
South	2.62	BWR	2.390	Compact-Affiliated[2]	10.854	9.118
Midwest	2.75			Combination	8.697	7.186
West	2.83			South Carolina		
				Compact-Affiliated	32.329	28.314
				Combination	11.607	12.872
				Texas[3]		
				Compact-Affiliated	8.508	8.293
				Combination	11.054	10.731
				Unaffiliated/No Disposal Facility[4]	12.853	13.422

The data supporting the calculation of these escalation factors is attached. In our calculations, we have data available from the U.S. Department of Labor, Bureau of Labor Statistics (4Q '18 for Labor and December '18 for Energy) and from the NRC NUREG-1307 (Revision 17) for Burial.

* * * * *

For additional information regarding the foregoing, please contact Marty Pugh at 202-756-8368 or at mpugh@mwe.com or Justin Jesse at 202-756-8777 or jjesse@mwe.com.

Memoranda to the Utility Decommissioning Tax Group are periodic publications of McDermott Will & Emery LLP designed to alert Group members to tax and regulatory developments concerning nuclear decommissioning funds. The memoranda do not constitute legal advice or a legal opinion on any specific facts or circumstances.

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[2] Effective with NUREG-1307, Revision 15, the NRC changed the nomenclature for the two disposal options, previously referred to as "Direct Disposal" and "Direct Disposal with Vendors" to "Compact-Affiliated Disposal Facility Only" and "Combination of Compact-Affiliated and Non-Compact Disposal Facilities," respectively, to better describe the options.

[3] Effective with NUREG-1307, Revision 16 (March 2017), the NRC added the Compact Waste Facility located in Andrews County, Texas as a full-service low-level radioactive waste disposal facility for generators located in states affiliated with the Texas Compact. The Texas Compact is comprised of Texas and Vermont.

[4] Effective with NUREG-1307, Revision 16 (March 2017), because the Texas facility is also available to states not affiliated with the Texas Compact, the NRC recomputed the burial factor for generators located in non-compact affiliated states and for generators located in compact affiliated states that have no disposal facility. This new burial factor represents the composite of the disposal rates for the Texas facility and the disposal facility located in Clive, Utah that is available for any Class A low level waste generated in the United States.

LABOR FACTOR

Census Region[1]	Base Labor Adjustment Factor (Dec '05)[2]	4Q. '18[3] (Dec. '05 Base)	Current Labor (L) Adjustment Factor[4]
Northeast	2.16	136.5	2.95
South	1.98	132.5	2.62
Midwest	2.08	132.3	2.75
West	2.06	137.2	2.83

1. The census regions consist of the following geographical areas:

   Northeast -- Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Puerto Rico, Rhode Island, U.S. Virgin Islands, and Vermont.

   South -- Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia and West Virginia.

   Midwest -- Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota and Wisconsin.

   West -- Alaska, Arizona, California, Colorado, Guam, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming.

2. The Base Labor Adjustment Factor (December 2005) is contained in column 2 of Table 3-2 of NUREG 1307, Revision 17 (February 2019).

3. Values for 4Q 2018 used in this chart were obtained from the "Employment Cost Indexes," published by the U.S. Department of Labor, Bureau of Labor Statistics. Specifically, regional data from Table 6 entitled "Compensation (not seasonally adjusted): Employment Cost Index, for total compensation, for private industry workers, by bargaining status, census region, census divisions, and area," has been used. Appendix C to NUREG 1307, Revision 17 (February 2019) states that the requisite information can be obtained on the internet by entering the following URL: http://www.bls.gov/data/; then clicking on the item labeled "Series Report;" and then entering into the box labeled "Enter series id(s) below," the following four series ids, one id per line:

CIU2010000000210I	(Total compensation, private industry, Northeast region)
CIU2010000000220I	(Total compensation, private industry, South region)
CIU2010000000230I	(Total compensation, private industry, Midwest region)
CIU2010000000240I	(Total compensation, private industry, West region)

4. As discussed in Section 3.1 of NUREG-1307, Revision 17 (February 2019), the Current Labor Adjustment Factor (L) may be calculated for each region by multiplying the Base Labor Adjustment Factor (December 2005) by the current Employment Cost Index (column 2 above by column 3 above) and then dividing by the reference 100.

ENERGY FACTOR

P (Dec. '18) / P (Jan. '86)[1]	F (Dec. '18) / F (Jan. '86)[1]	PWR[2]	BWR[3]
240.2/114.2 = 2.103	223.6/82.0 = 2.727	2.365	2.390

1. Values for the January 1986 reference data were obtained from Section 3.3 of NUREG-1307, Revision 17 (February 2019). Values for December 2018 for electric power (P) and fuel oil (F) were obtained from the Producer Price Indexes (PPI), available in the "PPI Detailed Report," published by the U.S. Department of Labor, Bureau of Labor Statistics, P is taken from data for industrial electric power (PPI Commodity code 0543), and F is taken from data for light fuel oils (PPI Commodity code 0573). The values are preliminary and are subject to final adjustment up to four months after original publication. Appendix C to NUREG 1307, Revision 17 (February 2019) states that the requisite information can be obtained on the internet by entering the following URL: http://www.bls.gov/data/; then clicking on the item labeled "Series Report;" and then entering into the box labeled "Enter series id(s) below," one id per line. The series ids are wpu0543 (industrial electric power) and wpu0573 (light fuel oils).

2. E (PWR) = 0.58P + 0.42F. See Section 3.3 of NUREG-1307, Revision 17 (February 2019).

3. E (BWR) = 0.54P + 0.46F. See Section 3.3 of NUREG-1307, Revision 17 (February 2019).

WASTE BURIAL FACTOR[5]

	PWR	BWR
Washington[6]		
Compact-Affiliated	10.854	9.118
Combination	8.697	7.186
South Carolina[7]		
Compact-Affiliated	32.329	28.314
Combination	11.607	12.872
Texas		
Compact-Affiliated	8.508	8.293
Combination	11.054	10.731
Unaffiliated/No Disposal Facility	12.853	13.422

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[5] *See* Table 2-1 of NUREG 1307, Revision 17 (February 2019).
[6] Effective January 1, 1993, the Washington site is not accepting waste from outside the Northwest and Rocky Mountain Compacts.
[7] Effective July 1, 2000, different price schedules at the South Carolina burial site apply for states within and outside the Atlantic Compact.

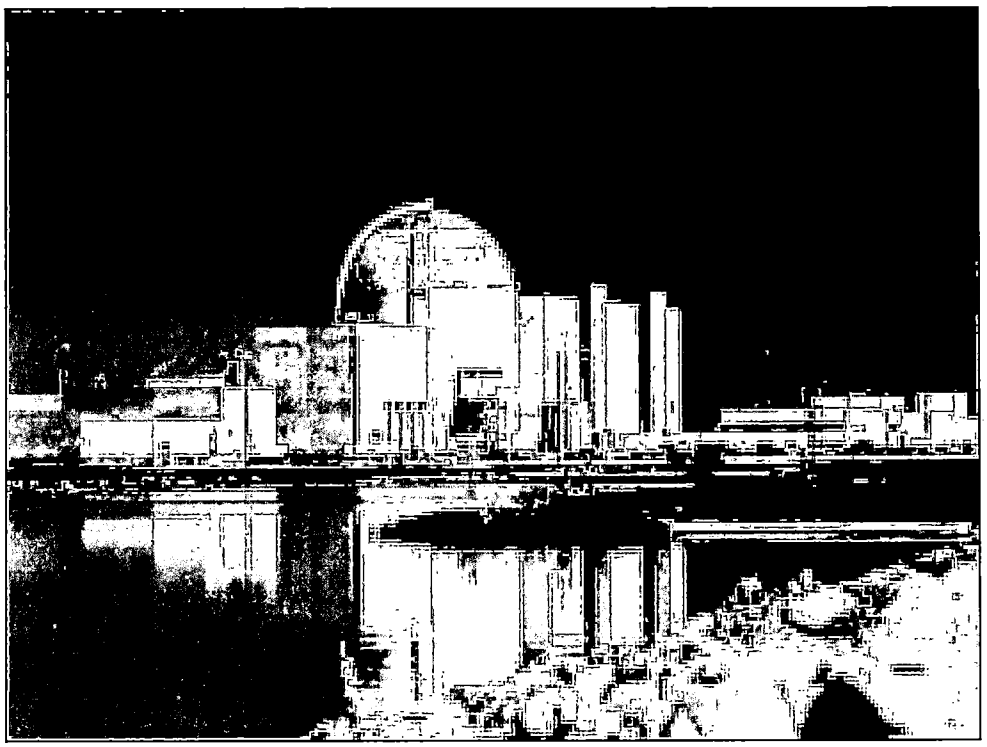
Decommissioning Cost Analysis for the Wolf Creek Generating Station
(W11-1741-001, Rev. 0)
(139 pages)

Document W11-1741-001, Rev. 0

DECOMMISSIONING COST ANALYSIS

for the

WOLF CREEK GENERATING STATION



prepared for the

Wolf Creek Nuclear Operating Corporation

prepared by

TLG Services, Inc.
Bridgewater, Connecticut

August 2017

APPROVALS

Project Manager	William A. Cloutier, Jr.	08/21/2017 Date
Project Engineer	Timothy A. Arnold	8/21/17 Date
Technical Manager	Francis W. Seymore	8/21/17 Date

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REVISION LOG

No.	Date	Item Revised	Reason for Revision
0	08-21-2017		Original Issue

EXECUTIVE SUMMARY

This report presents estimates of the cost to decommission the Wolf Creek Generating Station (Wolf Creek) for the selected decommissioning alternatives following the scheduled and permanent cessation of plant operations. The estimates are designed to provide the Wolf Creek Nuclear Operating Corporation (WCNOC), the plant's operator, and its owners: Kansas Gas and Electric Company, a wholly owned subsidiary of Westar Energy, Inc., Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy Incorporated, and Kansas Electric Power Cooperative, Inc., with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The analysis relies upon site-specific, technical information from an evaluation prepared in 2014,[1] updated to reflect current assumptions pertaining to the disposition of the nuclear station and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but estimates prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission Wolf Creek; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The 2014 plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, was reviewed for this analysis. There were no substantive changes made to the plant inventory (that would impact decommissioning). The current analysis does include, however, the costs to decommission the structural changes made to the condensate storage tank (for missile projection) and the control building, the new refueling cavity elevator, the fire protection system and emergency service water system modifications, and other minor modifications identified by the site.

The costs to decommission Wolf Creek for the alternatives evaluated are tabulated at the end of this section. Costs are reported in 2017 dollars and include monies anticipated to be spent for radiological remediation and operating license termination, spent fuel management, and site restoration activities.

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1 "Decommissioning Cost Analysis for the Wolf Creek Generating Station," Document No. W11-1697-001, Rev. 0, TLG Services, Inc., August 2014

A complete discussion of the assumptions relied upon in this analysis is provided in Section 3, along with schedules of annual expenditures for the two scenarios. A sequence of significant project activities is provided in Section 4 with a timeline for each scenario. Detailed cost reports, used to generate the summary tables contained within this document, are provided in Appendices C and D.

Consistent with the 2014 analysis, the current cost estimates assume that the shutdown of the nuclear station is a scheduled and pre-planned event (e.g., there is no delay in transitioning the plant and workforce from operations or in obtaining regulatory relief from operating requirements, etc.). The estimates include the continued operation of the fuel handling building as an interim wet fuel storage facility for approximately five and one-half years after operations cease (years 2045 through 2050). During this time period, it is assumed that the Department of Energy (DOE) will complete the transfer of the spent fuel from the site to a federal facility.

Alternatives and Regulations

The ultimate objective of the decommissioning process is to reduce the inventory of contaminated and activated material so that the license can be terminated. The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule adopted on June 27, 1988.[2] In this rule, the NRC set forth financial criteria for decommissioning licensed nuclear power facilities. The regulations addressed planning needs, timing, funding methods, and environmental review requirements for decommissioning. The rule also defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB.

> DECON is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."[3]
>
> SAFSTOR is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred

2 U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72 "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (p 24018 et seq.), June 27, 1988

3 Ibid. Page FR24022, Column 3

decontamination) to levels that permit release for unrestricted use."[4] Decommissioning is to be completed within 60 years, although longer time periods will be considered when necessary to protect public health and safety.

ENTOMB is defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactive material decays to a level permitting unrestricted release of the property."[5] As with the SAFSTOR alternative, decommissioning is currently required to be completed within 60 years, although longer time periods will also be considered when necessary to protect public health and safety.

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 1997, the Commission directed its staff to re-evaluate this alternative and identify the technical requirements and regulatory actions that would be necessary for entombment to become a viable option. The resulting evaluation provided several recommendations; however, rulemaking has been deferred pending the completion of additional research studies, for example, on engineered barriers. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process.[6] The amendments allow for greater public participation and better define the transition process from operations to decommissioning. Regulatory Guide 1.184, issued in July 2000, (as revised in October 2013), further described the methods and procedures that are acceptable to the NRC staff for implementing the requirements of the 1996 revised rule that relate to the initial activities and the major phases of the decommissioning process. The costs and

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4 Ibid.

5 Ibid. Page FR24023, Column 2

6 U.S. Code of Federal Regulations, Title 10, Parts 2, 50, and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, Federal Register Volume 61, (p 39278 et seq.), July 29, 1996

schedules presented in this analysis follow the general guidance and sequence in the amended regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202, issued in February 2005.[7]

In 2011, the NRC issued regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[8] The regulations require licensees to report additional details in their decommissioning cost estimate, including a decommissioning estimate for any on-site Independent Spent Fuel Storage Installation (ISFSI). Since an ISFSI may be required to support continued operation at Wolf Creek, a representative decommissioning cost is included within the DECON and SAFSTOR estimates.

Decommissioning Scenarios

Two decommissioning scenarios were evaluated for the Wolf Creek nuclear unit. The scenarios selected are representative of alternatives currently available to the owners and are defined as follows:

1. The first scenario assumes that the nuclear unit is promptly decommissioned (DECON alternative) upon the expiration of the current operating license in 2045. Following the permanent cessation of operations, and over the first five and one-half years, the spent fuel is transferred directly from the wet storage pool to the DOE (the fuel stored on the ISFSI is also removed from the site during this time period). Concurrently, the majority of the plant components, including the nuclear steam supply system components, are removed. Once the spent fuel stored in the fuel handling building's pool has been transferred off-site, the remaining portions of the power block are decommissioned and the surrounding site remediated. Following the termination of the operating license, non-essential structures (not designated for reuse) are dismantled.

2. In the second scenario, the nuclear unit is placed into safe-storage (SAFSTOR alternative) upon the expiration of the current operating license in 2045. As with the first scenario, the spent fuel removed from the site (transferred to the DOE) during the first five and one-half years following the permanent cessation of operations. The facility is then placed into safe-storage (with non-essential systems de-energized and buildings secured).

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7 "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, Nuclear Regulatory Commission, February 2005

8 U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 70, and 72, "Decommissioning Planning," Nuclear Regulatory Commission, Federal Register Volume 76, (p 35512 et seq.), June 17, 2011

The start of decontamination and dismantling activities is deferred to the maximum extent (approximately 50 years from the cessation of operations) such that the license is terminated within the required 60-year period.

Methodology

The methodology used to develop the estimates described within this document follows the basic approach originally presented in the cost estimating guidelines[9] developed by the Atomic Industrial Forum (now Nuclear Energy Institute). This reference describes a unit factor method for determining decommissioning activity costs. The unit factors used in this analysis incorporate site-specific costs and the latest available information on worker productivity in decommissioning.

An activity duration critical path is used to determine the total decommissioning program schedule. This is required for calculating the carrying costs, which include program management, administration, field engineering, equipment rental, quality assurance, and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

The estimates also reflect lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Contingency

Consistent with cost estimating practice, contingencies are applied to the decontamination and dismantling costs developed as "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."[10] The cost elements in the estimates are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a

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9 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

10 Project and Cost Engineers' Handbook, Second Edition, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, p. 239

line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

Contingency funds are expected to be fully expended throughout the program. As such, inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks.

Low-Level Radioactive Waste Disposal

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,[11] and its Amendments of 1985,[12] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

With the exception of 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). The facility is also able to accept limited quantities of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to WCNOC. The majority of the low-level radioactive waste designated for controlled disposal (Class A[13]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon WCNOC's "Long Term Waste Disposal Agreement" with Energy*Solutions*. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The WCS facility is able to receive the Class B and C waste. As such, for this analysis, Class B and C waste was assumed to be shipped to the WCS facility for disposal. Disposal costs were based upon preliminary and indicative information for the WCS site.

The dismantling of the components residing closest to the reactor core generates radioactive waste that may be considered unsuitable for shallow-land disposal (i.e.,

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11 "Low-Level Radioactive Waste Policy Act of 1980," Public Law 96-573, 1980

12 "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, 1986.

13 Waste is classified in accordance with U.S. Code of Federal Regulations, Title 10, Part 61.55

low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis only, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and shipped directly to a DOE facility as it is generated.

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This material can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to eliminate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act"[14] (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. The DOE 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, despite DOE's submittal of its License Application for a geologic repository to the NRC in 2008. The Obama administration eliminated 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."[15] Towards this goal, the Obama administration appointed a Blue Ribbon Commission on

14 "Nuclear Waste Policy Act of 1982 and Amendments," DOE's Office of Civilian Radioactive Management, 1982

15 "Advisory Committee Charter, Blue Ribbon Commission on America's Nuclear Future," Appendix A, January 2012

America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter included a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[16]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of 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"[17]
- "[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."[18]

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..."[19] This document states:

"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

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16 Ibid.

17 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," p. 32, January 2012

18 Ibid., p.27

19 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."[20]

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)[21] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application, to the extent allowed by 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 adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

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 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. The current spent fuel management plan for the Wolf Creek spent fuel is based in general upon: 1) a 2025 start date for DOE initiating transfer of commercial spent fuel to a federal facility, and 2) a 2032 start date for the transfer of spent fuel from the Wolf Creek site based on an oldest fuel first priority, and the DOE achieving an annual rate of transfer (3,000 metric tons of uranium per year) as reflected in DOE's latest Acceptance Priority Ranking and Annual Capacity Report.[22]

The estimates also assume that the DOE would give priority to fuel at shutdown sites, i.e., it is assumed that Congress would "(1)...direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process."[23]

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20 Ibid., p.2

21 U.S. Court of Appeals for the District Of Columbia Circuit, In Re: Aiken County, et al, Aug. 2013

22 "Acceptance Priority Ranking and Annual Capacity Report," U.S. DOE, Office of Civilian Radioactive Waste Management, DOE/RW-0567, July 2004

23 "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

It is generally necessary that spent fuel be cooled and stored for a minimum period at the generating site prior to transfer. As such, the NRC requires that licensees establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE, pursuant to 10 CFR Part 50.54(bb).[24] The post-shutdown costs incurred to satisfy this requirement include the isolation and continued operation of the spent fuel pool and the ISFSI during the five and one-half years following the cessation of plant operations.

At shutdown, the spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core. Over the following five and one-half years the assemblies are packaged into multipurpose canisters for transfer to the DOE. It is assumed that this period provides the necessary cooling for the final core to meet the transportation system requirements for decay heat.

Interim storage of the fuel, until the DOE has completed the transfer, will be in the wet storage pool located in the fuel building (as well as on the ISFSI). The pool will be isolated, allowing WCNOC to proceed with decommissioning (or safe-storage preparations) in the shortest time possible.

Sensitivity of Spent Fuel Management Assumptions

The estimates described in this analysis were developed with the assumption that the DOE would give priority to removing spent fuel from shutdown sites. The estimates further assume that the spent fuel would be removed from the Wolf Creek site within five and one-half years of the cessation of plant operations (i.e., five and one-half years would provide sufficient cooling time for the spent fuel to meet DOE transportation requirements).

If DOE is unable to remove the spent fuel from the Wolf Creek site within this time period, wet storage pool operations would need to be extended (potentially delaying decommissioning) and/or the ISFSI would be used for the interim storage of the fuel so that decommissioning could proceed. Appendix E evaluates such a scenario (i.e., where spent fuel is accepted from generators in the order in which it was generated or oldest fuel first and the ISFSI is used for interim storage, similar to what has occurred at recently decommissioned reactor sites).

The resulting costs for long-term spent fuel management (summarized in Table E) are illustrative only and based upon current regulations and associated constraints that

[24] U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

may change as a result of actions taken on the Blue Ribbon Commission's recommendations. It should also be noted that the costs, while incurred by the licensee, may also be recoverable as a result of DOE's breech of its contract to take possession of the spent fuel in a timely manner. However, the analysis described in Appendix E may prove useful as a planning basis should delays continue in the development of a national solution for the disposition of spent fuel and high-level waste.

Site Restoration

The efficient removal of the contaminated materials at the site may result in damage to many of the site structures. Blasting, coring, drilling, and the other decontamination activities can substantially damage power block structures, potentially weakening the footings and structural supports. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures with a work force already mobilized is more efficient and less costly than if the process is deferred.

Consequently, this study assumes that non-essential site structures addressed by this analysis are removed, once remediation is complete, to a nominal depth of three feet below the local grade level, wherever possible. The site is then graded and stabilized.

Summary

The costs to decommission Wolf Creek assume the removal of all contaminated and activated plant components and structural materials such that the owners may then have unrestricted use of the site with no further requirements for an operating license. Low-level radioactive waste, other than GTCC waste, is sent to a commercial processor for treatment/conditioning or to a controlled disposal facility.

Decommissioning is accomplished within the 60-year period required by current NRC regulations.

The decommissioning scenarios are described in Section 2. The assumptions are presented in Section 3, along with schedules of annual expenditures. The major cost contributors are identified in Section 6, with detailed activity costs, waste volumes, and associated manpower requirements delineated in Appendices C and D. The major cost components are also identified in the cost summary provided at the end of this section.

The cost elements in the estimates are assigned to one of three subcategories: NRC License Termination, Spent Fuel Management, and Site Restoration. The subcategory "NRC License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR Part 50.75). The cost reported for this subcategory is generally sufficient to terminate the station's operating license, recognizing that there may be some additional cost impact from spent fuel management. The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). Section 3.4.1 provides the basis for the ISFSI decommissioning cost.

The "Spent Fuel Management" subcategory contains costs associated with the transfer of the spent fuel to the DOE as well as the operation of the spent fuel pool until such time that the transfer is complete.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are removed to a depth of three feet and backfilled to conform to local grade.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligations determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, an owner may decide to remove non-contaminated structures early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As noted within this document, the estimates were developed and costs are presented in 2017 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the reactor or during the decommissioning period.

DECON COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Cost
Decontamination	16,486
Removal	120,128
Packaging	24,544
Transportation	12,533
Waste Disposal	84,171
Off-site Waste Processing	24,134
Program Management [1]	273,568
Security	115,889
Corporate Allocations	2,002
Spent Fuel Pool Isolation	13,445
Spent Fuel Management - Direct Costs [2]	46,385
Insurance and Regulatory Fees	19,065
Energy	14,431
Characterization and Licensing Surveys	24,313
Property Taxes	15,363
Miscellaneous Equipment	7,279
Total [3]	813,733

Cost Element	Cost
License Termination	711,273
Spent Fuel Management	48,251
Site Restoration	54,208
Total [3]	813,733

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

SAFSTOR COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Cost
Decontamination	14,346
Removal	123,154
Packaging	19,286
Transportation	9,751
Waste Disposal	62,163
Off-site Waste Processing	26,984
Program Management [1]	366,223
Security	224,686
Corporate Allocations	3,292
Spent Fuel Pool Isolation	13,445
Spent Fuel Management - Direct Costs [2]	46,385
Insurance and Regulatory Fees	71,272
Energy	29,815
Characterization and Licensing Surveys	24,929
Property Taxes	33,724
Miscellaneous Equipment	23,661
Total [3]	1,093,117

Cost Element	Cost
License Termination	980,846
Spent Fuel Management	58,028
Site Restoration	54,243
Total [3]	1,093,117

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

1. INTRODUCTION

This report presents estimates of the cost to decommission the Wolf Creek Generating Station (Wolf Creek) for the selected decommissioning scenarios following the scheduled cessation of plant operations. The estimates are designed to provide the Wolf Creek Nuclear Operating Corporation (WCNOC), the plant's operator, and its owners: Kansas Gas and Electric Company, a wholly owned subsidiary of Westar Energy, Inc., Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy Incorporated, and Kansas Electric Power Cooperative, Inc., with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The analysis relies upon site-specific, technical information from an earlier evaluation prepared in 2014,[1]* updated to reflect current assumptions pertaining to the disposition of the nuclear station and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but rather estimates prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission Wolf Creek; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The 2014 plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, were reviewed for this analysis. There were no substantive changes made to the plant inventory (that would impact decommissioning). The current analysis does include, however, the costs to decommission the structural changes made to the condensate storage tank (for missile projection) and the control building, the new refueling cavity elevator, the fire protection system and emergency service water system modifications, and other minor modifications identified by the site.

1.1 OBJECTIVES OF STUDY

The objectives of this study were to prepare comprehensive estimates of the costs to decommission Wolf Creek, to provide a sequence or schedule for the

* References provided in Section 7 of the document

associated activities, and to develop waste stream projections from the decontamination and dismantling activities.

An operating license was originally issued for Wolf Creek in June of 1985. A license renewal application was filed for the nuclear station in October 2006. The NRC approved the application and a renewed licensed was issued in November 2008. As such, this analysis is based upon a 60-year operating life, with a final shutdown date (license expiration) in March of 2045.

1.2 SITE DESCRIPTION

The Wolf Creek site is located approximately 3.5 miles northeast of the town of Burlington, in Coffey County, Kansas, approximately 75 miles southwest of Kansas City, Kansas. The site is on the east side of a man-made lake formed by impounding Wolf Creek. The station is an 1,170 MWe (nominal) pressurized water reactor with supporting facilities.

Westinghouse Electric Company designed the Nuclear Steam Supply System (NSSS). The system consists of a pressurized water reactor with four independent primary coolant loops, each of which contains a reactor coolant pump and a steam generator. An electrically heated pressurizer and connecting piping complete the system. The NSSS is rated at a thermal power level of 3,579 MWt (3,565 MWt reactor core plus 14 MWt for reactor coolant pumps), with a corresponding turbine-generator gross output of 1,267 MWe. The system is housed within a containment structure, a pre-stressed, post-tensioned concrete structure with cylindrical wall, a hemispherical dome, and a flat foundation slab. The wall and dome form a pre-stressed post-tensioned system. The inside surface of the structure is covered with a carbon steel liner, providing a leak tight membrane.

A power conversion system converts heat produced in the reactor to electrical energy. This system converts the thermal energy of the steam into mechanical shaft power and then into electrical energy. The turbine-generator is a tandem-compound, six-flow, four element, 1800-rpm unit. The unit consists of one high pressure and three low-pressure turbine elements driving a directly coupled generator. (The four turbine elements were replaced in 2010 with very similar equipment.) The turbine is operated in a closed feedwater cycle that condenses the steam; the feedwater is returned to the steam generators. Heat rejected in the main condensers is removed by the circulating water system.

The circulating water system supplies cooling water to the main condenser, condensing the steam exhausted from the turbine. A large cooling lake

provides the heat sink required for removal of waste heat in the power plant's thermal cycle.

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 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 ENTOMB alternative has not been viewed as a viable option for power reactors due to the significant time required to isolate the long-lived radionuclides for decay to permissible levels. However, with rulemaking permitting the controlled release of a site,[4] the NRC has re-evaluated this alternative. The resulting feasibility study, based upon an assessment by Pacific Northwest National Laboratory, concluded that the method did have

conditional merit for some, if not most reactors. However, the staff also found that additional rulemaking would be needed before this option could be treated as a generic alternative. The NRC had considered rulemaking to alter the 60-year time for completing decommissioning and to clarify the use of engineered barriers for reactor entombments.[5]

The NRC's staff has recommended that rulemaking be deferred, based upon several factors, e.g., no licensee has committed to pursuing the entombment option, and the NRC's current priorities, at least until after the additional research studies are complete. The NRC concurred with the staff's recommendation. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants.[6] When the decommissioning regulations were 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 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, along with related changes to Technical Specifications, 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 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 includes a license termination plan (LTP).

In 2011, the NRC issued regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[7] The regulations require licensees to report additional details in their decommissioning cost estimate including a decommissioning estimate for any on-site Independent Spent Fuel Storage Installation (ISFSI). Since an ISFSI may be required to support continued operation at Wolf Creek, a representative decommissioning cost is included within the DECON and SAFSTOR estimates.

1.3.1 High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act"[8] (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. The DOE 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 has 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."[9]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of 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."[10]

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..."[11]

"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)[12] ordering NRC to comply with federal law and resume its review of DOE's Yucca Mountain repository license application, to the extent allowed by 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 adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

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 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. The current spent fuel management plan for the Wolf Creek spent fuel is based in general upon: 1) a 2025 start date for DOE initiating transfer of commercial spent fuel to a federal facility, and 2) a 2032 start date for the transfer of spent fuel from the Wolf Creek site based on an oldest fuel first priority, and the DOE achieving an annual rate of transfer (3,000 metric tons of uranium per year) as reflected in DOE's latest Acceptance Priority Ranking and Annual Capacity Report.[13]

The estimates also assume that the DOE would give priority to fuel at shutdown sites, i.e., it is assumed that Congress would "(1)...direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process."[14]

It is generally necessary that spent fuel be cooled and stored for a minimum period at the generating site prior to transfer. As such, the NRC requires that licensees establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the DOE, pursuant to 10 CFR Part 50.54(bb).[15] The post-shutdown costs incurred to satisfy this requirement include the isolation and continued operation of the spent fuel pool and the ISFSI during the five and one-half years following the cessation of plant operations.

At shutdown, the spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core. Over the following five and one-half years the assemblies are packaged into multipurpose canisters for transfer to the DOE. It is assumed that this period provides the necessary cooling for the final core to meet the transportation system requirements for decay heat.

Interim storage of the fuel, until the DOE has completed the transfer, will be in the wet storage pool located in the fuel building (as well as on the ISFSI). The pool will be isolated, allowing WCNOC to proceed with decommissioning (or safe-storage preparations) in the shortest time possible.

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,[16] and its Amendments of 1985,[17] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders.

With the exception of 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). The facility is also able to accept limited volumes of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to WCNOC. The majority of the low-level radioactive waste designated for controlled disposal (Class A[18]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon WCNOC's "Long Term Waste Disposal Agreement" with Energy*Solutions*. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The WCS facility is able to receive the Class B and C waste. As such, for this analysis, Class B and C waste was assumed to be shipped to the WCS facility for disposal. Disposal costs were based upon preliminary and indicative information for the WCS site.

The dismantling of the components residing closest to the reactor core generates radioactive waste that may be considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste.

However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis only, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and shipped directly to a DOE facility as it is generated.

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This material can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to eliminate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

1.3.3 Radiological Criteria for License Termination

In 1997, the NRC published Subpart E, "Radiological Criteria for License Termination,"[19] amending 10 CFR Part 20. This subpart provides radiological criteria for releasing a facility for unrestricted use. The regulation states that the site can be released for unrestricted use if radioactivity levels are such that the average member of a critical group would not receive a Total Effective Dose Equivalent (TEDE) in excess of 25 millirem per year, and provided that residual radioactivity has been reduced to levels that are As Low As Reasonably Achievable (ALARA). The decommissioning estimates assume that the Wolf Creek site will be remediated to a residual level consistent with the NRC-prescribed level.

It should be noted that the NRC and the Environmental Protection Agency (EPA) differ on the amount of residual radioactivity considered acceptable in site remediation. The EPA has two limits that apply to radioactive materials. An EPA limit of 15 millirem per year is derived from criteria established by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[20] An additional and separate limit of 4 millirem per year, as defined in 40 CFR §141.66, is applied to drinking water.[21]

On October 9, 2002, the NRC signed an agreement with the EPA on the radiological decommissioning and decontamination of NRC-licensed sites. The Memorandum of Understanding (MOU)[22] provides that EPA will defer exercise of authority under CERCLA for the majority of facilities decommissioned under NRC authority. The MOU also includes provisions for NRC and EPA consultation for certain sites when, at the time of license termination, (1) groundwater contamination exceeds EPA-permitted levels; (2) NRC contemplates restricted release of the site; and/or (3) residual radioactive soil concentrations exceed levels defined in the MOU.

