ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

ROBERT "BOB" BURNS
CHAIRMAN
BOYD DUNN
COMMISSIONER
SANDRA KENNEDY
COMMISSIONER
JUSTIN OLSON
COMMISSIONER
LEA MARQUEZ PETERSON
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONALBE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES TO DEVELOP SUCH RETURN.	Docket No. E-01345A-19-0236

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Frank Radigan, John Cassidy and Jordy Fuentes in the above-referenced matter.

RESPECTFULLY SUBMITTED this 2nd day of October, 2020.

S/ Daniel W. Pozefsky
Daniel W. Pozefsky
Chief Counsel

ORIGINAL of the foregoing will be
e-filed this 2nd day of October, 2020 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

ACC - Docket Control - Received 10/2/2020 4:56 PM
ACC - Docket Control - Docketed 10/5/2020 8:12 AM

COPIES of the foregoing mailed/emailed this 2nd day of October, 2020, to:

Adam Stafford
Western Resource Advocates
P.O. Box 30497
Phoenix, AZ 85046
stacy@westernresources.org
adam.stafford@westernresources.org
steve.michel@westernresources.org
autumn.johnson@westernresources.org
Consented to Service by Email

Albert H. Acken
DICKINSON WRIGHT PLLC
1850 N Central Ave.,
Suite 1400
Phoenix, AZ 85004
aacken@dickinson-wright.com
Consented to Service by Email

Armando Nava
The Nava Law Firm PLLC
1641 E. Osborn Road, Suite 8
Phoenix, AZ 85016
Filings@navalawaz.com
Consented to Service by Email

Court Rich
ROSE LAW GROUP PC
7144 E Stetson Drive
Suite 300
Scottsdale, AZ 85251
CRich@RoseLawGroup.com
Consented to Service by Email

Daniel W. Pozefsky
RUCO
1110 W. Washington St., Ste. 220
Phoenix, AZ 85007
dpozefsky@azruco.gov
jfuentes@azruco.gov
procedural@azruco.gov
rdelafuente@azruco.gov
Consented to Service by Email

David Bender
EarthJustice
1001 G Street, NW, Ste. 1000
Washington DC 20001
dbender@earthjustice.org
Consented to Service by Email

Garry Hays
Law Office of Garry Hays PC
2198 E. Camelback Road
Suite 230
Phoenix, AZ 85016
Ghays@lawgdh.com
Consented to Service by Email

Giancarlo Estrada
KAMPER ESTRADA, LLP
3030 N. 3rd Street, Suite 770
Phoenix, AZ 85012
gestrada@lawphx.com
Consented to Service by Email

Greg Patterson
MUNGER CHADWICK/COMPETITIVE POWER ALLIANCE
5511 S. Jolly Roger
Tempe, AZ 85283
Greg@azcpa.org
Consented to Service by Email

Gregory M. Adams
515 N. 27th St.
Boise, ID 83702
greg.bass@calpinesolutions.com
Consented to Service by Email

Holly L. Buchanan
139 Barnes Dr., Ste. 1
Tyndall AFB, FL 32403
Holly.buchanan.1@us.af.mil
Consented to Service by Email

Jason Y. Moyes
MOYES SELLERS & HENDRICKS
1850 N. Central Ave., Ste. 1100
Phoenix, AZ 85004
jasonmoyes@law-msh.com
jim@harcuvar.com
jjw@krsaline.com
Consented to Service by Email

Jason R. Mullis
WOOD SMITH BENNING & BERMAN LLP
2525 E. Camelback Road, Ste. 450
Phoenix, AZ 85016
jmullis@wshblaw.com
greg.bass@calpinesolutions.com
greg@richardsonadams.com
Consented to Service by Email

John B. Coffman
John B. Coffman LLC
871 Tuxedo Blvd.
St. Louis, MO 63119
john@johncoffman.net
Consented to Service by Email

John S. Thornton
8008 N. Invergordon Rd.
Paradise Valley, AZ 85253
john@thorntonfinancial.org
Consented to Service by Email

Jonathan Jones
14324 N 160th Dr
Surprise, AZ 85379
jones.2792@gmail.com
Consented to Service by Email

Karen S. White
AFIMSC/JAQ
139 Barnes Ave
Tyndall AFB, FL 32403
Karen.white.13@us.af.mil
Consented to Service by Email

Kimberly A. Dutcher
NAVAJO NATION DEPARTMENT OF JUSTICE
PO Box 2010
Window Rock, AZ 86515
kdutcher@nndoj.org
aquinn@nndoj.org
Consented to Service by Email

Kurt J. Boehm
BOEHM, KURTZ & LOWRY
36 E. Seventh St. Suite 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com
jkylercohn@BKLlawfirm.com
Consented to Service by Email

MAJ Scott Kirk
AFLOA/JACE-ULFSC
139 Barnes Dr., Suite 1
Tyndall AFB, FL 32403-5317
Scott.kirk.2@us.af.mil
Consented to Service by Email

Marta Darby
Earthjustice
633 17th Street
Suite 1600
Denver, CO 80202
mdarby@earthjustice.org
Consented to Service by Email

Melissa M. Krueger
PINNACLE WEST CAPITAL CORPORATION
400 N. 5th Street, MS 8695
Phoenix, Arizona 85004
Melissa.Krueger@pinnaclewest.com
Thomas.Mumaw@pinnaclewest.com
Theresa.Dwyer@pinnaclewest.com
Andrew.Schroeder@aps.com
Leland.Snook@aps.com
rodney.ross@aps.com
ratecase@aps.com
Consented to Service by Email

Nicholas J. Enoch
LUBIN & ENOCH, PC
349 N. Fourth Ave.
Phoenix, AZ 85003
nick@lubinandenoch.com
bruce@lubinandenoch.com
clara@lubinandenoch.com
Consented to Service by Email

Patricia Madison
13345 W. Evans Drive
Surprise, AZ 85379
Patricia_57@q.com
Consented to Service by Email

Patrick J. Black
Fennemore Craig, P.C.
2394 E. Camelback Road
Suite 600
Phoenix, AZ 85016
pblack@fclaw.com
lferrigni@fclaw.com
Consented to Service by Email

Richard Gayer
526 West Wilshire Drive
Phoenix, AZ 85003
rgayer@cox.net
Consented to Service by Email

Robert A. Miller
PROPERTY OWNERS AND RESIDENTS
ASSOCIATION OF SUN CITY WEST
12817 W. Ballad Drive
Sun City West, AZ 85378-5375
Bob.miller@porascw.org
rdjscw@gmail.com
Consented to Service by Email

Robin R. Mitchell
Director & Chief Counsel - Legal Division
ARIZONA CORPORATION COMMISSION
1200 W. Washington Street
Phoenix, Arizona 85007
legaldiv@azcc.gov
utildivservicebyemail@azcc.gov
Consented to Service by Email

Scott S. Wakefield
HIENTON CURRY, P.L.L.C.
5045 N 12th Street, Suite 110
Phoenix, AZ 85014-3302
swakefield@hclawgroup.com
Stephen.Chriss@walmart.com
Consented to Service by Email

Shelly A. Kaner
8831 W. Athens St.
Peoria, AZ 85382

Thomas Harris
Distributed Energy Resource Association (DERA)
5215 E. Orchid Ln
Paradise Valley, AZ 85253
Thomas.Harris@DERA-AZ.org
Consented to Service by Email

Thomas A. Jernigan
AFIMSC/JAU
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5317
Thomas.jernigan.3@us.af.mil
Consented to Service by Email

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
514 W. Roosevelt St.
Phoenix, AZ 85003
ezuckerman@swenergy.org
thogan@aclpi.org
briana@votesolar.org
sandy.bahr@sierraclub.org
louisa.eberle@sierraclub.org
janderson@aclpi.org
sbatten@aclpi.org
czwick@wildfireaz.org
cpotter@swenergy.org
miriam.raffel-smith@sierraclub.org
rose.monahan@sierraclub.org
brendon@gabelassociates.com
Consented to Service by Email

By *s/ Renee de la Fuente*
Renee de la Fuente

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-19-0236

PUBLIC

DIRECT TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

OCTOBER 2, 2020

TABLE OF CONTENTS

Page

INTRODUCTION **1**

PURPOSE OF DIRECT TESTIMONY **3**

ADJUSTMENTS TO RATE BASE **6**

Post Test Year Plant Additions and Accumulated Depreciation 6

FOUR CORNERS SELECTIVE CATALYTIC REDUCTION EQUIPMENT **10**

ADJUSTMENTS TO OPERATING EXPENSES **17**

Property Taxes 17
Cash Incentive 17
Executive Compensation 20
Industry Association Dues 21
Directors and Officers Insurance Expense 22
Four Corners Deferral 24
Post Test Year Plant Depreciation Expense 24
Regulatory Asset Amortization 25
Depreciation and the Company's Proffered Depreciation Study 26

SECTION 1 – DEPRECIATION BACKGROUND **27**

SECTION 2 – AVERAGE SERVICE LIFE ANALYSIS **32**

SECTION 3 – NET SALVAGE ANALYSIS **41**

CONCLUSION **43**

EXHIBITS

Resume of Frank W. Radigan FWR-1
RUCO Schedules A, B and C FWR-2
APS Clean Energy Commitment FWR-3
APS Response to Sierra Club discovery question 1.3 ..... FWR-4
Commissioner Burns letter August 11, 2020 ..... FWR-5
APS Letter to Docket Control in Reply to Commissioner Burns 8-11-20 Letter FWR-6
Excerpts from APS- 2019 FERC Form 1 ..... FWR-7
Excerpt from APS 2017 IRP – Portfolio Summaries FWR-8
Excerpt from APS 2017 IRP – Carbon Reduction Discussion FWR-9
Excerpt from APS 2017 IRP – Chart of 2032 System Average Costs by Portfolio FWR-10
Calculations of APS Return of and Return on Four Corners Investment FWR-11
APS DR Response confirming 2-Year lag on Property Tax for New Plant FWR-12
APS Annual Incentive Award Plan – REDACTED FWR-13
Award Plan 2019 Results – REDACTED FWR-14
APS Response to AECC Discovery Question on Cash Incentives FWR-15
APS Response to Initial Discovery Question 1.40 regarding Cash Incentive FWR-16
Commissioner Burns September 1, 2020 regarding APS Upper Management Compensation FWR-17
APS Responses to various Discovery Responses on Membership Dues FWR-18
Details on Membership Dues FWR-19
APS Response on Directors and Officers Liability Insurance FWR-20

List of APS' regulatory assets FWR-21
Account 361 – Graph and depreciation data FWR-22
Account 362 – Graph and depreciation data FWR-23
Account 364 – Graph and depreciation data FWR-24
Account 365 – Graph and depreciation data FWR-25
Account 366 – Graph and depreciation data FWR-26
Account 367 – Graph and depreciation data FWR-27
Account 369 – Graph and depreciation data FWR-28
Account 371 – Graph and depreciation data FWR-29
Account 373 – Graph and depreciation data FWR-30
Net Salvage Data for Accounts 365 and 367 ..... FWR-31

EXECUTIVE SUMMARY

Arizona Public Service Company ("APS" or "Company") is an Arizona Corporation, and for profit, certificated Arizona public service Corporation that provides electric utility service to more than 1.2 million customers in Arizona various communities throughout Arizona. APS filed its rate case on October 31, 2019 in accordance with the ACC's Decision No. Decision No. 77270 which recognized, a number of factors have changed since the conclusion of APS's last rate case, including items such as APS's investment in plant and infrastructure, revenue and expenses, the cost of capital, customer growth, and billing determinants.

The Company utilized a test year ended June 30, 2019 and the Company-proposed rates, as filed, produce total base rate revenues of $3.347 billion an increase of $183.6 million. The Company-proposed revenue will provide operating income of $657 million for a 5.34% rate of return on its proposed $12.3 billion fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total base rate operating revenues of $3.143 billion a decrease of an increase of $135.8 million. RUCO would allow the transfer of the Tax Expense Adjustor Mechanism to base rates which had the effect of reducing the proposed rate decrease in customer's bills to $20.773 million. RUCO's recommended revenue will provide operating income of $548.6 million and a 4.69 percent return on the $11.699 billion RUCO-adjusted FVRB (see RUCO Exhibit FWR-2)

Other Items:

RUCO recommends denial of the request to consider including the rate effects of the Four Corners Selective Catalytic ("SCRs") reduction equipment at this time. This reduces net plant by $432 million, pro-forma depreciation expense by $27.6 million, and a $8.2 million proforma adjustment for the amortization of the Four Corners SCR deferral.

RUCO recommends Post-Test Year Plant Additions of $608 million rather than the $773 million requested.

RUCO recommends reducing the pro-forma deprecation adjustment related to PTYP additions from $37.5 million by $7.9 million.

RUCO recommends denial of the requested $11.1 million pro-forma property tax adjustment on post test year plant

RUCO recommends reducing the Company's expense for cash incentive by $27.7 million to reflect a more appropriate sharing of this expense item between shareholders and ratepayers.

Because of the duality of benefits of membership dues and liability insurance for Directors and Officers, RUCO recommends a 50/50 sharing of costs between shareholders and ratepayers and recommends reducing expense for these items by $2.2 million.

RUCO recommends a reduction of $27.9 million related to the proposed deprecation rates for the Company's proposed Distribution plant depreciation rates.

RUCO recommends a $80.0 million increase in amortization expense in order to accelerate the Company's existing production related stranded.

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas, steam, and water utility industry matters, and specializing in the fields of rates, planning, depreciation, and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. PLEASE DESCRIBE THE HUDSON RIVER ENERGY GROUP.

A. The Hudson River Energy Group ("HREG") is an engineering consulting firm specializing in the fields of rates, planning, economics, and utility operations for the electric, natural gas, steam, and water utility industries. HREG was founded in 1998 and has served a wide variety of clients including municipal utilities, government agencies, state commissions, consumer advocates, law firms, industrial companies, power companies, and environmental organizations. HREG conducts rate design and cost of service studies, and designs performance-based rate plans. HREG also assists clients in handling the complexities of deregulation and restructuring, including Open Access Transmission Tariff pricing, unbundling of rates, depreciation, resource adequacy, transmission planning policies and power supply. During HREG's existence, we have proffered our expertise before the Federal Energy Regulatory Commission ("FERC") and a large number of state utility regulatory commissions across the country.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now known as "Clarkson University") in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the

Staff of the New York State Department of Public Service (the "Department") in the Rates and System Planning Sections of the Power Division as well as service in the Rates Section of the Gas and Water Division. My responsibilities included resource planning and the analysis of rates, depreciation rates, and tariffs of electric, gas, water, and steam utilities in the State. I also received specialized training in depreciation from Depreciation Programs, Inc. through a series of week-long intensive training programs and which predated the current depreciation society, Society of Depreciation Professionals. These duties also encompassed rate design, embedded and marginal cost of service studies, and depreciation studies. Before leaving the Department, I was responsible for directing all engineering staff during major proceedings, including those relating to rates, integrated resource planning ("IRP"), and environmental impact studies. In February 1997, I left the Department and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own consulting firm.

In my 39 years of experience, I have testified as an expert witness in utility rate proceedings on more than one hundred and forty occasions before various utility regulatory bodies, including: the Arizona Corporation Commission, the Connecticut Department of Public Utility Control (now the Connecticut Public Utilities Regulatory Authority), the Delaware Public Service Commission, the Kentucky Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the Mississippi Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission,

the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and FERC. Currently, I advise a variety of regulatory commissions, consumer advocates, municipal utilities, and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my professional qualifications and experience, including a listing of cases in which I have proffered testimony, is attached (see Exhibit FWR-1).

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes.

PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present RUCO's recommended revenue requirement including the rate of return and cost of capital information presented by RUCO witness John Cassidy, the rate impact of the recommendations being made by RUCO's Director Jordy Fuentes and RUCO Schedules A, B and C. I also address rate base related areas of post-test year plant, inclusion of the Four Corners Selective Catalytic Reduction Equipment in rate base, and rate treatment of regulatory assets. I also address operating expenses relating to the Company's deprecation study, the rate treatment of the Company's cash incentive program, property taxes on post test year plant, depreciation expense related to post test

year plant, industry association dues, and Directors and Officers Liability Insurance Expense.

Q. WHAT INFORMATION DID YOU REVIEW IN CONDUCTING YOUR ANALYSIS?

A. I reviewed the Application and direct testimony of APS, responses to data requests, and public information.

Q. PLEASE SUMMARIZE RUCO's RECOMMENDATIONS.

A. The RUCO recommends rates that produce total base rate operating revenues of $3.143 billion a decrease of $135.8 million. RUCO would allow the transfer of the Tax Expense Adjustor Mechanism to base rates which had the effect of reducing the proposed rate decrease in customer's bills to $20.773 million. RUCO's recommended revenue will provide operating income of $548.6 million and a 4.69% return on the $11.699 billion RUCO-adjusted FVRB (see RUCO Exhibit FWR-2 which contains the RUCO A, B and C Schedules). The RUCO recommended decrease of $20.773 million included the 8.94% return on equity recommended by RUCO witness John Cassidy, which results in an overall return of 6.75%. The RUCO revenue requirement also reflects Mr. Cassidy's recommendation that the Fair Value increment be set at 0%. RUCO also recommended <u>reduction</u> to the Company's authorized Return on Equity ("ROE"), of 20 basis points, from 8.94% to 8.74% for the Company's customer service performance as discussed and recommend by RUCO witness and Director Jordy Fuentes. Mr. Fuentes recommended adjustment alone results in a $12.1 million-dollar annual decrease and is included in the $20.773 million reduction.