The MOU does not impose any new requirements on NRC licensees and should reduce the involvement of the EPA with NRC licensees who are decommissioning. Most sites are expected to meet the NRC criteria for unrestricted use, and the NRC believes that only a few sites will have groundwater or soil contamination in excess of the levels specified in the MOU that trigger consultation with the EPA. However, if there are other hazardous materials on the site, the EPA may be involved in the cleanup. As such, the possibility of dual regulation remains for certain licensees. The present study does not include any costs for this occurrence.

2. DECOMMISSIONING ALTERNATIVES

Detailed cost estimates were developed to decommission Wolf Creek for the approved decommissioning alternatives: DECON and SAFSTOR. Although the alternatives differ with respect to technique, process, cost, and schedule, they attain the same result: the ultimate release of the site for unrestricted use.

Two decommissioning scenarios were evaluated for the Wolf Creek nuclear unit. The scenarios selected are representative of alternatives currently available to the owners and are defined as follows:

1. The first scenario assumes that the nuclear unit is promptly decommissioned (DECON alternative) upon the expiration of the current operating license in 2045. Following the permanent cessation of operations, and over the first five and one-half years, the spent fuel is transferred directly from the wet storage pool to the DOE (the fuel stored on the ISFSI is also removed from the site during this time period). Concurrently, the majority of the plant components, including the nuclear steam supply system components, are removed. Once the spent fuel stored in the fuel handling building's pool has been transferred off-site, the remaining portions of the power block are decommissioned and the surrounding site remediated. Following the termination of the operating license, non-essential structures (not designated for reuse) are dismantled.

2. In the second scenario, the nuclear unit is placed into safe-storage (SAFSTOR alternative) upon the expiration of the current operating license in 2045. As with the first scenario, the spent fuel removed from the site (transferred to the DOE) during the first five and one-half years following the permanent cessation of operations. The facility is then placed into safe-storage (with non-essential systems de-energized and buildings secured). The start of decontamination and dismantling activities is deferred to the maximum extent (approximately 50 years from the cessation of operations) such that the license is terminated within the required 60-year period.

The following sections describe the basic activities associated with each alternative. Although detailed procedures for each activity identified are not provided, and the actual sequence of work may vary, the activity descriptions provide a basis not only for estimating but also for the expected scope of work, i.e., engineering and planning at the time of decommissioning.

The conceptual approach that the NRC has described in its regulations divides 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. During the first phase, notification is to be provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessel. The licensee is then prohibited from reactor operation.

The second phase encompasses activities during the storage period or during major decommissioning activities, or a combination of the two. The third phase pertains to the activities involved in license termination. The decommissioning estimates developed for Wolf Creek are also divided into phases or periods; however, demarcation of the phases is based upon major milestones within the project or significant changes in the projected expenditures.

2.1 DECON

The DECON alternative, as defined by the NRC, is "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." This study does not address the cost to dispose of the spent fuel residing at the site; such costs are funded through a surcharge on electrical generation.

2.1.1 Period 1 - Preparations

In anticipation of the cessation of plant operations, detailed preparations are undertaken to provide a smooth transition from plant operations to site decommissioning. Through implementation of a staffing transition plan, the organization required to manage the intended decommissioning activities is assembled from available plant staff and outside resources. Preparations include the planning for permanent defueling of the reactor, revision of technical specifications applicable to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

Engineering and Planning

The PSDAR, required prior to or within two years of permanent cessation of operations, provides a description of the licensee's planned decommissioning activities, a timetable, and the associated financial requirements of the intended decommissioning program. Upon receipt of the PSDAR, the NRC will make the document available to the public

for comment in a local hearing to be held in the vicinity of the reactor site. Ninety days following submittal and NRC receipt of the PSDAR, the licensee may begin to perform major decommissioning activities under a modified 10 CFR §50.59 procedure, i.e., without specific NRC approval. Major activities are defined as any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components (for shipment) containing GTCC, as defined by 10 CFR §61. Major components are further defined as comprising the reactor vessel and internals, large bore reactor coolant system piping, and other large components that are radioactive. The NRC includes the following additional criteria for use of the §50.59 process in decommissioning. The proposed activity must not:

- foreclose release of the site for possible unrestricted use,
- significantly increase decommissioning costs,
- cause any significant environmental impact, or
- violate the terms of the licensee's existing license.

Existing operational technical specifications are reviewed and modified to reflect plant conditions and the safety concerns associated with permanent cessation of operations. The environmental impact associated with the planned decommissioning activities is also considered. Typically, a licensee will not be allowed to proceed if the consequences of a particular decommissioning activity are greater than that bounded by previously evaluated environmental assessments or impact statements. In this instance, the licensee would have to submit a license amendment for the specific activity and update the environmental report.

The decommissioning program outlined in the PSDAR will be designed to accomplish the required tasks within the ALARA guidelines (as defined in 10 CFR §20) for protection of personnel from exposure to radiation hazards. It will also address the continued protection of the health and safety of the public and the environment during the dismantling activity. Consequently, with the development of the PSDAR, activity specifications, cost-benefit and safety analyses, work packages and procedures, would be assembled to support the proposed decontamination and dismantling activities.

Site Preparations

Following final plant shutdown, and in preparation for actual decommissioning activities, the following activities are initiated:

- Characterization of the site and surrounding environs. This includes radiation surveys of work areas, major components (including the reactor vessel and its internals), internal piping, and primary shield cores.
- Isolation of the spent fuel storage pool and fuel handling systems, such that decommissioning operations can commence on the balance of the plant. The pool will remain operational for approximately five and one-half years following the cessation of operations before the inventory resident at shutdown can be transferred to the DOE.
- Specification of transport and disposal requirements for activated materials and/or hazardous materials, including shielding and waste stabilization.
- Development of procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste (including dry-active waste, resins, filter media, metallic and non-metallic components generated in decommissioning), site security and emergency programs, and industrial safety.

2.1.2 Period 2 - Decommissioning Operations

This period includes the physical decommissioning activities associated with the removal and disposal of contaminated and activated components and structures, including the successful termination of the 10 CFR §50 operating license. Significant decommissioning activities in this phase include:

- Construction of temporary facilities and/or modification of existing facilities to support dismantling activities. This may include a centralized processing area to facilitate equipment removal and component preparations for off-site disposal.
- Reconfiguration and modification of site structures and facilities as needed to support decommissioning operations. This may include the upgrading of roads (on- and off-site) to facilitate hauling and transport. Modifications may be required to the containment structure to facilitate access of large/heavy equipment. Modifications may also be required to the refueling area of the building to support

the segmentation of the reactor vessel internals and component extraction.

- Design and fabrication of temporary and permanent shielding to support removal and transportation activities, construction of contamination control envelopes, and the procurement of specialty tooling.
- Procurement (lease or purchase) of shipping canisters, cask liners, and industrial packages for the disposition of low-level radioactive waste.
- Decontamination of components and piping systems as required to control (minimize) worker exposure.
- Removal of piping and components no longer essential to support decommissioning operations.
- Removal of control rod drive housings and the head service structure from the reactor vessel head. Segmentation of the vessel closure head.
- Removal and segmentation of the upper internals assemblies. Segmentation will maximize the loading of the shielded transport casks, i.e., by weight and activity. The operations are conducted under water using remotely operated tooling and contamination controls.
- Disassembly and segmentation of the remaining reactor internals, including the core shroud and lower core support assembly. Some material is expected to exceed Class C disposal requirements. As such, the segments will be packaged in modified fuel storage canisters for geologic disposal.
- Segmentation of the reactor vessel. A shielded platform is installed for segmentation as cutting operations are performed in-air using remotely operated equipment within a contamination control envelope. The water level is maintained just below the cut to minimize the working area dose rates. Segments are transferred in-air to containers that are stored under water, for example, in an isolated area of the refueling canal.
- Removal of the activated portions of the concrete biological shield and accessible contaminated concrete surfaces. If dictated by the steam generator and pressurizer removal scenarios, those portions of the associated cubicles necessary for access and component extraction are removed.

- Removal of the steam generators and pressurizer for material recovery and controlled disposal. The generators will be moved to an on-site processing center, the steam domes removed and the internal components segregated for recycling. The lower shell and tube bundle will be packaged for direct disposal. These components can serve as their own burial containers provided that all penetrations are properly sealed and the internal contaminants are stabilized, e.g., with grout. Steel shielding will be added, as necessary, to those external areas of the package to meet transportation limits and regulations. The pressurizer is disposed of intact.

At least two years prior to the anticipated date of license termination, an LTP is required. Submitted as a supplement to the Final Safety Analysis Report (FSAR) or its equivalent, the plan must include: a site characterization, description of the remaining dismantling activities, plans for site remediation, procedures for the final radiation survey, designation of the end use of the site, an updated cost estimate to complete the decommissioning, and any associated environmental concerns. The NRC will notice the receipt of the plan, make the plan available for public comment, and schedule a local hearing. LTP approval will be subject to any conditions and limitations as deemed appropriate by the Commission. The licensee may then commence with the final remediation of site facilities and services, including:

- Removal of remaining plant systems and associated components as they become nonessential to the decommissioning program or worker health and safety (e.g., waste collection and treatment systems, electrical power and ventilation systems).
- Removal of the steel liners from refueling canal, disposing of the activated and contaminated sections as radioactive waste. Removal of any activated/ contaminated concrete.
- Surveys of the decontaminated areas of the containment structure.
- Remediation and removal of the contaminated equipment and material from the fuel building and any other contaminated facility. Radiation and contamination controls will be utilized until residual levels indicate that the structures and equipment can be released for unrestricted access and conventional demolition. This activity may necessitate the dismantling and disposition of most of the systems and components (both clean and contaminated) located within these buildings. This activity facilitates surface decontamination and subsequent verification surveys required prior to obtaining release for demolition.

- Routing of material removed in the decontamination and dismantling to a central processing area. Material certified to be free of contamination is released for unrestricted disposition, e.g., as scrap, recycle, or general disposal. Contaminated material is characterized and segregated for additional off-site processing (disassembly, chemical cleaning, volume reduction, and waste treatment), and/or packaged for controlled disposal at a low-level radioactive waste disposal facility.

Incorporated into the LTP is the Final Survey Plan. This plan identifies the radiological surveys to be performed once the decontamination activities are completed and is developed using the guidance provided in the "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)."[23] This document incorporates the statistical approaches to survey design and data interpretation used by the EPA. It also identifies state-of-the-art, commercially available instrumentation and procedures for conducting radiological surveys. Use of this guidance ensures that the surveys are conducted in a manner that provides a high degree of confidence that applicable NRC criteria are satisfied. Once the survey is complete, the results are provided to the NRC in a format that can be verified. The NRC then reviews and evaluates the information, performs an independent confirmation of radiological site conditions, and makes a determination on final termination of the license.

The NRC will terminate the operating license if it determines that site remediation has been performed in accordance with the LTP, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release.

2.1.3 Period 3 - Site Restoration

Following completion of decommissioning operations, site restoration activities will begin. Efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below the NRC limits will result in substantial damage to many of the structures. Although performed in a controlled, safe manner, blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially degrade power block structures including the reactor, fuel handling, radioactive waste, solidification facility and condensate polishing buildings. Under certain circumstances, verifying that subsurface radionuclide concentrations meet NRC site release requirements will require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This removal

activity will be necessary for those facilities and plant areas where historical records, when available, indicate the potential for radionuclides having been present in the soil, where system failures have been recorded, or where it is required to confirm that subsurface process and drain lines were not breached over the operating life of the station.

It is not currently anticipated that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures, once remediation is complete, with a work force already mobilized on site is more efficient than if the process is deferred.

This cost study presumes that non-essential structures and site facilities are dismantled as a continuation of the decommissioning activity. Foundations and exterior walls are removed to a nominal depth of three feet below grade. The three-foot depth allows for the placement of gravel for drainage, as well as topsoil, so that vegetation can be established for erosion control. Site areas affected by the dismantling activities are restored and the plant area graded as required to prevent ponding and inhibit the refloating of subsurface materials.

Non-contaminated concrete rubble produced by demolition activities is processed to remove reinforcing steel and miscellaneous embedments. The processed material is then used on site to backfill foundation voids. Excess non-contaminated materials are trucked to an off-site area for disposal as construction debris.

2.2 SAFSTOR

The NRC defines SAFSTOR as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." The facility is left intact (during the dormancy period), with structures maintained in a sound condition. Systems that are not required to support the spent fuel pool or site surveillance and security are drained, de-energized, and secured. Minimal cleaning/removal of loose contamination and/or fixation and sealing of remaining contamination are performed. Access to contaminated areas is secured to provide controlled access for inspection and maintenance.

The engineering and planning requirements are similar to those for the DECON alternative, although a shorter time period is expected for these

activities due to the more limited work scope. Site preparations are also similar to those for the DECON alternative. However, with the exception of the required radiation surveys and site characterizations, the mobilization and preparation of site facilities is less extensive.

2.2.1 Period 1 - Preparations

Preparations for long-term storage include the planning for permanent defueling of the reactor, revision of technical specifications appropriate to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

The process of placing the plant in safe-storage includes, but is not limited to, the following activities:

- Isolation of the spent fuel storage services and fuel handling systems so that safe-storage operations may commence on the balance of the plant. This activity may be carried out by plant personnel in accordance with existing operating technical specifications. Activities are scheduled around the fuel handling systems to the greatest extent possible.
- Transfer of the spent fuel from the storage pool to the DOE following the minimum required cooling period in the spent fuel pool (any spent fuel stored at the ISFSI is also removed from the site during this time period).
- Draining and de-energizing of the non-contaminated systems not required to support continued site operations or maintenance.
- Disposing of contaminated filter elements and resin beds not required for processing wastes from layup activities for future operations.
- Draining of the reactor vessel, with the internals left in place and the vessel head secured.
- Draining and de-energizing non-essential, contaminated systems with decontamination as required for future maintenance and inspection.
- Preparing lighting and alarm systems whose continued use is required; de-energizing portions of fire protection, electric power, and HVAC systems whose continued use is not required.
- Cleaning of the loose surface contamination from building access pathways.

- Performing an interim radiation survey of plant, posting warning signs where appropriate.
- Erecting physical barriers and/or securing all access to radioactive or contaminated areas, except as required for inspection and maintenance.
- Installing security and surveillance monitoring equipment and relocating security fence around secured structures, as required.

2.2.2 Period 2 - Dormancy

The second phase identified by the NRC in its rule addresses licensed activities during a storage period and is applicable to the dormancy phases of the deferred decommissioning alternatives. Dormancy activities include a 24-hour security force, preventive and corrective maintenance on security systems, area lighting, general building maintenance, heating and ventilation of buildings, routine radiological inspections of contaminated structures, maintenance of structural integrity, and a site environmental and radiation monitoring program. Resident maintenance personnel perform equipment maintenance, inspection activities, routine services to maintain safe conditions, adequate lighting, heating, and ventilation, and periodic preventive maintenance on essential site services.

An environmental surveillance program is carried out during the dormancy period to ensure that releases of radioactive material to the environment are prevented and/or detected and controlled. Appropriate emergency procedures are established and initiated for potential releases that exceed prescribed limits. The environmental surveillance program constitutes an abbreviated version of the program in effect during normal plant operations.

Security during the dormancy period is conducted primarily to prevent unauthorized entry and to protect the public from the consequences of its own actions. The security fence, sensors, alarms, and other surveillance equipment provide security. Fire and radiation alarms are also monitored and maintained.

Consistent with the DECON scenario, the spent fuel storage pool and the ISFSI are emptied within five and one-half years of the cessation of operations. The pool is secured for storage and decommissioned along with the power block structures in Period 4.

After a period of storage (such that license termination is accomplished within 60 years of final shutdown), it is required that the licensee submit an application to terminate the license, along with an LTP (described in Section 2.1.2), thereby initiating the third phase.

2.2.3 Periods 3 and 4 - Delayed Decommissioning

Prior to the commencement of decommissioning operations, preparations are undertaken to reactivate site services and prepare for decommissioning. Preparations include engineering and planning, a detailed site characterization, and the assembly of a decommissioning management organization. Final planning for activities and the writing of activity specifications and detailed procedures are also initiated at this time.

Much of the work in developing a termination plan is relevant to the development of the detailed engineering plans and procedures. The activities associated with this phase and the follow-on decontamination and dismantling processes are detailed in Sections 2.1.1 and 2.1.2. The primary difference between the sequences anticipated for the DECON and this deferred scenario is the absence, in the latter, of any constraint on the availability of the fuel storage facilities for decommissioning.

Variations in the length of the dormancy period are expected to have little effect upon the quantities of radioactive wastes generated from system and structure removal operations. Given the levels of radioactivity and spectrum of radionuclides expected from sixty years of plant operation, no plant process system identified as being contaminated upon final shutdown will become releasable due to the decay period alone, i.e., there is no significant reduction in the waste generated from the decommissioning activities. However, due to the lower activity levels, a greater percentage of the waste volume can be designated for off-site processing and recovery.

The delay in decommissioning also yields lower working area radiation levels. As such, the estimate for this delayed scenario incorporates reduced ALARA controls for the SAFSTOR's lower occupational exposure potential.

Although the initial radiation levels due to ^{60}Co will decrease during the dormancy period, the internal components of the reactor vessel will still exhibit sufficiently high radiation dose rates to require remote sectioning under water due to the presence of long-lived radionuclides

such as ^{94}Nb, ^{59}Ni, and ^{63}Ni. Therefore, the dismantling procedures described for the DECON alternative would still be employed during this scenario. Portions of the biological shield will still be radioactive due to the presence of activated trace elements with long half-lives (^{152}Eu and ^{154}Eu). Decontamination will require controlled removal and disposal. It is assumed that radioactive corrosion products on inner surfaces of piping and components will not have decayed to levels that will permit unrestricted use or allow conventional removal. These systems and components will be surveyed as they are removed and disposed of in accordance with the existing radioactive release criteria.

2.2.4 Period 5 - Site Restoration

Following completion of decommissioning operations, site-restoration activities can begin. Dismantling, as a continuation of the decommissioning process, is clearly the most appropriate and cost-effective option, as described in Section 2.1.3. The basis for the dismantling cost in this scenario is consistent with that described for DECON, presuming the removal of structures and site facilities to a nominal depth of three feet below grade and the limited restoration of the site.

3. COST ESTIMATE

The cost estimates prepared for decommissioning Wolf Creek consider the unique features of the site, including the nuclear steam supply system, electric power generating systems, structures and supporting facilities. The basis of the estimates, including the sources of information relied upon, the estimating methodology employed, site-specific considerations, and other pertinent assumptions, is described in this section.

3.1 BASIS OF ESTIMATE

The current estimates were developed using the site-specific, technical information relied upon in the decommissioning analysis prepared in 2014. This information was reviewed for the current analysis and updated as deemed appropriate. The site-specific considerations and assumptions used in the previous evaluation were also revisited. Modifications were incorporated where new information was available or experience from ongoing decommissioning programs provided viable alternatives or improved processes.

3.2 METHODOLOGY

The methodology used to develop the estimates follows the basic approach originally presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"[24] and the DOE "Decommissioning Handbook."[25] These documents present a unit factor method for estimating decommissioning activity costs, which simplifies the estimating calculations. Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) are developed using local labor rates. The activity-dependent costs are estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents. Removal rates and material costs for the conventional disposition of components and structures rely upon information available in the industry publication, "Building Construction Cost Data," published by RSMeans.[26]

The unit factor method provides a demonstrable basis for establishing reliable cost estimates. The detail provided in the unit factors, including activity duration, labor costs (by craft), and equipment and consumable costs, ensures that essential elements have not been omitted. Appendix A presents the detailed development of a typical unit factor. Appendix B provides the values contained within one set of factors developed for this analysis.

Regulatory Guide 1.184[27] Revision 1, issued in October 2013, describes the methods and procedures that are acceptable to the NRC staff for implementing the requirements that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202,[28] issued February 2005.

This analysis reflects lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Work Difficulty Factors

TLG has historically applied work difficulty adjustment factors (WDFs) to account for the inefficiencies in working in a power plant environment. WDFs are assigned to each unique set of unit factors, commensurate with the inefficiencies associated with working in confined, hazardous environments. The ranges used for the WDFs are as follows:

- Access Factor 10% to 20%
- Respiratory Protection Factor 10% to 50%
- Radiation/ALARA Factor 10% to 37%
- Protective Clothing Factor 10% to 30%
- Work Break Factor 8.33%

The factors and their associated range of values were developed in conjunction with the AIF/NESP-036 study. The application of the factors is discussed in more detail in that publication.

Scheduling Program Durations

The unit factors, adjusted by the WDFs as described above, are applied against the inventory of materials to be removed in the radiological controlled areas. The resulting man-hours, or crew-hours, are used in the development of the

decommissioning program schedule, using resource loading and event sequencing considerations. The scheduling of conventional removal and dismantling activities is based upon productivity information available from the "Building Construction Cost Data" publication.

An activity duration critical path is used to determine the total decommissioning program schedule. The schedule is relied upon in calculating the carrying costs, which include program management, administration, field engineering, equipment rental, and support services such as quality control and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

3.3 FINANCIAL COMPONENTS OF THE COST MODEL

TLG's proprietary decommissioning cost model, DECCER, produces a number of distinct cost elements. These direct expenditures, however, do not comprise the total cost to accomplish the project goal, i.e., license termination and site restoration.

Inherent in any cost estimate that does not rely on historical data is the inability to specify the precise source of costs imposed by factors such as tool breakage, accidents, illnesses, weather delays, and labor stoppages. In the DECCER cost model, contingency fulfills this role. Contingency is added to each line item to account for costs that are difficult or impossible to develop analytically. Such costs are historically inevitable over the duration of a job of this magnitude; therefore, this cost analysis includes funds to cover these types of expenses.

3.3.1 Contingency

The activity- and period-dependent costs are combined to develop the total decommissioning cost. A contingency is then applied on a line-item basis, using one or more of the contingency types listed in the AIF/NESP-036 study. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook"[29] as "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." The cost elements in this analysis are based upon ideal conditions and maximum efficiency; therefore, consistent with industry practice, contingency is included. In the AIF/NESP-036 study, the types of

unforeseeable events that are likely to occur in decommissioning are discussed and guidelines are provided for percentage contingency in each category. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

Contingency funds are an integral part of the total cost to complete the decommissioning process. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, subsequent related activities. For this study, TLG examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, transport, and waste disposal) that necessitate a contingency. Individual activity contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from TLG's actual decommissioning experience. The contingency values used in this study are as follows:

- Decontamination 50%
- Contaminated Component Removal 25%
- Contaminated Component Packaging 10%
- Contaminated Component Transport 15%
- Low-Level Radioactive Waste Disposal 25%

- Low-Level Radioactive Waste Processing 15%
- Reactor Segmentation 75%
- NSSS Component Removal 25%
- Reactor Waste Packaging 25%
- Reactor Waste Transport 25%

- Reactor Vessel Component Disposal 50%
- GTCC Disposal 15%
- Non-Radioactive Component Removal 15%
- Heavy Equipment and Tooling 15%
- Supplies 25%

- Engineering 15%
- Energy 15%
- Insurance, Taxes and Fees 10%
- Staffing 15%
- Characterization and Termination Surveys 30%
- Operations and Maintenance Expense 15%
- ISFSI Decommissioning 25%

The contingency values are applied to the appropriate components of the estimates on a line item basis. A composite value is then reported at the end of each detailed estimate (as provided in Appendix C and D). A contingency of 25% is applied to the subtotal of the ISFSI decommissioning costs.

3.3.2 Financial Risk

In addition to the routine uncertainties addressed by contingency, another cost element that is sometimes necessary to consider when bounding decommissioning costs relates to uncertainty, or risk. Examples can include changes in work scope, pricing, job performance, and other variations that could conceivably, but not necessarily, occur. Consideration is sometimes necessary to generate a level of confidence in the estimate, within a range of probabilities. TLG considers these types of costs under the broad term "financial risk." Included within the category of financial risk are:

- Transition activities and costs: ancillary expenses associated with eliminating 50% to 80% of the site labor force shortly after the cessation of plant operations, added cost for worker separation packages throughout the decommissioning program, national or company-mandated retraining, and retention incentives for key personnel.
- Delays in approval of the decommissioning plan due to intervention, public participation in local community meetings, legal challenges, and national and local hearings.
- Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.
- Regulatory changes, for example, affecting worker health and safety, site release criteria, waste transportation, and disposal.
- Policy decisions altering national commitments (e.g., in the ability to accommodate certain waste forms for disposition), or in the timetable for such, for example, the start and rate of acceptance of spent fuel by the DOE.
- Pricing changes for basic inputs such as labor, energy, materials, and disposal. Items subject to widespread price competition (such as

materials) may not show significant variation; however, others such as waste disposal could exhibit large pricing uncertainties, particularly in markets where limited access to services is available.

This cost study does not add any additional costs to the estimate for financial risk, since there is insufficient historical data from which to project future liabilities. Consequently, the areas of uncertainty or risk are revisited periodically and addressed through repeated revisions or updates of the base estimates.

3.4 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impact of the considerations identified below is included in this cost study.

3.4.1 Spent Fuel Management

The cost to dispose the spent fuel generated from plant operations is not reflected within the estimates to decommission Wolf Creek. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, until recently, the disposal cost was being financed by a 1 mill/kWhr surcharge on nuclear generated energy delivered to customers, the fee being paid into the DOE's waste fund during operations. The D.C. Circuit ruling on November 19, 2013, ordered the DOE to submit a proposal to Congress to suspend the Nuclear Waste Fund fee "until such time as either the Secretary chooses to comply with the Act as it is currently written, or until Congress enacts an alternative waste management plan." The fee was reduced to 0.0 mill/kWh as of May 16, 2014. The fee is expected to be reinstated in the future.

Nonetheless, the NRC does requires licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor until title of the fuel is transferred to the Secretary of Energy. This funding requirement is fulfilled through inclusion of certain high-level waste cost elements within the estimates, as described below.

For estimating purposes, WCNOC has assumed that all spent fuel will be removed to a DOE facility within five and one-half years after shutdown. Interim storage of the fuel, until the DOE has completed the

transfer, will be in the spent fuel pool located in the fuel building (as well as on the ISFSI). The spent fuel storage pool and fuel handling systems will be isolated (i.e., a spent fuel island created). This will allow WCNOC to proceed with decommissioning (or safe-storage) operations in the shortest time possible. A delay in the start of fuel pickup, or a decrease in the spent fuel acceptance rate, will correspondingly prolong the transfer process and result in the fuel remaining at the Wolf Creek site longer.

It is assumed that the five and one-half years also provides the necessary cooling period for the final core to meet DOE's transport system requirements for decay heat. Once the pool is emptied, the spent fuel storage and handling facilities are available for decommissioning. Operation and maintenance costs for the spent fuel pool are included within the estimate as well as the costs to transfer the spent fuel to the DOE.

Supplemental Storage

It is likely that supplemental spent fuel storage will be required to support continued plant operations (i.e., maintain full core off-load capability). This analysis assumes that an ISFSI is constructed during operations and that 592 spent fuel assemblies (16 equivalent dry storage system modules) are transferred to the ISFSI during plant operations (assuming that the DOE begins removing fuel from the Wolf Creek site in 2032). The fuel will remain in storage until it is off-loaded into a DOE-provided transport cask. The transfer is assumed to occur once the spent fuel pool has been emptied. The estimates include the cost for the transfer only.

Canister Loading and Transfer

The estimates include the cost to load the spent fuel in the wet storage pool into a DOE-provided multi-purpose canister (e.g., Transport, Aging and Disposal or TAD canister), seal the canisters and place the canister into the DOE transport vehicle. The estimates also include the cost to transfer each canister stored at the ISFSI into the DOE transport vehicle.

Operations and Maintenance

The estimates include the cost of operating and maintaining the spent fuel pool for approximately five and one half years after the cessation of operations.

ISFSI Decommissioning

In accordance with 10 CFR §72.30, licensees must have a proposed decommissioning plan for the ISFSI site and facilities that includes a cost estimate for the plan. The plan needs to contain sufficient information on the proposed practices and procedures for the decontamination of the ISFSI and for the disposal of residual radioactive materials after the spent fuel has been removed.

For purposes of this study only, the decommissioning cost for a future ISFSI was included in the DECON and SAFSTOR estimates. The decommissioning estimate is based on the premise that some of the storage casks will contain low levels of neutron-induced residual radioactivity that would necessitate remediation at the time of decommissioning. As an allowance, 6 casks are assumed to be affected, i.e., contain residual radioactivity. The allowance is based upon the number of casks required for the final core off-load (i.e., 193 offloaded assemblies, 37 assemblies per cask) which results in 6 storage modules. It is assumed that these are the final casks offloaded; consequently they have the least time for radioactive decay of any neutron activation products.

No contamination or activation of the ISFSI pad is assumed. It would be expected that this assumption would be confirmed as a result of good radiological practice of surveying potentially impacted areas after each spent fuel transfer campaign. As such, only verification surveys are included for the pad in the decommissioning estimate. The estimate is limited to costs necessary to terminate the ISFSI's NRC license and meet the §20.1402 criteria for unrestricted use.

In accordance with the specific requirements of 10 CFR §72.30 for the ISFSI work scope, the cost estimate for decommissioning the ISFSI reflects: 1) the cost of an independent contractor performing the decommissioning activities; 2) an adequate contingency factor; and 3) the cost of meeting the criteria for unrestricted use.

GTCC

The dismantling of the reactor internals is expected to generate radioactive waste considered unsuitable for shallow land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. Although the DOE is responsible for disposing of GTCC waste, any costs for that service have not been determined.

For purposes of this study, GTCC is packaged in the same canisters used to transport spent fuel. The GTCC is assumed to be disposed of as it is generated during reactor vessel segmentation operations.

3.4.2 Reactor Vessel and Internal Components

The reactor pressure vessel and internal components are segmented for disposal in shielded, reusable transportation casks. Segmentation is performed in the refueling canal, where a turntable and remote cutter are installed. The vessel is segmented in place, using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the reactor cavity. Transportation cask specifications and transportation regulations dictate the segmentation and packaging methodology.

Intact disposal of reactor vessel shells has been successfully demonstrated at several of the sites currently being decommissioned. Access to navigable waterways has allowed these large packages to be transported to the Barnwell, South Carolina and Hanford, Washington disposal sites with minimal overland travel. Intact disposal of the reactor vessel and internal components can provide savings in cost and worker exposure by eliminating the complex segmentation requirements, isolation of the GTCC material, and transport/storage of the resulting waste packages. Portland General Electric (PGE) was able to dispose of the Trojan reactor as an intact package (including the internals). However, its location on the Columbia River simplified the transportation analysis since:

- the reactor package could be secured to the transport vehicle for the entire journey, i.e., the package was not lifted during transport,
- there were no man-made or natural terrain features between the plant site and the disposal location that could produce a large drop, and
- transport speeds were very low, limited by the overland transport vehicle and the river barge.

As a member of the Northwest Compact, PGE had a site available for disposal of the package - the US Ecology facility in Washington State. The characteristics of this arid site proved favorable in demonstrating compliance with land disposal regulations.

It is not known whether this option will be available when Wolf Creek ceases operation. Future viability of this option will depend upon the ultimate location of the disposal site, as well as the disposal site licensee's ability to accept highly radioactive packages and effectively isolate them from the environment. Consequently, the study assumes the reactor vessel will require segmentation, as a bounding condition.

3.4.3 Primary System Components

In the DECON scenario, the reactor coolant system components are assumed to be decontaminated using chemical agents prior to the start of dismantling operations. This type of decontamination can be expected to have a significant ALARA impact, since in this scenario the removal work is done within the first few years of shutdown. In the SAFSTOR scenario, radionuclide decay is expected to provide the same benefit and, therefore, a chemical decontamination is not included.

The following discussion deals with the removal and disposition of the steam generators, but the techniques involved are also applicable to other large components, such as heat exchangers, component coolers, and the pressurizer. The steam generators' size and weight, as well as their location within the reactor building, will ultimately determine the removal strategy.

A trolley crane is set up for the removal of the generators. It can also be used to move portions of the steam generator cubicle walls and floor slabs from the reactor building to a location where they can be decontaminated and transported to the material handling area.

Interferences within the work area, such as grating, piping, and other components are removed to create sufficient laydown space for processing these large components.

The generators are rigged for removal, disconnected from the surrounding piping and supports, and maneuvered into the open area where they are lowered onto a dolly. Each generator is rotated into the horizontal position for extraction from the containment and placed onto a multi-wheeled vehicle for transport to an on-site processing and storage area.

The generators are disassembled on-site with the steam dome and lightly contaminated subassemblies designated for off-site recycling. The more highly contaminated tube sheet and tube bundle are packaged for direct disposal. The interior volume is filled with low-density cellular concrete for stabilization of the internal contamination.

Reactor coolant piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and transported by shielded van. The reactor coolant pumps and motors are lifted out intact, packaged, and transported for processing and/or disposal.

3.4.4 Main Turbine and Condenser

The main turbine is dismantled using conventional maintenance procedures. The turbine rotors and shafts are removed to a laydown area. The lower turbine casings are removed from their anchors by controlled demolition. The main condensers are also disassembled and moved to a laydown area. Material is then prepared for transportation to an off-site recycling facility where it is surveyed and designated for either decontamination or volume reduction, conventional disposal, or controlled disposal. Components are packaged and readied for transport in accordance with the intended disposition.

3.4.5 Transportation Methods

Contaminated piping, components, and structural material other than the highly activated reactor vessel and internal components will qualify as LSA-I, II or III or Surface Contaminated Object, SCO-I or II, as described in Title 49.[30] The contaminated material will be packaged in Industrial Packages (IP-1, IP-2, or IP-3, as defined in subpart 173.411)

for transport unless demonstrated to qualify as their own shipping containers. The reactor vessel and internal components are expected to be transported in accordance with 10 CFR Part 71, as Type B. It is conceivable that the reactor, due to its limited specific activity, could qualify as LSA II or III. However, the high radiation levels on the outer surface would require that additional shielding be incorporated within the packaging so as to attenuate the dose to levels acceptable for transport.

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major reactor components to be shipped under current transportation regulations and disposal requirements.

Transport of the highly activated metal, produced in the segmentation of the reactor vessel and internal components, will be by shielded truck cask. Cask shipments may exceed 95,000 pounds, including vessel segment(s), supplementary shielding, cask tie-downs, and tractor-trailer. The maximum level of activity per shipment assumed permissible was based upon the license limits of the available shielded transport casks. The segmentation scheme for the vessel and internal segments is designed to meet these limits.

The transport of large intact components (e.g., large heat exchangers and other oversized components) will be by a combination of truck, rail, and/or multi-wheeled transporter.

Transportation costs for Class A radioactive material requiring controlled disposal are based upon the mileage to the Energy*Solutions* facility in Clive, Utah. Transportation costs for the higher activity Class B and C radioactive material are based upon the mileage to the WCS facility in Andrews County, Texas. The transportation cost for the GTCC material is assumed to be contained within the disposal cost. Transportation costs for off-site waste processing are based upon the mileage to Oak Ridge, Tennessee. Truck transport costs are estimated using published tariffs from Tri-State Motor Transit.[31]

3.4.6 Low-Level Radioactive Waste Disposal

To the greatest extent practical, metallic material generated in the decontamination and dismantling processes is processed to reduce the

total cost of controlled disposal. Material meeting the regulatory and/or site release criterion, is released as scrap, requiring no further cost consideration. Conditioning (preparing the material to meet the waste acceptance criteria of the disposal site) and recovery of the waste stream is performed off site at a licensed processing center. Any material leaving the site is subject to a survey and release charge, at a minimum. The mass of radioactive waste generated during the various decommissioning activities at the site is shown on a line-item basis in the appendices and summarized in Section 5. The quantified waste summaries shown in these tables are consistent with 10 CFR Part 61 classifications. Commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations. The volumes are calculated based on the exterior package dimensions for containerized material or a specific calculation for components serving as their own waste containers.

The more highly activated reactor components will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

The cost to dispose of the lowest level waste and the majority of the material generated from the decontamination and dismantling activities is based upon the current cost for disposal at Energy*Solutions* facility in Clive, Utah. Disposal costs for the higher activity waste (Class B and C) were based upon preliminary and indicative rates for WCS's Andrews County facility.

3.4.7 Site Conditions Following Decommissioning

The NRC will terminate the site license when it determines that site remediation has been performed in accordance with the license termination plan, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release. The NRC's involvement in the decommissioning process will end at this point. Local building codes and state environmental regulations will dictate the next step in the decommissioning process, as well as the owner's own future plans for the site.

The estimates presented herein include the dismantling of the major structures to just below ground level, backfilling and the collapsing of below grade voids, and regrading such that the site upon which the power block and supplemental structures are located is transformed into a "grassy plain."

Concrete rubble generated from demolition activities is processed and made available as clean fill for the power block foundations. Additional fill is brought in to cap the power block excavations and to permit seeding for erosion control.

A significant amount of the below grade piping is located around the perimeter of the power block. The estimate includes a cost to excavate this area to an average depth of six feet so as to expose the piping, duct bank, conduit, and any near-surface grounding grid. The overburden is surveyed and stockpiled on site for future use in backfilling the below grade voids.

The existing electrical switchyard and access roads will remain in support of the electrical transmission and distribution system. Other structures that will remain are the main dam, cooling lake, makeup water discharge structure (west side of lake), makeup water screen house (located below the John Redmond Dam) and associated underground piping, the Eisenhower Learning Center, and a railroad spur running about 11.5 miles from the plant southeast to near Aliceville, Kansas, where it connects to a Union Pacific Railroad line.

The estimates do not assume the remediation of any significant volume of contaminated soil. Costs are included, however, for the remediation of the firing range, i.e., removal of soil containing lead residue. This assumption may be affected by continued plant operations and/or future regulatory actions, such as the development of site-specific release criteria.

3.5 ASSUMPTIONS

The following are the major assumptions made in the development of the estimates for decommissioning the site.

3.5.1 Estimating Basis

Decommissioning costs are reported in the year of projected expenditure; however, the values are provided in 2017 dollars. Costs are not inflated, escalated, or discounted over the periods of performance.

The estimates rely upon the physical plant inventory that was the basis for the 2014 analysis.

The study follows the principles of ALARA through the use of work duration adjustment factors. These factors address the impact of activities such as radiological protection instruction, mock-up training, and the use of respiratory protection and protective clothing. The factors lengthen a task's duration, increasing costs and lengthening the overall schedule. ALARA planning is considered in the costs for engineering and planning, and in the development of activity specifications and detailed procedures. Changes to worker exposure limits may impact the decommissioning cost and project schedule.

3.5.2 Labor Costs

WCNOC, as the operator, will continue to provide site operations support, including decommissioning program management, licensing, radiological protection, and site security. A Decommissioning Operations Contractor (DOC) will provide the supervisory staff needed to oversee the labor subcontractors, consultants, and specialty contractors needed to perform the work required for the decontamination and dismantling effort. The DOC will also provide the engineering services needed to develop activity specifications, detailed procedures, detailed activation analyses, and support field activities such as structural modifications.

Personnel costs are based upon average salary information provided by WCNOC. Overhead costs are included for site and corporate support, reduced commensurate with the staffing of the project.

The craft labor required to decontaminate and dismantle the nuclear station is acquired through standard site contracting practices. The current cost of labor at the site is used as an estimating basis.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel.

A profile of the staffing levels for decommissioning, including contractors and craft, is provided in Figures 3.1 and 3.2 for the DECON and SAFSTOR scenarios, respectively. Utility staffing levels will gradually decrease after completing the removal of physical systems. Staffing levels and management support will vary based upon the amount and type of decommissioning work. Craft manpower levels decrease after systems removal and structures decontamination and drop substantially during the license termination survey period. However, craft levels increase again during the site restoration period due to the work associated with structures demolition.

3.5.3 Design Conditions

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major NSSS components to be shipped under current transportation regulations and disposal requirements.

The curie contents of the vessel and internals at final shutdown are derived from those listed in NUREG/CR-3474.[32] Actual estimates are derived from the curie/gram values contained therein and adjusted for the different mass of the Wolf Creek components, projected operating life, and different periods of decay. Additional short-lived isotopes were derived from CR-0130[33] and CR-0672,[34] and benchmarked to the long-lived values from CR-3474.

The control elements are disposed of along with the spent fuel, i.e., there is no additional cost provided for their disposal.

Activation of the containment building structure is confined to the biological shield.

3.5.4 General

Transition Activities

Existing warehouses are cleared of non-essential material and remain for use by WCNOC and its subcontractors. The plant's operating staff performs the following activities at no additional cost or credit to the project during the transition period:

- Drain and collect fuel oils, lubricating oils, and transformer oils for recycle and/or sale.
- Drain and collect acids, caustics, and other chemical stores for recycle and/or sale.
- Process operating waste inventories (i.e., the estimates do not address the disposition of any legacy wastes; the disposal of operating wastes during this initial period is not considered a decommissioning expense).

Scrap and Salvage

The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. WCNOC will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that some buyers wanted equipment stripped down to very specific requirements before they would consider purchase. This required expensive rework after the equipment had been removed from its installed location. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall decommissioning expenses, this analysis does not attempt to quantify the value that an owner may realize based upon those efforts.

It is assumed, for purposes of this analysis, that any value received from the sale of scrap generated in the dismantling process would be more than offset by the on-site processing costs. The dismantling techniques assumed in the decommissioning estimates do not include the additional cost for size reduction and preparation to meet "furnace ready" conditions. For example, the recovery of copper from electrical cabling may require the removal and disposition of any contaminated insulation, an added expense. With a volatile market, the potential profit margin in scrap recovery is highly speculative, regardless of the ability to free release this material. This assumption is an implicit recognition of scrap value in the disposal of clean metallic waste at no additional cost to the project.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property is removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts are also made available for alternative use.

Energy

For estimating purposes, the plant is assumed to be de-energized, with the exception of those facilities associated with spent fuel storage. Replacement power costs are used to calculate the cost of energy consumed during decommissioning for tooling, lighting, ventilation, and essential services.

Emergency Planning

FEMA and state fees associated with emergency planning are assumed to continue for approximately 18 months following the cessation of operations. At this time, the fees are discontinued. The timing is based upon the anticipated condition of the spent fuel (i.e., the hottest spent fuel assemblies are assumed to be cool enough that no substantial Zircaloy oxidation and off-site event would occur with the loss of spent fuel pool water). State and local fees continue until all fuel has been removed from the site (approximately five and one-half years following the cessation of operations).

Insurance

Costs for continuing coverage (nuclear liability and property insurance) following cessation of plant operations and during decommissioning are included and based upon current operating premiums. Reductions in premiums, throughout the decommissioning process, are based upon the guidance provided in SECY-00-0145, "Integrated Rulemaking Plan for Nuclear Power Plant Decommissioning"[35] The NRC's financial protection requirements are based on various reactor (and spent fuel) configurations.

Taxes

Property tax payments are included for the land and those facilities that will continue to be used to support the decommissioning project. When the facilities are no longer needed, the taxes are reduced accordingly.

Site Modifications

The perimeter fence and in-plant security barriers will be moved, as appropriate, to conform to the Site Security Plan in force during the various stages of the project.

3.6 COST ESTIMATE SUMMARY

Schedules of expenditures are provided in Tables 3.1 and 3.2. The tables delineate the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal).

The cost elements are also assigned to one of three subcategories: "License Termination," "Spent Fuel Management," and "Site Restoration." The subcategory "License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). The cost reported for this subcategory is generally sufficient to terminate the station's operating license, recognizing that there may be some additional cost impact from spent fuel management. These costs are identified in Tables 3.1a and 3.2a.

The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). The basis for the ISFSI decommissioning cost that is included in both Appendices C and D is described in Section 3.4.1.

The "Spent Fuel Management" subcategory contains costs associated with the five and one-half years of post-shutdown pool and ISFSI operations, and the management of the spent fuel until such time that the transfer of all fuel from this facility to an off-site location is complete. These costs are identified in Tables 3.1b and 3.2b.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are removed to a depth of three feet and backfilled to conform to local grade. These costs are identified in Tables 3.1c and 3.2c.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligation determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, an owner may decide to remove non-contaminated structures early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support

activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As discussed in Section 3.4.1, while designated for disposal at the geologic repository along with the spent fuel, GTCC waste is still classified as low-level radioactive waste and, as such, included as a "License Termination" expense.

The estimates were developed and costs are presented in 2017 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the reactor or during the decommissioning period. The schedules are based upon the detailed activity costs reported in Appendices C and D, along with the timeline presented in Section 4.

TABLE 3.1
DECON ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	58,361	2,378	1,969	33	9,446	72,188
2046	79,873	21,825	3,615	14,402	27,684	147,398
2047	76,699	32,056	2,307	32,769	20,185	164,016
2048	72,060	23,138	2,066	21,513	14,659	133,436
2049	67,183	14,384	1,821	10,505	9,232	103,125
2050	58,152	13,450	1,560	11,115	9,239	93,516
2051	33,150	5,285	664	4,607	4,793	48,499
2052	18,938	10,854	277	4	1,885	31,959
2053	10,625	7,677	152	0	1,142	19,595
Total	475,042	131,047	14,431	94,948	98,265	813,733

Note: Columns may not add due to rounding

TABLE 3.1a
DECON ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	57,604	1,585	1,969	33	7,509	68,700
2046	77,006	17,414	3,615	14,402	25,472	137,908
2047	73,503	26,787	2,307	32,769	18,372	153,738
2048	68,660	17,316	2,066	21,513	12,841	122,396
2049	63,604	8,058	1,821	10,505	7,419	91,407
2050	55,274	9,065	1,560	11,115	7,982	84,997
2051	31,860	5,285	664	4,607	4,793	47,209
2052	4,201	248	68	4	308	4,829
2053	88	0	0	0	0	88
Total	431,800	85,759	14,069	94,948	84,697	711,273

Note: Columns may not add due to rounding

TABLE 3.1b
DECON ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	264	793	0	0	1,938	2,995
2046	1,460	4,380	0	0	2,212	8,053
2047	1,724	5,171	0	0	1,813	8,708
2048	1,911	5,733	0	0	1,818	9,461
2049	2,082	6,245	0	0	1,813	10,139
2050	1,840	4,329	0	0	1,257	7,425
2051	1,290	0	0	0	0	1,290
2052	180	0	0	0	0	180
2053	0	0	0	0	0	0
Total	10,751	26,651	0	0	10,850	48,251

Note: Columns may not add due to rounding

TABLE 3.1c
DECON ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	493	0	0	0	0	493
2046	1,407	30	0	0	0	1,437
2047	1,472	98	0	0	0	1,570
2048	1,489	89	0	0	0	1,579
2049	1,498	81	0	0	0	1,578
2050	1,038	56	0	0	0	1,094
2051	0	0	0	0	0	0
2052	14,558	10,606	210	0	1,577	26,950
2053	10,537	7,677	152	0	1,142	19,507
Total	32,491	18,637	361	0	2,719	54,208

Note: Columns may not add due to rounding

TABLE 3.2
SAFSTOR ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	50,301	1,936	1,969	33	9,446	63,686
2046	52,967	10,775	1,832	1,389	23,599	90,562
2047	28,085	6,228	486	15	6,065	40,878
2048	28,162	6,245	487	16	6,082	40,990
2049	28,085	6,228	486	15	6,065	40,878
2050	20,521	4,415	411	13	4,624	29,985
2051	3,437	322	243	7	1,370	5,378
2052	3,446	323	243	7	1,374	5,393
2053	3,437	322	243	7	1,370	5,378
2054	3,437	322	243	7	1,370	5,378
2055	3,437	322	243	7	1,370	5,378
2056	3,446	323	243	7	1,374	5,393
2057	3,437	322	243	7	1,370	5,378
2058	3,437	322	243	7	1,370	5,378
2059	3,437	322	243	7	1,370	5,378
2060	3,446	323	243	7	1,374	5,393
2061	3,437	322	243	7	1,370	5,378
2062	3,437	322	243	7	1,370	5,378
2063	3,437	322	243	7	1,370	5,378
2064	3,446	323	243	7	1,374	5,393
2065	3,437	322	243	7	1,370	5,378
2066	3,437	322	243	7	1,370	5,378
2067	3,437	322	243	7	1,370	5,378
2068	3,446	323	243	7	1,374	5,393
2069	3,437	322	243	7	1,370	5,378
2070	3,437	322	243	7	1,370	5,378
2071	3,437	322	243	7	1,370	5,378
2072	3,446	323	243	7	1,374	5,393
2073	3,437	322	243	7	1,370	5,378
2074	3,437	322	243	7	1,370	5,378
2075	3,437	322	243	7	1,370	5,378
2076	3,446	323	243	7	1,374	5,393
2077	3,437	322	243	7	1,370	5,378

TABLE 3.2 (continued)
SAFSTOR ALTERNATIVE
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2078	3,437	322	243	7	1,370	5,378
2079	3,437	322	243	7	1,370	5,378
2080	3,446	323	243	7	1,374	5,393
2081	3,437	322	243	7	1,370	5,378
2082	3,437	322	243	7	1,370	5,378
2083	3,437	322	243	7	1,370	5,378
2084	3,446	323	243	7	1,374	5,393
2085	3,437	322	243	7	1,370	5,378
2086	3,437	322	243	7	1,370	5,378
2087	3,437	322	243	7	1,370	5,378
2088	3,446	323	243	7	1,374	5,393
2089	3,437	322	243	7	1,370	5,378
2090	3,437	322	243	7	1,370	5,378
2091	3,437	322	243	7	1,370	5,378
2092	3,446	323	243	7	1,374	5,393
2093	3,437	322	243	7	1,370	5,378
2094	3,437	322	243	7	1,370	5,378
2095	3,437	322	243	7	1,370	5,378
2096	3,446	323	243	7	1,374	5,393
2097	3,437	322	243	7	1,370	5,378
2098	8,030	526	530	10	1,416	10,512
2099	39,843	3,003	2,428	35	1,725	47,034
2100	51,668	21,348	2,352	19,715	11,194	106,277
2101	52,224	26,356	2,272	29,879	16,007	126,738
2102	43,514	7,481	1,821	10,054	5,614	68,485
2103	43,514	7,481	1,821	10,054	5,614	68,485
2104	36,028	4,171	1,047	4,233	3,422	48,900
2105	19,989	11,805	289	6	1,828	33,916
2106	11,872	9,571	164	0	1,237	22,843
Total	676,430	142,714	29,815	75,790	168,367	1,093,117

TABLE 3.2a
SAFSTOR ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	50,036	1,143	1,969	33	7,509	60,690
2046	50,641	6,213	1,758	1,389	21,375	81,375
2047	23,538	465	243	15	4,213	28,474
2048	23,602	467	243	16	4,224	28,552
2049	23,538	465	243	15	4,213	28,474
2050	17,370	421	243	13	3,340	21,387
2051	3,437	322	243	7	1,370	5,378
2052	3,446	323	243	7	1,374	5,393
2053	3,437	322	243	7	1,370	5,378
2054	3,437	322	243	7	1,370	5,378
2055	3,437	322	243	7	1,370	5,378
2056	3,446	323	243	7	1,374	5,393
2057	3,437	322	243	7	1,370	5,378
2058	3,437	322	243	7	1,370	5,378
2059	3,437	322	243	7	1,370	5,378
2060	3,446	323	243	7	1,374	5,393
2061	3,437	322	243	7	1,370	5,378
2062	3,437	322	243	7	1,370	5,378
2063	3,437	322	243	7	1,370	5,378
2064	3,446	323	243	7	1,374	5,393
2065	3,437	322	243	7	1,370	5,378
2066	3,437	322	243	7	1,370	5,378
2067	3,437	322	243	7	1,370	5,378
2068	3,446	323	243	7	1,374	5,393
2069	3,437	322	243	7	1,370	5,378
2070	3,437	322	243	7	1,370	5,378
2071	3,437	322	243	7	1,370	5,378
2072	3,446	323	243	7	1,374	5,393
2073	3,437	322	243	7	1,370	5,378
2074	3,437	322	243	7	1,370	5,378
2075	3,437	322	243	7	1,370	5,378
2076	3,446	323	243	7	1,374	5,393
2077	3,437	322	243	7	1,370	5,378

TABLE 3.2a (continued)
SAFSTOR ALTERNATIVE
LICENSE TERMINATION EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2078	3,437	322	243	7	1,370	5,378
2079	3,437	322	243	7	1,370	5,378
2080	3,446	323	243	7	1,374	5,393
2081	3,437	322	243	7	1,370	5,378
2082	3,437	322	243	7	1,370	5,378
2083	3,437	322	243	7	1,370	5,378
2084	3,446	323	243	7	1,374	5,393
2085	3,437	322	243	7	1,370	5,378
2086	3,437	322	243	7	1,370	5,378
2087	3,437	322	243	7	1,370	5,378
2088	3,446	323	243	7	1,374	5,393
2089	3,437	322	243	7	1,370	5,378
2090	3,437	322	243	7	1,370	5,378
2091	3,437	322	243	7	1,370	5,378
2092	3,446	323	243	7	1,374	5,393
2093	3,437	322	243	7	1,370	5,378
2094	3,437	322	243	7	1,370	5,378
2095	3,437	322	243	7	1,370	5,378
2096	3,446	323	243	7	1,374	5,393
2097	3,437	322	243	7	1,370	5,378
2098	7,946	526	530	10	1,416	10,428
2099	39,068	3,003	2,428	35	1,725	46,259
2100	49,978	21,279	2,352	19,715	11,194	104,518
2101	50,548	26,248	2,272	29,879	16,007	124,954
2102	42,190	7,410	1,821	10,054	5,614	67,089
2103	42,190	7,410	1,821	10,054	5,614	67,089
2104	35,472	4,141	1,047	4,233	3,422	48,315
2105	6,309	1,835	92	6	346	8,588
2106	457	1,251	0	0	0	1,708
Total	624,509	97,424	28,482	75,790	154,641	980,846

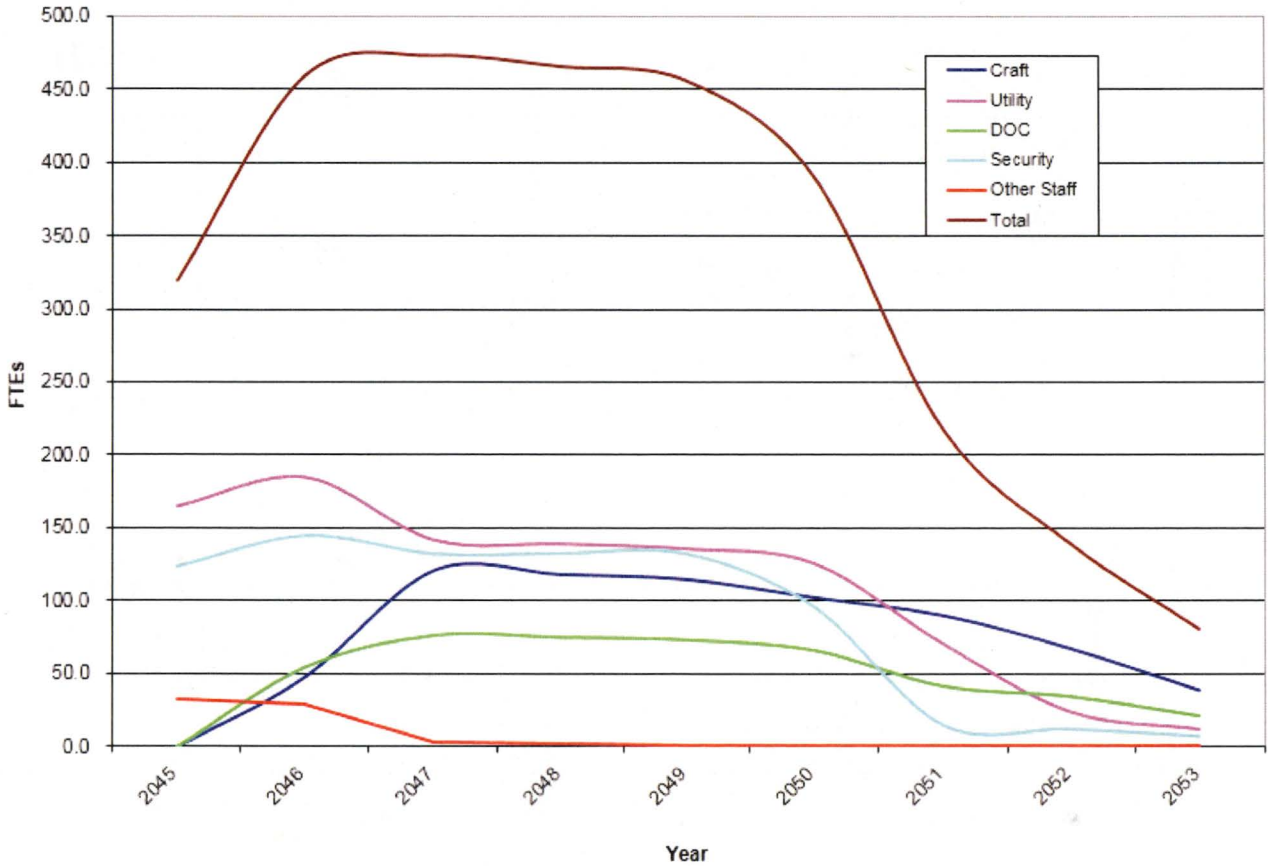
TABLE 3.2b
SAFSTOR ALTERNATIVE
SPENT FUEL MANAGEMENT EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	264	793	0	0	1,938	2,995
2046	2,327	4,562	75	0	2,224	9,187
2047	4,547	5,762	243	0	1,852	12,404
2048	4,560	5,778	243	0	1,857	12,438
2049	4,547	5,762	243	0	1,852	12,404
2050	3,152	3,994	168	0	1,284	8,598
2051-2106	0	0	0	0	0	0
Total	19,397	26,651	972	0	11,008	58,028

TABLE 3.2c
SAFSTOR ALTERNATIVE
SITE RESTORATION EXPENDITURES
(thousands, 2017 dollars)

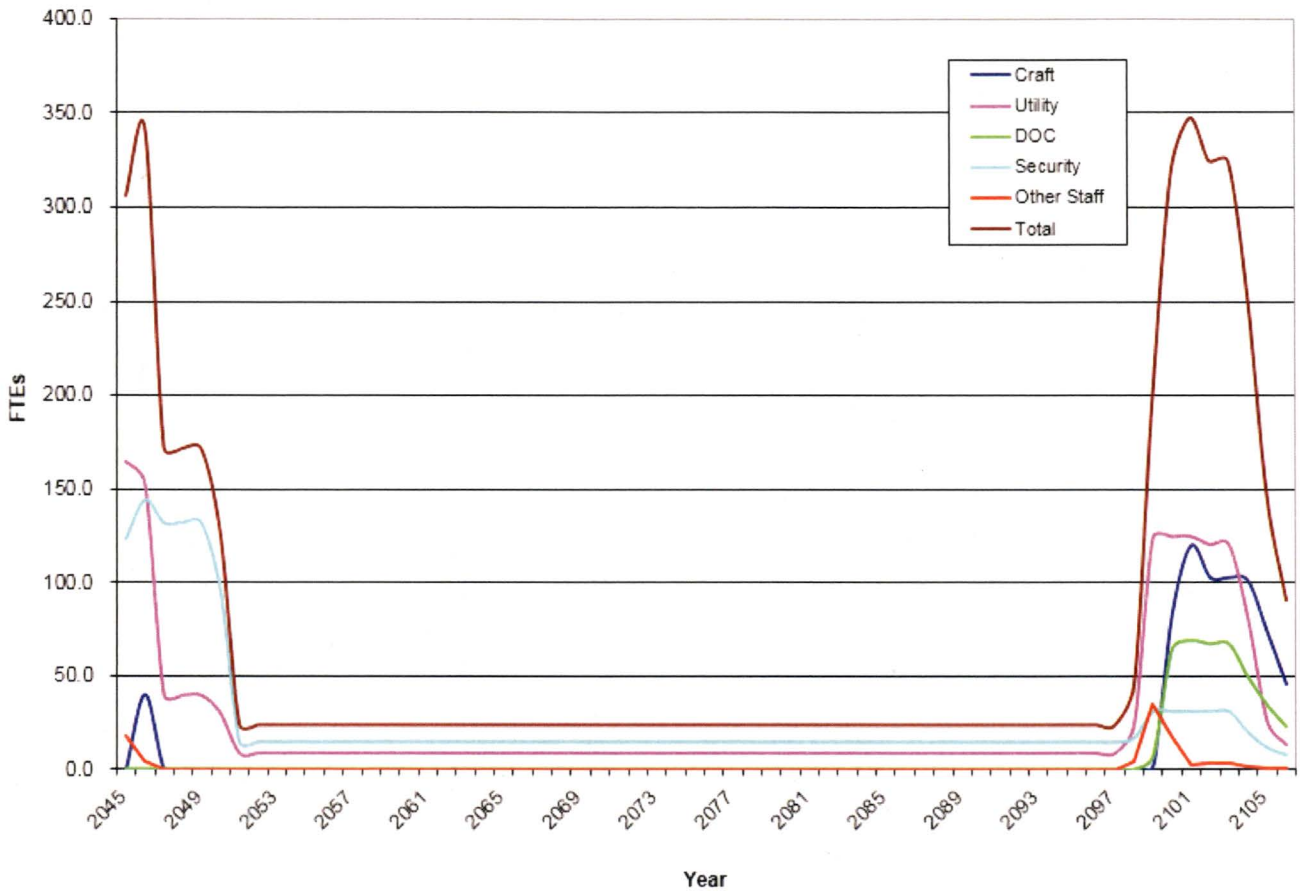
Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045-97	0	0	0	0	0	0
2098	84	0	0	0	0	84
2099	775	0	0	0	0	775
2100	1,690	69	0	0	0	1,759
2101	1,676	107	0	0	0	1,784
2102	1,325	71	0	0	0	1,396
2103	1,325	71	0	0	0	1,396
2104	555	30	0	0	0	585
2105	13,680	9,970	197	0	1,482	25,328
2106	11,415	8,319	164	0	1,237	21,135
Total	32,525	18,639	361	0	2,719	54,243

FIGURE 3.1
DECOMMISSIONING PERSONNEL LEVELS
DECON



Note that the labor hour basis of this chart was taken from Appendix C; however not all line items in Appendix C have labor hour values available (e.g. spent fuel canister loading estimates)

FIGURE 3.2
DECOMMISSIONING PERSONNEL LEVELS
SAFSTOR



Note that the labor hour basis of this chart was taken from Appendix D; however not all line items in Appendix D have labor hour values available (e.g. spent fuel canister loading estimates)

4. SCHEDULE ESTIMATE

The schedules for the decommissioning scenarios considered in this study follow the sequences presented in the AIF/NESP-036 study, with minor changes to reflect recent experience and site-specific constraints. In addition, the scheduling has been revised to reflect the spent fuel management plan described in Section 3.4.1.

A schedule or sequence of activities for the DECON alternative is presented in Figure 4.1. The scheduling sequence assumes that fuel is removed from the spent fuel pool within five and one-half years. The key activities listed in the schedule do not reflect a one-to-one correspondence with those activities in the cost tables, but reflect dividing some activities for clarity and combining others for convenience. The schedule was prepared using the "Microsoft Project Professional" computer software.[36]

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedule reflects the results of a precedence network developed for the site decommissioning activities, i.e., a PERT (Program Evaluation and Review Technique) Software Package. The work activity durations used in the precedence network reflect the actual man-hour estimates from the cost table, adjusted by stretching certain activities over their slack range and shifting the start and end dates of others. The following assumptions were made in the development of the decommissioning schedule:

- The fuel building is isolated until such time that all spent fuel has been transferred from the spent fuel pool to the DOE. Decontamination and dismantling of the storage pool is initiated once the transfer of spent fuel is complete (DECON option).
- All work (except vessel and internals removal) is performed during an 8-hour workday, 5 days per week, with no overtime. There are eleven paid holidays per year.
- Reactor and internals removal activities are performed by using separate crews for different activities working on different shifts, with a corresponding backshift charge for the second shift.
- Multiple crews work parallel activities to the maximum extent possible, consistent with optimum efficiency, adequate access for cutting, removal and laydown space, and with the stringent safety measures necessary during demolition of heavy components and structures.

- For plant systems removal, the systems with the longest removal durations in areas on the critical path are considered to determine the duration of the activity.