Based on my review of the Company's rate application and the supporting workpapers, I propose a few adjustments to the Company's position. My adjustments are as follows:

Remove $165 million of post-test year gross plant from rate base as it was either not built or was not of sufficient dollar value to be significant to a utility of this size and therefore would not impacts the utility's financial health from its exclusion (Exhibit FWR-2, Schedule B-2, Adjustments B-2-1 through B-2-5 inclusive).

Remove the Four Corners Selective Catalytic Reduction Equipment from rate base which reduces net plant by approximately $399 million which was the 12/31/2019 net plant balance for the reasons as discussed within this testimony (Exhibit FWR-2 Schedule B-2, Adjustment B-2-6).

Reverse the $33 million pro-forma adjustment to net plant balance for the Four Corners SCR deferral balance as the SCRs should not be considered at this time (Exhibit FWR-2, Schedule B-2, Adjustment B-2-8).

Remove the unsupported $11.1 million for property taxes on post-test year plant additions (Exhibit FWR-2, Schedule C-2, Adjustments C-2-1 through C-2-5 inclusive).

To recognize the reduction in pro-forma PTYP additions reduce the requested prof-forma expense adjustment of $37.5 million downward by $7.9 million (Exhibit FWR-2, Schedule C-2, Adjustments C-2-1 through C-2-5 inclusive).

Remove the ACC jurisdictional $5.1 pro-forma adjustment to operating expenses for the "normalization" of the Company's cash incentive program (Exhibit FWR-2, Schedule C-2, Adjustments C-2-8).

Remove $24.6 million of the cash incentive program being requested in rates out of the total $32.8 million paid to employee to reflect the proper sharing of shareholder/ratepayer benefit. This reduces ACC jurisdictional operating expenses by $22.6 million (Exhibit FWR-2, Schedule C-2, Adjustment C-2-9).

Because of the duality of benefits, I recommend all membership dues be shared 50/50 between ratepayers and shareholders and recommend operation and maintenance expense be reduced by $1.8 million (Exhibit FWR-2, Schedule C-2, Adjustment C-2-11).

Since liability insurance not only benefits ratepayers, but also shareholders, RUCO recommends a 50/50 sharing between ratepayers and shareholders. This recommendation reduces operation and maintenance expense by $0.4 million (Exhibit FWR-2, Schedule C-2, Adjustment C-2-11).

Consistent with my recommendation that it is premature to consider the impact of the Four Corners SCRs in this rate proceeding, I recommend reversing the Company's proposed $8.2 million pro-forma adjustment to operating expenses for an amortization of the Four Corners deferral (Exhibit FWR-2, Schedule C-2, Adjustments C-2-1 through C-2-6).

Consistent with my recommendation that it is premature to consider the impact of the Four Corners SCRs in this rate proceeding, I recommend reversing $27.6 million of the Company's recommended $27.2 million pro-forma adjustment to steam production depreciation expense related to the inclusion of the Four Corners SCR in rate base. This decrease the proposed pro-forma depreciation expense adjustment by $27.6 million (Exhibit FWR-2, Schedule C-2, Adjustment C-2-12).

To reflect my proposed average service lives and net salvage rates for the distribution plant accounts, reduce the Company's proposed pro-forma depreciation expense adjustment by $27.9 million (Exhibit FWR-2, Schedule C-2, Adjustment C-2-12).

To increase the write down of the Company's outstanding balance of unused and non-useful regulatory assets associated with generating plants, increase the amortization write-off of these assets in the amount of another $80.00 million per year (Exhibit FWR-2, Schedule C-2, Adjustment C-2-7).

ADJUSTMENTS TO RATE BASE

Post Test Year Plant Additions and Accumulated Depreciation

Q. PEASE DISCUSS THE COMPANY'S PRESENTATION ON POST TEST YEAR PLANT ADDITIONS?

A. The Company is proposing to include plant additions that go into service after the Test Year, but well before new base rates are expected to be in effect (the post test year period proposed by the Company is July 1, 2019 to June 30, 2020). APS is requesting a total of $773.3 million in total Company capital expenditures in five major business areas: renewable generation, technology innovation, nuclear

generation, distribution (including information technology and facilities), and fossil generation. Company witness Elizabeth Blankenship addresses the mechanics of the pro-forma adjustment and Company witness Barbara Lockwood presents the detail of the Post-Test Year Plant ("PTYP") additions by plant category (See Blankenship at 19-21 and Lockwood at 15-20). The sum of the forecast plant in service costs, less accumulated depreciation and deferred income taxes, was presented by functional unit and included in the Rate Base pro forma adjustments (Blankenship at 21). Property taxes, income taxes, and depreciation expense were calculated and reflected as pro-forma adjustments to operating expenses. The Company also proposes to roll forward the Test Year Depreciation for the Post Test Year Period.

Q. PLEASE COMMENT ON THE REASONABLENESS OF THE COMPANY'S PROPOSAL.

A. The Commission has opened a generic docket to set a policy specifically on PTYP which is ongoing, Docket AU-00000A-19-0080. Among the issues being examined are whether PTYP additions should be limited by time (no more than 6 months from the end of the test year or 12 months) or some other criteria. Criteria that are being considered by parties (1) allowance in only special or unusual situations (2) is the magnitude of the PTYP investment relative to the utility's total investment such that not including the PTYP in the cost of service would jeopardize the utility's financial health, (3) the cost of the PTYP is significant and substantial (4) the investments are not being made to generate or support system growth or new customers; (5) the plant additions are prudent and reflects appropriate and timely decision-making; and, (6) the investments can be verified as to whether they are/will be in service by the date of the hearing in the docket. It is my understanding that all stakeholders in the generic proceeding seem to agree that at a minimum the PTYP must be in

service by the end of the Post test year, the plant must be used and useful and the plant must be revenue neutral.

The Company's presentation in testimony did not specifically address many of the criteria listed above. For example, the Company states that the PTYP projects at the Palo Verde Nuclear Generating Station will ensure continued safe, reliable, and efficient generation at the station for the long term, and provide customers with clean energy for many years to come (Lockwood at 17). On the other hand, APS does roll forward all accumulated depreciation and excludes revenue producing plant which are significant issues being considered in the generic docket (Blankenship at 21 and 20 respectively).

As I reviewed the Company's request on PTYP, the project list and its finances I can see that the utility is trying to strike some sort of balance between its needs and that of its ratepayers. The exclusion of revenue producing plant and the reflection of accumulated depreciation expense go a long way in this regard. On the other hand, many of the projects are relatively small for a utility as large as APS with cash available through depreciation expense on the order of $450 million per year.

Projects such as the purchase of a spare generator at the Palo Verde Generating Station at a cost of $1,518,257 (See Attachment BDL-3DR, project no. 21) and its inclusion or exclusion from this rate case will not impact APS's financial health. There are many projects of this size and type on the list of projects that APS proposes to include in PTYP.

I believe a reasonable balance for PTYP for this utility is one that considers the timing of the project, its size, and the fact that it is in service by the conclusion of the requested time period requested.

Another factor, which is significant, and separates APS from all other utilities in Arizona, is its recognition that if the Company is going to ask for significant PTYP, it is only fair to the ratepayers that the test year accumulated depreciation be rolled forward for the post test year. Arizona utilizes a historical test year, and while the Commission's Rules allow for pro-forma adjustments, there is an inherent unfairness to ratepayers to consider only the plant and its associated depreciation in rate base for an extra year beyond the test year. Rolling forward the test year A/D does not solve the unfairness or eliminate the matching concerns, but it does ameliorate the inherent unfairness associated with the PTY plant. It also ameliorates the harm of regulatory lag from the ratepayers perspective in that the ratepayer will be credited for paying down the plant prior to the next rate case.

Given APS' position on the roll forward of test year A/D and the significant benefit it provides ratepayers, RUCO looks at the issue of PTYP in this case differently than others and is willing to reconsider some of the other traditional criterion. As such, using an updated project list of proposed PTYP projects I came up with a criterion that 1) if a project was complete by December 31, 2019 it would be included regardless of size and 2) if a project was complete by June 30, 2020 it could be included if the expenditures were over $5,000,000.

Given the delay in the procedural process in this case, allowing any PTYP up through December 31, 2019 seems reasonable since those projects have all been in service for at least nine months (January 1, 2020-September 30, 2020) and the

utility should be allowed to start earning a return on its investment. As to the projects after that, however, there should still be an examination of their significance to the utility's financial well-being. I used the $5 million threshold as a project so small that it would not need upper management approval for a utility of this size but rather under normal business operation be handled under a blanket work order or middle management. Many utilities in my experience use project cost size as a delimitators for management approval and I chose $5 million as small given that APS has been spending approximately $1 billion per year. By applying this criteria, $608 million of the $734 million that went into service by June 30, 2020 should be allowed as significant enough to be included as PTYP.

FOUR CORNERS SELECTIVE CATALYTIC REDUCTION EQUIPMENT

Q. PLEASE DISCUSS THE ISSUE OF THE FOUR CORNERS SELEVCTIVE CATALYTIC REDUCTION ("SCRs") EQUIPMENT AS IT RELATES TO THIS PROCEEDING?

A. Arizona Public Service Company ("APS") filed its rate case on October 31, 2019 in accordance with the ACC's Decision No. Decision No. 77270 which recognized, a number of factors have changed since the conclusion of APS's last rate case, including items such as APS's investment in plant and infrastructure, revenue and expenses, the cost of capital, customer growth, and billing determinants. Included in the rate filing is a request to include the costs, of the recently completed installation, of the Four Corners SCRs equipment, on Units 4 and 5 at the 970 MW Four Corners Generating Station, owned by APS located near Fruitland, New Mexico. The installation of the SCRs was mandated by the Federal Government under the provisions of the Clean Air Act. The cost to APS for its share of the plant

to install the SCRs was approximately $467 million[1] and its cost recovery is subject to a separate proceeding, E-01345A-16-0036, which has an existing recommended opinion and order (ROO issued 11/27/18) from an Administrative Law Judge concluding the project was prudent and the cost should be included in APS's base rates.

In this proceeding, when summarizing the rate request, APS President Jeffrey Guldner stated that it is important to note that the overall bill impact includes the SCR project at Four Corners and that the environmental upgrade has undergone its own regulatory process and currently has an existing ROO, concluding the project was prudent and the cost should be included in APS's base rates (Guldner at 5). He further stated that APS recommends the ROO be preserved, and the SCR project to stay on its own separate path (Id). Mr. Guldner concluded that with that in mind, the additional revenue request from this rate case is $111 million and should the Commission elect to rule on these two items simultaneously, the impact to customers would be $184 million (Id).

Q. ARE THERE ANY OTHER FACTS THAT SHOULLD BE CONSIDERED WHEN DISCUSSING THE FOUR CORNERS SCRs?

A. Yes, On January 22, 2020 APS issued a press release announcing its newly adopted Clean Energy Commitment which is centered around a goal to deliver 100 percent clean, carbon-free electricity to customers by 2050 (See Exhibit FWR-3). The goal includes a nearer-term 2030 target of achieving a resource mix that is 65 percent clean energy, with 45 percent of our portfolio coming from renewable energy. APS will end all coal-fired generation by 2031, seven years sooner than

[1] The SCR equipment on Unit 5 was completed on December 17, 2017. The SCR equipment on Unit 4 was completed in April 2018. The cost of plant additions associated with this environmental compliance in 2017 and 2018 was approximately $467 million (APS response to Sierra Club Discovery question 2.4).

previously projected (Id). The only coal fired generation that APS is schedule to have in 2031 is the Four Corners Generating Station, which had approximately $1.1 in net plant costs on the books at the end of 2019 (Exhibit FWR-4, APS Response to Sierra Club discovery question 1.1). To date, APS has not updated is rates request to reflect the rate impact of its Clean Energy Announcement and the accelerated retirement of the Four Corners generating station.

In response to APS' announcement, ACC Commissioner Burns wrote a letter to this rate case Docket, on August 11, 2020, and noted that with the early closure of Four Corners there will be stranded costs from the plant that will need to be recovered (Exhibit FWR-5). Commissioner Burns requested that APS develop and submit a comprehensive analysis of the rate impacts, of the early retirement, for the Commission's consideration in this rate case. Included in this analysis, Commissioner Burn's specifically asked for the utility to examine the issue of "securitization" as a means to minimize rate impacts (Id). Securitization is a financing mechanism that allows a utility to recover costs by issuing bonds, with lower than normal financing costs, thereby saving customers money. The Commissioner also asked the Company to review scenarios where the plant was to be retired in 2026 and 2029. APS is required to supply that analysis by October 2, 2020 but APS has requested it have until November 6, 2020 to adequately produce the requested analysis (Exhibit FWR-6).

Q. COULD YOU PLEASE DISCUSS THE COST TO OPERATE AND SUPPORT THE FOUR CORNERS PLANT?

A. Yes, as I discussed above the net book plant cost of Four Corners at the end of 2019 was $1,094,255 (Exhibit FWR-4). With APS's requested 7.41% requested rate of return, after accounting for the income taxes due on the return, the return to

investors for the plant was approximately $108 million per year. Depreciation expense for the plant in 2019 was approximately $37 million and the cost for property insurance and property taxes was approximately $9 million (Id). From APS' FERC Form 1, we know that the cost for fuel, operation and maintenance in 2019 was approximately $250 million (Exhibit FWR-7, page 3, line 34, columns (d) and (e)) which results in a total cost of $ 405 million. With generation at the plant in 2019 being approximately 5.5 million MWh (Id), the per unit cost to get power from the station in 2019 was $73 per MWh.

Q. HOW DOES FOUR CORNERS COMPARE TO OTHER ENERGY SOURCES?

A. APS estimates its avoided cost, for the 2020-2024 time period, in the range of $21/MWh to $24 per MWh (See Attachment BJA-1DR). This includes avoided cost for energy and capacity (including generation, transmission and distribution capacity). APS reports that purchases at the Palo Verde wholesale market trading hub, traded during the non-summer months of 2019, at $20-$40 per MWH. APS also reports that during the summer months of 2019, energy at the Palo Verde hub was trading at $30-$50 per MWH (See APS witness Albert at page 10, Figure 4). On either of these metrics the all-in cost of Four Corners is expensive.

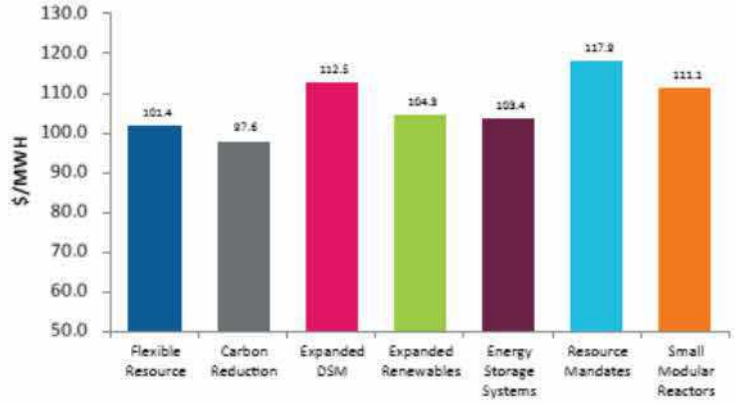
Q. HAS APS STUDIED THE POSSIBILITY OF RETIRING FOUR CORNERS BEFORE THE CLEAN ENERGY COMMITMENT?

A. Yes, APS studied abandoning coal in its 2017 IRP, under a portfolio titled carbon reduction. The results of comparing alternate portfolios led APS to choose a flexible resource portfolio as its preferred alternative. In its IRP, APS described the flexible resource portfolio as follows:

> The Flexible Resource Portfolio is designed to deliver an increasingly flexible set of resources that does not overly rely on one specific fuel source during the 15-year Planning Period. It incorporates a significant level of rooftop solar generation expected to be installed by APS customers, adds approximately 50 MW per year of peak demand reducing DSM programs, over 500 MW of energy storage systems, microgrids, demand response and flexible gas generation. It recognizes the economically and operationally challenging environment for coal power plants and accordingly assumes that APS will no longer receive coal-fired generation from the Navajo Generating Station after 2019, and no longer burn coal at Cholla Units 1 and 3 beyond 2024. The reduced coal capacity along with the increase in flexible energy storage and natural gas generation allows APS customers to benefit from the low wholesale market prices being created by neighboring states with high renewable mandates. (Exhibit FWR-8, excerpt from APS 2017 IRP at 120).