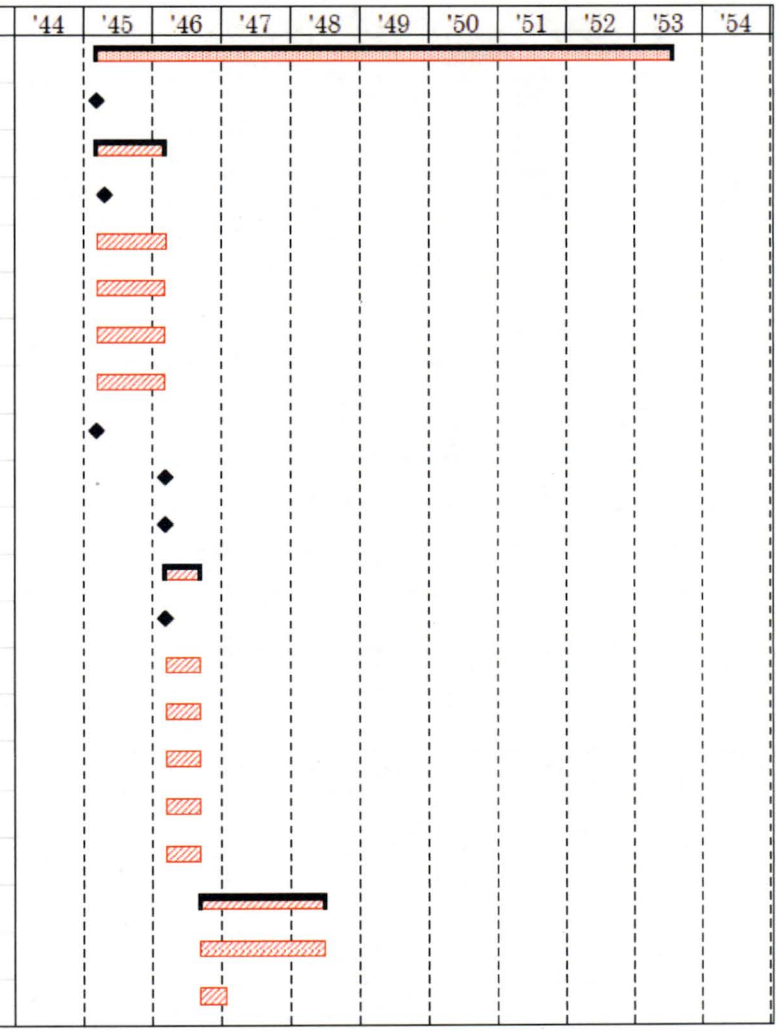
4.2 PROJECT SCHEDULE

The period-dependent costs presented in the detailed cost tables are based upon the durations developed in the schedules for decommissioning. Durations are established between several milestones in each project period; these durations are used to establish a critical path for the entire project. In turn, the critical path duration for each period is used as the basis for determining the period-dependent costs. A second critical path is shown for the spent fuel storage period, which determines the release of the fuel building for final decontamination.

Project timelines are provided in Figures 4.2 and 4.3 with milestone dates based on a 2045 shutdown date. The fuel pool is emptied approximately five and one-half years after shutdown. Deferred decommissioning in the SAFSTOR scenarios is assumed to commence so that the operating license is terminated within a 60-year period from the cessation of plant operations.

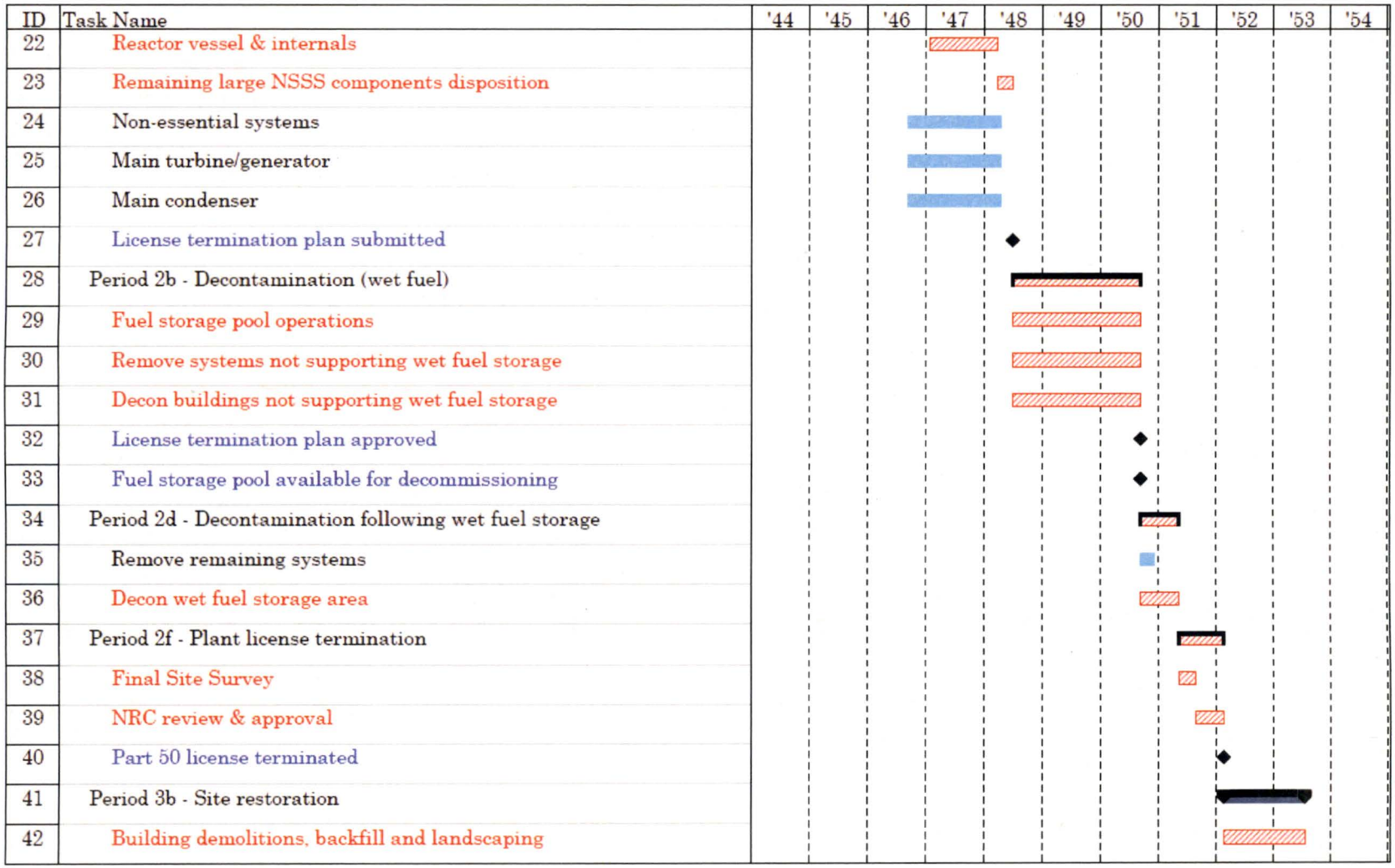
FIGURE 4.1
ACTIVITY SCHEDULE

ID	Task Name
1	Wolf Creek Decon Project Schedule
2	Shutdown plant
3	Period 1a - Shutdown through transition
4	Certificate of permanent cessation of operations submitted
5	Fuel storage pool operations
6	Reconfigure plant
7	Prepare activity specifications
8	Perform site characterization
9	Written certificate of permanent removal of fuel submitted
10	PSDAR submitted
11	Site specific decommissioning cost estimate submitted
12	Period 1b - Decommissioning preparations
13	DOC staff mobilized
14	Fuel storage pool operations
15	Reconfigure plant (continued)
16	Prepare detailed work procedures
17	Decon NSSS
18	Isolate spent fuel pool
19	Period 2a - Large component removal
20	Fuel storage pool operations
21	Preparation for reactor vessel removal



Red text indicates critical path activities
Blue text indicates milestones

FIGURE 4.1
ACTIVITY SCHEDULE
(continued)



Red text indicates critical path activities
Blue text indicates milestones

FIGURE 4.2
DECOMMISSIONING TIMELINE
DECON ALTERNATIVE
(not to scale)

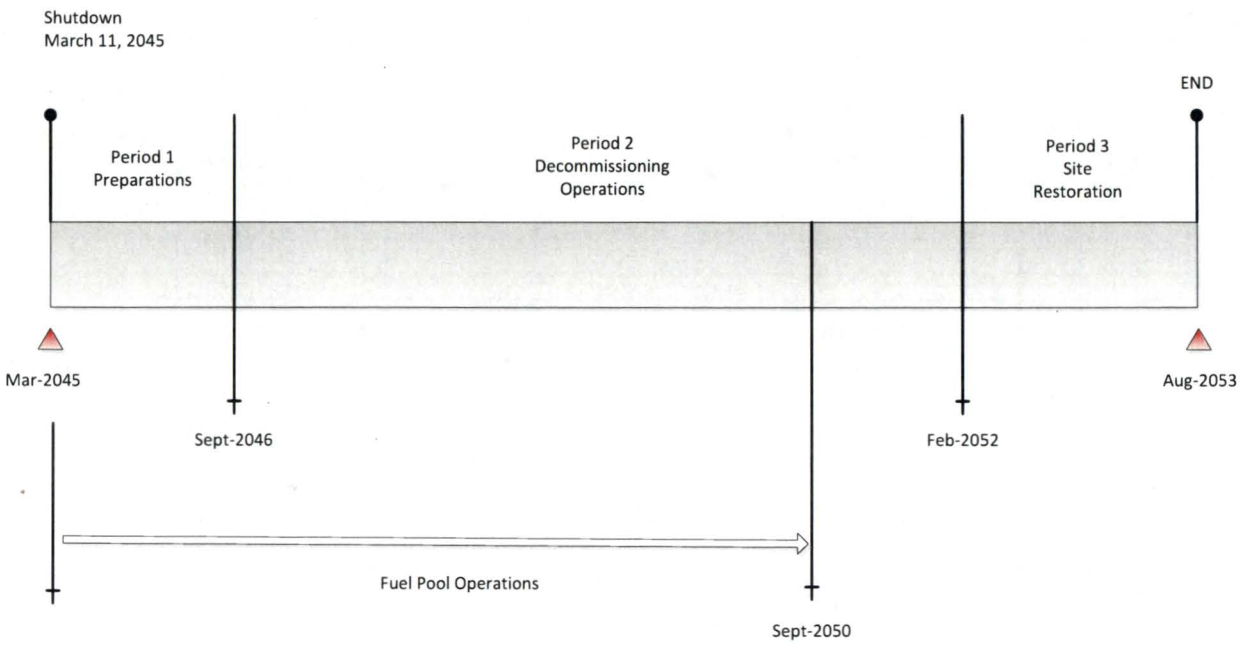
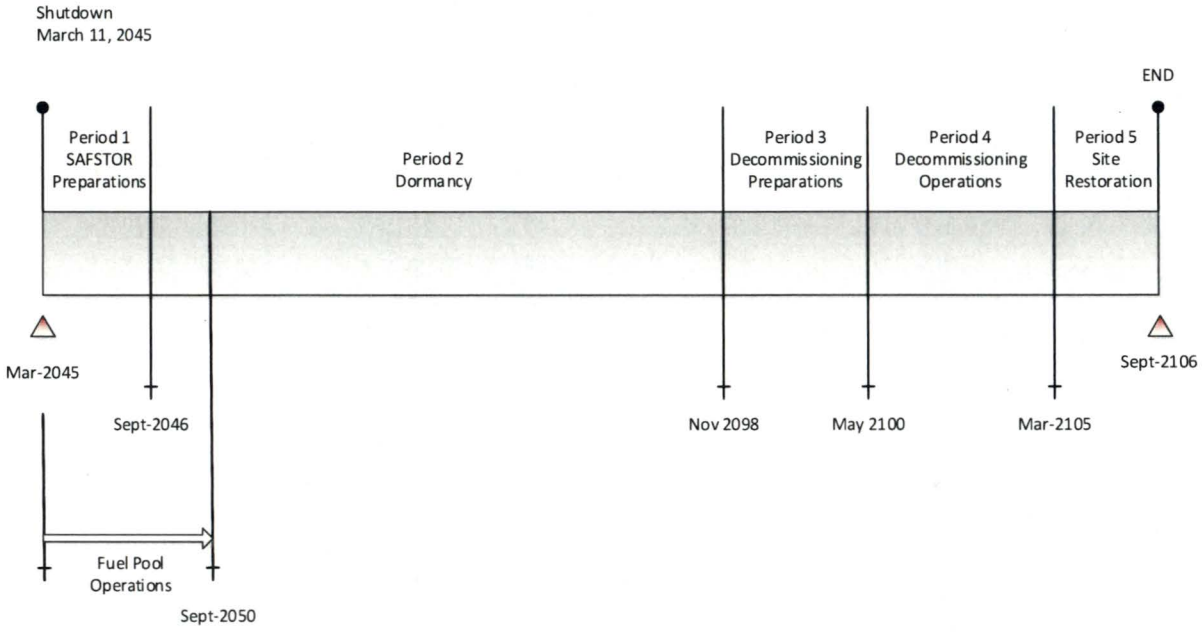


FIGURE 4.3
DECOMMISSIONING TIMELINE
SAFSTOR ALTERNATIVE
(not to scale)



5. RADIOACTIVE WASTES

The objectives of the decommissioning process are the removal of all radioactive material from the site that would restrict its future use and the termination of the NRC license. This currently requires the remediation of all radioactive material at the site in excess of applicable legal limits. Under the Atomic Energy Act,[37] the NRC is responsible for protecting the public from sources of ionizing radiation. Title 10 of the Code of Federal Regulations delineates the production, utilization, and disposal of radioactive materials and processes. In particular, Part 71 defines radioactive material as it pertains to transportation and Part 61 specifies its disposition.

Most of the materials being transported for controlled burial are categorized as Low Specific Activity (LSA) or Surface Contaminated Object (SCO) materials containing Type A quantities, as defined in 49 CFR Parts 173-178. Shipping containers are required to be Industrial Packages (IP-1, IP-2 or IP-3, as defined in 49 CFR §173.411). For this study, commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations.

The destinations for the various waste streams from decommissioning are identified in Figures 5.1 and 5.2. The volumes of radioactive waste generated during the various decommissioning activities at the site are shown on a line-item basis in Appendices C and D, and summarized in Tables 5.1 and 5.2. The quantified waste volume summaries shown in these tables are consistent with Part 61 classifications. The volumes are calculated based on the exterior dimensions for containerized material and on the displaced volume of components serving as their own waste containers.

The reactor vessel and internals are categorized as large quantity shipments and, accordingly, will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

No process system containing/handling radioactive substances at shutdown is presumed to meet material release criteria by decay alone (i.e., systems radioactive at shutdown will still be radioactive over the time period during which the decommissioning is accomplished, due to the presence of long-lived radionuclides).

While the dose rates decrease with time, radionuclides such as ^{137}Cs will still control the disposition requirements.

The waste material produced in the decontamination and dismantling of the nuclear station is primarily generated during Period 2 of DECON and Period 4 of SAFSTOR. Material that is considered potentially contaminated when removed from the radiological controlled area is sent to processing facilities in Tennessee for conditioning and disposal. Heavily contaminated components and activated materials are routed for controlled disposal. The disposal volumes reported in the tables reflect the savings resulting from reprocessing and recycling.

For purposes of constructing the estimates, the cost for disposal at the Energy*Solutions* facility was used as a proxy for future disposal facilities. Separate rates were used for containerized waste and large components, including the steam generators and reactor coolant pump motors. Demolition debris including miscellaneous steel, scaffolding, and concrete was disposed of at a bulk rate. The decommissioning waste stream also included resins and dry active waste.

Since Energy*Solutions* is not currently able to receive the more highly radioactive components generated in the decontamination and dismantling of the nuclear steam supply system, disposal costs for the Class B and C material were based preliminary and indicative rates for WCS's Andrews County disposal facility.

A small quantity of material generated during the decommissioning will not be considered suitable for near-surface disposal, and is assumed to be disposed of in a geologic repository, in a manner similar to that envisioned for spent fuel disposal. Such material, known as Greater-Than-Class-C or GTCC material, is estimated to require six spent fuel storage canisters (or the equivalent) to dispose of the most radioactive portions of the reactor vessel internals. The volume and weight reported in Tables 5.1 and 5.2 represent the packaged weight and volume of the spent fuel storage canisters.

FIGURE 5.1
RADIOACTIVE WASTE DISPOSITION

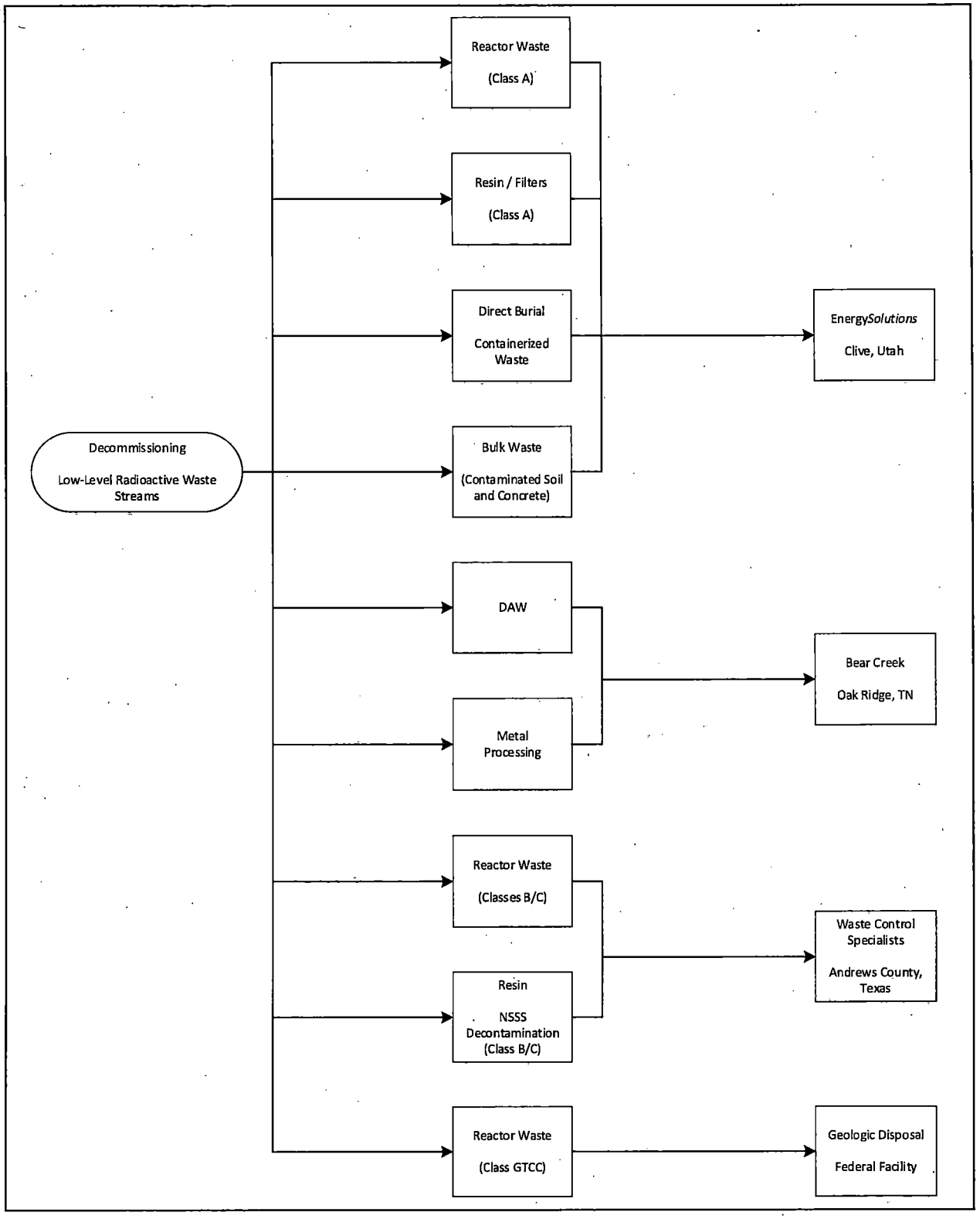


FIGURE 5.2
DECOMMISSIONING WASTE DESTINATIONS
RADIOLOGICAL

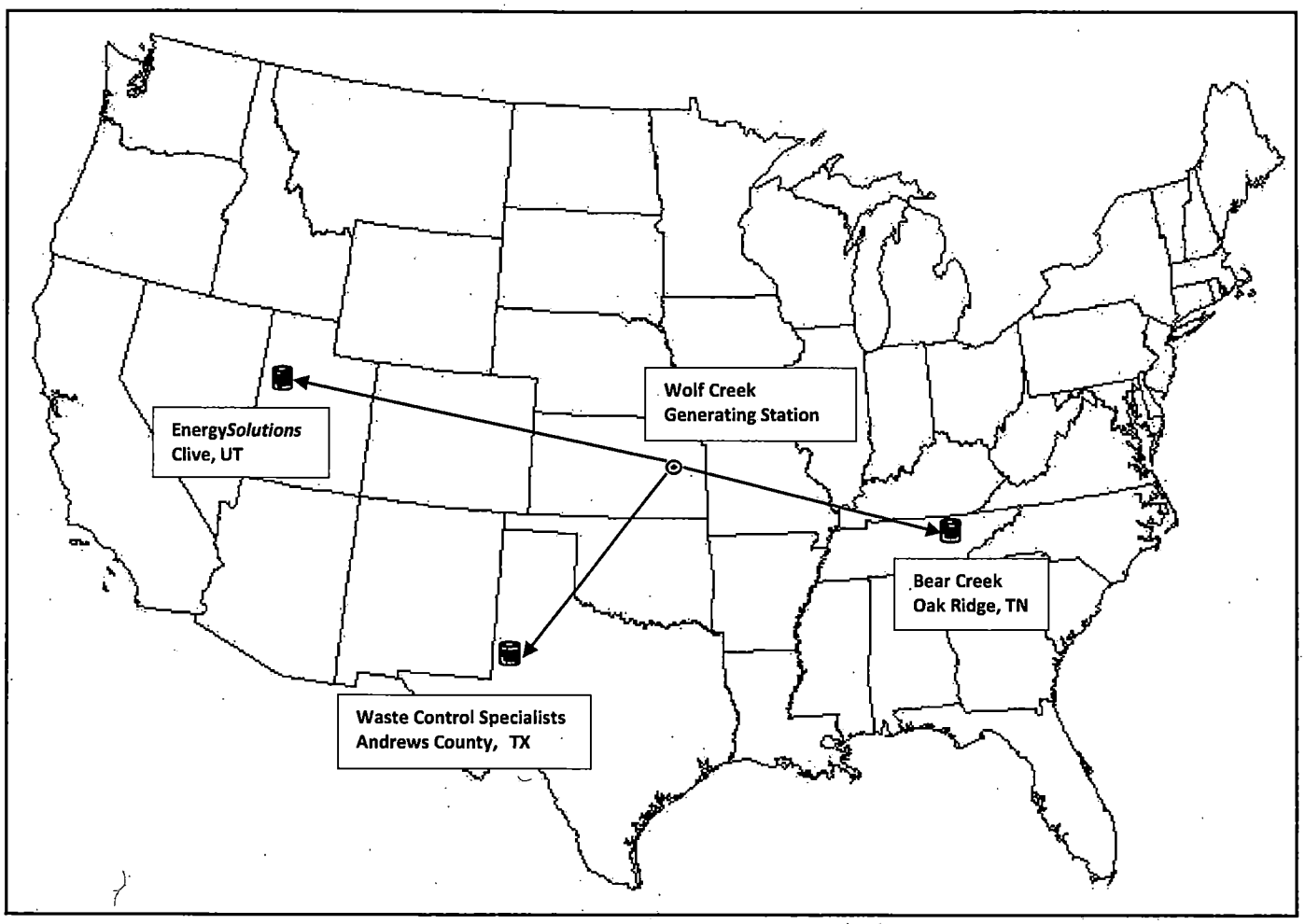


TABLE 5.1
DECON ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions*	A	187,840	11,878,919
	WCS	B	1,750	191,469
	WCS	C	393	47,411
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	2,217	433,180
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	254,732	9,940,690
Totals [2]			446,931	22,491,670

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.2
SAFSTOR ALTERNATIVE
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions*	A	153,674	9,409,645
	WCS	B	501	50,254
	WCS	C	393	47,411
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	2,217	433,180
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	282,530	11,104,170
Totals [2]			439,314	21,044,660

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

6. RESULTS

The analysis to estimate the costs to decommission Wolf Creek relied upon the site-specific, technical information developed for a previous analysis prepared in 2014. While not an engineering study, the estimates provide the operator and the plant owners with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The estimates are based on numerous fundamental assumptions that consider current regulations, low-level radioactive waste disposal options, spent fuel management requirements, site restoration practices, and project contingencies. The estimates incorporate a minimum cooling period of approximately five and one-half years for the spent fuel that resides in the plant's wet storage pool when operations cease. During this period, it is assumed that the DOE will complete the transfer of the spent fuel from the site to a federal facility.

The cost projected to promptly decommission (DECON) Wolf Creek is estimated to be $813.7 million. The majority of this cost (approximately 87.4%) is associated with the physical decontamination and dismantling of the nuclear station so that the operating license can be terminated. Another 5.9% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 6.7% is for the demolition of the designated structures and limited restoration of the site.

The cost projected for deferred decommissioning (SAFSTOR) is estimated to be $1,093.1 million. The majority of this cost (approximately 89.7%) is associated with placing the station in storage, ongoing caretaking of the station during dormancy, and the eventual physical decontamination and dismantling of the nuclear station so that the operating license can be terminated. Another 5.3% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 5.0% is for the demolition of the designated structures and limited restoration of the site.

The primary cost contributors, identified in Tables 6.1 and 6.2, are either labor-related or associated with the management and disposition of the radioactive waste. Program management is the largest single contributor to the overall cost. The magnitude of the expense is a function of both the size of the organization required to manage the decommissioning, as well as the duration of the program. It is assumed, for purposes of this analysis, that WCNOC will oversee the decommissioning program, using a DOC to manage the decommissioning labor force and the associated subcontractors. The size and composition of the management organization varies with the decommissioning phase and associated site activities.

However, once the operating license is terminated, the staff is substantially reduced for the conventional demolition and restoration of the site (for the DECON alternative).

As described in this report, the spent fuel pool will remain operational for a minimum of five and one-half years following the cessation of operations. The pool will be isolated and an independent spent fuel island created. This will allow decommissioning operations to proceed in and around the pool area. Over the five and one-half year period, the spent fuel will be packaged into transportable canisters for loading into a DOE-provided transport cask.

The cost for waste disposal includes only those costs associated with the controlled disposition of the low-level radioactive waste generated from decontamination and dismantling activities, including plant equipment and components, structural material, filters, resins and dry-active waste. As described in Section 5, disposition of the low-level radioactive material requiring controlled disposal is at licensed facility (e.g., Energy*Solutions*' or equivalent). Highly activated components, requiring additional isolation from the environment (GTCC), are packaged for geologic disposal. The cost of geologic disposal is based upon a cost equivalent for spent fuel.

A significant portion of the metallic waste is designated for additional processing and treatment at an off-site facility. Processing reduces the volume of material requiring controlled disposal through such techniques and processes as survey and sorting, decontamination, and volume reduction. The material that cannot be unconditionally released is packaged for controlled disposal at one of the currently operating facilities. The cost identified in the summary tables for processing is all-inclusive, incorporating the ultimate disposition of the material.

Removal costs reflect the labor-intensive nature of the decommissioning process, as well as the management controls required to ensure a safe and successful program. Decontamination and packaging costs also have a large labor component that is based upon prevailing union wages. Non-radiological demolition is a natural extension of the decommissioning process. The methods employed in decontamination and dismantling are generally destructive and indiscriminate in inflicting collateral damage. With a work force mobilized to support decommissioning operations, non-radiological demolition can be an integrated activity and a logical expansion of the work being performed in the process of terminating the operating license. Prompt demolition reduces future liabilities and can be more cost effective than deferral, due to the deterioration of the facilities (and therefore the working conditions) with time.

The reported cost for transport includes the tariffs and surcharges associated with moving large components and/or overweight shielded casks overland, as well as the general expense, e.g., labor and fuel, of transporting material to the destinations identified in this report. For purposes of this analysis, material is primarily moved overland by truck.

Decontamination is used to reduce the plant's radiation fields and minimize worker exposure. Slightly contaminated material or material located within a contaminated area is sent to an off-site processing center, i.e., this analysis does not assume that contaminated plant components and equipment can be decontaminated for uncontrolled release in-situ. Centralized processing centers have proven to be a more economical means of handling the large volumes of material produced in the dismantling of a nuclear station.

License termination survey costs are associated with the labor intensive and complex activity of verifying that contamination has been removed from the site to the levels specified by the regulating agency. This process involves a systematic survey of all remaining plant surface areas and surrounding environs, sampling, isotopic analysis, and documentation of the findings. The status of any plant components and materials not removed in the decommissioning process will also require confirmation and will add to the expense of surveying the facilities alone.

The remaining costs include allocations for heavy equipment and temporary services, as well as for other expenses such as regulatory fees and the premiums for nuclear insurance. While site operating costs are greatly reduced following the final cessation of plant operations, certain administrative functions do need to be maintained either at a basic functional or regulatory level.

TABLE 6.1
DECON ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	16,486	2.0
Removal	120,128	14.8
Packaging	24,544	3.0
Transportation	12,533	1.5
Waste Disposal	84,171	10.3
Off-site Waste Processing	24,134	3.0
Program Management [1]	273,568	33.6
Security	115,889	14.2
Corporate Allocations	2,002	0.2
Spent Fuel Pool Isolation	13,445	1.7
Spent Fuel Management - Direct Costs [2]	46,385	5.7
Insurance and Regulatory Fees	19,065	2.3
Energy	14,431	1.8
Characterization and Licensing Surveys	24,313	3.0
Property Taxes	15,363	1.9
Miscellaneous Equipment	7,279	0.9
Total [3]	813,733	100.0

Cost Element	Total	Percentage
License Termination	711,273	87.4
Spent Fuel Management	48,251	5.9
Site Restoration	54,208	6.7
Total [3]	813,733	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging costs/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

TABLE 6.2
SAFSTOR ALTERNATIVE
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	14,346	1.3
Removal	123,154	11.3
Packaging	19,286	1.8
Transportation	9,751	0.9
Waste Disposal	62,163	5.7
Off-site Waste Processing	26,984	2.5
Program Management [1]	366,223	33.5
Security	224,686	20.6
Corporate Allocations	3,292	0.3
Spent Fuel Pool Isolation	13,445	1.2
Spent Fuel Management - Direct Costs [2]	46,385	4.2
Insurance and Regulatory Fees	71,272	6.5
Energy	29,815	2.7
Characterization and Licensing Surveys	24,929	2.3
Property Taxes	33,724	3.1
Miscellaneous Equipment	23,661	2.2
Total [3]	1,093,117	100.0

Cost Element	Total	Percentage
License Termination	980,846	89.7
Spent Fuel Management	58,028	5.3
Site Restoration	54,243	5.0
Total [3]	1,093,117	100.0

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/packaging costs/spent fuel pool O&M and Emergency Planning fees
[3] Columns may not add due to rounding

7. REFERENCES

1. "Decommissioning Cost Analysis for the Wolf Creek Generating Station," Document No. W11-1697-001, Rev. 0, TLG Services, Inc., August 2014

2. U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72, "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, 53 Fed. Reg. 24018, June 27, 1988 [Open]

3. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," Rev. 2, October 2011 [Open]

4. U.S. Code of Federal Regulations, Title 10, Part 20, Subpart E, "Radiological Criteria for License Termination" [Open]

5. U.S. Code of Federal Regulations, Title 10, Parts 20 and 50, "Entombment Options for Power Reactors," Advance Notice of Proposed Rulemaking, 66 Fed. Reg. 52551, October 16, 2001 [Open]

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7. U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 70, and 72, "Decommissioning Planning," Nuclear Regulatory Commission, Federal Register Volume 76, (p 35512 et seq.), June 17, 2011 [Open]

8. "Nuclear Waste Policy Act of 1982," 42 U.S. Code 10101, et seq. [Open]

9. Charter of the Blue Ribbon Commission on America's Nuclear Future, "Objectives and Scope of Activities" [Open]

10. "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," p. 27, 32, January 2012 [Open]

11. "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013 [Open]

12. United States Court of Appeals for the District of Columbia Circuit, In Re: Aiken County, Et Al., August 2013 [Open]

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14. "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

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16. "Low-Level Radioactive Waste Policy Act," Public Law 96-573, 1980 [Open]

17. "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, January 15, 1986 [Open]

18. U.S. Code of Federal Regulations, Title 10, Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste" [Open]

19. U.S. Code of Federal Regulations, Title 10, Part 20, Subpart E, "Final Rule, Radiological Criteria for License Termination," 62 Fed. Reg. 39058, July 21, 1997 [Open]

20. "Establishment of Cleanup Levels for CERCLA Sites with Radioactive Contamination," EPA Memorandum OSWER No. 9200.4-18, August 22, 1997 [Open]

21. U.S. Code of Federal Regulations, Title 40, Part 141.66, "Maximum contaminant levels for radionuclides" [Open]

22. "Memorandum of Understanding Between the Environmental Protection Agency and the Nuclear Regulatory Commission: Consultation and Finality on Decommissioning and Decontamination of Contaminated Sites," OSWER 9295.8-06a, October 9, 2002 [Open]

23. "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)," NUREG-1575, Rev. 1, EPA 402-R-97-016, Rev. 1, August 2000 [Open]

24. T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

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28. "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, Nuclear Regulatory Commission, February 2005 [Open]

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34. H.D. Oak, et al., "Technology, Safety and Costs of Decommissioning a Reference Boiling Water Reactor Power Station," NUREG/CR-0672 and addenda, Pacific Northwest Laboratory for the Nuclear Regulatory Commission, June 1980 [Open Main Report] [Open Appendices]

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APPENDIX A

UNIT COST FACTOR DEVELOPMENT

APPENDIX A
UNIT COST FACTOR DEVELOPMENT

Example: Unit Factor for Removal of Contaminated Heat Exchanger < 3,000 lbs.