In reviewing the carbon reduction scenario APS ranked it second and commented that "The Carbon Reduction Portfolio has slightly higher costs than the Flexible Resource Portfolio in the 15-year NPV, and slightly lower in the 30-year NPV." (Exhibit FWR-9 Id at 128). In addition, in 2032 the carbon reduction scenario also had the lower system average cost which indicates how close the economics of the two portfolios were. The 2032 system average costs by portfolio from the APS 2017 IRP, as shown on the chart below, which was copied from the APS 2017 IRP (Exhibit FWR-10).

FIGURE 7-19. SYSTEM AVERAGE COST IN 2032



Q. PLEASE DISCUSS THE CONSEQUENCES OF THE PROPSED EARLY RETIREMENT TO BOTH RATEPAYERS AND SHAREHOLDERS?

A. If I were an APS ratepayer, I would be shocked to learn that the utility now wants to retire the plant seven years early so shortly after they invested so much money into the plant. I would also be shocked that 40% of the 5.6% increase in rates requested was due solely to paying for the SCRs that the utility seems so willing to dispose of seven years early. This certainly does not seem to be the deal that ratepayers bargained for when the Company originally bought it before the Commission for approval – nor the deal when the Commission originally approved it.

For the Company, the rate case as filed, there is simply no downside consequences whatsoever. Perhaps worse, is that if approved, it will be the ratepayers who will be held entirely at risk, not the shareholders for a situation that the Company proposed and maintained would be in the best interests of its customers. If the APS rate request is approved as proposed, the utility estimates its revenue requirement will increase by $73 million on top of the revenues already being provided to support the plant. This amount includes a full recovery on its requested rate of return, 7.41%, on its net plant investment in total Four Corners plant – net plant balance of $1,0944,255. This rate of return available to APS shareholders equates to approximately $73 million per year after rates are reset. Moreover, since the ROO in the SCR proceeding has a finding that concludes the project was prudent and the cost should be included in APS's base rates, if the Company's proposal were allowed it would guarantee the profits. It will also allow the Company to earn a return on its full Four Corners investment out until 2038 for shareholders in the amount of approximately $677 million. If that happed, approximately $93 million of this $667 million amount would be earned by the Company after the plant is retired and is no longer used nor useful. I should also mention that under the Company's proposal it would also get full recovery of its initial investment of approximately $1.1 billion for a total cash flow relating

to return on and return of investment for Four Corners in the amount of $1.7 billion (Exhibit FWR-11).

I think it fair to conclude that if APS ratepayers were told of these consequences less than two year after investing $465 million in the plant, their reaction would change from shock to incensed. As such, I believe that it is necessary that the Commission examine the issue of securitization, as well as other issues associated with the Four Corners situation including the study of retiring the plant even earlier than that proposed by APS. RUCO eagerly awaits the Company's report.

Q. SHOULD THECOMMISSION CONSIDER THE ROO FROM THE SCR PROCEEDING AT THE SAME TIME AS THE RATE PROCEEDING AS APS SUGGEST?

A. No. The APS Clean Energy Commitment and its resultant stranded costs warrant careful examination of the rate impacts. Moreover, the early retirement of Four Corners will result in an installed capacity shortfall that must be replaced which also result in a rate impact. To date, as I mentioned previously, APS has not updated is rates request to reflect the rate impact of its Clean Energy Announcement and the accelerated retirement of the Four Corners generating station. Accordingly, without the benefit of that analysis, I believe it would be premature for RUCO to endorse the utility's request to include the costs of the SCRs in base rates at this time and the Commission should eliminate the SCRs from the revenue requirement in this proceeding at this time. The adjustment to rate base of reduction of $399 million to net plant has been reflected in my Schedule B-2 attached. This recommendation is also the reason for reversing the proposed pro-forma rate base adjustment of $33 million net plant for the Four Corners SCR deferral balance.

ADJUSTMENTS TO OPERATING EXPENSES

Property Taxes

Q. PLEASE COMMENT ON THE COMPANY'S REQUEST TO INCLUDE PROPERTY TAXES ON THE POST TEST YEAR PLANT ADDITIONS?

A. As part of the Company's request to include one year of post-test year plant additions to rate base, there is also components to the operating expenses of depreciation expense, related to the plant and property taxes that will be eventually be imposed when the new plant enters the tax rolls. The property taxes relating to the post-test year plant amounts to $11.06 million.

There is no testimony from a Company witness explaining why the Company believes this expense is reasonable and should be included in the revenue requirement. Moreover, in the Company's last rate proceeding, the Company acknowledged that there is generally a lag between when plant goes into service and when it is recognized on the tax rolls and the utility is subject to pay property taxes on it (Exhibit FWR-12). That lag is two years and the expense will not be incurred until after rates go into effect in this case. Accordingly, I can find no support for the Company request for this operating expense and recommend it not be considered. This recommendation reduces operating expenses by $11.060 million.

Cash Incentive

Q. PLEASE DISCUSS THE ISSUE OF CASH INCENTIVE.

A. Company witness Elizabeth Blankenship sponsors a pro forma adjustment to operating expenses which increase ACC jurisdictional expenses by $5.146 million (Blankenship direct at page 27). The adjustment is for the Company Cash Incentive program which is paid to employees. The Cash Incentive program is formally titled the Annual Incentive Reward Plan ("the Plan") which has the main objective of ensuring APS' workforce efforts are aligned with the APS business plan, tiered

metrics and supporting initiatives (Exhibit FWR-13). The Plan objective goes on to say that achieving annual goals, we work to continue to strengthen APS' financial performance over the long term (Id). The Plan further states that these objectives are measured financially, by business unit performance, and by individual performance (Id). In support of her proposal, Company witness Blankenship states that the use of a three-year normalization of cash incentive expense was first proposed by Staff and endorsed by the Commission in Decision No. 71448.

Q. PLEASE COMMENT ON THE REASONABLENESS OF THE COMPANY'S PROPOSAL.

A. I researched Docket E-01345A-08-172, which was the subject of Decision No. 71448, and found that the decision adopted a settlement in which incentive compensation was not addressed. As such, it should not be used as precedent. Also, I note that Staff in the Company's last rate proceeding, rejected a similar normalization adjustment and instead proposed sharing the cost of the cash incentive program 50/50 between shareholders and ratepayers (See Docket E-01345-16-0036, Staff Witness Ralph Smith Direct at pgs. 81-89). Moreover, in the Docket, Staff listed a long string of Commission decisions which supported a position on the proper sharing of such an expense between ratepayers and shareholders[2].

[redacted]

[2] Decision No. 70011with respect to UNS Gas, Decision 70360 with respect to UNS Electric, Decision No. 68487with respect to Southwest Gas Company, Decision No.70665 with respect to Southwest Gas Company, Decision 71623 with respect to UNS Gas, and Decision 71914 with respect to UNS Electric.

[redacted] I believe it is reasonable to assign 50% to shareholders and 50% to ratepayers. The remaining 50% is already due solely to shareholders. This results in a weighted average of 75% shareholders and 25% ratepayer.

Q. WHAT ADJUSTMENTS RESULT FROM THIS RECOMMENDATION?

A. There are three adjustments that need to be made. The first adjustment is to reject the proposed normalization of the cash incentive amount, as there is no true basis for the $5.612 million adjustment. The second adjustment is to allow only 25% of the amount being requested in rates. The Company states the test year amounts is $32.789 million (Exhibit FWR-16) and a 75% reduction of this amount lowers test year operating expenses

by $25.592 million (Exhibit FWR-2, Schedule C-2, Adjustment C-2-8). The third adjustment relates to rate base. The Company states that incentive compensation follows payroll so there is also a portion of the incentive compensation that gets capitalized. The Company states that there were $9.1 million of incentive compensation capitalized in 2018 and $8.0 million capitalized in 2019. I recommend removing the $8.0 million paid in 2019 (Exhibit FWR-2, Schedule B-2, Adjustment B-2-7). I propose that 75% of the 2019 amount be removed from rate base, as that cost should be allocated to shareholders.

Executive Compensation

Q. PLEASE DISCUSS THE ISSUE OF EXECUTIVE COMPENSATION.

A. Yes, September 1, 2020 Commissioner Burns sent a letter to this rate case Docket where the subject was the compensation level paid to the upper management of APS. In that letter, Exhibit FWR-17, Commissioner Burn asked a series of questions regarding the number of upper management positions (Vice President and above) and the salary level of this upper level. Specifically, the Commission was asking whether the number and salaries of APS upper management compared with other large utilities and other large corporations (Id). Commissioner Burns requested that Staff, RUCO and APS respond to his letter, requesting that APS provide responses no later than October 9, 2020 and RUCO, Staff and any other interested party by November 6, 2020.

RUCO is still gathering information so that it can respond to Commissioner Burns' request and will file a response by the requested date. RUCO will update its position in surrebuttal testimony.

Industry Association Dues

Q. HAS THE COMPANY INCLUDED ANY COSTS IN ITS FILING FOR PAYMENTS TO INDUSTRY ASSOCIATIONS?

A. Yes, there were several discovery questions issued by parties in this proceeding, as the issue of cost sharing of industry association and/or membership dues has been an issue in several dockets (e.g., the Commission recommended a reduction in Edison Electric Institute ("EEI") dues of 49.93% in Decision Nos. 71914 and 70860). In this case the most informative discovery responses were the response to Vote Solar 1.36, Initial 1.33 and SEIA data request 1.2, with the later providing the most comprehensive list of memberships and detailing the amount paid during the test year (Exhibit FWR-18). I have totaled the amount and it is $3,8019,065 with the biggest amounts paid to EEI, $1,103, 374, and the Electric Power Research Institute ("EPRI"), $2.001,192. APS states that none of the expenses being requested were used for lobbying expenses (Id).

Q. PLEASE EXPLAIN THE PURPOSE OF EEI AND EPRI.

A. EEI describes its mission and vision as a trade association providing public policy leadership, strategic business intelligence, and essential conferences and forums[3]. EPRI describes itself as an independent, nonprofit organization for public interest energy and environmental research that focuses on electricity generation, delivery, and use in collaboration with the electricity sector, its stakeholders and others to enhance the quality of life by making electric power safe, reliable, affordable, and environmentally responsible[4]. Other trade association have similar descriptions but may be technological specific (e.g., solar, green building, etc.) or geographic (e.g. Arizona, Western States or North America, etc.) but all serving the needs of the utility industry.

[3] www.eei.org/about/mission
[4] www.epri.com/about

Q. HOW HAS THE COMMISSION TREATED MEMBERSHIP DUES IN PAST DOCKETS?

A. As noted above, a reflection of a 50/50 sharing between ratepayers and shareholders has been upheld by the Commission in several proceedings (Decision Nos. 71914 and 70860). As explained by the Commission in Decision 71914, "we adopted Staff' s position and disallowed 49.93 percent of because EEI's core dues related to legislative advocacy, regulatory advocacy, advertising, marketing, and public relations.

Q. PLEASE CONTINUE.

A. EEI is not unique in the fact that the expense benefits both ratepayers and shareholders. Other membership dues have similar dual benefits. For example, Chartwell is a specialized information provider for the utility industry that is devoted to providing in-depth research in customer facing areas. This benefits shareholders and the information providing better enables them to communicate with customers. Better communication and outreach help ratepayers understand the Company, its procedures and rate options which should reduce the number of customer complaints. EPRI's research activities also benefit both shareholders and ratepayers. For example, examining ways to reduce line losses help both shareholders and ratepayers as it reduces unnecessary waste of electric power and makes the energy more economic. Because of the duality of benefits, I recommend all membership dues be shared 50/50 between ratepayers and shareholders and recommend operation and maintenance expense be reduced by $1,791,178 (Exhibit FWR-19).

Directors and Officers Insurance Expense

Q. WHAT IS DIRECTORS AND OFFICERS ("D&O") LIABILITY INSURANCE?

A. D&O liability Insurance is liability insurance that covers directors and officers for claims made against them by shareholder(s) or others for decisions they may make as Officers of the Company.

Q. HAS THE COMPANY REQUESTED THAT RATEPAYERS BEAR THE FULL BURDEN OF THIS COST?

A. Yes. Pinnacle West incurred $752,342 in costs for D&O insurance during the test year and APS has included the ACC jurisdictional amount of $720.860 as an Administrative and General expense charged to Account 925 (Exhibit FWR-20). The Company explains that these expenses are customary and are necessary to attract and retain qualified Directors and Officers (Id).

Q. DO YOU BELIEVE RATEPAYERS SHOULD BEAR THE FULL BURDEN OF THIS EXPENSE?

A. No, because both shareholders and ratepayers benefit from this insurance protection. Shareholders, as a body, receive a benefit, as this insurance pays for litigation costs and liabilities resultant from a claim made against the Company. As to ratepayers, the Company is correct that it helpful to have this type of insurance to attract and retain qualified Directors and Officers and, therefore, protect them from personal liability claims during a lawsuit.

Q. WHAT DOES RUCO BELIEVE IS A REASONABLE SHARING OF COSTS?

A. Since liability insurance not only benefits ratepayers, but also shareholders, RUCO recommends a 50/50 sharing between ratepayers and shareholders. This recommendation reduces operation and maintenance expense by $376,176.

Four Corners Deferral

Q. PLEASE DISCUSS THE OPERATING INCOME ADJUSTMENT FOR THE SCR DEFERRAL ADJUSTMENT?

A. In the 2017 Settlement Agreement, APS was allowed to defer for later recovery the costs related to the SCRs[5]. In accordance with that provision of the Settlement and APS' decision to include the cost of the Four Corners SCRs in this rate proceeding, APS has made an operating expense income pro forma adjustment of $8.3 million more to reflect the amortization of the SCR deferral over ten years (see Blankenship direct at 36 and Attachment EAB-30DR and SFR Schedule C-2, page 9, column 25). Consistent with my recommendation that it is premature to consider the impact of the Four Corners SCRs in this rate proceeding, I recommend reversing the Company's proposed pro-forma adjustment.

Post Test Year Plant Depreciation Expense

Q. COULD YOU PLEASE DISCUSS THE DEPRECIATION EXPENSE IMPACT ON OPERATING EXPENSES ASSOCIATED WITH POST TEST YEAR PLANT?

A. Yes. APS is requesting a total of $773.3 million in total Company capital expenditures for the 12-month period ending June 30, 2020, which is the 12-month period immediately after the Test Year in this case (Company Witness Lockwood at 15). The investments that make up this request are in five major business areas: renewable generation, technology innovation, nuclear generation, distribution, and fossil generation (Id). The Company has made pro-forma operating expense adjustments for depreciation expenses for each of these plant categories that total $39.1 million and have reflected them in the rate case (Attachment EAB-7DR). Consistent with my recommendation to allow only PTYP that was placed into service in 2019 or if in 2020, was significant, over $5 million, I adjusted the pro-

[5] Decision No. 76295, Exhibit A, Section 9, Paragraphs 9.1, 9.2, and 9.3.

forma depreciation expense to reflect the recommend PTYP plant balance and made a $7.9 million downward adjustment.

Regulatory Asset Amortization

Q. PLEASE DISCUSS THE COMPANY REGULATORY ASSETS?

A. At the end of the test year, APS had $1,283,538 in regulatory assets which are included in rates and the ACC jurisdictional amount of these assets are included in rate base for full cost recovery, at the Company's weighted average cost of capital (See B-1, line 16). Among the list of APS' regulatory assets are the stranded costs of the retired Navajo Plant at $82.8 million (Exhibit FWR-21). Also, on the list is another $17.8 million liability for the Navajo coal mine reclamation, a $81.1 million balance on the retired units at the Cholla generating station and another $17.4 million in other stranded costs related to other production plant assets. These production plant assets totaled $199.1 million.

With the Clean Energy Commitment this stranded asset list will continue to grow and ratepayers will be left to fund a return of and return on assets that will not be used and not be useful. RUCO is very concerned about this and believes stranded costs should be eliminated as soon as is practically possible. Since RUCO has recommended that the Four Corners SCRs not be reflected in rates, until such time the true rate impact of the Clean Energy Commitment and securitization can be examined, this adjustment reduces the requested revenue requirement – as noted previously APS estimates the revenue requirement solely due to the SCRs is $73 million. With that adjustment and the decreased revenue requirement, there is now sufficient cash flow to accelerate the elimination of stranded costs. As such, RUCO proposes to accelerate the reduction of stranded costs by making pro-forma adjustment to depreciation and amortization expense in the amount of $80 million per year. By including this cash flow in the Company's depreciation and amortization expense, I calculate that the outstanding production of plant regulatory assets

would be eliminated by the end of 2020. After the existing production plant related stranded costs are eliminated this cash flow could be returned to ratepayers as an adjustor mechanism, refunded or retained and used to write down other future production related stranded costs (i.e., Chola and Four Corners).