1. SCOPE

Heat exchangers weighing < 3,000 lbs. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the waste processing area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration (minutes)	Critical Duration (minutes)*
a	Remove insulation	60	(b)
b	Mount pipe cutters	60	60
c	Install contamination controls	20	(b)
d	Disconnect inlet and outlet lines	60	60
e	Cap openings	20	(d)
f	Rig for removal	30	30
g	Unbolt from mounts	30	30
h	Remove contamination controls	15	15
i	Remove, wrap, send to waste processing area	60	60
	Totals (Activity/Critical)	355	255

Duration adjustment(s):	
+ Respiratory protection adjustment (50% of critical duration)	128
+ Radiation/ALARA adjustment (37% of critical duration)	95
Adjusted work duration	478
+ Protective clothing adjustment (30% of adjusted duration)	143
Productive work duration	621
+ Work break adjustment (8.33 % of productive duration)	52
Total work duration (minutes)	673

***** Total duration = 11.217 hr *****

* alpha designators indicate activities that can be performed in parallel

APPENDIX A
(continued)

3. LABOR REQUIRED

Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	3.00	11.217	$20.56	$691.86
Craftsmen	2.00	11.217	$37.39	$838.81
Foreman	1.00	11.217	$41.07	$460.68
General Foreman	0.25	11.217	$44.42	$124.56
Fire Watch	0.05	11.217	$20.56	$11.53
Health Physics Technician	1.00	11.217	$48.84	$547.84
Total Labor Cost				$2,675.28

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	none
Consumables/Materials Costs	
• Universal Polypropylene Sorbent 50 @ $0.64/sq ft [1]	$32.00
• Tarpaulin, oil resistant, fire retardant 50 @ $0.47/sq ft [2]	$23.50
• Gas torch consumables 1 @ $21.17 x 1 /hr [3]	$21.17
Subtotal cost of equipment and materials	$76.67
Overhead & profit on equipment and materials @ 18.50 %	$14.18
Total costs, equipment & material	$90.85

TOTAL COST:

Removal of contaminated heat exchanger <3000 pounds:	**$2,766.13**
Total labor cost:	$2,675.28
Total equipment/material costs:	$90.85
Total craft labor man-hours required per unit:	81.88

5. NOTES AND REFERENCES

- Work difficulty factors were developed in conjunction with the Atomic Industrial Forum's (now NEI) program to standardize nuclear decommissioning cost estimates and are delineated in Volume 1, Chapter 5 of the "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

- References for equipment & consumables costs:

  1. www.mcmaster.com online catalog, McMaster Carr Spill Control (7193T88)
  2. RSMeans (2017) Division 01 56, Section 13.60-0600, page 23
  3. RSMeans (2017) Division 01 54 33, Section 40-6360, page 718

- Material and consumable costs were adjusted using the regional indices for Emporia, Kansas.

APPENDIX B

UNIT COST FACTOR LISTING
(DECON: Power Block Structures Only)

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean instrument and sampling tubing, $/linear foot	0.26
Removal of clean pipe 0.25 to 2 inches diameter, $/linear foot	2.66
Removal of clean pipe >2 to 4 inches diameter, $/linear foot	3.99
Removal of clean pipe >4 to 8 inches diameter, $/linear foot	8.27
Removal of clean pipe >8 to 14 inches diameter, $/linear foot	15.35
Removal of clean pipe >14 to 20 inches diameter, $/linear foot	20.19
Removal of clean pipe >20 to 36 inches diameter, $/linear foot	29.64
Removal of clean pipe >36 inches diameter, $/linear foot	35.12
Removal of clean valve >2 to 4 inches	54.75
Removal of clean valve >4 to 8 inches	82.70
Removal of clean valve >8 to 14 inches	153.51
Removal of clean valve >14 to 20 inches	201.85
Removal of clean valve >20 to 36 inches	296.44
Removal of clean valve >36 inches	351.19
Removal of clean pipe hanger for small bore piping	21.27
Removal of clean pipe hanger for large bore piping	66.80
Removal of clean pump, <300 pound	144.29
Removal of clean pump, 300-1000 pound	405.30
Removal of clean pump, 1000-10,000 pound	1,556.09
Removal of clean pump, >10,000 pound	3,026.06
Removal of clean pump motor, 300-1000 pound	165.70
Removal of clean pump motor, 1000-10,000 pound	641.11
Removal of clean pump motor, >10,000 pound	1,442.51
Removal of clean heat exchanger <3000 pound	846.90
Removal of clean heat exchanger >3000 pound	2,154.97
Removal of clean feedwater heater/deaerator	5,994.85
Removal of clean moisture separator/reheater	12,217.99
Removal of clean tank, <300 gallons	185.04
Removal of clean tank, 300-3000 gallon	574.34
Removal of clean tank, >3000 gallons, $/square foot surface area	5.04

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean electrical equipment, <300 pound	74.99
Removal of clean electrical equipment, 300-1000 pound	269.78
Removal of clean electrical equipment, 1000-10,000 pound	539.55
Removal of clean electrical equipment, >10,000 pound	1,310.99
Removal of clean electrical transformer < 30 tons	910.47
Removal of clean electrical transformer > 30 tons	2,621.97
Removal of clean standby diesel generator, <100 kW	929.96
Removal of clean standby diesel generator, 100 kW to 1 MW	2,075.72
Removal of clean standby diesel generator, >1 MW	4,297.17
Removal of clean electrical cable tray, $/linear foot	7.28
Removal of clean electrical conduit, $/linear foot	3.20
Removal of clean mechanical equipment, <300 pound	74.99
Removal of clean mechanical equipment, 300-1000 pound	269.78
Removal of clean mechanical equipment, 1000-10,000 pound	539.55
Removal of clean mechanical equipment, >10,000 pound	1,310.99
Removal of clean HVAC equipment, <300 pound	90.68
Removal of clean HVAC equipment, 300-1000 pound	324.16
Removal of clean HVAC equipment, 1000-10,000 pound	646.04
Removal of clean HVAC equipment, >10,000 pound	1,310.99
Removal of clean HVAC ductwork, $/pound	0.27
Removal of contaminated instrument and sampling tubing, $/linear foot	1.00
Removal of contaminated pipe 0.25 to 2 inches diameter, $/linear foot	16.21
Removal of contaminated pipe >2 to 4 inches diameter, $/linear foot	25.54
Removal of contaminated pipe >4 to 8 inches diameter, $/linear foot	41.86
Removal of contaminated pipe >8 to 14 inches diameter, $/linear foot	77.54
Removal of contaminated pipe >14 to 20 inches diameter, $/linear foot	91.96
Removal of contaminated pipe >20 to 36 inches diameter, $/linear foot	124.55
Removal of contaminated pipe >36 inches diameter, $/linear foot	145.84
Removal of contaminated valve >2 to 4 inches	306.15
Removal of contaminated valve >4 to 8 inches	361.56

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated valve >8 to 14 inches	709.67
Removal of contaminated valve >14 to 20 inches	894.66
Removal of contaminated valve >20 to 36 inches	1,179.75
Removal of contaminated valve >36 inches	1,392.59
Removal of contaminated pipe hanger for small bore piping	101.80
Removal of contaminated pipe hanger for large bore piping	319.02
Removal of contaminated pump, <300 pound	652.86
Removal of contaminated pump, 300-1000 pound	1,494.51
Removal of contaminated pump, 1000-10,000 pound	4,475.05
Removal of contaminated pump, >10,000 pound	10,895.28
Removal of contaminated pump motor, 300-1000 pound	672.15
Removal of contaminated pump motor, 1000-10,000 pound	1,859.76
Removal of contaminated pump motor, >10,000 pound	4,175.77
Removal of contaminated heat exchanger <3000 pound	2,766.13
Removal of contaminated heat exchanger >3000 pound	8,143.01
Removal of contaminated tank, <300 gallons	1,094.05
Removal of contaminated tank, >300 gallons, $/square foot	20.31
Removal of contaminated electrical equipment, <300 pound	484.52
Removal of contaminated electrical equipment, 300-1000 pound	1,187.87
Removal of contaminated electrical equipment, 1000-10,000 pound	2,290.07
Removal of contaminated electrical equipment, >10,000 pound	4,544.55
Removal of contaminated electrical cable tray, $/linear foot	23.53
Removal of contaminated electrical conduit, $/linear foot	12.77
Removal of contaminated mechanical equipment, <300 pound	538.22
Removal of contaminated mechanical equipment, 300-1000 pound	1,308.86
Removal of contaminated mechanical equipment, 1000-10,000 pound	2,519.06
Removal of contaminated mechanical equipment, >10,000 pound	4,544.55
Removal of contaminated HVAC equipment, <300 pound	538.22
Removal of contaminated HVAC equipment, 300-1000 pound	1,308.86
Removal of contaminated HVAC equipment, 1000-10,000 pound	2,519.06

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated HVAC equipment, >10,000 pound	4,544.55
Removal of contaminated HVAC ductwork, $/pound	1.60
Removal/plasma arc cut of contaminated thin metal components, $/linear in.	2.51
Additional decontamination of surface by washing, $/square foot	5.25
Additional decontamination of surfaces by hydrolasing, $/square foot	24.42
Decontamination rig hook up and flush, $/ 250 foot length	4,477.76
Chemical flush of components/systems, $/gallon	21.64
Removal of clean standard reinforced concrete, $/cubic yard	66.27
Removal of grade slab concrete, $/cubic yard	75.32
Removal of clean concrete floors, $/cubic yard	307.36
Removal of sections of clean concrete floors, $/cubic yard	873.10
Removal of clean heavily rein concrete w/#9 rebar, $/cubic yard	95.43
Removal of contaminated heavily rein concrete w/#9 rebar, $/cubic yard	1,621.76
Removal of clean heavily rein concrete w/#18 rebar, $/cubic yard	129.29
Removal of contaminated heavily rein concrete w/#18 rebar, $/cubic yard	2,141.37
Removal heavily rein concrete w/#18 rebar & steel embedments, $/cubic yard	355.85
Removal of below-grade suspended floors, $/cubic yard	181.13
Removal of clean monolithic concrete structures, $/cubic yard	680.04
Removal of contaminated monolithic concrete structures, $/cubic yard	1,603.30
Removal of clean foundation concrete, $/cubic yard	539.47
Removal of contaminated foundation concrete, $/cubic yard	1,494.90
Explosive demolition of bulk concrete, $/cubic yard	39.35
Removal of clean hollow masonry block wall, $/cubic yard	23.17
Removal of contaminated hollow masonry block wall, $/cubic yard	60.60
Removal of clean solid masonry block wall, $/cubic yard	23.17
Removal of contaminated solid masonry block wall, $/cubic yard	60.60
Backfill of below-grade voids, $/cubic yard	31.73
Removal of subterranean tunnels/voids, $/linear foot	82.06
Placement of concrete for below-grade voids, $/cubic yard	146.85
Excavation of clean material, $/cubic yard	2.81

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Excavation of contaminated material, $/cubic yard	35.81
Removal of clean concrete rubble (tipping fee included), $/cubic yard	24.27
Removal of contaminated concrete rubble, $/cubic yard	22.94
Removal of building by volume, $/cubic foot	0.26
Removal of clean building metal siding, $/square foot	0.93
Removal of contaminated building metal siding, $/square foot	3.46
Removal of standard asphalt roofing, $/square foot	1.21
Removal of transite panels, $/square foot	1.49
Scarifying contaminated concrete surfaces (drill & spall), $/square foot	10.15
Scabbling contaminated concrete floors, $/square foot	5.60
Scabbling contaminated concrete walls, $/square foot	14.25
Scabbling contaminated ceilings, $/square foot	48.40
Scabbling structural steel, $/square foot	4.67
Removal of clean overhead crane/monorail < 10 ton capacity	394.64
Removal of contaminated overhead crane/monorail < 10 ton capacity	1,242.95
Removal of clean overhead crane/monorail >10-50 ton capacity	947.13
Removal of contaminated overhead crane/monorail >10-50 ton capacity	2,982.57
Removal of polar crane > 50 ton capacity	4,027.16
Removal of gantry crane > 50 ton capacity	16,387.31
Removal of structural steel, $/pound	0.14
Removal of clean steel floor grating, $/square foot	3.29
Removal of contaminated steel floor grating, $/square foot	10.07
Removal of clean free standing steel liner, $/square foot	7.56
Removal of contaminated free standing steel liner, $/square foot	23.55
Removal of clean concrete-anchored steel liner, $/square foot	3.78
Removal of contaminated concrete-anchored steel liner, $/square foot	27.49
Placement of scaffolding in clean areas, $/square foot	14.44
Placement of scaffolding in contaminated areas, $/square foot	21.21
Landscaping with topsoil, $/acre	24,013.40
Cost of CPC B-88 LSA box & preparation for use	2,083.45

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Cost of CPC B-25 LSA box & preparation for use	1,958.03
Cost of CPC B-12V 12 gauge LSA box & preparation for use	1,540.78
Cost of CPC B-144 LSA box & preparation for use	10,871.54
Cost of LSA drum & preparation for use	194.02
Cost of cask liner for CNSI 8 120A cask (resins)	12,196.03
Cost of cask liner for CNSI 8 120A cask (filters)	8,614.99
Decontamination of surfaces with vacuuming, $/square foot	0.59

APPENDIX C

DETAILED COST ANALYSIS

DECON

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									n											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									n											
1a.1.5	Deactivate plant systems & process waste									n											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									n											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	362	54	417	417	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	584	88	672	672	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	575	86	661	595	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	487	73	560	504	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	830	124	954	954	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	760	114	874	874	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	365	55	419	419	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	187	28	215	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	365	55	419	210	-	210	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	105	16	121	60	-	60	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,421	663	5,084	4,477	-	607	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	281	42	323	323	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	188	188	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	165	165	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,735	2,210	16,945	16,338	-	607	-	-	-	-	-	-	-	78,157
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,754	375	4,130	4,130	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,274	227	2,502	2,502	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	3	-	33	-	10	59	59	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	2,111	317	2,428	2,428	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,225	122	1,347	-	1,347	-	-	-	-	-	-	-	-	-
1a.4.9	INPO Fees	-	-	-	-	-	-	333	50	383	383	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate Allocations	-	-	-	-	-	-	357	54	411	411	-	-	-	-	-	-	-	-	-	-
1a.4.13	NEI Annual Fees	-	-	-	-	-	-	530	79	609	609	-	-	-	-	-	-	-	-	-	-
1a.4.14	Security Staff Cost	-	-	-	-	-	-	19,401	2,910	22,311	22,311	-	-	-	-	-	-	-	-	-	316,295
1a.4.15	Utility Staff Cost	-	-	-	-	-	-	28,719	4,308	33,027	33,027	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	3	-	33	60,721	8,914	70,766	68,377	2,389	-	-	610	-	-	-	12,190	20	738,535
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	3	-	33	76,590	11,294	89,016	84,715	3,694	607	-	610	-	-	-	12,190	20	816,691

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	553	83	636	573	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	292	44	336	336	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	181	45	-	136	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	424	64	488	488	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	140	21	161	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	60	60	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	140	21	161	161	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	134	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,885	583	4,468	3,628	-	840	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	721	-	-	-	-	-	-	361	1,082	1,082	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	721	-	-	-	-	-	3,885	943	5,550	4,710	-	840	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	2,984	895	3,880	3,880	-	-	-	-	-	-	-	-	19,100	7,852
1b.2.3	Misc/Hazardous Waste	-	-	76	20	16	-	-	13	125	125	-	-	2,151	-	-	-	-	137,800	740	-
1b.2	Subtotal Period 1b Additional Costs	-	-	76	20	16	-	14,676	2,662	17,449	17,449	-	-	2,151	-	-	-	-	137,800	19,840	7,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	45	-	29	70	-	129	-	68	341	341	-	-	-	283	-	-	-	16,989	55	-
1b.3.4	Process decommissioning chemical flush waste	2	-	77	278	-	3,307	-	877	4,542	4,542	-	-	-	-	788	-	-	83,917	147	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	2,015	-	-	-	-	-	-	302	2,317	2,317	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	3,025	454	3,478	-	3,478	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	3,034	1,202	106	348	-	3,437	4,347	2,226	14,700	11,222	3,478	-	-	283	788	-	-	100,906	203	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	36	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,893	189	2,082	2,082	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,147	115	1,261	1,261	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	295	-	-	-	-	-	74	369	369	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	19	-	6	35	35	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	2,129	319	2,448	2,448	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	618	62	679	-	679	-	-	-	-	-	-	-	-	-
1b.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	405	61	465	-	465	-	-	-	-	-	-	-	-	-
1b.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.12	Corporate Allocations	-	-	-	-	-	-	181	27	208	208	-	-	-	-	-	-	-	-	-	-
1b.4.13	NEI Annual Fees	-	-	-	-	-	-	267	40	307	307	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	9,577	1,437	11,014	11,014	-	-	-	-	-	-	-	-	-	156,018
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,350	803	6,153	6,153	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	14,551	2,183	16,733	16,733	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	36	581	8	2	-	19	36,491	5,406	42,543	41,339	1,204	-	-	360	-	-	-	7,197	12	433,883
1b.0	TOTAL PERIOD 1b COST	3,791	1,783	189	370	16	3,456	59,399	11,238	80,243	74,719	4,683	840	2,151	643	788	-	-	245,903	21,120	474,978
PERIOD 1 TOTALS		3,791	2,865	202	373	16	3,489	135,989	22,532	169,259	159,435	8,376	1,448	2,151	1,253	788	-	-	258,093	21,140	1,291,669