Depreciation and the Company's Proffered Depreciation Study

Q. PLEASE EXPLAIN HOW YOU ANALYZED THE COMPANY'S PROFFERED DEPRECIATION STUDY.

A. The concept of the depreciation of utility property is easily translatable to our everyday lives and, therefore, very real and understandable. It is also important because it has a huge impact on the ultimate rates. The challenge involves obtaining appropriate rates that insure that ratepayers do not overpay and the Company is assured to recover its costs. Everyone who owns a car lives with the concept of depreciation and implicitly understands service life and salvage value. When shopping for a car, a buyer considers the characteristics of service life and salvage value when shopping for a new or used vehicle. The expected ownership time is the service life; the trade-in or re-sale value is akin to net salvage. USA Today reports that the average age of vehicles on the road in the U.S. has risen to a record high of 11.5 years, which is attributable to substantial increases in reliability.[6] This is substantially different from when I first purchased a car in the early 1980s, when the average service life was closer to seven years. According to the New York Times, in the 1960s and 1970s, the typical car reached its end of life at around 100,000 miles, but due to manufacturing improvements, such as tighter tolerances and better anti-corrosion coatings, the typical car is now able to last closer to 200,000 miles.[7]

[6] Nathan Bomey, *Average Age of Cars on US Road Breaks Record*, USA TODAY (July 29, 2015), http://www.usatoday.com/story/money/2015/07/29/new-car-sales-soaring-but-cars-getting-older-too/30821191/ (last visited May 19, 2019).
[7] Dexter Ford, *As Cars Are Kept Longer, 200,000 is New 100,000*, N.Y. TIMES (Mar. 16, 2012), https://www.nytimes.com/2012/03/18/automobiles/as-cars-are-kept-longer-200000-is-new-100000.html?_r=2&ref=business&pagewanted=all& (last visited May 19, 2019).

Thus, improvements and differences between new and old equipment, which drive the basic principles of depreciation, can be understood by every driver.

Q. WHAT IS RUCO'S RECOMMENDATION REGARDING THE COMPANY'S PRO-OFFERED DEPRECIATION STUDY?

A. For reasons that will be more fully discussed below, RUCO recommends the Commission approve the depreciation study and proposed rates subject to certain modifications. As such, my testimony going forward is separated into three parts: 1) a short background section on the terms and concepts of depreciation, 2) a presentation of my findings and recommendations with respect to average service lives, and 3) a presentation of my findings and recommendations with respect to net salvage rates.

SECTION 1 – DEPRECIATION BACKGROUND

Q. WHAT IS DEPRECIATION?

A. According to the Supreme Court of the United States:

> Broadly speaking, depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence. Annual depreciation is the loss which takes place in a year.[8]

Another commonly cited definition comes from the American Institute of Certified Public Accountants, which defines depreciation as follows:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a

[8] *Lindheimer v. Ill. Bell Tel. Co.*, 292 U.S. 151, 167 (1934) (footnote omitted).

> portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

Q. WHAT IS AN AVERAGE SERVICE LIFE?

A. The service life of any one unit of property is the number of years of service that the property lasts. For example, while there may be many thousands of utility poles in a utility's system, each pole's service life is going to be impacted by its location, environment, and outside forces. Thus, while two poles may have been placed into service on the same day, one pole might be close to a main street while the other might be placed in a rural area with sandy, well-drained soil away from any nearby trees. The first pole might only survive for two or three years, while the second might be in service for sixty or seventy years. The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

Q. PLEASE DISCUSS THE TERMS "SURVIVOR CURVE," "LIFE TABLE," AND "OBSERVED LIFE TABLE."

A. The "original life table" (or "observed life table," "life table," or "original survivor curve") is the survival history of a group of property units in an account installed over a certain period of time ("the experience band"). A life table is arranged by age (newest to oldest) and shows the number of dollars or units that are exposed to retirement (exposures) at the beginning of a year, as well as the amount of retirements that actually happened at that plant age. The percent surviving is developed using actual plant data and recent history for the account. The data is then plotted with the x-axis representing the age of the plant, and the y-axis representing the percent of the plant surviving at that age. This is the observed life

table. Once an observed life table is prepared, then a series of standardized smoothed curves are fitted along the observed data (this can be done either through statistical analysis or by visually fitting standardized curves with known average service lives to the observed life table), and one is chosen as most closely matching the shape of the actual data for the account. The area under the smoothed curve is the estimated service life for the property in the account, and this is known as the average service life or ASL.

Q. WHAT IS AN IOWA CURVE?

A. The "Iowa Curves" were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. There are four families in the Iowa system, which are labeled in accordance with the location of the modes of the retirements in relation to the average life and the relative height of the modes.

The left-moded curves, or L Curves, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. Think of a type of property where some might not last very long, but then others might last a very long time. The standard description of an L Curve is one that has assets that have the greatest frequency of retirements prior to the average service life, and a minority of the property will be in service for a very long time. Back to the car comparison, one might imagine that this could occur with Chevrolet Corvettes, where many are over utilized or driven recklessly, while a few are cherished and pampered in the garage.

The symmetrical-moded curves, or S Curves, are those in which the greatest frequency of retirement occurs at the average service life.

The right-moded curves, or R Curves, are those in which the greatest frequency occurs to the right of, or after, the average service life. For example, a small percentage of utility poles may be damaged early on by lightning strikes or other accidents, but the vast majority will stay in service for a long time, until decay sets in and they have to be replaced in large numbers.

The origin-moded curves, or O Curves, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero.

The letter designation of each family of curves (L, S, R, or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

Q. WHAT IS NET SALVAGE?

A. "Net salvage" is the value obtained from retired property (the gross salvage) less the cost of removal. Net salvage can be either positive or negative. Net salvage can be positive in cases where the salvage value of the property exceeds the cost of removing the property. For example, when one sells a truck, it costs little or nothing to consign the truck to a dealer, and the money received offsets the original cost of the truck. On the other hand, net salvage can be negative in cases where cost of removal is greater than gross salvage. As an example, an old rotted utility pole might have little or no residual value, i.e., salvage value, but a truck and crew must still be dispatched to remove it, which carries with it a cost to the utility.

Q. HOW DOES NET SALVAGE IMPACT THE CALCULATION OF DEPRECIATION?

A. The intent of the depreciation process is to allow the Company to recover 100% of proven investment less net salvage. As an example, if net salvage is a positive 10%, then the utility should only recover 90% of its investment through annual depreciation charges under the theory that it will recover the remaining 10% through net salvage at the time the asset retires (90% + 10% = 100%). Alternatively, if net salvage is a negative 10%, then the utility should be allowed to recover 110% of its investment through annual depreciation charges, so that the negative 10% net salvage that is expected to occur at the end of the property's life will still leave the utility whole (110% - 10% = 100%).

Q. WHAT IS A DEPRECIATION RATE?

A. The depreciation rate is expressed as a percentage and is calculated by the following equation.

$$\text{Annual Accrual Rate, Percent} = \frac{(100\% - \text{Net Salvage, Percent})}{\text{Average Service Life}}.$$

For example, for an account with a negative net salvage rate of 20% and a 40 average service life, the depreciation rate would be 100% less negative -20% to arrive at a figure of 120% divided by 40 years to arrive at an annual depreciation rate of 3.0%.

Q. WHAT IS DEPRECIATION EXPENSE?

A. The depreciation expenses of a utility are determined by applying approved depreciation rates to the depreciable plant balances. The rates are developed separately for particular classes of plant, such as production (*e.g.*, steam generation, combustion turbine, hydroelectric production, etc.), transmission, and distribution plant.

Q. WHAT IS THE DEPRECIATION RESERVE?

A. While depreciation expense represents the annual recovery of the capital investment, there is another depreciation category that records all depreciation expense, retirements, cost of removal and gross salvage on a continuous basis. This account is the accumulated provision for depreciation, also known as the depreciation reserve. The depreciation reserve serves as a "running total" of the extent to which individual assets or groups of assets have been depreciated. In a depreciation study, the depreciation reserve is known by several other names, as well, the most notable being the "book reserve," the "recorded reserve," or the "actual reserve."

Q. WHAT IS A DEPRECIATION STUDY?

A. A depreciation study is the process whereby each account is examined to determine the appropriate survivor curve, average service life, and net salvage rate to be used in the calculation of depreciation rates, thereby allowing calculation of depreciation expense, which would allow the utility to properly recover its invested capital. This depreciation expense calculation is then circulated to a utility's revenue requirement department where it is combined with other utility costs such as operations and maintenance costs, return on investment costs, taxes, etc., in order to compute a total revenue requirement. As such, although depreciation can seem somewhat arcane and unglamorous, depreciation is a very important component of setting customer rates.

SECTION 2 – AVERAGE SERVICE LIFE ANALYSIS

Q. COULD YOU PLEASE DISCUSS YOUR REVIEW OF THE COMPANY'S RECOMMENDED AVERAGE SERVICE LIVES?

A. Yes, the Company's presentation is comprised of approximately 219 pages consisting of four parts: part 1 is testimony which is 12 pages, part 2 is , the depreciation study, 18 pages, part 3 is deprecation statements presenting balances, depreciation reserves and

the components of depreciation rates, 147 pages, and part 4 which is titled analysis which is 54 pages.

Part 1 of the presentation is a summary the values presented in the deprecation study. Part 2 of the presentation give a short summary of the Company, its' assets, and an outline of the steps undertaken to complete the study. Part 3 of is a series of tables presenting the mathematical results of the study. Part 4 of the study is titled analysis but no analysis is presented but rather it simply shows an example of the mathematical results of a deprecation analysis for one account; Account 367 – Underground Conductors and Devices[9].

Part 4 is the true backbone to analyzing deprecation rates because it is these mathematical results which much be analyzed to develop depreciation rates. Included in this mathematical analysis is the historical plant data, the retirement data, the observed life table derived from the plant history and retirements, net salvage data, the results of mathematical curve fitting and a presentation of data used to develop the accrual rates. I would note that there is no discussion of the proposed changes contained in the study or the basis for the changes. This is a shortcoming, because the deprecation study as presented gives no indication on why its results are reasonable and should be adopted.

As to individual plant accounts, the Company uses a life span analysis for production plant account using the expected plant retirement dates at the time the depreciation study was conducted. I propose no changes to these accounts, as the study simply updates the deprecation rates for the latest plant balances[10]. For transmission plant accounts, the

[9] In discovery, the Company did provide over 1,300 pages of the mathematical results for the rest of the plant accounts but, again, no written analysis was provided.

[10] The endorsement of the production plant average service lives and deprecation rates excludes my recommendation of not including the SCRs at the Four Corners plant previously discussed.

Company proposes no changes to the underlying components of the depreciation rates. For the General Plant Accounts, most of which use amortization schedules rather than depending on actuarial analysis, the Company proposes no changes to average service lives. The Company does propose changes to several Depreciation Plant Accounts and I discuss these in the following section.

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 361 – STATION EQUIPMENT

A. Account 361 –Structures and Improvements includes the cost of structures and improvements for electric distribution other than for the transformation and switching equipment in the substation. This is a relatively small account with $93 million in assets as of December 31, 2018. The current average service life for this account is 60 years and the Company proposes to retain that. The Company believes the best Iowa Curve for this account is a R3 curve.

The mathematical analysis of curve fitting indicates that the best fit is a L1 Iowa curve with an average service life of 98 years. When I graph the observed life table against the Company's proposed average service life, the Company's proposed curve was below the observed life table starting at the year 40. When a fitted curve is below the observed life table that indicates that the chosen service life is too short. I graphed 65 years and it was a much better fit to the observed data as shown on graph below. I recommend an R3 Iowa curve with a 65-year, a 65R3, average service life which fits the observed life data better and it closer to the indicated average service life, indicated by the mathematical curve fitting process.

Exhibit FWR-22 attached shows a graph showing the observed life table, my recommended Iowa curve and the Company's proposed Iowa curve, the observed life table and the results

of the mathematical curve is process for the shrinking band analysis. I will provide this same information for each exhibit accompanies a discussion of a plant account.

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 362 – STATION EQUIPMENT.

A. This account includes costs of station equipment used for the purpose of changing the characteristics of electricity in connection with its distribution. This is one of the larger Distribution Plant account with approximately $632 million in invested assets as of December 31, 2018. The current average service life for this account is 43 years with a L0.5 Iowa Curve. The Company proposes to increase the average service life to 45 years and maintain the Iowa Curve as the best curve fitting the observed data.

The mathematical curve fitting analysis for this account is 46 to 48 years with good results. When I graphed the Company's proposed service life and curve, I observed that the Company's proposed curve was under the observed life table for a considerable amount of the observed data. As I mentioned previously this indicates a too short service life. I then plotted the same Iowa curve with a 48-year average service life which fit better both mathematically and visually. I recommend a 48-year average service life with a L0.5 curve (See Exhibit FWR-23).

Q. PLEASE DISCUSS YOU ANALYSIS OF ACOUNT 364.02 – POLES, TOWERS AND FIXTURES – STEEL.

A. This account includes the cost of steel poles, towers and appurtenant fixtures for supporting electric overhead distribution conductors and service wires. This is meaningfully sized distribution accounts with approximately $324 million in assets at 12/31/2018. The current average service life for this account is 50 years with an R0.5 Iowa curve. The Company proposes to retain the service life and Iowa curve for this account.

When I plotted the observed life table against the Company's proposed average service life and curve, I observed that for almost all of the data points the Company's proposed service life was well below the observed data. The mathematical curve fitting analysis confirmed my observation as it indicates that for the longest observation band, 2004-2018 with plant in service placements going back to 1955, the indicated average service life is 68 years with a LO Iowa curve. I plotted the Company's proposed Iowa curve with an average service life of 65 years and it fit much better than that proposed by the Company and I propose that service life and Iowa curve be used for this account (See Exhibit FWR-24).

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 365 – OVERHEAD CONDUCTORS AND DEVICES?

A. This account includes the costs of electric overhead conductors and devices used for distribution purposes. This is the one of the largest Distribution Plant account with $469 million of assets at 12/31/2018. The current average service life for this account is 50 years with a SC curve and the Company proposes to retain these depreciation parameters.

The mathematical analysis for this account indicates an average service life of about 70 years. I then plotted various Iowa curves with various service lives against the observed data and found that the best fitting curve graphically was a LO with a 55-year average service life. As shown on the graph (Exhibit FWR-25) it fits the data quite well and if much closer the mathematical curve fitting result of 70 years. I propose that the 55LO curve be used for this account (Id).

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 366 – UNDERGROUND CONDUIT.

A. This account includes the costs associated with underground conduit and tunnels for housing distribution cables. This is the second largest Distribution Plant with $728 million in assets as of 12/31/2018. The current average service life for this account is 60 years with a L1 curve and the Company proposes to retain that.

The mathematical curve fitting for this account with an observation band of 1971-2018 with plant placements going back to 1940 indicates that the best fitting curves show an average service life of 70 years. When I plotted the Company's proposed curve against the observed life table, I observed the Company's proposed curve was below the observed data for almost all of the data points indicating that the Company's choice is too short. I plotted a L1 curve with an average service life and this was a better fit and closer the average service life which is indicated by the mathematical curve fitting. I recommend it be used to this account (See Exhibit FWR-26).

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 367 – UNDERGROUND CONDUCTORS AND DEVICES.

A. This account includes costs associated with electric underground conductors and devices used for electric distribution. This is the single largest Distribution Plant account with $1,864 million of assets as of December 31, 2018. The current average service life for this account is 40 years with an L1 Iowa curve. The Company proposes no changes to the account.

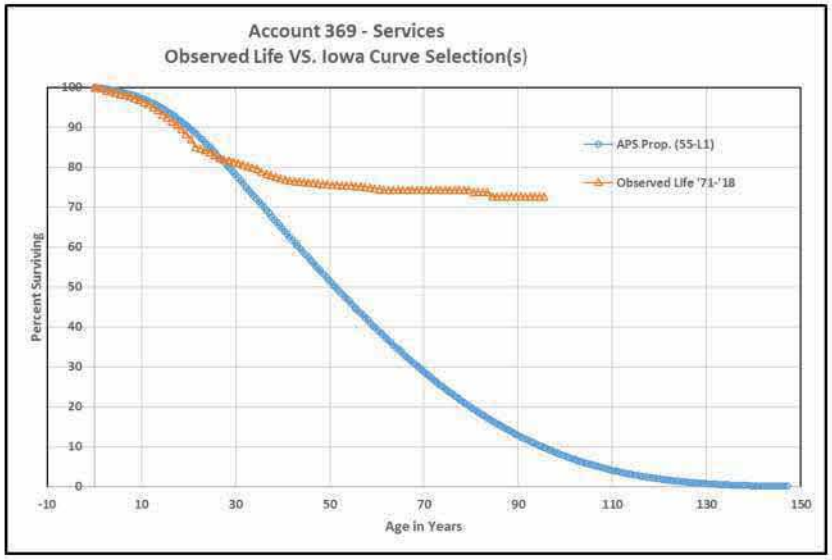
The mathematically curve fitting for this account with an observation band of 1971-2018 with plant placements going back to 1940 indicates that the best fitting curves show an average service life of 44 years with an L1 curve. When I graphed the best fitting curve to

the observed data and the Company's proposed curve, I observed the best fitting curve fits the data better and I recommend it be used for this account (See Exhibit FWR-27).