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	129	140	42	49	-	542	-	247	1,149	1,149	-	-	-	2,046	-	-	-	142,726	6,863	-
2a.1.1.2	Pressurizer Relief Tank	22	18	12	14	-	153	-	57	276	276	-	-	-	578	-	-	-	40,338	1,077	-
2a.1.1.3	Reactor Coolant Pumps & Motors	72	74	123	213	-	1,091	-	364	1,906	1,906	-	-	-	3,386	-	-	-	816,140	4,188	100
2a.1.1.4	Pressurizer	35	37	692	159	-	1,171	-	404	2,497	2,497	-	-	-	3,739	-	-	-	293,734	2,534	1,875
2a.1.1.5	Steam Generators	274	5,183	3,875	3,165	2,688	7,273	-	4,546	26,974	26,974	-	-	40,845	23,217	-	-	-	3,577,181	30,060	5,750
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	109	202	256	53	-	639	-	298	1,557	1,557	-	-	-	4,534	-	-	-	168,041	8,136	-
2a.1.1.7	Reactor Vessel Internals	98	6,706	9,397	1,492	-	14,843	396	15,282	48,214	48,214	-	-	-	1,878	963	393	-	329,968	34,307	1,531
2a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	11,615	-	1,742	13,357	13,357	-	-	-	-	-	-	2,217	433,180	-	-
2a.1.1.9	Reactor Vessel	78	8,230	2,820	1,180	-	4,491	396	9,516	26,711	26,711	-	-	-	13,554	-	-	-	972,836	34,307	1,531
2a.1.1	Totals	817	20,590	17,125	6,325	2,688	41,788	793	32,426	122,551	122,551	-	-	40,845	52,932	963	393	2,217	6,774,144	121,472	10,786
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	336	419	75	619	615	-	384	2,449	2,449	-	-	4,844	2,698	-	-	-	462,027	9,734	-
2a.1.3	Main Condensers	-	936	241	85	738	776	-	576	3,353	3,353	-	-	7,701	3,216	-	-	-	550,847	27,762	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	443	-	-	-	-	-	66	510	510	-	-	-	-	-	-	-	-	4,871	-
2a.1.4.2	Auxiliary	-	229	-	-	-	-	-	34	264	264	-	-	-	-	-	-	-	-	2,194	-
2a.1.4.3	Hot Machine Shop	-	1	-	-	-	-	-	0	1	1	-	-	-	-	-	-	-	-	7	-
2a.1.4.4	Radwaste	-	44	-	-	-	-	-	7	51	51	-	-	-	-	-	-	-	-	387	-
2a.1.4.5	Fuel Building	-	97	-	-	-	-	-	15	112	112	-	-	-	-	-	-	-	-	773	-
2a.1.4	Totals	-	815	-	-	-	-	-	122	937	937	-	-	-	-	-	-	-	-	8,233	-
Disposal of Plant Systems																					
2a.1.5.1	AB - Main Steam	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,833	-
2a.1.5.2	AB - Main Steam RCA	-	60	4	11	186	-	-	45	305	305	-	-	2,156	-	-	-	-	87,550	1,515	-
2a.1.5.3	AC - Main Turbine	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,641	-
2a.1.5.4	AD - Condensate	-	181	-	-	-	-	-	27	208	-	-	208	-	-	-	-	-	-	6,144	-
2a.1.5.5	AE - Feedwater	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	4,271	-
2a.1.5.6	AF - Feedwater Htr Extrction, Drn & Vnt	-	152	-	-	-	-	-	23	175	-	-	175	-	-	-	-	-	-	5,352	-
2a.1.5.7	AK - Condensate Demineralizer	-	56	-	-	-	-	-	8	65	-	-	65	-	-	-	-	-	-	1,944	-
2a.1.5.8	AL - Auxiliary Feedwater	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	1,174	-
2a.1.5.9	AL-Auxiliary Feedwater Surge Tanks	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	72	-
2a.1.5.10	AQ - Condensate & Feedwater Chem Additn	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	468	-
2a.1.5.11	AX - Acid Feed	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	754	-
2a.1.5.12	Auxiliary Bldg Non-System Specific	-	85	7	6	41	68	-	46	253	253	-	-	474	282	-	-	-	37,164	2,282	-
2a.1.5.13	Auxiliary Bldg Non-System Specific RCA	-	537	13	38	660	-	-	240	1,487	1,487	-	-	7,629	-	-	-	-	309,812	13,471	-
2a.1.5.14	BL - Reactor Makeup Water	-	223	23	21	167	207	-	138	779	779	-	-	1,928	850	-	-	-	132,796	5,872	-
2a.1.5.15	BM - Steam Generator Blowdown	-	452	8	26	446	-	-	185	1,118	1,118	-	-	5,160	-	-	-	-	209,560	11,982	-
2a.1.5.16	CA - Steam Seal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	455	-
2a.1.5.17	CB - Main Turbine Lube Oil	-	38	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	1,207	-
2a.1.5.18	CC - Generator Hydrogen & CO2	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	198	-
2a.1.5.19	CD - Generator Seal Oil	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	287	-
2a.1.5.20	CE - Stator Cooling Water	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	241	-
2a.1.5.21	CF - Lube Oil Strg. Xfer & Purification	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	812	-
2a.1.5.22	CG - Condenser Air Removal	-	19	-	-	-	-	-	3	22	-	-	22	-	-	-	-	-	-	657	-
2a.1.5.23	CH - Main Turbine Control Oil	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,219	-
2a.1.5.24	CL - Chlorination	-	17	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	569	-
2a.1.5.25	CO - Carbon Dioxide	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	121	-
2a.1.5.26	CW - Circulating Water	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	7,858	-
2a.1.5.27	CZ - Caustic Acid	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	111	-
2a.1.5.28	DA - Circulating Water System	-	223	-	-	-	-	-	33	256	-	-	256	-	-	-	-	-	-	7,953	-
2a.1.5.29	DM - Equipment Drains	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	1,223	-
2a.1.5.30	DM - Equipment Drains RCA	-	111	26	77	1,336	-	-	242	1,793	1,793	-	-	15,445	-	-	-	-	627,223	2,840	-
2a.1.5.31	EG - Component Cooling Water RCA	-	557	24	70	1,225	-	-	336	2,213	2,213	-	-	14,161	-	-	-	-	575,071	13,646	-
2a.1.5.32	EJ - Residual Heat Removal	-	287	58	46	236	585	-	266	1,477	1,477	-	-	2,727	2,411	-	-	-	264,564	7,897	-
2a.1.5.33	EM - High Pressure Coolant Injection	-	240	18	15	109	158	-	120	660	660	-	-	1,260	648	-	-	-	92,828	6,201	-
2a.1.5.34	EN - Containment Spray	-	170	5	15	262	-	-	84	536	536	-	-	3,026	-	-	-	-	122,874	4,134	-
2a.1.5.35	FB - Auxiliary Steam	-	60	-	-	-	-	-	9	69	-	-	69	-	-	-	-	-	-	2,106	-
2a.1.5.36	FB - Auxiliary Steam RCA	-	66	1	4	71	-	-	28	169	169	-	-	816	-	-	-	-	33,148	1,537	-
2a.1.5.37	FC - Auxiliary Turbines	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,301	-
2a.1.5.38	FE - Auxiliary Steam Chemical Addition	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	105	-
2a.1.5.39	GE - Turbine Bldg HVAC	-	86	-	-	-	-	-	13	99	-	-	99	-	-	-	-	-	-	3,189	-
2a.1.5.40	GF - Miscellaneous Building HVAC	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	987	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2a.1.5.41	GS - Containment Hydrogen Control	-	58	4	5	57	26	-	31	180	180	-	-	658	104	-	-	-	33,502	1,659	-
2a.1.5.42	HF - Secondary Liquid Waste	547	741	85	73	535	780	-	754	3,515	3,515	-	-	6,186	3,203	-	-	-	456,359	31,896	-
2a.1.5.43	HY - Hydrogen	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	223	-
2a.1.5.44	KH - Service Gas	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	644	-
2a.1.5.45	LE - Oily Waste	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,575	-
2a.1.5.46	LE - Oily Waste RCA	-	153	3	9	149	-	-	62	376	376	-	-	1,718	-	-	-	-	69,785	3,518	-
2a.1.5.47	NT - Nitrogen	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	149	-
2a.1.5.48	OX - Oxygen	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	171	-
2a.1.5.49	SW - Screen Wash	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	635	-
2a.1.5.50	Turbine Bldg Non-System Specific	-	471	-	-	-	-	-	71	542	-	-	542	-	-	-	-	-	-	15,405	-
2a.1.5.51	VH - Circ Water & Makeup Water Scrnhs	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	272	-
2a.1.5.52	VV - Misc Bldg HVAC	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	148	-
2a.1.5.53	WG - Gland Water & Motor Cooling Water	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	593	-
2a.1.5.54	WL - Cooling Lake Makeup & Blowdown	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	745	-
2a.1.5	Totals	547	6,171	279	414	5,479	1,823	-	2,941	17,656	14,861	-	2,794	63,344	7,498	-	-	-	3,052,234	192,162	-
2a.1.6	Scaffolding in support of decommissioning	-	1,035	29	8	116	26	-	287	1,500	1,500	-	-	1,206	106	-	-	-	61,032	36,964	-
2a.1	Subtotal Period 2a Activity Costs	1,364	29,884	18,094	6,907	9,640	45,029	793	36,736	148,446	145,651	-	2,794	117,940	66,450	963	393	2,217	10,900,280	396,325	10,786
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,827	548	2,376	2,376	-	-	-	-	-	-	-	-	37,415	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	1,827	548	2,376	2,376	-	-	-	-	-	-	-	-	37,415	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	161	-	105	257	-	474	-	248	1,246	1,246	-	-	-	1,037	-	-	-	62,244	202	-
2a.3.2	Process decommissioning chemical flush waste	1	-	26	94	-	216	-	71	408	408	-	-	-	266	-	-	-	28,388	50	-
2a.3.3	Small tool allowance	-	278	-	-	-	-	-	42	319	287	-	32	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	10,792	1,619	12,411	-	12,411	-	-	-	-	-	-	-	-	-
2a.3.5	On-site survey and release of 115.8 tons clean metallic waste	-	-	-	-	-	-	165	16	181	181	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	162	278	131	351	-	691	10,956	1,996	14,565	2,122	12,411	32	-	1,304	-	-	-	90,632	252	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	127	-	-	-	-	-	-	32	159	159	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,248	125	1,373	1,373	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	4,094	409	4,503	4,503	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	3,021	-	-	-	-	-	755	3,777	3,777	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,952	-	-	-	-	-	593	4,545	4,545	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	140	35	-	347	-	106	629	629	-	-	-	6,453	-	-	-	129,051	210	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	3,610	542	4,152	4,152	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	1,042	104	1,146	1,146	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,262	126	1,388	-	1,388	-	-	-	-	-	-	-	-	-
2a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	1,445	217	1,661	-	1,661	-	-	-	-	-	-	-	-	-
2a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	186	28	214	-	214	-	-	-	-	-	-	-	-	-
2a.4.12	Corporate Allocations	-	-	-	-	-	-	448	67	516	516	-	-	-	-	-	-	-	-	-	-
2a.4.13	NEI Annual Fees	-	-	-	-	-	-	953	143	1,096	1,096	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	30,401	4,560	34,961	34,961	-	-	-	-	-	-	-	-	-	493,870
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	23,034	3,455	26,490	26,490	-	-	-	-	-	-	-	-	-	284,544
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	37,595	5,639	43,234	43,234	-	-	-	-	-	-	-	-	-	529,776
2a.4	Subtotal Period 2a Period-Dependent Costs	127	6,974	140	35	-	347	105,318	16,901	129,842	126,579	3,263	-	-	6,453	-	-	-	129,051	210	1,308,190
2a.0	TOTAL PERIOD 2a COST	1,652	37,135	18,365	7,293	9,640	46,067	118,894	56,182	295,229	276,729	15,674	2,826	117,940	74,207	963	393	2,217	11,119,970	434,203	1,318,976
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	AN - Demineralized Wtr Storage & xfer	-	45	-	-	-	-	-	7	51	-	-	51	-	-	-	-	-	-	1,548	-
2b.1.1.2	AN - Demineralized Wtr Strg & xfer RCA	-	15	0	1	10	-	-	5	32	32	-	-	120	-	-	-	-	4,855	334	-
2b.1.1.3	AP - Condensate Storage & Transfer	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,660	-
2b.1.1.4	BB - Reactor Coolant	-	226	38	31	151	404	-	189	1,038	1,038	-	-	1,746	1,669	-	-	-	177,118	6,412	-
2b.1.1.5	BG - Chemical & Volume Control	726	721	121	90	424	1,197	-	932	4,210	4,210	-	-	4,899	4,925	-	-	-	513,906	27,846	-
2b.1.1.6	BN - Borated Refueling Water Storage	-	247	20	34	477	129	-	173	1,080	1,080	-	-	5,512	533	-	-	-	257,802	6,939	-
2b.1.1.7	Control Bldg Non-System Specific	-	139	4	11	185	-	-	64	402	402	-	-	2,139	-	-	-	-	86,849	3,413	-
2b.1.1.8	Control Bldg Non-System Specific Cln	-	988	-	-	-	-	-	148	1,137	-	-	1,137	-	-	-	-	-	-	29,076	-
2b.1.1.9	DO - Diesel Oil	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	48	-
2b.1.1.10	EA - Service Water	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,592	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.11	EB - Closed Cooling Water	-	36	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,267	-
2b.1.1.12	EF - Essential Service Water	-	108	-	-	-	-	-	16	124	-	-	124	-	-	-	-	-	-	3,800	-
2b.1.1.13	EF - Essential Service Water RCA	-	70	2	7	123	-	-	37	240	240	-	-	1,427	-	-	-	-	57,959	1,734	-
2b.1.1.14	EP - Accumulator Safety Injection	-	124	10	12	136	69	-	71	422	422	-	-	1,568	283	-	-	-	81,940	3,246	-
2b.1.1.15	FA - Auxiliary Steam Generator	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	521	-
2b.1.1.16	FO - Fuel Oil	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	486	-
2b.1.1.17	FP - Fire Protection	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	3,826	-
2b.1.1.18	FP - Fire Protection RCA	-	150	8	22	389	-	-	100	669	669	-	-	4,492	-	-	-	-	182,411	3,541	-
2b.1.1.19	GA - Plant Heating	-	55	-	-	-	-	-	8	63	-	-	63	-	-	-	-	-	-	1,912	-
2b.1.1.20	GA - Plant Heating RCA	-	92	1	4	64	-	-	33	194	194	-	-	746	-	-	-	-	30,275	2,072	-
2b.1.1.21	GB - Central Chilled Water	-	52	-	-	-	-	-	8	59	-	-	59	-	-	-	-	-	-	1,803	-
2b.1.1.22	GB - Central Chilled Water RCA	-	21	0	1	16	-	-	8	47	47	-	-	187	-	-	-	-	7,591	482	-
2b.1.1.23	GD - Esstl Srvc Wtr Pumphs Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	284	-
2b.1.1.24	GH - Radwaste Building HVAC	-	145	6	13	210	24	-	76	474	474	-	-	2,425	98	-	-	-	104,702	3,455	-
2b.1.1.25	GK - Control Building HVAC	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	3,959	-
2b.1.1.26	GL - Auxiliary Building HVAC	-	363	13	28	438	55	-	176	1,073	1,073	-	-	5,064	228	-	-	-	220,197	8,491	-
2b.1.1.27	GM - Diesel Generator Building HVAC	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	695	-
2b.1.1.28	GN - Containment Cooling	-	392	26	45	636	156	-	242	1,495	1,495	-	-	7,354	643	-	-	-	339,572	9,502	-
2b.1.1.29	GP - Containmnt Integratd Leak Rate Test	-	30	1	3	50	-	-	16	100	100	-	-	580	-	-	-	-	23,570	750	-
2b.1.1.30	GR - Containment Atmospheric Control	-	14	3	6	94	10	-	21	148	148	-	-	1,086	41	-	-	-	46,686	392	-
2b.1.1.31	GT - Contaiment Purge HVAC	-	92	7	12	168	41	-	61	382	382	-	-	1,948	170	-	-	-	89,946	2,259	-
2b.1.1.32	HA - Gaseous Radwaste	-	278	23	23	241	164	-	152	882	882	-	-	2,782	666	-	-	-	156,216	7,037	-
2b.1.1.33	HB - Liquid Radwaste	584	657	77	64	480	670	-	713	3,244	3,244	-	-	5,544	2,742	-	-	-	401,460	30,762	-
2b.1.1.34	HC - Solid Radwaste	-	369	52	41	241	505	-	266	1,474	1,474	-	-	2,781	2,076	-	-	-	245,800	9,589	-
2b.1.1.35	HD - Decontamination	-	78	6	7	85	42	-	44	262	262	-	-	983	171	-	-	-	50,973	2,051	-
2b.1.1.36	HE - Boron Recycle	297	383	38	32	225	344	-	373	1,691	1,691	-	-	2,600	1,411	-	-	-	196,130	16,660	-
2b.1.1.37	JE - Emergency Fuel Oil	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	1,260	-
2b.1.1.38	KA - Compressed Air and Instrument	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	6,089	-
2b.1.1.39	KB - Breathing Air	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	1,075	-
2b.1.1.40	KC - Fire Protection	-	262	-	-	-	-	-	39	301	-	-	301	-	-	-	-	-	-	9,256	-
2b.1.1.41	KC - Fire Protection RCA	-	271	10	30	514	-	-	150	975	975	-	-	5,944	-	-	-	-	241,384	6,383	-
2b.1.1.42	KD - Domestic Water	-	50	-	-	-	-	-	7	57	-	-	57	-	-	-	-	-	-	1,708	-
2b.1.1.43	KE - Fuel Hndlg & Strg Reactor Vssl Serv	-	14	4	5	57	38	-	23	141	141	-	-	661	158	-	-	-	36,889	375	-
2b.1.1.44	KJ - Standby Diesel Engine	-	208	-	-	-	-	-	31	239	-	-	239	-	-	-	-	-	-	6,749	-
2b.1.1.45	LA - Sanitary Drains	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	290	-
2b.1.1.46	LA - Sanitary Drains RCA	-	21	0	1	24	-	-	9	55	55	-	-	272	-	-	-	-	11,053	422	-
2b.1.1.47	LB - Roof Drains	-	37	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,276	-
2b.1.1.48	LB - Roof Drains RCA	-	113	4	11	185	-	-	58	371	371	-	-	2,139	-	-	-	-	86,858	2,694	-
2b.1.1.49	LC - Yard Drains	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	96	-
2b.1.1.50	LD - Chemical & Detergent Waste	54	91	6	5	44	51	-	70	321	321	-	-	504	211	-	-	-	33,951	3,490	-
2b.1.1.51	LF - Floor & Equipment Drains	-	1,129	129	94	323	1,386	-	704	3,766	3,766	-	-	3,739	5,724	-	-	-	516,484	29,320	-
2b.1.1.52	RM - Process Sampling & Analysis	-	100	8	7	57	60	-	50	283	283	-	-	661	240	-	-	-	42,525	2,774	-
2b.1.1.53	Radwaste Bldg Non-System Specific	-	139	11	10	61	120	-	77	418	418	-	-	705	497	-	-	-	60,190	3,653	-
2b.1.1.54	Radwaste Bldg Non-System Specific RCA	-	893	22	63	1,097	-	-	400	2,475	2,475	-	-	12,684	-	-	-	-	515,103	21,919	-
2b.1.1.55	Reactor Bldg Non-System Specific	-	71	4	4	23	45	-	33	180	180	-	-	269	186	-	-	-	22,727	1,760	-
2b.1.1.56	Reactor Bldg Non-System Specific RCA	-	460	8	24	412	-	-	181	1,086	1,086	-	-	4,768	-	-	-	-	193,612	10,425	-
2b.1.1.57	SBO Diesel Generator	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,610	-
2b.1.1.58	SJ - Nuclear Sampling	-	57	6	5	37	46	-	32	182	182	-	-	423	184	-	-	-	29,191	1,620	-
2b.1.1.59	ST - Sewage Treatment	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	2,316	-
2b.1.1.60	SZ - Service Air	-	54	-	-	-	-	-	8	62	-	-	62	-	-	-	-	-	-	1,892	-
2b.1.1.61	VA - I&C Shop HVAC	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	155	-
2b.1.1.62	VB - I&C Shop Computer Room HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	106	-
2b.1.1.63	VC - Health Physics Computer Room HVAC	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	208	-
2b.1.1.64	VJ - Shop Bldg Machine Shop Area Vent	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	57	-
2b.1.1.65	VL - Shop Building HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	101	-
2b.1.1.66	VS - Admin Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	262	-
2b.1.1.67	VT - Tech Support Building HVAC	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	87	-
2b.1.1.68	VW - Waste Water Treatment Ventilation	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	52	-
2b.1.1.69	WD - Domestic Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	870	-
2b.1.1.70	WM - Makeup Demineralizer	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,929	-
2b.1.1.71	WS - Plant Services Water	-	93	-	-	-	-	-	14	107	-	-	107	-	-	-	-	-	-	3,297	-
2b.1.1.72	WS - Plant Services Water RCA	-	29	3	9	159	-	-	33	233	233	-	-	1,838	-	-	-	-	74,625	782	-
2b.1.1.73	WT - Waste Water Treatment	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	769	-
2b.1.1.74	WZ - Radioactive Liquid Waste	-	36	6	4	10	62	-	27	145	145	-	-	120	258	-	-	-	21,303	879	-
2b.1.1.75	Yard Non-System Specific	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	603	-
2b.1.1	Totals	1,661	11,052	679	758	7,846	5,617	-	6,054	33,668	30,191	-	3,477	90,709	23,114	-	-	-	5,161,856	333,052	-
2b.1.2	Scaffolding in support of decommissioning	-	1,294	36	10	145	32	-	358	1,875	1,875	-	-	1,508	133	-	-	-	76,290	46,205	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	885	837	54	202	515	1,640	-	1,175	5,308	5,308	-	-	5,955	17,517	-	-	-	997,209	44,353	-
2b.1.3.2	Auxiliary	463	302	24	93	189	250	-	414	1,735	1,735	-	-	2,185	6,943	-	-	-	417,552	19,560	-
2b.1.3.3	Communication Corridor - Contaminated	10	5	0	2	1	5	-	8	33	33	-	-	17	152	-	-	-	7,854	395	-
2b.1.3.4	Hot Machine Shop	13	10	1	2	-	6	-	11	43	43	-	-	-	188	-	-	-	8,892	597	-
2b.1.3.5	RWST Foundation Decon	-	7	1	4	-	11	-	5	28	28	-	-	-	335	-	-	-	15,840	108	-
2b.1.3.6	Radwaste	246	144	12	48	73	130	-	211	865	865	-	-	844	3,681	-	-	-	208,617	10,005	-
2b.1.3.7	Radwaste Drum Storage	28	15	1	5	6	14	-	23	92	92	-	-	66	413	-	-	-	22,243	1,093	-
2b.1.3.8	Radwaste Storage Building	71	32	3	13	-	37	-	55	210	210	-	-	-	1,090	-	-	-	51,480	2,634	-
2b.1.3	Totals	1,715	1,353	96	369	784	2,094	-	1,902	8,314	8,314	-	-	9,068	30,319	-	-	-	1,729,687	78,745	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	479	72	551	551	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	3,377	13,699	811	1,137	8,775	7,743	479	8,386	44,407	40,930	-	3,477	101,284	53,566	-	-	-	6,967,833	458,002	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,236	671	2,907	2,907	-	-	-	-	-	-	-	-	45,787	-
2b.2.2	Operational Equipment	-	-	19	49	624	-	-	103	794	794	-	-	11,710	-	-	-	-	292,750	32	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	49	624	-	2,236	774	3,701	3,701	-	-	11,710	-	-	-	-	292,750	45,819	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	190	-	128	311	-	575	-	299	1,504	1,504	-	-	-	1,258	-	-	-	75,490	245	-
2b.3.2	Process decommissioning chemical flush waste	4	-	145	524	-	1,203	-	396	2,271	2,271	-	-	-	1,481	-	-	-	157,863	277	-
2b.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	289	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	15,949	2,392	18,342	-	18,342	-	-	-	-	-	-	-	-	-
2b.3.5	On-site survey and release of 44.30 tons clean metallic waste	-	-	-	-	-	-	63	6	69	69	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	195	251	272	835	-	1,778	16,012	3,131	22,474	4,133	18,342	-	-	2,740	-	-	-	233,353	523	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,600	-	-	-	-	-	-	400	2,000	2,000	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,527	153	1,680	1,680	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	5,010	501	5,511	5,511	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	3,553	-	-	-	-	-	888	4,442	4,442	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,973	-	-	-	-	-	746	5,719	5,719	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	139	35	-	344	-	105	622	622	-	-	-	6,385	-	-	-	127,708	208	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	3,488	523	4,011	4,011	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,275	128	1,403	1,403	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,544	154	1,698	-	1,698	-	-	-	-	-	-	-	-	-
2b.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	1,768	265	2,033	-	2,033	-	-	-	-	-	-	-	-	-
2b.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	446	67	513	513	-	-	-	-	-	-	-	-	-	-
2b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	227	34	262	-	262	-	-	-	-	-	-	-	-	-
2b.4.13	Corporate Allocations	-	-	-	-	-	-	526	79	604	604	-	-	-	-	-	-	-	-	-	-
2b.4.14	NEI Annual Fees	-	-	-	-	-	-	1,166	175	1,341	1,341	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	37,203	5,580	42,783	42,783	-	-	-	-	-	-	-	-	-	604,370
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,105	4,066	31,171	31,171	-	-	-	-	-	-	-	-	-	334,464
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	44,158	6,624	50,782	50,782	-	-	-	-	-	-	-	-	-	620,820
2b.4	Subtotal Period 2b Period-Dependent Costs	1,600	8,527	139	35	-	344	125,443	20,488	156,575	152,582	3,993	-	-	6,385	-	-	-	127,708	208	1,559,655
2b.0	TOTAL PERIOD 2b COST	5,171	22,477	1,241	2,056	9,399	9,865	144,171	32,779	227,158	201,346	22,335	3,477	112,994	62,691	-	-	-	7,621,644	504,552	1,563,751
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	521	50	281	83	-	1,509	-	691	3,134	3,134	-	-	-	6,250	-	-	-	397,077	1,722	-
Disposal of Plant Systems																					
2d.1.2.1	EC - Fuel Pool Cooling & Cleanup	-	305	28	27	225	264	-	183	1,033	1,033	-	-	2,600	1,088	-	-	-	175,058	8,041	-
2d.1.2.2	Fuel Bldg Non-System Specific	-	37	3	2	15	29	-	19	106	106	-	-	170	120	-	-	-	14,568	954	-
2d.1.2.3	Fuel Bldg Non-System Specific RCA	-	245	5	16	277	-	-	106	649	649	-	-	3,200	-	-	-	-	129,974	5,859	-
2d.1.2.4	Fuel Building Fire Protection	-	119	5	15	254	-	-	71	463	463	-	-	2,941	-	-	-	-	119,444	2,802	-
2d.1.2.5	GG - Fuel Building HVAC	-	199	9	21	323	38	-	112	701	701	-	-	3,729	155	-	-	-	161,297	4,673	-
2d.1.2	Totals	-	906	51	81	1,093	331	-	490	2,953	2,953	-	-	12,641	1,364	-	-	-	600,340	22,329	-
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Building	569	611	12	34	234	85	-	500	2,046	2,046	-	-	2,705	1,864	-	-	-	199,762	31,564	-
2d.1.3	Totals	569	611	12	34	234	85	-	500	2,046	2,046	-	-	2,705	1,864	-	-	-	199,762	31,564	-
2d.1.4	Scaffolding in support of decommissioning	-	259	7	2	29	6	-	72	375	375	-	-	302	27	-	-	-	15,258	9,241	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic.Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
2d.1	Subtotal Period 2d Activity Costs	1,090	1,826	351	200	1,356	1,931	-	1,753	8,507	8,507	-	-	15,647	9,505	-	-	-	1,212,437	64,856	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,340	402	1,742	1,742	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	684	205	890	890	-	-	-	-	-	-	-	-	14,009	-
2d.2.3	Excavation of Underground Services	-	2,001	-	-	-	-	907	636	3,545	3,545	-	-	-	-	-	-	-	-	15,949	-
2d.2.4	License Termination ISFSI	-	155	205	500	-	2,529	1,964	1,338	6,691	6,691	-	-	-	36,660	-	-	-	1,893,161	5,152	10,496
2d.2	Subtotal Period 2d Additional Costs	-	2,156	205	500	-	2,529	4,895	2,582	12,867	12,867	-	-	-	36,660	-	-	-	1,893,161	35,110	22,976
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	86	-	58	141	-	261	-	135	681	681	-	-	-	571	-	-	-	34,248	111	-
2d.3.3	Small tool allowance	-	54	-	-	-	-	-	8	62	62	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	45	575	128	-	139	1,030	1,030	-	-	6,000	529	-	-	-	303,608	147	-
2d.3	Subtotal Period 2d Collateral Costs	86	54	201	187	575	389	-	282	1,773	1,773	-	-	6,000	1,100	-	-	-	337,856	258	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	229	-	-	-	-	-	-	57	286	286	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	467	47	514	514	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	447	45	492	492	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	760	-	-	-	-	-	190	950	950	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,522	-	-	-	-	-	228	1,750	1,750	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	45	11	-	111	-	34	201	201	-	-	-	2,065	-	-	-	41,306	67	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	569	85	655	655	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	330	33	363	363	-	-	-	-	-	-	-	-	-	-
2d.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	273	41	314	314	-	-	-	-	-	-	-	-	-	-
2d.4.10	Corporate Allocations	-	-	-	-	-	-	112	17	129	129	-	-	-	-	-	-	-	-	-	-
2d.4.11	Security Staff Cost	-	-	-	-	-	-	1,558	234	1,791	1,791	-	-	-	-	-	-	-	-	-	43,808
2d.4.12	DOC Staff Cost	-	-	-	-	-	-	5,766	865	6,631	6,631	-	-	-	-	-	-	-	-	-	70,093
2d.4.13	Utility Staff Cost	-	-	-	-	-	-	9,719	1,458	11,177	10,305	872	-	-	-	-	-	-	-	-	132,476
2d.4	Subtotal Period 2d Period-Dependent Costs	229	2,282	45	11	-	111	19,241	3,333	25,252	24,380	872	-	-	2,065	-	-	-	41,306	67	246,377
2d.0	TOTAL PERIOD 2d COST	1,405	6,317	802	897	1,931	4,960	24,136	7,950	48,399	47,527	872	-	21,647	49,330	-	-	-	3,484,760	100,291	269,353
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	536	54	589	589	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	513	51	564	564	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	768	-	-	-	-	-	192	960	960	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	19	-	6	35	35	-	-	-	360	-	-	-	7,203	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	431	43	474	474	-	-	-	-	-	-	-	-	-	-
2f.4.7	Corporate Allocations	-	-	-	-	-	-	65	10	74	74	-	-	-	-	-	-	-	-	-	-
2f.4.8	Security Staff Cost	-	-	-	-	-	-	900	135	1,036	1,036	-	-	-	-	-	-	-	-	-	19,284
2f.4.9	DOC Staff Cost	-	-	-	-	-	-	5,038	756	5,794	5,794	-	-	-	-	-	-	-	-	-	58,656
2f.4.10	Utility Staff Cost	-	-	-	-	-	-	6,051	908	6,959	5,963	995	-	-	-	-	-	-	-	-	76,333
2f.4	Subtotal Period 2f Period-Dependent Costs	-	768	8	2	-	19	13,859	2,203	16,859	15,864	995	-	-	360	-	-	-	7,203	12	154,273
2f.0	TOTAL PERIOD 2f COST	-	768	8	2	-	19	21,830	4,396	27,023	26,028	995	-	-	360	-	-	-	7,203	152,831	160,513
PERIOD 2 TOTALS		8,228	66,697	20,416	10,249	20,970	60,910	309,031	101,306	597,808	551,629	39,875	6,303	252,581	186,588	963	393	2,217	22,233,570	1,191,877	3,312,593

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	2,518	-	-	-	-	-	378	2,896	-	-	2,896	-	-	-	-	-	-	27,724	-
3b.1.1.2	Access Vaults	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	59	-
3b.1.1.3	Administration	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,724	-
3b.1.1.4	Auxiliary	-	2,063	-	-	-	-	-	309	2,373	-	-	2,373	-	-	-	-	-	-	19,753	-
3b.1.1.5	Auxiliary Boiler	-	16	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	248	-
3b.1.1.6	Chemical Addition Structure	-	33	-	-	-	-	-	5	37	-	-	37	-	-	-	-	-	-	469	-
3b.1.1.7	Circ Water Pump Enclosure	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	164	-
3b.1.1.8	Circ Water Travel Screen Enclosure	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	160	-
3b.1.1.9	Circulating Water Discharge Structure	-	90	-	-	-	-	-	13	103	-	-	103	-	-	-	-	-	-	542	-
3b.1.1.10	Circulating Water Intake & Screenhouse	-	83	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	683	-
3b.1.1.11	Communication Corridor - Clean	-	683	-	-	-	-	-	102	785	-	-	785	-	-	-	-	-	-	8,280	-
3b.1.1.12	Communication Corridor - Contaminated	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	184	-
3b.1.1.13	Covered Walkways	-	11	-	-	-	-	-	2	12	-	-	12	-	-	-	-	-	-	242	-
3b.1.1.14	Diesel Generator	-	239	-	-	-	-	-	36	274	-	-	274	-	-	-	-	-	-	2,185	-
3b.1.1.15	E.S.W.S. Pumphouse	-	124	-	-	-	-	-	19	143	-	-	143	-	-	-	-	-	-	891	-
3b.1.1.16	ESWS Valve House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	42	-
3b.1.1.17	FLEX Building No. 1 & 2	-	347	-	-	-	-	-	52	399	-	-	399	-	-	-	-	-	-	2,880	-
3b.1.1.18	GOB - Administration Building	-	193	-	-	-	-	-	29	222	-	-	222	-	-	-	-	-	-	2,962	-
3b.1.1.19	Hot Machine Shop	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	243	-
3b.1.1.20	M.M.O. Building	-	225	-	-	-	-	-	34	259	-	-	259	-	-	-	-	-	-	2,389	-
3b.1.1.21	Material Center West	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,379	-
3b.1.1.22	Misc Structures and Additions	-	57	-	-	-	-	-	9	66	-	-	66	-	-	-	-	-	-	910	-
3b.1.1.23	Miscellaneous Site Foundations	-	204	-	-	-	-	-	31	234	-	-	234	-	-	-	-	-	-	1,242	-
3b.1.1.24	Miscellaneous Site Structures	-	1,284	-	-	-	-	-	193	1,477	-	-	1,477	-	-	-	-	-	-	13,693	-
3b.1.1.25	New Covered Walkway	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	79	-
3b.1.1.26	Oil Separator and Waste Tank	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	8	-
3b.1.1.27	Radwaste	-	864	-	-	-	-	-	130	993	-	-	993	-	-	-	-	-	-	8,111	-
3b.1.1.28	Radwaste Drum Storage	-	126	-	-	-	-	-	19	144	-	-	144	-	-	-	-	-	-	1,504	-
3b.1.1.29	Radwaste Storage Building	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	1,028	-
3b.1.1.30	SBO Diesel Generator	-	240	-	-	-	-	-	36	276	-	-	276	-	-	-	-	-	-	3,079	-
3b.1.1.31	Security Main Gate North	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	1,123	-
3b.1.1.32	Security Additions	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	405	-
3b.1.1.33	Security/Guardhouse	-	30	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	342	-
3b.1.1.34	Site Diesel Generator	-	2	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	18	-
3b.1.1.35	Support Complex	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	389	-
3b.1.1.36	Turbine Building	-	2,393	-	-	-	-	-	359	2,752	-	-	2,752	-	-	-	-	-	-	47,184	-
3b.1.1.37	Turbine Pedestal	-	478	-	-	-	-	-	72	549	-	-	549	-	-	-	-	-	-	2,934	-
3b.1.1.38	Waste Water Treatment	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	172	-
3b.1.1.39	Water Treatment Building North (Z110)	-	48	-	-	-	-	-	7	55	-	-	55	-	-	-	-	-	-	608	-
3b.1.1.40	Fuel Building	-	909	-	-	-	-	-	136	1,045	-	-	1,045	-	-	-	-	-	-	7,983	-
3b.1.1	Totals	-	13,727	-	-	-	-	-	2,059	15,787	-	-	15,787	-	-	-	-	-	-	163,924	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	948	-	-	-	-	-	142	1,090	-	-	1,090	-	-	-	-	-	-	5,352	-
3b.1.3	Grade & landscape site	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	512	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,660
3b.1	Subtotal Period 3b Activity Costs	-	14,776	-	-	-	-	182	2,244	17,202	210	-	16,992	-	-	-	-	-	-	169,788	1,660
Period 3b Additional Costs																					
3b.2.1	Concrete Crushing	-	880	-	-	-	-	11	134	1,025	-	-	1,025	-	-	-	-	-	-	4,585	-
3b.2.2	Circulating Water Intake Cofferdam	-	308	-	-	-	-	-	46	354	-	-	354	-	-	-	-	-	-	2,584	-
3b.2.3	E.S.W.S. Pumphouse Cofferdam	-	404	-	-	-	-	-	61	465	-	-	465	-	-	-	-	-	-	3,552	-
3b.2.4	Construction Debris	-	-	-	-	-	-	1,730	260	1,990	-	-	1,990	-	-	-	-	-	-	-	-
3b.2.5	Site Restoration ISFSI	-	462	-	-	-	-	111	86	659	-	-	659	-	-	-	-	-	-	4,099	160
3b.2.6	Firing Range Closure	-	-	-	-	-	-	692	104	796	-	-	796	-	-	-	-	-	-	-	-
3b.2	Subtotal Period 3b Additional Costs	-	2,055	-	-	-	-	2,544	690	5,289	-	-	5,289	-	-	-	-	-	-	14,821	160
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	105	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	105	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	-	-

Table C
Wolf Creek Generating Station
DECON Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs																					
3b.4.2	Property taxes	-	-	-	-	-	-	482	48	530	-	-	530	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	4,679	-	-	-	-	-	702	5,381	-	-	5,381	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	314	47	361	-	-	361	-	-	-	-	-	-	-	-
3b.4.5	Corporate Allocations	-	-	-	-	-	-	51	8	59	-	-	59	-	-	-	-	-	-	-	-
3b.4.6	Security Staff Cost	-	-	-	-	-	-	1,734	260	1,994	-	-	1,994	-	-	-	-	-	-	-	37,132
3b.4.7	DOC Staff Cost	-	-	-	-	-	-	9,107	1,366	10,473	-	-	10,473	-	-	-	-	-	-	-	105,208
3b.4.8	Utility Staff Cost	-	-	-	-	-	-	4,573	686	5,259	-	-	5,259	-	-	-	-	-	-	-	60,340
3b.4	Subtotal Period 3b Period-Dependent Costs	-	4,679	-	-	-	-	16,260	3,117	24,056	-	-	24,056	-	-	-	-	-	-	-	202,680
3b.0	TOTAL PERIOD 3b COST	-	21,614	-	-	-	-	18,987	6,066	46,667	210	-	46,457	-	-	-	-	-	-	184,609	204,400
PERIOD 3 TOTALS		-	21,614	-	-	-	-	18,987	6,066	46,667	210	-	46,457	-	-	-	-	-	-	184,609	204,400
TOTAL COST TO DECOMMISSION		12,020	91,177	20,618	10,622	20,986	64,399	464,007	129,904	813,733	711,273	48,251	54,208	254,732	187,840	1,760	393	2,217	22,491,670	1,397,626	4,808,663

TOTAL COST TO DECOMMISSION WITH 19% CONTINGENCY:	$813,733	thousands of 2017 dollars
TOTAL NRC LICENSE TERMINATION COST IS 87.41% OR:	$711,273	thousands of 2017 dollars
SPENT FUEL MANAGEMENT COST IS 5.93% OR:	$48,251	thousands of 2017 dollars
NON-NUCLEAR DEMOLITION COST IS 6.66% OR:	$54,208	thousands of 2017 dollars
TOTAL LOW-LEVEL RADIOACTIVE RADWASTE VOLUME BURIED (EXCLUDING GTCC):	189,983	cubic feet
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	2,217	cubic feet
TOTAL SCRAP METAL REMOVED:	69,384	tons
TOTAL CRAFT LABOR REQUIREMENTS:	1,397,626	man-hours

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX D

DETAILED COST ANALYSIS

SAFSTOR

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	380	114	494	494	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	175	26	202	202	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	362	54	417	417	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	584	88	672	672	-	-	-	-	-	-	-	-	-	5,000
1a.1.17	Prepare/submit Irradinted Fuel Management Plan	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	575	86	661	661	-	-	-	-	-	-	-	-	-	4,920
1a.1.18.2	Plant systems	-	-	-	-	-	-	487	73	560	560	-	-	-	-	-	-	-	-	-	4,167
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	365	55	419	419	-	-	-	-	-	-	-	-	-	3,120
1a.1.18.4	Waste management	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	234	35	269	269	-	-	-	-	-	-	-	-	-	2,000
1a.1.18	Total	-	-	-	-	-	-	1,894	284	2,178	2,178	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	138	21	159	159	-	-	-	-	-	-	-	-	-	1,183
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	140	21	161	161	-	-	-	-	-	-	-	-	-	1,200
1a.1.19	Total	-	-	-	-	-	-	279	42	320	320	-	-	-	-	-	-	-	-	-	2,383
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	12	2	13	13	-	-	-	-	-	-	-	-	-	100
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,568	892	6,461	6,461	-	-	-	-	-	-	-	-	-	44,390
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Transfer (ISFSI to DOE)	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	1,134	170	1,304	-	1,304	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	3,754	375	4,130	4,130	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,274	227	2,502	2,502	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	3	-	33	-	10	59	59	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	2,111	317	2,428	2,428	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,225	122	1,347	-	1,347	-	-	-	-	-	-	-	-	-
1a.4.9	INPO Fees	-	-	-	-	-	-	333	50	383	383	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Corporate Allocations	-	-	-	-	-	-	357	54	411	411	-	-	-	-	-	-	-	-	-	-
1a.4.13	NEI Annual Fees	-	-	-	-	-	-	530	79	609	609	-	-	-	-	-	-	-	-	-	-
1a.4.14	Security Staff Cost	-	-	-	-	-	-	19,401	2,910	22,311	22,311	-	-	-	-	-	-	-	-	-	316,295
1a.4.15	Utility Staff Cost	-	-	-	-	-	-	28,719	4,308	33,027	33,027	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	3	-	33	60,721	8,914	70,766	68,377	2,389	-	-	610	-	-	-	12,190	20	738,535
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	3	-	33	67,423	9,976	78,531	74,838	3,694	-	-	610	-	-	-	12,190	20	782,925