Q. PLEASE DISCUSS YOU ANALYSIS OF ACCOUNT 369 – SERVICES.

A. This account includes the cost of electric distribution services and includes both overhead and underground services. This is a relatively large Distribution Plant accounts with approximately $447 million in assets as of 12/31/2018. The current average service life for this account is 55 years with and L1 Iowa Curve. The Company proposes no changes.

The Company's proposal for no change for this account is odd given that the current average service life does not fit the observed life data very well at all. As shown on the graph below, the Company's curve is below the observed data for more than two-thirds of the data points.



The mathematically curve fitting shows that the best fitting curves have average service lives of 75-85 years. When I potted various corves to the data, I chose a R0.5 curve with a 65-year average service life. Admittedly, my curve is still below

most of the observed life table, but I believe it's a necessary and positive step to start moving the used average service life closer to the indicated average service life. I recommend my curve and service life be used (See Exhibit FWR-28).

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 370.03 – METERS – AMI.

A. This account includes the cost of meters or devices for use in measuring electricity delivered to customers. Advanced Metering Infrastructure ("AMI") meters, also known as "*Smart meters*" are updated, digital versions of the traditional electrical meter attached to the outside of your home. These new meters not only measure how much electricity is used, but also at what times during the day. The current average service for this account is 20 years. The Company proposes to change it to 15 years.

A review of the Company's testimony and depreciation study show that there is no mention of why the Company believes that a 15-year average service life should be used. In my experience the most common service life being used by utilities is 20 years. This is the expected service life being quoted by AMI vendors, when I have investigated the purchase of AMI meters for my utility clients. In addition, Nevada Power which serves the Las Vegas area and has been installing AMI meters since 2010 uses a 20-year average service life and has had two deprecation studies filed with the Nevada Commission. I reviewed both of those studies and agreed with a 20-year average service life. Given that the utility has not provided any support for its recommended change, it should be rejected.

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 371 – INSTALLATIONS ON CUSTOMERS PREMISES.

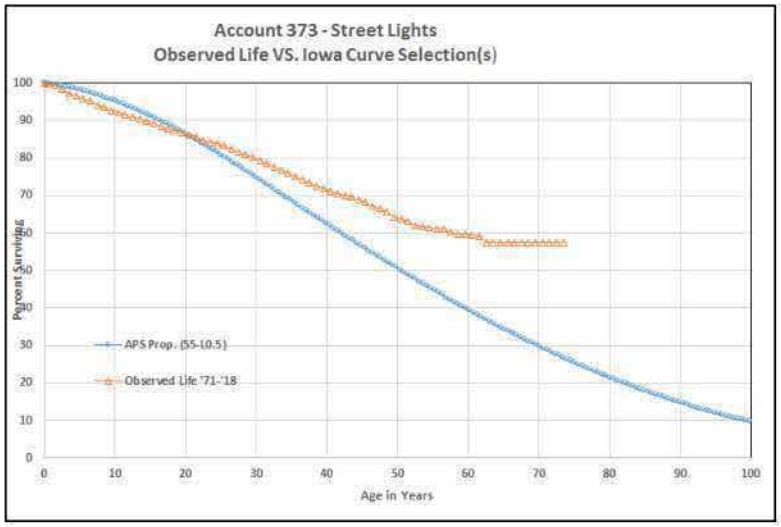
A. This account includes the cost of distribution equipment on the customer's side of the meter when the utility retains responsibility for the same. This is a very small account given that there is generally very little need to has equipment on a customer's property. At 12/31/18, the account had approximately $47 million in assets. This account includes the cost of distribution equipment on the customer's side of the meter when the utility retains responsibility for the same (i.e. outside the utility's Right-of-way). The current average service life for this account is 40 year with a LO Iowa curve.

The mathematical curve fitting for this account shows the best fitting curves indicate a 46-year average service life. These curves fit the data particularly well for all data points unlike the Company's proposed curve (40 LO) which is below all data points from age 30 on which indicates the Company has understated the average service life. I propose that the 45 year LO curve be used for this account (See Exhibit FWR-29).

Q. PLEASE DISCUSS YOUR ANALYSIS OF ACCOUNT 373 – STREET LIGHTING AND SIGNAL SYSTEMS.

A. As the account name implies this account includes the costs of overhead wires and cables, insulators and insulating equipment used primarily for the delivery of current to public outdoor lighting. As of 12/31/18 this account had approximately $80 million in assets. The current average service life is 55 years with a L0.5 Iowa curve and the Company proposes to retain both depreciation parameters.

The observed life table for this account is very well developed and shows a constant pattern of retirements year after year. The graph below, shows the observed life table and the Company's proposed curve (55L0.5). As can be easily seen the Company's proposed curve fits the observed life curve very poorly.



The mathematically curve fitting process for this account indicates the best fitting curves indicate an average service life of over 90 years. I visually fit curves to the observed life table and found that a 65-year R0.5 curve fit the data very well out through the first 60 years of observed life. This curve (65R0.5) is a much more reasonable but still a conservative estimate and I recommend it be used for this account (See Exhibit FWR-30).

SECTION 3 – NET SALVAGE ANALYSIS

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PRESENTATION OF NET SALVAGE?

A. The Company proposes a number of changes to net salvage and has provided historic net salvage data as support (See Exhibit FWR-31). I have reviewed each

of the proposed changes and only recommend changes to two accounts. Account 365 – Overhead Conductors and Devices and Account 367 – Underground Conductors and Devices.

For Account 365 the Company proses to increase net salvage from -10% to -20%. This proposal increases depreciation expense by $1.1 million per year. The historic data does not support the Company's proposal, however. Because for the period 1993-2015, the historic net salvage for this account was -10%. Since that time the weighted average has increase to -22% but that was driven be a negative gross salvage value in 2017 of $2.5 million which is an abnormality as one usually doesn't incur costs when salvaging property. There is no explanation in the Company's study on why this abnormal data entry exists or why it should be considered in the analysis for this account. Without such an explanation, I believe the Company's proposal is unsupported and should be rejected.

For Account 367, the historic data which shows net salvage data from 1993-2018 shows the weighted average net salvage for this account is -5.5%. The Company's depreciation study provides no explanation for the proposed change. Given that the historic data shows the current net salvage rate to be line with history and the Company has provided no explanation to support it change, I find the Company's proposal unsupported and recommend it be rejected.

Q. CAN YOU SUMMARIZE ALL OF THE MODIFICATIONS YOU ARE YOU PROPOSING?

A. When my proposed changes to the average service lives and net salvage rates are reflected in the calculation of proposed depreciation rates and pro-forma

deprecation expense is recalculated for the distribution accounts, it reduces the pro-forma expense proposed by the Company by $27.9 million.

Q. IF THESE MODIFICATIONS ARE MADE WOULD RUCO SUPPORT THE DEPRECIATION STUDY?

A. Yes, the depreciation study is complete and comprehensive. With the adjustments I made to the Company's proposed deprecation rates for the Distribution Plant account, I believe it produces reasonable results.

CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBITS

Of

FRANK W. RADIGAN

On Behalf Of

RESIDENTIAL UTILITY CONSUMER OFFICE

BEFORE THE ARIZONA CORPORATIOON COMMISSION

DOCKET NO. E-01345A-19-0236

Dated: October 2, 2020

DOCKET NO. E-01345A-19-0236

Exhibit FWR-1 Resume of Frank W. Radigan

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

PROFESSIONAL EXPERIENCE

1998–Present **Principal/Owner, Hudson River Energy Group, Albany, NY --** Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY –** Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY –** Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

EXPERT WITNESS TESTIMONY

Case 9487 – Maryland American Water Company – Testified on behalf of a group of large commercial water customers on the reasonableness of a proposed settlement that is schedule to increase their rates by thirty six percent. 2018

Docket No. OP 17-01942 – Before the State of New York Supreme Court Appellate Division in the matter of the City of Jamestown vs. the Town Council of the Town of Ellicott and the Board of Trustees of the Village of Falconer on behalf of the defendants testified on the reasonableness of the City's claimed reason for condemning property in the Town and Village. 2018

Docket No. 17-170 – Boston Gas and Colonial Gas-In behalf of the Massachusetts Attorney General testified on the reasonableness of the Companies proposed Gas Safety and Reliability Programs, the companies proposed depreciation rates and the Company's capital additions through the end of the test year. 2018.

Re: Steam Pipe Explosion at 41st St. and Lexington Ave. - New York County Index No.: 768000/08E – Testified on

behalf of Team Industrial Services, Inc. in opposition to the Motion for Summary Judgment filed by Consolidated Edison Company of New York, Inc. regarding the root cause for the explosion. 2017.

Docket No. 17-06004 – Nevada Power Company - On behalf of the Staff of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed electric depreciation rates. 2017.

Docket No. E-01345A-16-0036 – Arizona Public Service -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase, revenue allocation and rate design. 2017

Case 9423 – Maryland Water Services – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2016

Docket No. EL15-85-001- New Hampshire Transmission LLC – On behalf of the Massachusetts Attorney General, the Connecticut Public Utilities Regulatory Authority, the Connecticut Office of Consumer Counsel, the Rhode Island Division of Public Utilities and Carriers, the Rhode Island Attorney General, the Maine Public Advocate and the Vermont Department of Public Service on the reasonableness of the Company's accounting for certain expenses for transmission planning efforts and whether these expenses should have been recovered under a FERC approved formula rate for transmission revenue requirement - 2016

Docket No. 16-06008 – Sierra Power Company - On behalf of the Staff of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed electric depreciation rates. 2016.

Docket No. 16-06009 – Sierra Power Company - On behalf of the Staff of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed gas depreciation rates. 2016.

Docket No. E-01 933A-15-0322 – Tucson Electric Power -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase, revenue allocation and rate design. 2016

FC 1137 – Washington Gas Light -- On behalf of the Office of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's long term capital spending program and proposal for the recovery of costs of Washington Gas Light Company's pipe replacement programs. 2016

Docket No. 14-0741 – Utilities Services of Illinois, Inc. – On behalf of the Illinois Attorney General testified to the reasonableness of the proposed increase in water rates - 2015

D.P.U. Dockets 14-130 thru 14-135 – Six Massachusetts Gas Utilities – On behalf of On behalf of the Massachusetts Attorney General testified to the reasonableness of the accelerated gas pipe replacement programs for each of the investor owned gas distribution utilities in Massachusetts. 2015

Case 15-E-0283 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed depreciation rates, cost of service issues (including tree trimming), revenue allocation and rate design. 2015

Case No. 2014-00371 – Kentucky Utilities Company – On behalf of the Office of Rate Intervention of the Attorney General for the Commonwealth of Kentucky testified on the reasonableness of the Company proposed rate increase. 2015

Case No. 2014-00372 – Louisville Gas and Electric Company – On behalf of the Office of Rate Intervention of the Attorney General for the Commonwealth of Kentucky testified on the reasonableness of the Company proposed rate increase. 2015

Case No. 15-E-0307 – On behalf of the Massena Electric Department prepared rate filing before the New York Public Service Commission to increase its annual revenues and design rates designed to encourage energy efficiency. 2015

Docket No. WS-01303A-14-0010 – Epcor Water Arizona - On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase. 2015

Docket No. 14-0741 – Utilities, Inc. – On behalf of the Illinois Attorney General testified on the reasonableness of the water utility's proposed revenue requirement. 2015

Case 9344 – Green Ridge Utilities – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

FC 1115 – Washington Gas Light -- On behalf of the Office of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal for the recovery of costs and funding aspects of Washington Gas Light Company's Revised Accelerated Pipe Replacement Plan. 2014

Case No. EC-123-0082-00 – Entergy Mississippi – On behalf of Mississippi Public Utilities Staff reviewed and testified on the reasonableness of Entergy Mississippi, Inc.'s proposed depreciation rates and cost of service study. 2014

Case 9345 – Maryland Water Services – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

Case No. 2013-00167 – Columbia Gas of Kentucky – On behalf of the Office of Rate Intervention of the Attorney General for the Commonwealth of Kentucky testified on the reasonableness of the Company proposed rate increase. 2013

Docket 13-G-1301 – Consolidated Edison – On behalf of US Power Generating Company testified on the reasonableness of proposed modifications to natural gas balancing services. 2013

Docket No. 13-01-09 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2013

Case U-17169 - Semco Energy - On behalf of the Michigan Department of Attorney General testified on the reasonableness of the Company's proposal to modify its accelerated main replacement form for gas distribution facilities. 2013

Docket No. 13-06003 – Sierra Power Company - On behalf of the Staff of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2013.

Docket No. E-01 933A-I 2-0291 – Tucson Electric Power -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase. 2012

Case No. FC 1093 - Washington Gas and Light – On behalf of the Office of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal to replace and/or remediate certain gas distribution facilities that are subject of this case, 2012.

Docket No. C-2011-2226096 — Pennsylvania American Water Co. - In a class-action lawsuit, testified before the Pennsylvania Public Utility Commission on behalf of C. Leslie Pettko on the reasonableness of the surcharges imposed by Pennsylvania American Water Company. 2012

Docket No. 11-06007 – Nevada Power Company – On behalf of the Staff of the Nevada Public Service Commission, testified on the reasonableness of the Company electric depreciation study on Nevada Power Co. 2011

MEUA –On behalf of the Municipal Electric Utilities Association, filed testimony with the New York Power Authority (NYPA) on the reasonableness of the Authority's 2011 Rate Modification Plan for the Niagara Power Project. 2011

Case No. 9283 – Green Ridge Utilities, Inc. – On behalf of Maryland Office of People's Counsel testified on the

reasonableness of the water utility's proposed revenue requirement. 2011

Case No. 11-G-0280 – Corning Natural Gas -- On behalf of the Village of Bath, NY, testified on the construction program, revenue requirement, and rate design proposed by the gas distribution company serving the Village. 2011

Case No. 10-G-0598 – Bath Electric Gas and Water Systems - Testified as to the reasonableness of the Village of Bath's request for a refund relating to overcharges for gas purchased from the Corning Natural Gas Co. 2011

Case No. U-16472 – Detroit Edison -- On behalf of four large hospitals – Detroit Medical Center, Henry Ford Health Systems, William Beaumont Hospital, and Trinity Health Michigan – testified on the reasonableness of the continuation of a service class for large customers with special contracts. 2011

Case No. 9252 – Artesian Water Maryland, Inc. - On behalf of the Maryland Office of People's Counsel, analyzed proposed revenue requirement of Artesian Water Maryland, Inc. 2011.

Case No. 10-E-0362 – Orange and Rockland Utilities, Inc. - On behalf of a coalition of municipalities, testified on the reasonableness of the proposed revenue requirement of Company. 2010.

Docket No. 05-10-RE04 – Connecticut Light and Power Co. – On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the assist in its review of the application of Company for approval of full deployment of its Advance Metering Infrastructure ("AMI"). 2010

Docket Nos. 10-06003 and 10-06004 – Sierra Power Company - On behalf of the Staff of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2010.

Case No. 10-E-0050 – Niagara Mohawk Power Corporation -- On behalf of a coalition of municipalities, testified on the reasonableness of utility's proposal to eliminate contracts to provide street lighting service. 2010

Case No. 9248 – Maryland Water Services - On behalf of the Maryland Office of the People's Counsel, testified on the reasonableness of the proposed revenue requirement of Maryland Water Services, Inc. 2011

Docket No. 10-12-02 – Yankee Gas Services Company -- On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the Company's proposed depreciation rates. 2010

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel of the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in depreciation expense and

the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdrola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission

2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control

examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed

reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate

plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

OTHER PROJECT HIGHLIGHTS

Rate Setting Experience

OATT Rates – On behalf of several municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. Ongoing

Rate Setting – Village of Bath – Case No. 17-G-0423 - Prepared rate filing before the New York Public Service Commission for the Village of Bath Gas Department to increase its annual gas revenues. 2017

Rate Setting – Village of Bath – Case No. 17-E-0429 - Prepared rate filing before the New York Public Service Commission for the Village of Bath Electric Department to increase its annual electric revenues. 2017

Rate Setting – Village of Boonville – Case No. 16-E-0565 – Prepared rate filing before the New York Public Service Commission for the Village of Boonville Electric Department to increase its annual electric revenues. 2016

Rate Setting – Dover Plains Water Company – Case 14-W-0378 -- Prepared rate filing before the New York Public Service Commission for the Dover Plains Water Company to increase its annual water revenues. 2014

Rate Setting – Village of Castile – Case No. 14-E-0358 – Prepared rate filing before the New York Public Service Commission for the Village of Castile Electric Department to increase its annual electric revenues. 2014

Depreciation Study – Village of Swanton – On behalf of the Village of Swanton, Vt. Electric Department prepared a depreciation study for use in setting new depreciation rates to be submitted to the Vermont Public Service Board. 2014

Rate Setting – Village of Hamilton – Case 13-G-0584 – On behalf of the Village of Hamilton, NY designed initial rates for new municipal gas utility. Beginning with a preliminary feasibility study to determine the feasibility of initiating a natural gas utility within the Village of Hamilton performed feasibility study to determine potential load, supply options, construction cost and overall economics of such a venture. The feasibility study concluded that natural gas was economical if a lateral line was run from interstate pipelines to serve the University alone but not to the Village due to the Village's low load factor. The feasibility study also concluded that it would be even more economical if both the Village and University both started using natural gas to serve their needs. After reporting the results of the feasibility study Mr. Radigan was then retained to turn the feasibility study into reality and to stay with the project from its concept phase to inception and beyond. He was ten assigned to do a market penetration analysis to determine potential build out of the system and was charged with load forecasting, design day forecasting, market penetration analysis, economic analysis via alternative fuels, route planning, resource planning (an interesting assignment in an area that had no firm capacity and had to rely on backhauling) and the rate design for both firm and interruptible customers. 2013-Present

Rate Setting – Fillmore Gas Company - Case No. 13-G-0039 - Prepared rate filing before the New York Public Service Commission for the Fillmore Gas Company to increase its annual gas revenues. 2013

Rate Setting – Alliance Energy - Case No. 12-G-0256 - Prepared rate filing before the New York Public Service Commission for the Alliance Energy Transmission, LLC to increase its annual gas transportation. 2012

Rate Study – Atmos Energy – Docket No. 11-UN-184 – On behalf of the Mississippi Public Service Commission, submitted report on reasonableness of Company's depreciation study. 2012

Rate Study – Entergy Mississippi –Docket No. 11-UA-83 -- On behalf of the Mississippi Public Service Commission, prepared report on the reasonableness of Entergy Mississippi's depreciation study. 2012

Rate Case Cost of Service Study – Mississippi Power Company – On behalf of the Mississippi Public Service Commission, prepared report on reasonableness of embedded cost of service study submitted by Mississippi Power Co. 2012

Rate Case Cost of Service Study – Boonville, NY – Prepared class load study and embedded cost of service study to justify change in rate design for the purpose of conserving energy. 2010-2012

Rate Setting – Alliance Energy Transmission - Case No. 12-G-0256 – Prepared rate filing before the New York Public Service Commission for Alliance Energy Transmission. 2012

Rate Setting – Hamilton, NY - Case No. 12-E-0286 - Prepared rate filing before the New York Public Service Commission for the Village of Hamilton, NY to increase its annual electric revenues. 2012

Rate Setting – Fairport, NY – Case No. 11-E-0357 - Prepared rate filing before the New York Public Service

Commission for the Village of Fairport, NY to increase its annual electric revenues. 2011

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Analysis – Southwestern Power Company – On behalf of a coalition of retail customers analyzed reasonableness of utility's request to include the costs of Construction Work In Progress Expenditures in rates for a power plant known as the Turk Plant. 2010

Rate Study – Stowe Electric Department, VT – Docket No. 8169 – For small municipal electric utility, filed rate case before the Vermont Public Service Board. 2010

Docket No. 10-10-03 – Assisted in the CT OCC's review and development of recommendations for the Review of the 2011 Conservation and Load Management Plan. 2010

Rate Setting – Endicott, NY - Case No. 10-E-0588 – Prepared rate filing before the New York Public Service Commission for the Village of Endicott, NY to increase its annual electric revenues. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works **–** For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Setting Training – MMWEC – Assisted in training MMWEC staff on rate setting process so that they could provide service to members. 2009

Rate Setting – Connecticut Natural Gas -- Docket No. 08-12-06 - Assisted the Connecticut Office of Consumer Counsel on the analysis of the reasonableness of the of the Company's proposed revenue requirement. 2009

Rate Filing – Heritage Hills Water Works – Case No. 08-W-1201 – Prepared rate filing before the New York PSC for the Heritage Hills Water Works Corporation to increase its annual water revenues. 2008

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation. 2008

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the Prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reductions control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

PRESENTATIONS AND PUBLICATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2012 – Speaker on accelerated main replacement programs

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

Phillip S. Teumim and Frank W. Radigan: The Small Water Company Dilemma: Processes and Techniques for Effective Regulation, *National Regulatory Research Institute 2011-18*

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association
New York State Independent System Operator

DOCKET NO. E-01345A-19-0236

Exhibit FWR-2 RUCO Schedules A, B and C

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	Electric Original Cost	Electric RCND	Electric Fair Value	Line No.
1.	Rate Base	$ 8,261,698 (a)	$ 15,136,256 (a)	$ 11,698,977	1.
2.	Operating Income	661,420 (b)	661,420 (b)	661,420 (b)	2.
3.	Current Rate of Return	8.01%	4.37%	5.65%	3.
4.	Required Operating Income	548,577	548,577	548,577	4.
5.	Required Rate of Return on OCRB	6.64% *	3.62% *	4.69% *	5.
6.	Operating Income Deficiency on OCRB	(112,843)	(112,843)	(112,843)	6.
7.	Gross Revenue Conversion Factor	1.3288 (c)	1.3288 (c)	1.3288 (c)	7.
8.	Increase in Base Revenue Requirements Based on OCRB	$ (149,946) **	$ (149,946) **	$ (149,946) **	8.
9.	After Tax Return on Fair Value Increment			14,131	9.
10.	Requested Increase in Base Revenue Requirements			$ (135,815)	10.
11.	Required Rate of Return with Fair Value Increment			5.62%	11.

	Customer Classification	Present Rates 1, 2 ($000)	Projected Revenue Increase Due to Base Rates	Base Rate % Increase	Adjustor Transfers 3 ($000)	Total Rate Change	Bill Impact % Increase	
12.	Residential							
13.	General Service							
14.	Irrigation and Water Pumping							
15.	Outdoor Lighting							
16.	Dusk-to-Dawn							
17.	Total	$ 3,279,191	(135,815)	-4.14%	$ 115,042	$ (20,773)	-0.63%	17.

Notes:

* The Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) B-1
(b) C-1, page 2 of 2
(c) C-3
(d) H-1

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year Ended 6/30/2019 (a) (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 6/30/2019 (a) (C)	Unadjusted Test Year Ended 6/30/2019 (a) (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 6/30/2019 (a) (F)	Line No.
1.	Gross utility plant in service	$ 20,668,805	$ 93,784	$ 20,762,589	$ 17,522,166	$ 83,445	$ 17,605,611	1.
2.	Less: Accumulated depreciation & amortization	7,267,041	$ 537,932	7,804,973	6,323,177	526,704	6,849,881	2.
3.	Net utility plant in service	13,401,764	(444,148)	12,957,616	11,198,989	(443,259)	10,755,730	3.
	Deductions:							
4.	Deferred income taxes	1,908,074	(29,598)	1,878,476	1,903,462	(29,521)	1,873,940	4.
5.	Deferred investment tax credits (b)	197,749		197,749	196,585		196,585	5.
6.	Customer advances (b)	174,411		174,411	145,118		145,118	6.
7.	Customer deposits	81,423		81,423	81,423		81,423	7.
8.	Liabilities for pension benefits	305,207		305,207	280,177		280,177	8.
9.	Liability for asset retirements (b)	744,955		744,955	741,379		741,379	9.
10.	Other deferred credits	11,807		11,807	10,827		10,827	10.
11.	Coal mine reclamation (b)	197,443		197,443	196,800		196,800	11.
12.	Unrecognized tax benefits (b)	42,313		42,313	35,241		35,241	12.
13.	Operating lease liabilities (b)	111,553		111,553	99,615		99,615	13.
14.	Regulatory liabilities	2,008,573	(90,705)	1,917,868	1,988,207	(90,705)	1,897,502	14.
15.	Total deductions	5,783,508	(120,303)	5,663,205	5,678,833	(120,226)	5,558,607	15.
	Additions:							
16.	Regulatory assets	1,283,538	93,620	1,377,158	1,197,115	92,176	1,289,291	16.
17.	Other deferred debits	38,202		38,202	32,909		32,909	17.
18.	Nuclear Decommissioning trust (b)	950,448		950,448	945,886		945,886	18.
19.	Other special use funds (b)	241,558		241,558	240,398		240,398	19.
20.	Assets for other postretirement benefits (b)	52,611		52,611	48,297		48,297	20.
21.	Operating lease right-of-use assets (b)	174,320		174,320	155,663		155,663	21.
22.	Allowance for working capital (c)	384,155	(10,486)	373,669	361,755	(9,626)	352,129	22.
23.	Total additions	3,124,832	83,134	3,207,966	2,982,024	82,550	3,064,574	23.
24.	Total rate base	$ 10,743,088	$ (240,711)	$ 10,502,377	$ 8,502,181	$ (240,483)	$ 8,261,698 (d)	24.

Supporting Schedules:
(a) B-2
(b) E-1
(c) B-5

Recap Schedules:
(d) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		RCND						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year Ended 6/30/2019 (a) (d) (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 6/30/209 (a) (C)	Unadjusted Test Year Ended 6/30/2019 (a) (d) (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 6/30/209 (a) (F)	Line No.
1.	Gross utility plant in service	$ 39,632,048	$ 93,784	$ 39,725,832	$ 33,598,427	$ 83,445	$ 33,681,872	1.
2.	Less: Accumulated depreciation & amortization	14,668,992	$ 537,932	15,206,924	12,763,742	$ 526,704	13,290,446	2.
3.	Net utility plant in service	24,963,056	(444,148)	24,518,908	20,834,685	(443,259)	20,391,426	3.
	Deductions:							
4.	Deferred income taxes	3,608,594	$ (29,598)	3,578,996	3,599,871	$ (29,521)	3,570,350	4.
5.	Deferred investment tax credits (b)	197,749		197,749	196,585		196,585	5.
6.	Customer advances (b)	174,411		174,411	145,118		145,118	6.
7.	Customer deposits	81,423		81,423	81,423		81,423	7.
8.	Liabilities for pension benefits	305,207		305,207	280,177		280,177	8.
9.	Liability for asset retirements (b)	744,955		744,955	741,379		741,379	9.
10.	Other deferred credits	11,807		11,807	10,827		10,827	10.
11.	Coal mine reclamation (b)	197,443		197,443	196,800		196,800	11.
12.	Unrecognized tax benefits (b)	42,313		42,313	35,241		35,241	12.
13.	Operating lease liabilities (b)	111,553		111,553	99,615		99,615	13.
14.	Regulatory liabilities	3,084,207	$ (90,705)	2,993,502	3,052,935	$ (90,705)	2,962,230	14.
15.	Total deductions	8,559,662	(120,303)	8,439,359	8,439,970	(120,226)	8,319,744	15.
	Additions:							
16.	Regulatory assets	1,283,538	$ 93,620	1,377,158	1,197,115	$ 92,176	1,289,291	16.
17.	Other deferred debits	38,202		38,202	32,909		32,909	17.
18.	Nuclear Decommissioning trust (b)	950,448		950,448	945,886		945,886	18.
19.	Other special use funds (b)	241,558		241,558	240,398		240,398	19.
20.	Assets for other postretirement benefits (b)	52,611		52,611	48,297		48,297	20.
21.	Operating lease right-of-use assets (b)	174,320		174,320	155,663		155,663	21.
22.	Allowance for working capital (c)	384,155	$ (10,486)	373,669	361,755	$ (9,626)	352,129	22.
23.	Total additions	3,124,832	83,134	3,207,966	2,982,024	82,550	3,064,574	23.
24.	Total rate base	$ 19,528,226	$ (240,711) (d)	$ 19,287,515 (d)	$ 15,376,739	$ (240,483) (d)	$ 15,136,256 (d) (e)	24.

Supporting Schedules:
(a) B-3
(b) E-1
(c) B-5
(d) B-4a

Recap Schedules:
(e) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year 6/30/2019 (a) Total Co. (A)	(a) ACC (B)	RCUO Adj B-2-1 Fossil Generation Post-Test Year Plant Additions Total Co. (C)	ACC (D)	RCUO Adj B-2-2 Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 20,668,805	$ 17,522,166	$ 158,904	$ 158,142	$ 44,025	$ 43,814
2.	Less: Accumulated Depreciation & Amort.	7,267,041	6,323,177	201,688	200,720	36,557	36,382
3	Net Utility Plant in Service	13,401,764	11,198,989	(42,784)	(42,578)	7,468	7,432
4.	Less: Total Deductions	5,783,508	5,678,833	9,637	9,591	(623)	(620)
5.	Total Additions	3,124,832	2,982,024	-	-	-	-
6.	Total Rate Base	$ 10,743,088	$ 8,502,181	$ (52,421)	$ (32,762)	$ 8,091	$ 37,625

PRO FORMA WITNESS:		LOCKWOOD	LOCKWOOD
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1, page 1.

RC Adjustment to Test Year rate base to include post-Test Year Plant Additions for Fossil Generation with an estimated in service date prior to 6/30/2020.

RC Adjustment to Test Year rate base to include post-Test Year Plant Additions for Nuclear Generation with an estimated in service date prior to 6/30/2020.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	RCUO Adj B-2-3 Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (G)	RCUO Adj B-2-3 ACC (H)	RCUO Adj B-2-4 Technology Innovation Post-Test Year Plant Additions Total Co. (I)	RCUO Adj B-2-4 ACC (J)	RCUO Adj B-2-5 Renewables Post-Test Year Plant Additions Total Co. (K)	RCUO Adj B-2-5 ACC (L)
1.	Gross Utility Plant in Service	$ 360,286	$ 348,268	$ 14,187	$ 14,187	$ 17,048	$ 17,048
2.	Less: Accumulated Depreciation & Amort.	287,026	276,835	-	-	33,094	33,094
3	Net Utility Plant in Service	73,260	71,432	14,187	14,187	(16,046)	(16,046)
4.	Less: Total Deductions	4,315	4,180	433	433	2,183	2,183
5.	Total Additions	-	-	-	-	635	635
6.	Total Rate Base	$ 68,945	$ 172,449	$ 13,754	$ 24,669	$ (17,594)	$ (11,215)

PRO FORMA WITNESS:	LOCKWOOD	LOCKWOOD	LOCKWOOD
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Distribution functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries	1. ACC Specific 2. Functionalized on Distribution	1. ACC Specific 2. Renewables functionalized on Demand Production (Retail DEMPROD1)

RC Adjustment to Test Year rate base to include post-Test Year Plant Additions for Distribution and IT/Facilities with an estimated in service date prior to 6/30/2020.

RC Adjustment to Test Year rate base to include post-Test Year Plant Additions for Technology Innovation with an estimated in service date prior to 6/30/2020.

RC Adjustment to Test Year rate base to include post-Test Year Plant Additions for Renewables with an estimated in service date prior to 6/30/2020.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	RCUO Adj B-2-6 Four Corners SCRs Total Co.	RCUO Adj B-2-6 Four Corners SCRs ACC	RCUO Adj B-2-7 Eliminate Capitalized Amount of Cash Incenti Total Co.	RCUO Adj B-2-7 Eliminate Capitalized Amount of Cash Incenti ACC
1.	Gross Utility Plant in Service	$ (478,802)	$ (476,216)	$ (8,031)	$ (8,031)
2.	Less: Accumulated Depreciation & Amort.	(14,001)	(13,925)		
3	Net Utility Plant in Service	(464,801)	(462,290)	(8,031)	(8,031)
4.	Less: Total Deductions	(63,893)	$ (63,548)		
5.	Total Additions	-	-		
6.	Total Rate Base	$ (400,908)	$ (398,743)	$ (8,031)	$ (8,031)

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

Supporting Schedules
(a) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	ve	(7) Cloud Computing		(8) Include West Phoenix Unit 4 Regulatory Disallowance		(9) Include Property Tax Deferral	
			Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Gross Utility Plant in Service		$ -	$ -	$ (13,833)	$ (13,767)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.		-	-	(6,432)	(6,401)	-	-
3	Net Utility Plant in Service		-	-	(7,401)	(7,365)	-	-
4.	Less: Total Deductions		-	-	(1,502)	(1,495)	(544)	(544)
5.	Total Additions		12,779	11,731	-	-	(2,198)	(2,198)
6.	Total Rate Base		$ 12,779	$ 11,731	$ (5,899)	$ (5,871)	$ (1,654)	$ (1,654)

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1)

(7) Adjustment to Test Year rate base to reflect the impacts of Cloud Computing in alignment with NARUC's Cloud Computing Resolution.

(8) Adjustment to Test Year rate base to include the regulatory disallowance for West Phoenix CC Unit #4 as required by Decision Nos. 67744 and 69663.

(9) Adjustment to Test Year rate base to include the deferred property tax amounts from 7/1/19 to 12/31/20 per Decision No. 76295.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(10) Adjust Cash Working Capital for Cost of Service		(11) Include Ocotillo Deferral		(12) Include Four Corners SCR Deferral	
		Total Co. (S)	ACC (T)	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	20,395	20,297	10,920	10,867
5.	Total Additions	(10,486)	(9,626)	82,403	82,008	44,120	43,908
6.	Total Rate Base	$ (10,486)	$ (9,626)	$ 62,009	$ 61,711	$ 33,200	$ 33,041
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	

(10) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

(11) Adjustment to Test Year rate base to include the estimated Ocotillo Modernization Project deferral amount from 7/1/19 to 12/31/20 per Decision No. 76295.