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	872	-	-	-	-	-	-	436	1,308	1,308	-	-	-	-	-	-	-	-	24,102	-
1b.1.1.2	Auxiliary	436	-	-	-	-	-	-	218	653	653	-	-	-	-	-	-	-	-	12,527	-
1b.1.1.3	Communication Corridor - Contaminated	10	-	-	-	-	-	-	5	14	14	-	-	-	-	-	-	-	-	276	-
1b.1.1.4	Fuel Building	562	-	-	-	-	-	-	281	842	842	-	-	-	-	-	-	-	-	14,371	-
1b.1.1.5	Hot Machine Shop	12	-	-	-	-	-	-	6	18	18	-	-	-	-	-	-	-	-	344	-
1b.1.1.6	Radwaste	232	-	-	-	-	-	-	116	348	348	-	-	-	-	-	-	-	-	6,671	-
1b.1.1.7	Radwaste Drum Storage	26	-	-	-	-	-	-	13	39	39	-	-	-	-	-	-	-	-	750	-
1b.1.1.8	Radwaste Storage Building	61	-	-	-	-	-	-	30	91	91	-	-	-	-	-	-	-	-	1,690	-
1b.1.1	Totals	2,209	-	-	-	-	-	-	1,105	3,314	3,314	-	-	-	-	-	-	-	-	60,731	-
1b.1	Subtotal Period 1b Activity Costs	2,209	-	-	-	-	-	-	1,105	3,314	3,314	-	-	-	-	-	-	-	-	60,731	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	172	-	110	269	-	497	-	262	1,310	1,310	-	-	-	1,086	-	-	-	65,189	212	-
1b.3.4	Small tool allowance	-	35	-	-	-	-	-	5	40	40	-	-	-	-	-	-	-	-	-	-
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,512	227	1,739	-	1,739	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,145	35	110	269	-	497	1,512	640	4,208	2,469	1,739	-	-	1,086	-	-	-	65,189	212	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,502	-	-	-	-	-	-	376	1,878	1,878	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	946	95	1,041	1,041	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	573	57	631	631	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	421	-	-	-	-	-	105	526	526	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	16	4	-	40	-	12	73	73	-	-	-	753	-	-	-	15,052	25	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	532	80	612	612	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	309	31	340	-	340	-	-	-	-	-	-	-	-	-
1b.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.11	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.12	Corporate Allocations	-	-	-	-	-	-	90	14	104	104	-	-	-	-	-	-	-	-	-	-
1b.4.13	NEI Annual Fees	-	-	-	-	-	-	134	20	154	154	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	4,792	719	5,511	5,511	-	-	-	-	-	-	-	-	-	78,063
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	7,239	1,086	8,325	8,325	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	1,502	564	16	4	-	40	15,005	2,666	19,797	19,195	602	-	-	753	-	-	-	15,052	25	184,491
1b.0	TOTAL PERIOD 1b COST	4,856	599	127	273	-	537	16,517	4,410	27,319	24,978	2,341	-	-	1,839	-	-	-	80,241	60,968	184,491
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	394	-	-	-	-	-	59	453	453	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	26	-	-	-	-	-	4	30	30	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	14,124	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	68	10	78	78	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	420	-	-	-	-	801	293	1,515	1,515	-	-	-	-	-	-	-	-	17,824	583
Period 1c Additional Costs																					
1c.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1c.2.2	Misc/Hazardous Waste	-	-	76	20	16	-	-	13	125	125	-	-	2,151	-	-	-	-	137,800	740	-
1c.2	Subtotal Period 1c Additional Costs	-	-	76	20	16	-	11,691	1,767	13,570	13,570	-	-	2,151	-	-	-	-	137,800	740	-
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	187	-	120	293	-	541	-	285	1,425	1,425	-	-	-	1,183	-	-	-	70,966	231	-
1c.3.3	Small tool allowance	-	2	-	-	-	-	-	0	3	3	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,512	227	1,739	-	1,739	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	187	2	120	293	-	541	1,512	512	3,167	1,428	1,739	-	-	1,183	-	-	-	70,966	231	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	946	95	1,041	1,041	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	573	57	631	631	-	-	-	-	-	-	-	-	-	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 1c Period-Dependent Costs (continued)																					
1c.4.3	Health physics supplies	-	220	-	-	-	-	-	55	275	275	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	8	-	3	15	15	-	-	-	154	-	-	-	3,073	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	532	80	612	612	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	309	31	340	-	340	-	-	-	-	-	-	-	-	-
1c.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1c.4.11	Corporate Allocations	-	-	-	-	-	-	90	14	104	104	-	-	-	-	-	-	-	-	-	-
1c.4.12	NEI Annual Fees	-	-	-	-	-	-	134	20	154	154	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	4,785	718	5,503	5,503	-	-	-	-	-	-	-	-	-	77,954
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	7,239	1,086	8,325	8,325	-	-	-	-	-	-	-	-	-	106,428
1c.4	Subtotal Period 1c Period-Dependent Costs	-	363	3	1	-	8	14,998	2,229	17,602	17,000	602	-	-	154	-	-	-	3,073	5	184,382
1c.0	TOTAL PERIOD 1c COST	187	785	199	313	16	549	29,003	4,801	35,854	33,512	2,341	-	2,151	1,336	-	-	-	211,838	18,799	184,965
PERIOD 1 TOTALS		5,043	2,467	339	590	16	1,119	112,943	19,187	141,704	133,328	8,376	-	2,151	3,785	-	-	-	304,269	79,787	1,152,381
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	408	61	469	469	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	564	141	706	706	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	973	202	1,175	1,175	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	26,741	4,011	30,752	-	30,752	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	26,741	4,011	30,752	-	30,752	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,775	277	3,052	3,052	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	9,104	910	10,014	10,014	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	828	-	-	-	-	-	207	1,034	1,034	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	20	5	-	50	-	15	90	90	-	-	-	921	-	-	-	18,419	30	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,690	254	1,944	972	972	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	1,027	103	1,130	1,130	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,806	281	3,086	-	3,086	-	-	-	-	-	-	-	-	-
2a.4.8	Spent Fuel Pool O&M	-	-	-	-	-	-	3,212	482	3,694	-	3,694	-	-	-	-	-	-	-	-	-
2a.4.9	ISFSI Operating Costs	-	-	-	-	-	-	413	62	475	-	475	-	-	-	-	-	-	-	-	-
2a.4.10	Corporate Allocations	-	-	-	-	-	-	278	42	320	162	158	-	-	-	-	-	-	-	-	-
2a.4.11	NEI Annual Fees	-	-	-	-	-	-	2,119	318	2,437	2,437	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	67,604	10,141	77,744	72,380	5,364	-	-	-	-	-	-	-	-	1,098,240
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	23,197	3,480	26,677	21,528	5,149	-	-	-	-	-	-	-	-	328,865
2a.4	Subtotal Period 2a Period-Dependent Costs	-	828	20	5	-	50	114,226	16,570	131,698	112,799	18,899	-	-	921	-	-	-	18,419	30	1,427,105
2a.0	TOTAL PERIOD 2a COST	-	828	20	5	-	50	141,940	20,784	163,625	113,974	49,651	-	-	921	-	-	-	18,419	30	1,427,105
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	4,914	737	5,652	5,652	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	6,798	1,700	8,498	8,498	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	11,713	2,437	14,150	14,150	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	32,234	3,223	35,457	35,457	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	15,605	1,561	17,166	17,166	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	4,548	-	-	-	-	-	1,137	5,685	5,685	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	107	27	-	264	-	81	478	478	-	-	-	4,907	-	-	-	98,142	160	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	10,179	1,527	11,705	11,705	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	10,722	1,072	11,795	11,795	-	-	-	-	-	-	-	-	-	-
2c.4.7	Corporate Allocations	-	-	-	-	-	-	743	111	854	854	-	-	-	-	-	-	-	-	-	-
2c.4.8	Security Staff Cost	-	-	-	-	-	-	83,336	12,500	95,837	95,837	-	-	-	-	-	-	-	-	-	1,504,097

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2c Period-Dependent Costs (continued)																					
2c.4.9	Utility Staff Cost	-	-	-	-	-	-	57,514	8,627	66,141	66,141	-	-	-	-	-	-	-	-	-	877,390
2c.4	Subtotal Period 2c Period-Dependent Costs	-	4,548	107	27	-	264	210,333	29,839	245,117	245,117	-	-	-	4,907	-	-	-	98,142	160	2,381,486
2c.0	TOTAL PERIOD 2c COST	-	4,548	107	27	-	264	222,046	32,276	259,267	259,267	-	-	-	4,907	-	-	-	98,142	160	2,381,486
PERIOD 2 TOTALS		-	5,375	127	32	-	314	363,985	53,060	422,893	373,241	49,651	-	-	5,828	-	-	-	116,561	190	3,808,591
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									n											
3a.1.4	End product description	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	152	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	877	131	1,008	1,008	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	362	54	417	417	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	584	88	672	672	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	861	129	991	892	-	99	-	-	-	-	-	-	-	7,370
3a.1.9.2	Plant systems	-	-	-	-	-	-	487	73	560	504	-	56	-	-	-	-	-	-	-	4,167
3a.1.9.3	Reactor internals	-	-	-	-	-	-	830	124	954	954	-	-	-	-	-	-	-	-	-	7,100
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	760	114	874	874	-	-	-	-	-	-	-	-	-	6,500
3a.1.9.5	Biological shield	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	500
3a.1.9.6	Steam generators	-	-	-	-	-	-	365	55	419	419	-	-	-	-	-	-	-	-	-	3,120
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	187	28	215	108	-	108	-	-	-	-	-	-	-	1,600
3a.1.9.8	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.9	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.10	Plant structures & buildings	-	-	-	-	-	-	365	55	419	210	-	210	-	-	-	-	-	-	-	3,120
3a.1.9.11	Waste management	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
3a.1.9.12	Facility & site closeout	-	-	-	-	-	-	105	16	121	60	-	60	-	-	-	-	-	-	-	900
3a.1.9	Total	-	-	-	-	-	-	4,649	697	5,346	4,706	-	640	-	-	-	-	-	-	-	39,777
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	281	42	323	323	-	-	-	-	-	-	-	-	-	2,400
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	164	25	188	188	-	-	-	-	-	-	-	-	-	1,400
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	144	22	165	165	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	13,619	2,043	15,662	15,021	-	640	-	-	-	-	-	-	-	68,607
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	669	67	736	736	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	324	32	356	356	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	460	-	-	-	-	-	113	563	563	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	3	-	28	-	8	50	50	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	2,111	317	2,428	2,428	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	341	34	376	376	-	-	-	-	-	-	-	-	-	-
3a.4.8	Corporate Allocations	-	-	-	-	-	-	218	33	251	251	-	-	-	-	-	-	-	-	-	-
3a.4.9	Security Staff Cost	-	-	-	-	-	-	2,311	347	2,658	2,658	-	-	-	-	-	-	-	-	-	65,000
3a.4.10	Utility Staff Cost	-	-	-	-	-	-	17,990	2,699	20,689	20,689	-	-	-	-	-	-	-	-	-	257,920
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,018	11	3	-	28	23,965	3,734	28,758	28,758	-	-	-	514	-	-	-	10,287	17	322,920
3a.0	TOTAL PERIOD 3a COST	-	1,018	11	3	-	28	37,583	5,777	44,420	43,779	-	640	-	514	-	-	-	10,287	17	391,527
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	553	83	636	573	-	64	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	292	44	336	336	-	-	-	-	-	-	-	-	-	2,500
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	158	24	181	45	-	136	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	134	134	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	424	64	488	488	-	-	-	-	-	-	-	-	-	3,630

Table D
Wolf Creek Generating Station
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Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Detailed Work Procedures (continued)																					
3b.1.1.8	Facility closeout	-	-	-	-	-	-	140	21	161	81	-	81	-	-	-	-	-	-	-	1,200
3b.1.1.9	Missile shields	-	-	-	-	-	-	53	8	60	60	-	-	-	-	-	-	-	-	-	450
3b.1.1.10	Biological shield	-	-	-	-	-	-	140	21	161	161	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.11	Steam generators	-	-	-	-	-	-	538	81	618	618	-	-	-	-	-	-	-	-	-	4,600
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	117	18	134	67	-	67	-	-	-	-	-	-	-	1,000
3b.1.1.13	Main Turbine	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
3b.1.1.14	Main Condensers	-	-	-	-	-	-	182	27	210	-	-	210	-	-	-	-	-	-	-	1,560
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
3b.1.1.16	Reactor building	-	-	-	-	-	-	319	48	367	330	-	37	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	3,769	565	4,334	3,494	-	840	-	-	-	-	-	-	-	32,243
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	3,769	565	4,334	3,494	-	840	-	-	-	-	-	-	-	32,243
Period 3b Additional Costs																					
3b.2.1	Site Characterization	-	-	-	-	-	-	2,984	895	3,880	3,880	-	-	-	-	-	-	-	-	19,100	7,852
3b.2	Subtotal Period 3b Additional Costs	-	-	-	-	-	-	2,984	895	3,880	3,880	-	-	-	-	-	-	-	-	19,100	7,852
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,323	524	4,020	4,020	-	-	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	36	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	349	35	384	384	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	163	16	180	180	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	250	-	-	-	-	-	63	313	313	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	16	-	5	29	29	-	-	-	293	-	-	-	5,866	10	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	1,064	160	1,224	1,224	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	172	17	189	189	-	-	-	-	-	-	-	-	-	-
3b.4.9	Corporate Allocations	-	-	-	-	-	-	110	17	127	127	-	-	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	1,165	175	1,340	1,340	-	-	-	-	-	-	-	-	-	32,767
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	4,865	730	5,595	5,595	-	-	-	-	-	-	-	-	-	58,719
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	9,069	1,360	10,429	10,429	-	-	-	-	-	-	-	-	-	130,020
3b.4	Subtotal Period 3b Period-Dependent Costs	36	536	6	2	-	16	16,958	2,629	20,182	20,182	-	-	-	293	-	-	-	5,866	10	221,506
3b.0	TOTAL PERIOD 3b COST	1,008	1,736	6	2	-	16	25,034	4,614	32,416	31,575	-	840	-	293	-	-	-	5,866	19,110	261,601
PERIOD 3 TOTALS		1,008	2,754	18	4	-	43	62,617	10,391	76,835	75,355	-	1,481	-	808	-	-	-	16,153	19,126	653,128
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	25	129	42	28	137	271	-	142	775	775	-	-	967	1,023	-	-	-	135,750	3,982	-
4a.1.1.2	Pressurizer Relief Tank	4	16	12	8	39	77	-	34	190	190	-	-	273	289	-	-	-	38,367	602	-
4a.1.1.3	Reactor Coolant Pumps & Motors	16	65	62	199	-	1,061	-	326	1,728	1,728	-	-	-	3,386	-	-	-	816,140	2,700	80
4a.1.1.4	Pressurizer	7	37	420	147	-	1,171	-	370	2,152	2,152	-	-	-	3,739	-	-	-	241,053	1,539	1,500
4a.1.1.5	Steam Generators	54	5,183	2,904	3,116	2,688	7,063	-	4,249	25,257	25,257	-	-	40,845	22,546	-	-	-	3,356,336	22,021	4,500
4a.1.1.6	CRDMs/ICIs/Service Structure Removal	21	178	248	37	97	439	-	210	1,230	1,230	-	-	1,227	3,012	-	-	-	160,939	5,371	-
4a.1.1.7	Reactor Vessel Internals	87	6,283	7,575	1,270	-	10,290	337	12,163	38,006	38,006	-	-	-	2,504	591	393	-	329,177	28,573	1,301
4a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	11,615	-	1,742	13,357	13,357	-	-	-	-	-	-	2,217	433,180	-	-
4a.1.1.9	Reactor Vessel	-	7,807	2,219	496	-	4,897	337	9,033	24,788	24,788	-	-	-	15,631	-	-	-	979,036	28,573	1,301
4a.1.1	Totals	215	19,699	13,483	5,301	2,960	36,883	674	28,268	107,483	107,483	-	-	43,312	52,130	591	393	2,217	6,489,979	93,362	8,683
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	297	283	37	652	-	-	206	1,475	1,475	-	-	5,099	-	-	-	-	305,952	8,585	-
4a.1.3	Main Condensers	-	842	176	45	777	-	-	351	2,191	2,191	-	-	8,106	-	-	-	-	364,767	24,802	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	443	-	-	-	-	-	66	510	510	-	-	-	-	-	-	-	-	4,871	-
4a.1.4.2	Auxiliary	-	229	-	-	-	-	-	34	264	264	-	-	-	-	-	-	-	-	2,194	-
4a.1.4.3	Fuel Building	-	97	-	-	-	-	-	15	112	112	-	-	-	-	-	-	-	-	773	-
4a.1.4.4	Hot Machine Shop	-	1	-	-	-	-	-	0	1	1	-	-	-	-	-	-	-	-	7	-
4a.1.4.5	Radwaste	-	44	-	-	-	-	-	7	51	51	-	-	-	-	-	-	-	-	387	-
4a.1.4	Totals	-	815	-	-	-	-	-	122	937	937	-	-	-	-	-	-	-	-	8,233	-

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Wolf Creek Generating Station
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Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems																					
4a.1.5.1	AB - Main Steam	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,833	-
4a.1.5.2	AB - Main Steam RCA	-	60	4	11	186	-	-	45	305	305	-	-	2,156	-	-	-	-	87,550	1,515	-
4a.1.5.3	AC - Main Turbine	-	163	-	-	-	-	-	24	187	-	-	187	-	-	-	-	-	-	5,641	-
4a.1.5.4	AD - Condensate	-	181	-	-	-	-	-	27	208	-	-	208	-	-	-	-	-	-	6,144	-
4a.1.5.5	AE - Feedwater	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	4,271	-
4a.1.5.6	AF - Feedwater Hter Extrction, Drn & Vnt	-	152	-	-	-	-	-	23	175	-	-	175	-	-	-	-	-	-	5,352	-
4a.1.5.7	AK - Condensate Demineralizer	-	56	-	-	-	-	-	8	65	-	-	65	-	-	-	-	-	-	1,944	-
4a.1.5.8	AL - Auxiliary Feedwater	-	34	-	-	-	-	-	5	39	-	-	39	-	-	-	-	-	-	1,174	-
4a.1.5.9	AL-Auxiliary Feedwater Surge Tanks	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	87	-
4a.1.5.10	AQ - Condensate & Feedwater Chem Additn	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	468	-
4a.1.5.11	AX - Acid Feed	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	754	-
4a.1.5.12	Auxiliary Bldg Non-System Specific	-	77	2	5	71	8	-	33	195	195	-	-	824	31	-	-	-	35,454	2,031	-
4a.1.5.13	Auxiliary Bldg Non-System Specific RCA	-	537	13	38	660	-	-	240	1,487	1,487	-	-	7,629	-	-	-	-	309,812	13,471	-
4a.1.5.14	BL - Reactor Makeup Water	-	203	15	18	219	102	-	113	670	670	-	-	2,629	418	-	-	-	129,620	5,227	-
4a.1.5.15	BM - Steam Generator Blowdown	-	413	8	26	446	-	-	175	1,069	1,069	-	-	5,160	-	-	-	-	209,560	10,703	-
4a.1.5.16	CA - Steam Seal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	455	-
4a.1.5.17	CB - Main Turbine Lube Oil	-	38	-	-	-	-	-	6	43	-	-	43	-	-	-	-	-	-	1,207	-
4a.1.5.18	CC - Generator Hydrogen & CO2	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	198	-
4a.1.5.19	CD - Generator Seal Oil	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	287	-
4a.1.5.20	CE - Stator Cooling Water	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	241	-
4a.1.5.21	CF - Lube Oil Strg. Xfer & Purification	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	812	-
4a.1.5.22	CG - Condenser Air Removal	-	19	-	-	-	-	-	3	22	-	-	22	-	-	-	-	-	-	657	-
4a.1.5.23	CH - Main Turbine Control Oil	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,219	-
4a.1.5.24	CL - Chlorination	-	17	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	569	-
4a.1.5.25	CO - Carbon Dioxide	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	121	-
4a.1.5.26	CW - Circulating Water	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	7,858	-
4a.1.5.27	CZ - Caustic Acid	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	111	-
4a.1.5.28	DA - Circulating Water System	-	223	-	-	-	-	-	33	256	-	-	256	-	-	-	-	-	-	7,953	-
4a.1.5.29	DM - Equipment Drains	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	1,223	-
4a.1.5.30	DM - Equipment Drains RCA	-	111	26	77	1,336	-	-	242	1,793	1,793	-	-	15,445	-	-	-	-	627,223	2,840	-
4a.1.5.31	EG - Component Cooling Water RCA	-	557	24	70	1,225	-	-	336	2,213	2,213	-	-	14,161	-	-	-	-	575,071	13,646	-
4a.1.5.32	EJ - Residual Heat Removal	-	261	33	38	386	283	-	203	1,203	1,203	-	-	4,461	1,166	-	-	-	255,554	7,018	-
4a.1.5.33	EM - High Pressure Coolant Injection	-	220	4	11	187	-	-	85	506	506	-	-	2,159	-	-	-	-	87,663	5,527	-
4a.1.5.34	EN - Containment Spray	-	170	5	15	262	-	-	84	536	536	-	-	3,026	-	-	-	-	122,874	4,134	-
4a.1.5.35	FB - Auxiliary Steam	-	60	-	-	-	-	-	9	69	-	-	69	-	-	-	-	-	-	2,106	-
4a.1.5.36	FB - Auxiliary Steam RCA	-	66	1	4	71	-	-	28	169	169	-	-	816	-	-	-	-	33,148	1,537	-
4a.1.5.37	FC - Auxiliary Turbines	-	39	-	-	-	-	-	6	45	-	-	45	-	-	-	-	-	-	1,301	-
4a.1.5.38	FE - Auxiliary Steam Chemical Addition	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	105	-
4a.1.5.39	GE - Turbine Bldg HVAC	-	86	-	-	-	-	-	13	99	-	-	99	-	-	-	-	-	-	3,189	-
4a.1.5.40	GF - Miscellaneous Building HVAC	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	987	-
4a.1.5.41	GS - Containment Hydrogen Control	-	53	1	4	69	-	-	24	152	152	-	-	801	-	-	-	-	32,539	1,395	-
4a.1.5.42	HF - Secondary Liquid Waste	-	677	52	63	729	387	-	390	2,298	2,298	-	-	8,431	1,588	-	-	-	444,251	17,832	-
4a.1.5.43	HY - Hydrogen	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	223	-
4a.1.5.44	KH - Service Gas	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	644	-
4a.1.5.45	LE - Oily Waste	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,575	-
4a.1.5.46	LE - Oily Waste RCA	-	153	3	9	149	-	-	62	376	376	-	-	1,718	-	-	-	-	69,785	3,518	-
4a.1.5.47	NT - Nitrogen	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	149	-
4a.1.5.48	OX - Oxygen	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	171	-
4a.1.5.49	SW - Screen Wash	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	635	-
4a.1.5.50	Turbine Bldg Non-System Specific	-	471	-	-	-	-	-	71	542	-	-	542	-	-	-	-	-	-	15,405	-
4a.1.5.51	VH - Circ Water & Makeup Water Scrnbs	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	272	-
4a.1.5.52	VV - Misc Bldg HVAC	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	148	-
4a.1.5.53	WG - Gland Water & Motor Cooling Water	-	16	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	593	-
4a.1.5.54	WL - Cooling Lake Makeup & Blowdown	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	745	-
4a.1.5	Totals	-	5,989	191	387	5,996	779	-	2,426	15,768	12,973	-	2,795	69,317	3,203	-	-	-	3,020,102	174,218	-
4a.1.6	Scaffolding in support of decommissioning	-	947	29	8	116	26	-	265	1,390	1,390	-	-	1,206	106	-	-	-	61,032	33,925	-
4a.1	Subtotal Period 4a Activity Costs	215	28,590	14,162	5,778	10,501	37,688	674	31,638	129,245	126,450	-	2,795	127,040	55,440	501	393	2,217	10,241,830	343,124	8,683
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,580	474	2,054	2,054	-	-	-	-	-	-	-	-	32,347	-
4a.2	Subtotal Period 4a Additional Costs	-	-	-	-	-	-	1,580	474	2,054	2,054	-	-	-	-	-	-	-	-	32,347	-
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	5	-	8	19	-	36	-	15	82	82	-	-	-	78	-	-	-	4,664	15	-
4a.3.3	Small tool allowance	-	236	-	-	-	-	-	35	271	244	-	27	-	-	-	-	-	-	-	-
4a.3.4	On-site survey and release of 116.8 tons clean metallic waste	-	-	-	-	-	-	166	17	182	182	-	-	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	5	236	8	19	-	36	166	67	536	509	-	27	-	78	-	-	-	4,664	15	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	110	-	-	-	-	-	-	27	137	137	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	1,079	108	1,187	1,187	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	504	50	554	554	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	2,583	-	-	-	-	-	646	3,229	3,229	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	3,417	-	-	-	-	-	513	3,929	3,929	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	115	29	-	284	-	87	513	513	-	-	-	5,271	-	-	-	105,415	172	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	3,121	468	3,590	3,590	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	867	87	954	954	-	-	-	-	-	-	-	-	-	-
4a.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	630	94	724	724	-	-	-	-	-	-	-	-	-	-
4a.4.10	Corporate Allocations	-	-	-	-	-	-	343	51	394	394	-	-	-	-	-	-	-	-	-	-
4a.4.11	Security Staff Cost	-	-	-	-	-	-	3,596	539	4,136	4,136	-	-	-	-	-	-	-	-	-	101,151
4a.4.12	DOC Staff Cost	-	-	-	-	-	-	17,745	2,662	20,407	20,407	-	-	-	-	-	-	-	-	-	223,341
4a.4.13	Utility Staff Cost	-	-	-	-	-	-	28,338	4,251	32,589	32,589	-	-	-	-	-	-	-	-	-	404,603
4a.4	Subtotal Period 4a Period-Dependent Costs	110	6,000	115	29	-	284	56,223	9,583	72,343	72,343	-	-	-	5,271	-	-	-	105,415	172	729,094
4a.0	TOTAL PERIOD 4a COST	329	34,826	14,284	5,826	10,501	38,007	58,643	41,762	204,177	201,355	-	2,822	127,040	60,788	501	393	2,217	10,351,910	375,658	737,777
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	475	50	281	83	-	1,609	-	668	3,065	3,065	-	-	-	6,250	-	-	-	397,077	1,722	-
Disposal of Plant Systems																					
4b.1.2.1	AN - Demineralized Wtr Storage & xfer	-	45	-	-	-	-	-	7	51	-	-	51	-	-	-	-	-	-	1,548	-
4b.1.2.2	AN - Demineralized Wtr Strg & xfer RCA	-	15	0	1	10	-	-	5	32	32	-	-	120	-	-	-	-	4,855	334	-
4b.1.2.3	AP - Condensate Storage & Transfer	-	53	-	-	-	-	-	8	61	-	-	61	-	-	-	-	-	-	1,660	-
4b.1.2.4	BB - Reactor Coolant	-	205	28	27	217	271	-	158	907	907	-	-	2,511	1,121	-	-	-	173,293	5,731	-
4b.1.2.5	BG - Chemical & Volume Control	-	661	74	75	705	630	-	447	2,592	2,592	-	-	8,155	2,586	-	-	-	496,849	17,005	-
4b.1.2.6	BN - Borated Refueling Water Storage	-	222	10	31	541	-	-	142	946	946	-	-	6,255	-	-	-	-	254,024	6,161	-
4b.1.2.7	Control Bldg Non-System Specific	-	139	4	11	185	-	-	64	402	402	-	-	2,139	-	-	-	-	86,849	3,413	-
4b.1.2.8	Control Bldg Non-System Specific Cln	-	988	-	-	-	-	-	148	1,137	-	-	1,137	-	-	-	-	-	-	29,076	-
4b.1.2.9	DO - Diesel Oil	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	48	-
4b.1.2.10	EA - Service Water	-	74	-	-	-	-	-	11	85	-	-	85	-	-	-	-	-	-	2,592	-
4b.1.2.11	EB - Closed Cooling Water	-	36	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,267	-
4b.1.2.12	EC - Fuel Pool Cooling & Cleanup	-	279	7	20	356	-	-	127	789	789	-	-	4,115	-	-	-	-	167,129	7,154	-
4b.1.2.13	EF - Essential Service Water	-	108	-	-	-	-	-	16	124	-	-	124	-	-	-	-	-	-	3,800	-
4b.1.2.14	EF - Essential Service Water RCA	-	70	2	7	123	-	-	37	240	240	-	-	1,427	-	-	-	-	57,959	1,734	-
4b.1.2.15	EP - Accumulator Safety Injection	-	113	3	10	169	-	-	56	351	351	-	-	1,958	-	-	-	-	79,502	2,904	-
4b.1.2.16	FA - Auxiliary Steam Generator	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	521	-
4b.1.2.17	FO - Fuel Oil	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	486	-
4b.1.2.18	FP - Fire Protection	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	3,826	-
4b.1.2.19	FP - Fire Protection RCA	-	150	8	22	389	-	-	100	669	669	-	-	4,492	-	-	-	-	182,411	3,541	-
4b.1.2.20	Fuel Bldg Non-System Specific	-	34	1	2	28	3	-	14	81	81	-	-	322	12	-	-	-	13,829	850	-
4b.1.2.21	Fuel Bldg Non-System Specific RCA	-	245	5	16	277	-	-	106	649	649	-	-	3,200	-	-	-	-	129,974	5,859	-
4b.1.2.22	Fuel Building Fire Protection	-	119	5	15	254	-	-	71	463	463	-	-	2,941	-	-	-	-	119,444	2,802	-
4b.1.2.23	GA - Plant Heating	-	55	-	-	-	-	-	8	63	-	-	63	-	-	-	-	-	-	1,912	-
4b.1.2.24	GA - Plant Heating RCA	-	92	1	4	64	-	-	33	194	194	-	-	746	-	-	-	-	30,275	2,072	-
4b.1.2.25	GB - Central Chilled Water	-	52	-	-	-	-	-	8	59	-	-	59	-	-	-	-	-	-	1,803	-
4b.1.2.26	GB - Central Chilled Water RCA	-	21	0	1	16	-	-	8	47	47	-	-	187	-	-	-	-	7,591	482	-
4b.1.2.27	GD - Esstl Srvc Wtr Pumphs Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	284	-
4b.1.2.28	GG - Fuel Building HVAC	-	183	6	20	341	-	-	100	650	650	-	-	3,945	-	-	-	-	160,195	4,052	-
4b.1.2.29	GH - Radwaste Building HVAC	-	133	4	13	222	-	-	69	440	440	-	-	2,561	-	-	-	-	104,012	3,004	-
4b.1.2.30	GK - Control Building HVAC	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	3,959	-
4b.1.2.31	GL - Auxiliary Building HVAC	-	332	9	27	465	-	-	158	991	991	-	-	5,381	-	-	-	-	218,514	7,364	-
4b.1.2.32	GM - Diesel Generator Building HVAC	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	695	-
4b.1.2.33	GN - Containment Cooling	-	359	14	41	714	-	-	204	1,331	1,331	-	-	8,250	-	-	-	-	335,052	8,317	-
4b.1.2.34	GP - Containmnt Integratd Leak Rate Test	-	30	1	3	50	-	-	16	100	100	-	-	580	-	-	-	-	23,570	750	-
4b.1.2.35	GR - Containment Atmospheric Control	-	13	2	6	99	-	-	19	138	138	-	-	1,143	-	-	-	-	46,407	350	-
4b.1.2.36	GT - Contiment Purge HVAC	-	84	4	11	189	-	-	51	339	339	-	-	2,185	-	-	-	-	88,746	1,973	-
4b.1.2.37	HA - Gaseous Radwaste	-	256	6	18	320	-	-	115	716	716	-	-	3,699	-	-	-	-	150,219	6,296	-
4b.1.2.38	HB - Liquid Radwaste	-	602	50	56	635	356	-	348	2,047	2,047	-	-	7,343	1,450	-	-	-	391,794	15,380	-
4b.1.2.39	HC - Solid Radwaste	-	339	35	36	345	295	-	219	1,269	1,269	-	-	3,986	1,211	-	-	-	239,489	8,570	-
4b.1.2.40	HD - Decontamination	-	71	2	6	106	-	-	35	219	219	-	-	1,220	-	-	-	-	49,558	1,828	-
4b.1.2.41	HE - Boron Recycle	-	351	25	28	299	194	-	188	1,086	1,086	-	-	3,460	794	-	-	-	191,531	8,970	-
4b.1.2.42	JE - Emergency Fuel Oil	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	1,260	-
4b.1.2.43	KA - Compressed Air and Instrument	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	6,089	-
4b.1.2.44	KB - Breathing Air	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	1,075	-
4b.1.2.45	KC - Fire Protection	-	262	-	-	-	-	-	39	301	-	-	301	-	-	-	-	-	-	9,256	-
4b.1.2.46	KC - Fire Protection RCA	-	271	10	30	514	-	-	150	975	975	-	-	5,844	-	-	-	-	241,384	6,383	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4b.1.2.47	KD - Domestic Water	-	50	-	-	-	-	-	7	57	-	-	57	-	-	-	-	-	-	1,708	-
4b.1.2.48	KE - Fuel Hndlg & Strg Reactor Vssl Serv	-	12	1	4	76	-	-	15	110	110	-	-	882	-	-	-	-	35,813	332	-
4b.1.2.49	KJ - Standby Diesel Engine	-	208	-	-	-	-	-	31	239	-	-	239	-	-	-	-	-	-	6,749	-
4b.1.2.50	LA - Sanitary Drains	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	290	-
4b.1.2.51	LA - Sanitary Drains RCA	-	21	0	1	24	-	-	9	55	55	-	-	272	-	-	-	-	11,053	422	-
4b.1.2.52	LB - Roof Drains	-	37	-	-	-	-	-	5	42	-	-	42	-	-	-	-	-	-	1,276	-
4b.1.2.53	LB - Roof Drains RCA	-	113	4	11	185	-	-	58	371	371	-	-	2,139	-	-	-	-	86,858	2,694	-
4b.1.2.54	LC - Yard Drains	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	96	-
4b.1.2.55	LD - Chemical & Detergent Waste	-	83	1	4	69	-	-	32	190	190	-	-	797	-	-	-	-	32,369	2,139	-
4b.1.2.56	LF - Floor & Equipment Drains	-	1,036	88	81	576	878	-	586	3,245	3,245	-	-	6,660	3,627	-	-	-	501,387	26,164	-
4b.1.2.57	RM - Process Sampling & Analysis	-	90	2	5	86	-	-	36	219	219	-	-	990	-	-	-	-	40,200	2,450	-
4b.1.2.58	Radwaste Bldg Non-System Specific	-	126	3	7	115	12	-	53	317	317	-	-	1,329	50	-	-	-	57,145	3,253	-
4b.1.2.59	Radwaste Bldg Non-System Specific RCA	-	893	22	63	1,097	-	-	400	2,475	2,475	-	-	12,684	-	-	-	-	515,103	21,919	-
4b.1.2.60	Reactor Bldg Non-System Specific	-	65	1	3	43	5	-	24	141	141	-	-	562	19	-	-	-	21,590	1,569	-
4b.1.2.61	Reactor Bldg Non-System Specific RCA	-	460	8	24	412	-	-	181	1,086	1,086	-	-	4,768	-	-	-	-	193,612	10,425	-
4b.1.2.62	SBO Diesel Generator	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,610	-
4b.1.2.63	SJ - Nuclear Sampling	-	51	1	3	59	-	-	22	136	136	-	-	677	-	-	-	-	27,501	1,430	-
4b.1.2.64	ST - Sewage Treatment	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	2,316	-
4b.1.2.65	SZ - Service Air	-	54	-	-	-	-	-	8	62	-	-	62	-	-	-	-	-	-	1,892	-
4b.1.2.66	VA - I&C Shop HVAC	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	155	-
4b.1.2.67	VB - I&C Shop Computer Room HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	106	-
4b.1.2.68	VC - Health Physics Computer Room HVAC	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	208	-
4b.1.2.69	VJ - Shop Bldg Machine Shop Area Vent	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	57	-
4b.1.2.70	VL - Shop Building HVAC	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	101	-
4b.1.2.71	VS - Admin Bldg HVAC	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	262	-
4b.1.2.72	VT - Tech Support Building HVAC	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	87	-
4b.1.2.73	VW - Waste Water Treatment Ventilation	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	52	-
4b.1.2.74	WD - Domestic Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	870	-
4b.1.2.75	WM - Makeup Demineralizer	-	113	-	-	-	-	-	17	130	-	-	130	-	-	-	-	-	-	3,929	-
4b.1.2.76	WS - Plant Services Water	-	93	-	-	-	-	-	14	107	-	-	107	-	-	-	-	-	-	3,297	-
4b.1.2.77	WS - Plant Services Water RCA	-	29	3	9	159	-	-	33	233	233	-	-	1,838	-	-	-	-	74,625	782	-
4b.1.2.78	WT - Waste Water Treatment	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	769	-
4b.1.2.79	WZ - Radioactive Liquid Waste	-	32	4	3	21	40	-	22	124	124	-	-	247	167	-	-	-	20,647	783	-
4b.1.2.80	Yard Non-System Specific	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	603	-
4b.1.2	Totals	-	11,425	456	753	10,557	2,683	-	4,967	30,840	27,363	-	3,477	122,048	11,036	-	-	-	5,662,357	307,229	-
4b.1.3	Scaffolding in support of decommissioning	-	1,421	43	12	173	39	-	397	2,085	2,085	-	-	1,809	160	-	-	-	91,548	50,887	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	797	692	51	186	515	494	-	805	3,541	3,541	-	-	5,955	13,318	-	-	-	874,477	38,225	-
4b.1.4.2	Auxiliary	410	180	15	52	189	135	-	321	1,301	1,301	-	-	2,185	3,518	-	-	-	255,780	15,363	-
4b.1.4.3	Communication Corridor - Contaminated	9	3	0	1	1	3	-	6	23	23	-	-	17	76	-	-	-	4,296	306	-
4b.1.4.4	Fuel Building	508	516	10	24	234	55	-	437	1,784	1,784	-	-	2,705	984	-	-	-	158,200	27,457	-
4b.1.4.5	Hot Machine Shop	11	5	0	1	-	3	-	8	28	28	-	-	-	94	-	-	-	4,446	421	-
4b.1.4.6	RWST Foundation Decon	-	3	0	2	-	6	-	3	14	14	-	-	-	168	-	-	-	7,920	48	-
4b.1.4.7	Radwaste	218	81	7	26	73	69	-	162	636	636	-	-	844	1,857	-	-	-	122,469	7,815	-
4b.1.4.8	Radwaste Drum Storage	25	8	1	3	6	7	-	17	67	67	-	-	66	208	-	-	-	12,565	850	-
4b.1.4.9	Radwaste Storage Building	62	14	1	7	-	18	-	41	144	144	-	-	-	545	-	-	-	25,740	2,013	-
4b.1.4	Totals	2,041	1,501	86	301	1,018	790	-	1,800	7,538	7,538	-	-	11,773	20,770	-	-	-	1,465,893	92,498	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	479	72	551	551	-	-	-	-	-	-	-	-	-	4,096
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	2,516	14,397	865	1,149	11,749	5,020	479	7,903	44,079	40,602	-	3,477	135,630	38,216	-	-	-	7,616,876	452,336	4,096
Period 4b Additional Costs																					
4b.2.1	Final Survey Program Management	-	-	-	-	-	-	1,340	402	1,742	1,742	-	-	-	-	-	-	-	-	-	12,480
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,528	759	3,287	3,287	-	-	-	-	-	-	-	-	51,767	-
4b.2.3	Operational Equipment	-	-	19	49	624	-	-	103	794	794	-	-	11,710	-	-	-	-	292,760	32	-
4b.2.4	License Termination ISFSI	-	155	205	500	-	2,529	1,964	1,338	6,691	6,691	-	-	-	36,660	-	-	-	1,893,161	5,152	10,496
4b.2	Subtotal Period 4b Additional Costs	-	155	224	549	624	2,529	5,833	2,601	12,514	12,514	-	-	11,710	36,660	-	-	-	2,185,911	56,950	22,976
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	12	-	21	51	-	93	-	39	216	216	-	-	-	204	-	-	-	12,264	40	-
4b.3.3	Small tool allowance	-	257	-	-	-	-	-	39	295	295	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	143	45	575	128	-	139	1,030	1,030	-	-	6,000	529	-	-	-	303,608	147	-
4b.3.5	On-site survey and release of 44.30 tons clean metallic waste	-	-	-	-	-	-	63	6	69	69	-	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	12	257	163	96	575	221	63	223	1,611	1,611	-	-	6,000	733	-	-	-	315,872	187	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,660	-	-	-	-	-	-	415	2,075	2,075	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	1,726	173	1,899	1,899	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	806	81	887	887	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	3,679	-	-	-	-	-	920	4,599	4,599	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	5,623	-	-	-	-	-	843	6,466	6,466	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	141	35	-	349	-	107	633	633	-	-	-	6,495	-	-	-	129,908	212	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	3,944	592	4,535	4,535	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	1,388	139	1,527	1,527	-	-	-	-	-	-	-	-	-	-
4b.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	1,008	151	1,159	1,159	-	-	-	-	-	-	-	-	-	-
4b.4.10	Corporate Allocations	-	-	-	-	-	-	517	78	595	595	-	-	-	-	-	-	-	-	-	-
4b.4.11	Security Staff Cost	-	-	-	-	-	-	5,755	863	6,618	6,618	-	-	-	-	-	-	-	-	-	161,877
4b.4.12	DOC Staff Cost	-	-	-	-	-	-	27,705	4,156	31,861	31,861	-	-	-	-	-	-	-	-	-	347,064
4b.4.13	Utility Staff Cost	-	-	-	-	-	-	43,042	6,456	49,498	49,498	-	-	-	-	-	-	-	-	-	611,247
4b.4	Subtotal Period 4b Period-Dependent Costs	1,660	9,302	141	35	-	349	85,891	14,973	112,352	112,352	-	-	-	6,495	-	-	-	129,908	212	1,120,187
4b.0	TOTAL PERIOD 4b COST	4,189	24,111	1,394	1,829	12,948	8,120	92,266	25,701	170,556	167,079	-	3,477	153,340	82,105	-	-	-	10,248,570	509,684	1,147,259
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	Final Site survey	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	6,489	1,947	8,436	8,436	-	-	-	-	-	-	-	-	152,819	6,240
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,323	198	1,521	1,521	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	536	54	589	589	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	250	25	275	275	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	768	-	-	-	-	-	192	960	960	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	8	2	-	19	-	6	35	35	-	-	-	360	-	-	-	7,203	12	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	431	43	474	474	-	-	-	-	-	-	-	-	-	-
4f.4.7	Corporate Allocations	-	-	-	-	-	-	65	10	74	74	-	-	-	-	-	-	-	-	-	-
4f.4.8	Security Staff Cost	-	-	-	-	-	-	900	135	1,036	1,036	-	-	-	-	-	-	-	-	-	19,284
4f.4.9	DOC Staff Cost	-	-	-	-	-	-	5,038	756	5,794	5,794	-	-	-	-	-	-	-	-	-	58,656
4f.4.10	Utility Staff Cost	-	-	-	-	-	-	6,051	908	6,959	6,959	-	-	-	-	-	-	-	-	-	76,333
4f.4	Subtotal Period 4f Period-Dependent Costs	-	768	8	2	-	19	13,597	2,177	16,571	16,571	-	-	-	360	-	-	-	7,203	12	154,273
4f.0	TOTAL PERIOD 4f COST	-	768	8	2	-	19	21,568	4,369	26,734	26,734	-	-	-	360	-	-	-	7,203	152,831	160,513
PERIOD 4 TOTALS		4,518	59,704	15,686	7,657	23,448	46,146	172,476	71,832	401,467	395,168	-	6,299	280,380	143,253	501	393	2,217	20,607,680	1,038,173	2,045,549
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	2,518	-	-	-	-	-	378	2,896	-	-	2,896	-	-	-	-	-	-	27,724	-
5b.1.1.2	Access Vaults	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	59	-
5b.1.1.3	Administration	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,724	-
5b.1.1.4	Auxiliary	-	2,063	-	-	-	-	-	309	2,373	-	-	2,373	-	-	-	-	-	-	19,753	-
5b.1.1.5	Auxiliary Boiler	-	16	-	-	-	-	-	2	19	-	-	19	-	-	-	-	-	-	248	-
5b.1.1.6	Chemical Addition Structure	-	33	-	-	-	-	-	5	37	-	-	37	-	-	-	-	-	-	469	-
5b.1.1.7	Circ Water Pump Enclosure	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	164	-
5b.1.1.8	Circ Water Travel Screen Enclosure	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	160	-
5b.1.1.9	Circulating Water Discharge Structure	-	90	-	-	-	-	-	13	103	-	-	103	-	-	-	-	-	-	542	-
5b.1.1.10	Circulating Water Intake & Screenhouse	-	83	-	-	-	-	-	12	95	-	-	95	-	-	-	-	-	-	683	-
5b.1.1.11	Communication Corridor - Clean	-	683	-	-	-	-	-	102	785	-	-	785	-	-	-	-	-	-	8,280	-
5b.1.1.12	Communication Corridor - Contaminated	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	184	-
5b.1.1.13	Covered Walkways	-	11	-	-	-	-	-	2	12	-	-	12	-	-	-	-	-	-	242	-
5b.1.1.14	Diesel Generator	-	239	-	-	-	-	-	36	274	-	-	274	-	-	-	-	-	-	2,185	-
5b.1.1.15	E.S.W.S. Pumphouse	-	124	-	-	-	-	-	19	143	-	-	143	-	-	-	-	-	-	801	-