(12) Adjustment to Test Year rate base to include the estimated Four Corners Selective Catalytic Reduction (SCR) deferral amount from 7/1/19 to 12/31/20 per Decision No. 76295.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

RCUO Adj B-2-8

Reverse Four Corners SCR Deferral

Line No.	Description	Total Co.	ACC
1.	Gross Utility Plant in Service		
2.	Less: Accumulated Depreciation & Amort.		
3	Net Utility Plant in Service		
4.	Less: Total Deductions	(10,920)	(10,867)
5.	Total Additions	(44,120)	(43,908)
6.	Total Rate Base	$ (33,200)	$ (33,041)

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

Supporting Schedules
(a) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(13) Excess Deferred Tax Total Co. (Y)	(13) Excess Deferred Tax ACC (Z)	(14) Total Original Cost Rate Base Pro Forma Adjustments (b) Total Co. (AA)	(14) Total Original Cost Rate Base Pro Forma Adjustments (b) ACC (BB)	(15) Adjusted at End of Test Year 6/30/2019 (b) Total Co. (CC)	(15) Adjusted at End of Test Year 6/30/2019 (b) ACC (DD)
1.	Gross Utility Plant in Service	$ -	$ -	$ 93,784	$ 83,445	$ 20,762,589	$ 17,605,611
2.	Less: Accumulated Depreciation & Amort.	-	-	537,932	526,704	7,804,973	6,849,881
3	Net Utility Plant in Service	-	-	(444,148)	(443,259)	12,957,616	10,755,730
4.	Less: Total Deductions	(90,705)	(90,705)	(120,303)	(120,226)	5,663,205	5,558,607
5.	Total Additions	-	-	83,134	82,550	3,207,966	3,064,574
6.	Total Rate Base	$ 90,705	$ 90,705	$ (240,711)	$ (240,483)	$ 10,502,377	$ 8,261,698

PRO FORMA WITNESS: BLANKENSHIP

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]
1. ACC Specific
2. Assigned to Production - Demand (Retail DEMPROD1)

(13) Adjustment to rate base to reflect amortization of excess deferred taxes associated with TEAM Phase III between the Test Year and the date proposed rates go into effect.
Assumes TEAM III amortization begins 1/1/2020 and rates go into effect 1/1/2021.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT
ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 6/30/2019 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (C)	Line No.
	Operating Revenues:				
1.	Revenues from Base Rates	$ 3,273,579	$ 5,612	$ 3,279,191	1.
2.	Revenues from Surcharges	128,979	(128,979)	0	2.
3.	Other Electric Revenues	148,270	(6,040)	142,230	3.
4.	Total	3,550,829	(129,407)	3,421,422	4.
	Operating expenses:				
5.	Fuel and purchased power	1,083,273	(139,278)	943,995	5.
6.	Operations and maintenance	1,052,961	(194,725)	858,236	6.
7.	Depreciation and amortization	511,942	144,734	656,676	7.
8.	Income taxes	113,517	7,118	120,635	8.
9.	Taxes other than income taxes	177,260	3,199	180,459	9.
10.	Total	2,938,954	(178,952)	2,760,002	10.
11.	Operating income	611,875	49,545	661,420 (b)	11.
	Other income (deductions):				
12.	Income taxes	-	-		12.
13.	Allowance for equity funds used during construction	-	-		13.
14.	Other income	-	-		14.
15.	Other expense	-	-		15.
16.	Total	-			16.
17.	Income before interest deductions	611,875	49,545	661,420	17.
	Interest deductions (income):				
18.	Interest charges	-	-		18.
19.	Allowance for borrowed funds used during construction	-	-		19.
20.	Total	-	-	-	20.
21.	Net income	$ 611,875	$ 49,545	$ 661,420	21.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	RUCO Adj C2-1 Fossil Generation Post-Test Year Plant Additions Total Co. (A)	ACC (B)	RUCO Adj C-2-2 Nuclear Generation Post-Test Year Plant Additions Total Co. (C)	ACC (D)	RUCO Adj C-2-3 Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (E)	ACC (F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	7,880	7,842	423	421	20,477	19,299
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	9,546	7,842	1,199	421	35,636	19,299
15.	Operating Income Before Income Tax	(9,546)	(7,842)	(1,199)	(421)	(35,636)	(19,299)
16.	Interest Expense	(410)	(408)	684	681	3,411	3,237
17.	Taxable Income	(9,136)	(7,434)	(1,883)	(1,101)	(39,047)	(22,536)
18.	Current Income Tax Rate - 24.75%	(2,261)	(1,840)	(466)	(273)	(9,664)	(5,578)
19.	Operating Income (line 15 minus line 18)	$ (7,285)	$ (6,002)	$ (733)	$ (148)	$ (25,972)	$ (13,721)

PRO FORMA WITNESS:	LOCKWOOD	LOCKWOOD	LOCKWOOD
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Distribution facilities functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries

(1) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 2.

(2) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

(3) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution and IT/Facilities Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	RUCO Adj C-2-4 Technology Innovation Post-Test Year Plant Additions Total Co. (G)	RUCO Adj C-2-4 ACC (H)	RUCO Adj C-2-5 Renewables Post-Test Year Plant Additions Total Co. (I)	RUCO Adj C-2-5 ACC (J)	(6) Base Fuel and Purchased Power Total Co. (K)	(6) ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	(51,260)	(51,260)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	51,260	51,260
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	1,419	1,419	648	648	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	3,025	1,419	1,023	648	-	-
15.	Operating Income Before Income Tax	(3,025)	(1,419)	(1,023)	(648)	51,260	51,260
16.	Interest Expense	473	473	(162)	(162)	-	-
17.	Taxable Income	(3,498)	(1,892)	(860)	(485)	51,260	51,260
18.	Current Income Tax Rate - 24.75%	(866)	(468)	(213)	(120)	12,687	12,687
19.	Operating Income (line 15 minus line 18)	$ (2,159)	$ (951)	$ (810)	$ (528)	$ 38,573	$ 38,573

PRO FORMA WITNESS:	LOCKWOOD	LOCKWOOD	SNOOK
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalize as Distribution.	1. ACC Specific 2. Renewables functionalized on Demand Production [Retail DEMPROD1]	1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2)

(4) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Technology Innovation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 5.

(5) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Renewables Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 6.

(6) Adjustment to Test Year operations to include 2018 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(7) Test Year PSA Revenue and Deferred Fuel Amortization		(8) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals		(9) Test Year Deferred Chemical Expense	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(89,285)	(89,040)	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(89,285)	(89,040)	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(90,598)	(90,349)	40,435	40,435	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	1,313	1,309	(40,435)	(40,435)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	1,313	1,309	-	-	-	-
8.	Maintenance	-	-	-	-	3,194	3,194
9.	Subtotal	1,313	1,309	-	-	3,194	3,194
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	1,313	1,309	-	-	3,194	3,194
15.	Operating Income Before Income Tax	-	-	(40,435)	(40,435)	(3,194)	(3,194)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	(40,435)	(40,435)	(3,194)	(3,194)
18.	Current Income Tax Rate - 24.75%	-	-	(10,008)	(10,008)	(791)	(791)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ (30,427)	$ (30,427)	$ (2,403)	$ (2,403)
	PRO FORMA WITNESS:	SNOOK		SNOOK		SNOOK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues and Expenses are class specific.		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)	

(7) Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods.

(8) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

(9) Adjustment to Test Year operation and maintenance costs to remove retail PSA deferred chemical expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(10) Normalize Weather Conditions Total Co. (S)	(10) Normalize Weather Conditions ACC (T)	(11) Annualize Customer Levels Total Co. (U)	(11) Annualize Customer Levels ACC (V)	(12) Schedule 1 Fees Total Co. (W)	(12) Schedule 1 Fees ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ (6,049)	$ (6,049)	$ 12,911	$ 12,911	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(6,040)	(6,040)
4.	Total Electric Operating Revenues	(6,049)	(6,049)	12,911	12,911	(6,040)	(6,040)
5.	Electric Fuel and Purchased Power Costs	(1,812)	(1,812)	3,854	3,854	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
18.	Current Income Tax Rate - 24.75%	(1,049)	(1,049)	2,242	2,242	(1,495)	(1,495)
19.	Operating Income (line 15 minus line 18)	$ (3,188)	$ (3,188)	$ 6,815	$ 6,815	$ (4,545)	$ (4,545)

PRO FORMA WITNESS:	SNOOK	SNOOK	HOBBICK
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Revenues and Expenses are class specific.	1. ACC Specific 2. Revenues and Expenses are class specific.	1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A)

(10) Adjustment to Test Year operating revenues to reflect normal weather conditions for the ten years ended 6/30/2019.

(11) Adjustment to Test Year operating revenues to reflect the annualization of customer levels at 6/30/2019.

(12) Adjustment to Test Year operations to account for additional adjustments related to disconnect policy.
Additional adjustments to Revenues reflecting policies changes to multiple fees collected.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description		(13) Uncollectible Bad Debt Total Co. (Y)	(13) Uncollectible Bad Debt ACC (Z)	(14) Crisis Bill Total Co. (AA)	(14) Crisis Bill ACC (AB)	(15) Customer Affordability Total Co. (AC)	(15) Customer Affordability ACC (AD)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ (1,250)	$ (1,250)	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	(1,250)	(1,250)	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	(1,250)	(1,250)	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		6,427	6,427	-	-	(17,782)	(17,782)
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		6,427	6,427	-	-	(17,782)	(17,782)
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		6,427	6,427	-	-	(17,782)	(17,782)
15.	Operating Income Before Income Tax		(6,427)	(6,427)	(1,250)	(1,250)	17,782	17,782
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		(6,427)	(6,427)	(1,250)	(1,250)	17,782	17,782
18.	Current Income Tax Rate -	24.75%	(1,591)	(1,591)	(309)	(309)	4,401	4,401
19.	Operating Income (line 15 minus line 18)		$ (4,836)	$ (4,836)	$ (941)	$ (941)	$ 13,381	$ 13,381

PRO FORMA WITNESS:	HOBBICK	HOBBICK	LOCKWOOD
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A)	1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN)	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission

(13) Adjustment to Test Year operations to account for expected increases in write-offs due to disconnect policy.

(14) Adjustment to Test Year operating revenues to reflect the increase need in crisis billing assistance.

(15) Adjustment to include forecasted impacts to 2020 O&M as a result of the Customer Affordability program.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description		(16) Active Union Medical Trust (VEBA) Total Co. (AE)	(16) Active Union Medical Trust (VEBA) ACC (AF)	(17) Fire Mitigation Total Co. (AG)	(17) Fire Mitigation ACC (AH)	(18) Remove Test Year Regulatory Assessment Total Co. (AI)	(18) Remove Test Year Regulatory Assessment ACC (AJ)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	(6,769)	(6,769)
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	(6,769)	(6,769)
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	(6,769)	(6,769)
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
15.	Operating Income Before Income Tax		3,643	3,344	(3,298)	(3,298)	-	-
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		3,643	3,344	(3,298)	(3,298)	-	-
18.	Current Income Tax Rate -	24.75%	902	828	(816)	(816)	-	-
19.	Operating Income (line 15 minus line 18)		$ 2,741	$ 2,516	$ (2,482)	$ (2,482)	$ -	$ -

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. ACC Specific 2. Functionalized on Distribution.	1. ACC Specific 2. Revenues are class specific and expenses are functionalized on Distribution of W&S

(16) Adjustment to Test Year operations to include interest income and realized gain on investments in active union medical trust.

(17) Adjustment to represent the forecasted impacts to 2020 O&M as a result of increases to the distribution Fire Mitigation program.

(18) Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from operating revenues and expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(19) Remove Test Year Transmission Cost Adjustor (TCA) Total Co. (AK)	(19) ACC (AL)	(20) Remove Test Year Lost Fixed Cost Recovery Mechanism (LFCR) Total Co. (AM)	(20) ACC (AN)	(21) Remove and Transfer Test Year Environmental Improvement Surcharge (EIS) Total Co. (AO)	(21) ACC (AP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(33,311)	(33,369)	(39,792)	(39,792)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(33,311)	(33,369)	(39,792)	(39,792)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(33,311)	(33,369)	(39,792)	(39,792)	-	-
15.	Operating Income Before Income Tax	-	-	-	-	(3,898)	(3,888)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	-	-	(3,898)	(3,888)
18.	Current Income Tax Rate - 24.75%	-	-	-	-	(965)	(962)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ -	$ -	$ (2,933)	$ (2,926)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues are class specific		1. ACC Specific 2. Revenues are class specific		1. Jurisdictional 2. Revenues are class specific	

(19) Adjustment to Test Year operations to remove the Transmission Cost Adjustor from operating revenues and expenses.

(20) Adjustment to Test Year operations to remove the LFCR mechanism from operating revenues.

(21) Adjustment to Test Year operations to remove the EIS from operating revenues.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(22) Remove Test Year Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense		(23) Remove Test Year and Transfer a Portion of Renewable Energy Adjustment Clause (REAC) Revenue and Expense		(24) Remove and Transfer Test Year Tax Expense Adjustor Mechanism (TEAM) Revenue	
		Total Co. (AQ)	ACC (AR)	Total Co. (AS)	ACC (AT)	Total Co. (AU)	ACC (AV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(26,717)	(26,689)	(72,697)	(72,670)	143,475	143,238
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(26,717)	(26,689)	(72,697)	(72,670)	143,475	143,238
5.	Electric Fuel and Purchased Power Costs	-	-	(38,930)	(38,916)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(26,717)	(26,689)	(33,767)	(33,754)	143,475	143,238
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(26,717)	(26,689)	(33,445)	(33,433)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(26,717)	(26,689)	(33,445)	(33,433)		
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(26,717)	(26,689)	(33,445)	(33,433)	-	-
15.	Operating Income Before Income Tax	-	0	(322)	(321)	143,475	143,238
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	0	(322)	(321)	143,475	143,238
18.	Current Income Tax Rate - 24.75%	-	-	(80)	(80)	35,510	35,451
19.	Operating Income (line 15 minus line 18)	$ -	$ 0	$ (242)	$ (241)	$ 107,965	$ 107,787
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues and Expenses are class specific.		1. Jurisdictional 2. Revenues and Expenses are class specific.		1. Jurisdictional 2. Revenues and Expenses are class specific.	

(22) Adjustment to Test Year operations to remove the DSMAC from operating revenues and expenses.

(23) Adjustment to Test Year operations to remove the REAC from operating revenues and transfer a portion of the expenses related to APS Solar Communities (formerly known as AZ Sun II) to base rates.

(24) Adjustment to Test Year operations to remove and transfer the TEAM adjustor from operating revenues.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

			(25)		RUCO Adj C-2-6		(26)	
			Four Corners SCR Deferral Amortization		Reverse Four Corners SCR Deferral Amortization		Ocotillo Modernization Project Deferral Amortization	
Line No.	Description		Total Co. (AW)	ACC (AX)	Total Co. (AW)	ACC (AX)	Total Co. (AY)	ACC (AZ)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		8,259	8,220	(8,259)	(8,220)	9,245	9,201
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		8,259	8,220	(8,259)	(8,220)	9,245	9,201
15.	Operating Income Before Income Tax		(8,259)	(8,220)	8,259	8,220	(9,245)	(9,201)
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		(8,259)	(8,220)	8,259	8,220	(9,245)	(9,201)
18.	Current Income Tax Rate -	24.75%	(2,044)	(2,034)	2,044	2,034	(2,288)	(2,277)
19.	Operating Income (line 15 minus line 18)		$ (6,215)	$ (6,186)	$ 6,215	$ 6,186	$ (6,957)	$ (6,924)

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1)

(25) Adjustment to Test Year operations to include the amortization of the Four Corners SCR deferral.

(26) Adjustment to Test Year operations to include the amortization of the Ocotillo Modernization Project deferral.

(27) Adjustment to Test Year operations to reflect Four Corners inventory cost recovery.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(27) Four Corners Inventory Total Co. (BA)	(27) Four Corners Inventory ACC (BB)	(28) Cholla Inventory Total Co. (BC)	(28) Cholla Inventory ACC (BD)	(29) West Phoenix Unit 4 Regulatory Disallowance Total Co. (BE)	(29) West Phoenix Unit 4 Regulatory Disallowance ACC (BF)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	1,045	1,040	1,523	1,516	(329)	(327)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	1,045	1,040	1,523	1,516	(329)	(327)
15.	Operating Income Before Income Tax	(1,045)	(1,040)	(1,523)	(1,516)	329	327
16.	Interest Expense	-	-	-	-	(110)	(109)
17.	Taxable Income	(1,045)	(1,040)	(1,523)	(1,516)	439	437
18.	Current Income Tax Rate - 24.75%	(259)	(257)	(377)	(375)	109	108
19.	Operating Income (line 15 minus line 18)	$ (786)	$ (783)	$ (1,146)	$ (1,141)	$ 220	$ 219

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)

(28) Adjustment to Test Year operations to reflect Cholla inventory cost recovery.