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Demolition of Remaining Site Buildings (continued)																					
5b.1.1.16	ESWS Valve House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	42	-
5b.1.1.17	FLEX Building NO. 1 & 2	-	347	-	-	-	-	-	52	399	-	-	399	-	-	-	-	-	-	2,880	-
5b.1.1.18	Fuel Building	-	909	-	-	-	-	-	136	1,045	-	-	1,046	-	-	-	-	-	-	7,983	-
5b.1.1.19	GOB - Administration Building	-	193	-	-	-	-	-	29	222	-	-	222	-	-	-	-	-	-	2,962	-
5b.1.1.20	Hot Machine Shop	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	243	-
5b.1.1.21	M.M.O. Building	-	225	-	-	-	-	-	34	259	-	-	259	-	-	-	-	-	-	2,389	-
5b.1.1.22	Material Center West	-	72	-	-	-	-	-	11	83	-	-	83	-	-	-	-	-	-	1,379	-
5b.1.1.23	Misc Structures and Additions	-	57	-	-	-	-	-	9	66	-	-	66	-	-	-	-	-	-	910	-
5b.1.1.24	Miscellaneous Site Foundations	-	204	-	-	-	-	-	31	234	-	-	234	-	-	-	-	-	-	1,242	-
5b.1.1.25	Miscellaneous Site Structures	-	1,284	-	-	-	-	-	193	1,477	-	-	1,477	-	-	-	-	-	-	13,693	-
5b.1.1.26	New Covered Walkway	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	79	-
5b.1.1.27	Oil Separator and Waste Tank	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	8	-
5b.1.1.28	Radwaste	-	864	-	-	-	-	-	130	993	-	-	993	-	-	-	-	-	-	8,111	-
5b.1.1.29	Radwaste Drum Storage	-	126	-	-	-	-	-	19	144	-	-	144	-	-	-	-	-	-	1,504	-
5b.1.1.30	Radwaste Storage Building	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	1,028	-
5b.1.1.31	SBO Diesel Generator	-	240	-	-	-	-	-	36	276	-	-	276	-	-	-	-	-	-	3,079	-
5b.1.1.32	Security Main Gate North	-	70	-	-	-	-	-	11	81	-	-	81	-	-	-	-	-	-	1,123	-
5b.1.1.33	Security Additions	-	30	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	405	-
5b.1.1.34	Security/Guardhouse	-	30	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	342	-
5b.1.1.35	Site Diesel Generator	-	2	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	18	-
5b.1.1.36	Support Complex	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	389	-
5b.1.1.37	Turbine Building	-	2,393	-	-	-	-	-	359	2,752	-	-	2,752	-	-	-	-	-	-	47,184	-
5b.1.1.38	Turbine Pedestal	-	478	-	-	-	-	-	72	549	-	-	549	-	-	-	-	-	-	2,934	-
5b.1.1.39	Waste Water Treatment	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	172	-
5b.1.1.40	Water Treatment Building North (Z110)	-	48	-	-	-	-	-	7	55	-	-	55	-	-	-	-	-	-	608	-
5b.1.1	Totals	-	13,727	-	-	-	-	-	2,059	15,787	-	-	15,787	-	-	-	-	-	-	163,924	-
Site Closeout Activities																					
5b.1.2	Remove Rubble	-	948	-	-	-	-	-	142	1,090	-	-	1,090	-	-	-	-	-	-	5,352	-
5b.1.3	Grade & landscape site	-	100	-	-	-	-	-	15	115	-	-	115	-	-	-	-	-	-	512	-
5b.1.4	Final report to NRC	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	14,776	-	-	-	-	182	2,244	17,202	210	-	16,992	-	-	-	-	-	-	169,788	1,560
Period 5b Additional Costs																					
5b.2.1	Concrete Crushing	-	880	-	-	-	-	11	134	1,025	-	-	1,025	-	-	-	-	-	-	4,585	-
5b.2.2	Circulating Water Intake Cofferdam	-	308	-	-	-	-	-	46	354	-	-	354	-	-	-	-	-	-	2,584	-
5b.2.3	E.S.W.S. Pumphouse Cofferdam	-	404	-	-	-	-	-	61	465	-	-	465	-	-	-	-	-	-	3,552	-
5b.2.4	Excavation of Underground Services	-	2,001	-	-	-	-	907	636	3,545	3,545	-	-	-	-	-	-	-	-	15,949	-
5b.2.5	Construction Debris	-	-	-	-	-	-	1,730	260	1,990	-	-	1,990	-	-	-	-	-	-	-	-
5b.2.6	Site Restoration ISFSI	-	462	-	-	-	-	111	86	659	-	-	659	-	-	-	-	-	-	4,099	160
5b.2.7	Firing Range Closure	-	-	-	-	-	-	692	104	796	-	-	796	-	-	-	-	-	-	-	-
5b.2	Subtotal Period 5b Additional Costs	-	4,056	-	-	-	-	3,451	1,326	8,833	3,545	-	5,289	-	-	-	-	-	-	30,770	160
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	110	-	-	-	-	-	17	127	-	-	127	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	110	-	-	-	-	-	17	127	-	-	127	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	482	48	530	-	-	530	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	4,679	-	-	-	-	-	702	5,381	-	-	5,381	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	314	47	361	-	-	361	-	-	-	-	-	-	-	-
5b.4.5	Corporate Allocations	-	-	-	-	-	-	51	8	59	-	-	59	-	-	-	-	-	-	-	-
5b.4.6	Security Staff Cost	-	-	-	-	-	-	1,734	260	1,994	-	-	1,994	-	-	-	-	-	-	-	37,132
5b.4.7	DOC Staff Cost	-	-	-	-	-	-	9,107	1,366	10,473	-	-	10,473	-	-	-	-	-	-	-	105,208
5b.4.8	Utility Staff Cost	-	-	-	-	-	-	4,573	686	5,259	-	-	5,259	-	-	-	-	-	-	-	60,340
5b.4	Subtotal Period 5b Period-Dependent Costs	-	4,679	-	-	-	-	16,260	3,117	24,056	-	-	24,056	-	-	-	-	-	-	-	202,680
5b.0	TOTAL PERIOD 5b COST	-	23,621	-	-	-	-	19,894	6,703	50,218	3,754	-	46,464	-	-	-	-	-	-	200,558	204,400
PERIOD 5 TOTALS		-	23,621	-	-	-	-	19,894	6,703	50,218	3,754	-	46,464	-	-	-	-	-	-	200,558	204,400
TOTAL COST TO DECOMMISSION		10,570	93,922	16,170	8,282	23,465	47,622	731,915	161,173	1,093,117	980,846	58,028	54,243	282,530	153,674	501	393	2,217	21,044,660	1,337,834	7,864,049

Table D
Wolf Creek Generating Station
SAFSTOR Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours

TOTAL COST TO DECOMMISSION WITH 17.29% CONTINGENCY:	$1,093,117	thousands of 2017 dollars
TOTAL NRC LICENSE TERMINATION COST IS 89.73% OR:	$980,846	thousands of 2017 dollars
SPENT FUEL MANAGEMENT COST IS 5.31% OR:	$58,028	thousands of 2017 dollars
NON-NUCLEAR DEMOLITION COST IS 4.96% OR:	$54,243	thousands of 2017 dollars
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	154,567	cubic feet
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED	2,217	cubic feet
TOTAL SCRAP METAL REMOVED:	69,526	tons
TOTAL CRAFT LABOR REQUIREMENTS:	1,337,834	man-hours

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX E

COST SENSITIVITY OF LONG-TERM, ON-SITE SPENT FUEL STORAGE

APPENDIX E

COST SENSITIVITY OF LONG-TERM, ON-SITE SPENT FUEL STORAGE

Introduction

As discussed in the last Decommissioning Cost Analysis for Wolf Creek issued in August 2014, developments in the area of spent nuclear fuel disposal suggest a possibility that the federal government may not have removed all of Wolf Creek's spent nuclear fuel and high-level radioactive waste (hereafter, simply "spent fuel") from the station by the time the plant has been decommissioned. There still is much uncertainty in this area. However, WCNOC asked TLG to consider that possibility, to make some assumptions regarding potential effects of the government's delayed removal of spent fuel from Wolf Creek, and to conduct a cost sensitivity analysis reflecting those assumptions. The following discussion is the result of that analysis. Because the assumptions used in this Appendix E analysis are so speculative at this point, the hypothetical cost effects shown here have not been included in the overall updated cost estimate in this report.

Congress passed the "Nuclear Waste Policy Act"[1] (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 Department of Energy (DOE). The NWPA provided that DOE would enter into contracts with generators in which DOE would promise to take the generator's spent fuel and high-level radioactive waste and the generators would pay the cost of the disposition services for that material. The NWPA, along with the individual contracts with the generators, specified that the DOE was to begin accepting spent fuel by January 31, 1998.

Since the original legislation, the DOE has announced several delays in the program schedule. By January 1998, the DOE had failed to accept any spent fuel or high level waste, as required by the NWPA and its contracts. Delays continue and, as a result, generators are no closer to shipping spent fuel today than in 1998.

Politically, the country is at an impasse on high-level waste disposal. The current administration has cut the budget for the geological repository program while promising to "conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle ... make recommendations for a new plan."[2] Towards this goal,

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1 "Nuclear Waste Policy Act of 1982 and Amendments," DOE's Office of Civilian Radioactive Management, 1982

2 Charter of the Blue Ribbon Commission on America's Nuclear Future, "Objectives and Scope of

the 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."[3]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of 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[4]
- "[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."[5]

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..."[6] This document states: "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

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Activities," http://www.brc.gov/index.php?q=page/charter

3 Ibid.

4 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," http://www.brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf, p. 32, January 2012

5 Ibid., p.27

6 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."

Completion of the decommissioning process (release of the entire site for unrestricted use) is highly dependent upon the DOE's ability to remove spent fuel from the site in a timely manner. DOE's repository program is currently based upon the premise that spent fuel allocations would be accepted for disposal from the nation's commercial nuclear plants, with limited exceptions, in the order in which it was discharged from the reactor (i.e., establishing a national "queue"). Even if spent fuel could be transferred to a federal facility for interim storage (in the absence of a permanent disposal facility), the nature of the queue would be expected to result in a long backlog of spent fuel at each site. Under the current system, as can be seen at sites where reactors have been decommissioned, the owner(s) can anticipate several decades of continuing, on-site storage of the spent fuel before the transfer could be expected to be complete.

It should be noted that the cost to dispose of the spent fuel generated from plant operations is not reflected within the estimates. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, until recently, the disposal cost was being financed by a 1 mill/kWhr surcharge on nuclear generated energy delivered to customers, the fee being paid into the DOE's waste fund during operations. The D.C. Circuit ruling on November 19, 2013, ordered the DOE to submit a proposal to Congress to suspend the Nuclear Waste Fund fee "until such time as either the Secretary chooses to comply with the Act as it is currently written, or until Congress enacts an alternative waste management plan". The fee was reduced to 0.0mill/kWh as of May 16, 2014. The fee is expected to be reinstated in the future.

Nonetheless, the NRC requires licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title to the fuel is transferred to the Secretary of Energy.[7] The post-shutdown costs incurred to satisfy this requirement are described below.

Base Analyses

The estimates described in the main report (and detailed in Appendix C and D) are based in general upon 1) a 2025 start date for DOE initiating transfer of commercial spent fuel to a federal facility, and 2) a 2032 start date for the transfer of spent fuel from the Wolf Creek site based on an "oldest fuel first" priority, and the DOE

7 U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

achieving an annual rate of transfer (3,000 metric tons of uranium per year) as reflected in DOE's latest Acceptance Priority Ranking and Annual Capacity Report.[8]

The assumed 2025 DOE start date is nominally based on the last position stated by the DOE. More importantly, the estimates assume that the DOE would give priority to fuel at shutdown sites,[9] i.e., it assumed that Congress would "(1)...direct the Department to take spent nuclear fuel from decommissioned commercial nuclear power reactors as soon as possible; (2) to establish an expedited siting process; and (3) to authorize the Department to construct and operate the facility under its regulatory authority, or, if the facility were to be constructed and operated under a U.S. Nuclear Regulatory Commission license, to provide for an expedited siting and licensing process."[10]

Under this scenario, once Wolf Creek permanently ceases operation, DOE would expedite the removal of spent fuel from the site. The cost estimates described in the main body of this report assumed that:

- The spent fuel pool would be at capacity following the final core off-load and contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core
- DOE would give priority to the spent fuel stored in the pool
- The spent fuel pool would be emptied within the first five and one-half years following plant shutdown.[11] This would allow decommissioning to be completed and the site released for unrestricted use within a relatively short time (see Figure 4.2) or placed into long-term storage without the need of maintaining/operating a spent fuel storage facility

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8 "Acceptance Priority Ranking and Annual Capacity Report," U.S. DOE, Office of Civilian Radioactive Waste Management, DOE/RW-0567, July 2004

9 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy," http://www.brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf, p. 42, January 2012: "[A]ccepting spent fuel according to the OFF 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."

10 "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

11 It is assumed that the five and one-half years provides the necessary cooling for the final core to meet transport requirements for decay heat

- The DOE is assumed to use its Transport, Aging and Disposal canister to empty the wet storage pool.[12] The canisters would be provided to WCNOC at no cost, however, Wolf Creek staff/or contractors would load, seal and transfer the multi-purpose canisters into a DOE-provided transport cask.
- Once the pool is emptied, the DOE would remove the spent fuel stored at the Wolf Creek Independent Spent Fuel Storage Installation (ISFSI). The current analysis assumes that 592 assemblies would be placed in dry storage during plant operations (i.e., maintain full core off-load capability in the spent fuel pool); 16 equivalent dry storage system modules.
- The ISFSI would be decommissioned in conjunction with the dismantling of the adjacent power block structures.
- Greater-than-Class C (GTCC)[13] material would be transferred directly to the DOE following the segmentation of the reactor internals.

Alternative Analysis

In 2008, the DOE issued a report to Congress in which it concluded that it did not have authority, under present law, to accept spent nuclear fuel for interim storage from decommissioned commercial nuclear power reactor sites.[14] It also concluded that legislation would be required that would eliminate the limitations in the Nuclear Waste Policy Act of 1982, as amended, on taking commercial spent nuclear fuel for interim storage prior to the opening of the Yucca Mountain repository.

For illustrative purposes only, this alternative analysis examines the impact of the status quo (i.e., the queue), on decommissioning and the resulting cost for long-term, on-site storage of the spent fuel generated during plant operations.[15] Under this scenario:

- DOE pickup of spent fuel would continue beyond the cessation of plant operations at the rates published for the Kansas Gas and Electric Company in the latest Acceptance Priority Ranking and Annual Capacity Report

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12 "Transport, Aging and Disposal Canister System Performance Specification," U.S. DOE, Civilian Radioactive Waste Management System, DOC ID: WMO-TADCS-000001, Rev.1, March 2008

13 U.S. Code of Federal Regulations, Title 10, Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste"

14 "Report to Congress on the Demonstration of the Interim Storage of Spent Nuclear Fuel from Decommissioned Nuclear Power Reactor Sites" DOE/RW-0596, December 2008

15 This analysis does not consider that the cost incurred would most likely be reimbursable as a result of DOE's breach of contract due to it non-performance

- Pickup of spent fuel beyond the last published date would be based upon the plant average of the previous ten years
- The residual inventory in the spent fuel pool after the five and one-half years of cooling would be transferred to the ISFSI
- Wolf Creek would utilize a dry storage system that can accommodate 37 assemblies per module
- The ISFSI would be expanded to accommodate the additional dry fuel storage modules needed to empty the spent fuel pool and the GTCC generated during the decommissioning (on the premise that the GTCC would not be accepted by the DOE until after the transfer of the spent fuel was completed)[16]
- WCNOC would operate the ISFSI and manage the spent fuel until such time that the DOE could complete the transfer to an off-site facility
- The DOE would accept the multi-purpose canister without the need for repackaging the assemblies, i.e., the DOE transport cask could accommodate the multi-purpose canister without modification
- WCNOC staff or WCNOC contracted staff would transfer the multi- purpose canister into the DOE-provided transport cask
- The concrete storage overpack and ISFSI pad would be decommissioned once the transfer is completed (2074)

The impact of these assumptions, as compared to the Base Analysis, is summarized as follows.

	Base Case	Alternative
Spent fuel pool inventory at shutdown (assemblies)	1,771	1,771
ISFSI inventory at shutdown (assemblies)	592	592
Spent fuel transferred to the DOE during plant ops	1,009	1,009
Spent fuel transferred to the DOE from pool during decommissioning (assemblies)	1,771	337
Spent fuel transferred to the ISFSI for interim storage within 5½ years after shutdown (assemblies)	0	1,434
Number of additional dry-storage modules need to support decommissioning (excluding GTCC)	0	39
Transfer of Spent Fuel to DOE Complete (year)	2050	2074

16 GTCC is assumed to be disposed of as it is generated in the base analysis, avoiding the need for interim storage

In essence, spent fuel is on site for additional 21 years after plant decommissioning (completion of site restoration), during which time WCNOC maintains and operates the ISFSI under a General (10 CFR Part 50) or Site-Specific (Part 72) license.

The alternative estimate is based upon a nominal value of $1.0 million for the capital cost of a dry storage module and an associated loading cost and transfer cost of $300,000 (from the wet pool to the ISFSI). A unit cost of $150,000 (one half the wet loading cost) was used for transferring the multipurpose canisters from the concrete overpacks at the ISFSI into the DOE-provided transport cask. All such numbers are based on comparative data. The alternative estimate does not include any costs for expanding the 16 cask-capacity ISFSI pad to the 60 casks capacity required for the alternative estimate.

The cost of operating an ISFSI, once decommissioning is complete, is shown in the following schedule, particularly in the years 2054 through 2074 following the decommissioning of Wolf Creek. Annual expenditures include the costs for:

- Periodic Spent Fuel Transfer
- Nuclear Insurance
- Property Taxes
- NRC ISFSI Licensing Fees and Oversight Costs
- Emergency Planning Fees
- ISFSI Operating Costs (maintenance budget, including energy, lighting, and remote surveillance systems)
- Security Staff (full time, round-the-clock)
- WCNOC Staff (for ISFSI operations, maintenance, and fuel transfer activities)

The schedule of expenditure in the following table delineates the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal). Costs are reported in 2017 dollars and are not inflated, escalated, or discounted over the period of expenditure.

Since it is assumed that the DOE would not accept GTCC waste prior to completing the transfer of spent fuel, the cost of GTCC disposal is shown in the final year of ISFSI operation (2074). This same cost is included during the decommissioning phase in the base analyses (e.g., in Table 3.1, during years 2046-2048 for the DECON alternative).

While this analysis attempts to capture the cost for long-term spent fuel management at the Wolf Creek site, under the scenario outlined above, it is WCNOC's position that

the DOE has a contractual obligation to accept Wolf Creek's fuel earlier than the projections set out above consistent with its contract commitments. No assumption made in this analysis should be interpreted to be inconsistent with this claim.

TABLE E
DECON ALTERNATIVE WITH LONG-TERM SPENT FUEL MANAGEMENT
SCHEDULE OF TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2045	58,996	4,282	1,969	33	9,446	74,727
2046	82,734	30,407	3,615	14,402	25,407	156,565
2047	78,739	38,176	2,307	32,769	12,765	164,756
2048	73,774	28,281	2,066	21,513	10,999	136,633
2049	68,573	18,553	1,821	10,505	9,232	108,683
2050	61,728	15,396	1,560	9,676	8,297	96,657
2051	43,584	5,662	664	2,885	4,615	57,409
2052	25,088	12,930	277	4	4,163	42,464
2053	16,174	9,051	179	0	3,750	29,154
2054	6,034	298	73	0	2,961	9,366
2055	6,034	298	73	0	2,961	9,366
2056	6,051	299	73	0	2,969	9,392
2057	6,034	298	73	0	2,961	9,366
2058	6,034	298	73	0	2,961	9,366
2059	6,034	298	73	0	2,961	9,366
2060	6,051	299	73	0	2,969	9,392
2061	6,034	298	73	0	2,961	9,366
2062	6,034	298	73	0	2,961	9,366
2063	6,034	298	73	0	2,961	9,366
2064	6,051	299	73	0	2,969	9,392
2065	6,034	298	73	0	2,961	9,366
2066	6,034	298	73	0	2,961	9,366
2067	6,034	298	73	0	2,961	9,366
2068	6,051	299	73	0	2,969	9,392
2069	6,034	298	73	0	2,961	9,366
2070	6,034	298	73	0	2,961	9,366
2071	6,034	298	73	0	2,961	9,366
2072	6,051	299	73	0	2,969	9,392
2073	6,034	298	73	0	2,961	9,366
2074	5,874	1,249	76	444	16,582	24,225
2075	2,636	1,130	58	2,717	3,081	9,621

TABLE E (continued)
DECON ALTERNATIVE WITH LONG-TERM SPENT FUEL MANAGEMENT
SCHEDULE OF TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
Total	638,669	171,087	16,049	94,948	167,591	1,088,344