(29) Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoeni plant as required by previous ACC Decision Nos. 67744 and 69663. Pro forma adjusted as shown o

(30) Adjustment to Test Year operations to remove Navajo O&M and A&G costs as a result of the closure

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

RUCO Adj C-2-7 (30) (31)

Line No.	Description	Regulatory Asset Amortization Total Co.	Regulatory Asset Amortization ACC	ACC	Remove Navajo Power Plant Costs Total Co. (BE)	Remove Navajo Power Plant Costs ACC (BF)	Ocotillo O&M Normalization Total Co. (BG)	Ocotillo O&M Normalization ACC (BH)
	Electric Operating Revenues							
1.	Revenues from Base Rates				$ -	$ -	$ -	$ -
2.	Revenues from Surcharges				-	-	-	-
3.	Other Electric Revenues				-	-	-	-
4.	Total Electric Operating Revenues				-	-	-	-
5.	Electric Fuel and Purchased Power Costs				-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs				-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense				(10,567)	(10,522)	5,643	5,618
8.	Maintenance				(6,446)	(6,418)	1,104	1,099
9.	Subtotal				(17,014)	(16,940)	6,747	6,717
10.	Depreciation and Amortization	80,000	80,000		-	-	-	-
11.	Amortization of Gain				-	-	-	-
12.	Administrative and General				541	539	(16)	(16)
13.	Other Taxes				-	-	-	-
14.	Total Other Operating Expense	80,000	80,000		(16,473)	(16,401)	6,730	6,701
15.	Operating Income Before Income Tax	(80,000)	(80,000)		16,473	16,401	(6,730)	(6,701)
16.	Interest Expense	-	-		-	-	-	-
17.	Taxable Income	(80,000)	(80,000)		16,473	16,401	(6,730)	(6,701)
18.	Current Income Tax Rate - 24.75%	(19,800)	(19,800)		4,077	4,059	(1,666)	(1,659)
19.	Operating Income (line 15 minus line 18)	$ (60,200)	$ (60,200)		$ 12,396	$ 12,342	$ (5,064)	$ (5,042)

PRO FORMA WITNESS:

BLANKENSHIP

BLANKENSHIP

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

1. Jurisdictional
2. Assigned to Production - Energy (ENERGY1)

1. Jurisdictional
2. Assigned to Production - Energy (ENERGY1)

(31) Adjust Test Year to reflect the continuing opera addition of the new units.

‹ Unit 4 over the remaining life of the
ı Schedule B-2, page 3, column 8.

(32) Adjustment to Test Year Operations to reflect tl

(33) Adjustment to Test Year operations to reflect d

of Navajo Power Plant.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(32) Include Interest Expense on Customer Deposits Total Co. (BI)	ACC (BJ)	(33) Adjust Depreciation Expense - 2019 Depreciation Rate Study Total Co. (BK)	ACC (BL)	RUCO Adj C-2-12 Adjust Pro-Forma Adjustmenr to Depreciation Expense Total Co. (BK)	ACC (BL)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -		
2.	Revenues from Surcharges	-	-	-	-		
3.	Other Electric Revenues	-	-	-	-		
4.	Total Electric Operating Revenues	-	-	-	-		
5.	Electric Fuel and Purchased Power Costs	-	-	-	-		
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-		
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	2,117	2,117	-	-		
8.	Maintenance	-	-	-	-		
9.	Subtotal	2,117	2,117	-	-		
10.	Depreciation and Amortization	-	-	89,703	88,861	(55,566)	(54,724)
11.	Amortization of Gain	-	-	-	-		
12.	Administrative and General	-	-	-	-		
13.	Other Taxes	-	-	-	-		
14.	Total Other Operating Expense	2,117	2,117	89,703	88,861	(55,566)	(54,724)
15.	Operating Income Before Income Tax	(2,117)	(2,117)	(89,703)	(88,861)	55,566	54,724
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(2,117)	(2,117)	(89,703)	(88,861)	55,566	54,724
18.	Current Income Tax Rate - 24.75%	(524)	(524)	(22,202)	(21,993)	13,753	13,544
19.	Operating Income (line 15 minus line 18)	$ (1,593)	$ (1,593)	$ (67,501)	$ (66,868)	$ 41,813	$ 41,180

PRO FORMA WITNESS:

BLANKENSHIP

BLANKENSHIP

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

1. ACC Specific
2. Assigned to Customer Accounts (CUSTDEP)

1. Jurisdictional
2. Assigned to PT&D, General and Intangible functionalized on Wages & Salaries

tions of the Ocotillo Power Plant with the retirment of the 2 steam units and the

ıe operating income impact of interest on customer deposits using January 2019 interest rates.

epreciation expense based on the 2019 Depreciation Rate Study.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(34) Annualize Payroll Expense Total Co. (BM)	(34) Annualize Payroll Expense ACC (BN)	(35) Normalize Employee Benefits Total Co. (BO)	(35) Normalize Employee Benefits ACC (BP)	(36) Remove Supplemental Excess Benefit Retirement Plan Expense (SERP) Total Co. (BQ)	(36) Remove Supplemental Excess Benefit Retirement Plan Expense (SERP) ACC (BR)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(410)	(376)	11,251	10,328	(8,429)	(7,738)
8.	Maintenance	(84)	(77)	-	-	-	-
9.	Subtotal	(494)	(453)	11,251	10,328	(8,429)	(7,738)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(494)	(453)	11,251	10,328	(8,429)	(7,738)
15.	Operating Income Before Income Tax	494	453	(11,251)	(10,328)	8,429	7,738
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	494	453	(11,251)	(10,328)	8,429	7,738
18.	Current Income Tax Rate - 24.75%	122	112	(2,785)	(2,556)	2,086	1,915
19.	Operating Income (line 15 minus line 18)	$ 372	$ 341	$ (8,466)	$ (7,772)	$ 6,343	$ 5,823
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(34) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2019 employee levels for performance review and March 2020 Union employee levels.

(35) Adjustment to Test Year operations to reflect the current December 2018 actuarial valuation of retirement program expenses.

(36) Adjustment to Test Year operations to remove Supplemental Excess Benefit Retirement Plan Expense (SERP).

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

(37) (38) RUCO Adj C-2-8

Line No.	Description	Remove Stock Compensation Total Co. (BS)	Remove Stock Compensation ACC (BT)	Normalize Cash Incentive Total Co. (BU)	Normalize Cash Incentive ACC (BV)	Reverse Normalization of Cash Incentive Total Co.	Reverse Normalization of Cash Incentive ACC
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(15,882)	(14,580)	4,153	3,812	(4,153)	(3,812)
8.	Maintenance	-	-	126	116	(126)	(116)
9.	Subtotal	(15,882)	(14,580)	4,279	3,928	(4,279)	(3,928)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	1,327	1,218	(1,327)	(1,218)
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(15,882)	(14,580)	5,606	5,146	(5,606)	(5,146)
15.	Operating Income Before Income Tax	15,882	14,580	(5,606)	(5,146)	5,606	5,146
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	15,882	14,580	(5,606)	(5,146)	5,606	5,146
18.	Current Income Tax Rate - 24.75%	3,931	3,608	(1,388)	(1,274)	1,388	1,274
19.	Operating Income (line 15 minus line 18)	$ 11,951	$ 10,972	$ (4,218)	$ (3,872)	$ 4,218	$ 3,872

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Functionalized on Wages & Salaries

(37) Adjustment to Test Year operations to remove stock compensation expense.

(38) Adjustment to Test Year operations to normalize the cash incentive program over a 3 year period.

(39) Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663, 71448, 73183, and 76295 using the 6/30/2019 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description		RUCO Adj C-2-9 Cash Incentive -Allow 25% of Cash Incentive Total Co.	RUCO Adj C-2-9 ACC	RUCO Adj C-2-10 D&E Insurance 50/50 Sharing Total Co.	RUCO Adj C-2-10 ACC	RUCO Adj C-2-11 EEI and Other Membership Dues - 50/50 Sharing Total Co.	RUCO Adj C-2-11 ACC
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(24,592)	(22,574)	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(24,592)	(22,574)	-	-	-	-
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	(376)	(376)	1,791	1,791
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(24,592)	(22,574)	(376)	(376)	1,791	1,791
15.	Operating Income Before Income Tax		24,592	22,574	376	376	(1,791)	(1,791)
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		24,592	22,574	376	376	(1,791)	(1,791)
18.	Current Income Tax Rate -	24.75%	6,086	5,587	93	93	(443)	(443)
19.	Operating Income (line 15 minus line 18)		$ 18,506	$ 16,987	$ 283	$ 283	$ (1,348)	$ (1,348)

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description		(39) Normalize Income Tax Expense/Interest Synchronization Total Co. (BW)	ACC (BX)	(40) Annualize Property Tax Expense Total Co. (BY)	ACC (BZ)	(41) Amortize Property Tax Deferral Total Co. (CA)	ACC (CB)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	4,549	3,789	(590)	(590)
14.	Total Other Operating Expense		-	-	4,549	3,789	(590)	(590)
15.	Operating Income Before Income Tax		-	-	(4,549)	(3,789)	590	590
16.	Interest Expense		23,665	24,404	-	-	(33)	(33)
17.	Taxable Income		(23,665)	(24,404)	(4,549)	(3,789)	623	623
18.	Current Income Tax Rate -	24.75%	(5,857)	$ (6,040)	(1,126)	(938)	154	154
19.	Operating Income (line 15 minus line 18)		$ 5,857	$ 6,040	$ (3,423)	$ (2,851)	$ 436	$ 436

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Calculated as the weighted average of "Other Tax Items"	1. Jurisdictional 2. Functionalized on P T & D	ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1)

(40) Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 20 ratio and tax rate.

(41) Adjustment to amortize the property tax deferral as authorized in Decision No. 76295 over 10 year: Pro forma adjusted as shown on Schedule B-2, page 3, column 9.

(42) Adjustment to include additional costs of removal related to the decommissioning of West Phoenix

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(42) West Phoenix Removal Costs Total Co. (CC)	(42) West Phoenix Removal Costs ACC (CD)	(43) Annualize Four Corners Power Plant Coal Reclamation Costs Total Co. (CE)	(43) Annualize Four Corners Power Plant Coal Reclamation Costs ACC (CF)	(44) Annualize Navajo Power Plant Coal Reclamation Costs Total Co. (CG)	(44) Annualize Navajo Power Plant Coal Reclamation Costs ACC (CH)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	(3,145)	(3,131)	1,910	1,902
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	3,145	3,131	(1,910)	(1,902)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	998	993	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	998	993	-	-	-	-
15.	Operating Income Before Income Tax	(998)	(993)	3,145	3,131	(1,910)	(1,902)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(998)	(993)	3,145	3,131	(1,910)	(1,902)
18.	Current Income Tax Rate - 24.75%	(247)	(246)	778	775	(473)	(471)
19.	Operating Income (line 15 minus line 18)	$ (751)	$ (747)	$ 2,367	$ 2,356	$ (1,437)	$ (1,431)

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)

19 tax assessment

Steam Units 4, 5 & 6.

(43) Adjustment to Test Year operations to reflect most recent Four Corners Power Plant coal reclamati

(44) Adjustment to Test Year operations to reflect the most recent Navajo Power Plant coal reclamation

(45) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment. Pro forma adjusted as shown on Schedule B-2, page 4, column 10.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description		(45) Adjust Cash Working Capital for Cost of Service Pro Formas		(46) Normalize Advertising		(47) Normalize Nuclear Maintenance Expense	
			Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
			(CI)	(CJ)	(CK)	(CL)	(CM)	(CN)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	(2,264)	(2,264)	-	-
8.	Maintenance		-	-	-	-	1,386	1,380
9.	Subtotal		-	-	(2,264)	(2,264)	1,386	1,380
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		-	-	(2,264)	(2,264)	1,386	1,380
15.	Operating Income Before Income Tax		-	-	2,264	2,264	(1,386)	(1,380)
16.	Interest Expense		(195)	(179)	-	-	-	-
17.	Taxable Income		195	179	2,264	2,264	(1,386)	(1,380)
18.	Current Income Tax Rate -	24.75%	48	44	560	560	(343)	(342)
19.	Operating Income (line 15 minus line 18)		$ (48)	$ (44)	$ 1,704	$ 1,704	$ (1,043)	$ (1,038)

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)

on study.

study.

(46) Adjustment to Test Year operations to normalize advertising expense over a 3 year period.

(47) Adjustment to Test Year operations to normalize nuclear production maintenance expense over a 3 y

(48) Adjustment to Test Year operations to normalize fossil production maintenance expense over a 6 yea

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(48) Normalize Fossil Maintenance Expense Total Co. (CO)	(48) ACC (CP)	(49) Adjust Sundance Maintenance Total Co. (CQ)	(49) ACC (CR)	(50) Remove Out of Period and Miscellaneous Items Total Co. (CS)	(50) ACC (CT)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-		-	-	-
3.	Other Electric Revenues	-	-		-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-		-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	5,882	5,856	1,487	1,481	-	-
9.	Subtotal	5,882	5,856	1,487	1,481	-	-
10.	Depreciation and Amortization	-	-		-	-	-
11.	Amortization of Gain	-	-		-	-	-
12.	Administrative and General	-	-		-	(14,207)	(13,042)
13.	Other Taxes	-	-		-	-	-
14.	Total Other Operating Expense	5,882	5,856	1,487	1,481	(14,207)	(13,042)
15.	Operating Income Before Income Tax	(5,882)	(5,856)	(1,487)	(1,481)	14,207	13,042
16.	Interest Expense	-	-		-	-	-
17.	Taxable Income	(5,882)	(5,856)	(1,487)	(1,481)	14,207	13,042
18.	Current Income Tax Rate - 24.75%	(1,456)	(1,449)	(368)	(366)	3,516	3,228
19.	Operating Income (line 15 minus line 18)	$ (4,426)	$ (4,407)	$ (1,119)	$ (1,115)	$ 10,691	$ 9,814

PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	1. Jurisdictional 2. Functionalized on Wages & Salaries

(49) Adjustment to Test Year operations to annualize the accrual of Sundance maintenance costs as a

ear period.

(50) Adjustment to Test Year operations to remove out of period and miscellaneous items from the Tes

r period.

(51) Adjust test year to amortize Cholla Unit 2 Regulatory Asset over the remaining plant life instead of in Decision No. 76295.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(51) Cholla Unit 2 Regulatory Asset Amortization Total Co. (CS)	(51) Cholla Unit 2 Regulatory Asset Amortization ACC (CT)	(52) Total Income Statement Adjustments (a) Total Co. (CU)	(52) Total Income Statement Adjustments (a) ACC (CV)
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ -	$ -	$ 5,612	$ 5,612
2.	Revenues from Surcharges	-	-	(128,995)	(128,979)
3.	Other Electric Revenues	-	-	(6,040)	(6,040)
4.	Total Electric Operating Revenues	-	-	(129,423)	(129,407)
5.	Electric Fuel and Purchased Power Costs	-	-	(139,546)	(139,278)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	10,123	9,871
	Other Operating Expenses:				
7.	Operations Excluding Fuel Expense	-	-	(193,555)	(190,135)
8.	Maintenance	-	-	6,523	6,515
9.	Subtotal	-	-	(187,032)	(183,620)
10.	Depreciation and Amortization	(11,504)	(11,454)	145,962	144,734
11.	Amortization of Gain	-	-	-	-
12.	Administrative and General	-	-	(12,268)	(11,105)
13.	Other Taxes	-	-	3,959	3,199
14.	Total Other Operating Expense	(11,504)	(11,454)	(49,379)	(46,792)
15.	Operating Income Before Income Tax	11,504	11,454	59,502	56,663
16.	Interest Expense	-	-	27,324	27,903
17.	Taxable Income	11,504	11,454	32,178	28,760
18.	Current Income Tax Rate - 24.75%	2,847	2,835	7,964	7,118
19.	Operating Income (line 15 minus line 18)	$ 8,657	$ 8,619	$ 51,538	$ 49,545

PRO FORMA WITNESS: BLANKENSHIP

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

1. Jurisdictional
2. Assigned to System Benefits (ERGSYSBEN)

ıthorized in Decision No. 69663.

t Year period.

the accelerated method approved

Supporting Schedules:	Recap Schedules:	Recap Schedules:
N/A	(a) C-1	(a) C-1

NOTE: There may be variances in displayed values due to rounding.

DOCKET NO. E-01345A-19-0236

Exhibit FWR-3 – APS Clean Energy Commitment

APS sets course for 100 percent clean energy future

Firm commitment to affordable, reliable service joined by a bold initiative that benefits economy, environment

Learn more about our **clean energy commitment**

PHOENIX – Today marks a historic milestone in the 134-year history of Arizona's largest electricity provider as Arizona Public Service (NYSE: PNW) announces a goal to deliver 100 percent clean, carbon-free electricity to customers by 2050. The company has been on a trajectory of increasingly clean energy through solar power innovation, major investments in energy storage technology, carbon-free nuclear operations and advances in energy efficiency solutions. Now, the company's destination for that path is set as the boldest clean-energy goal of all Arizona electric companies, as well as one of the most ambitious in the country.

The goal includes a nearer-term 2030 target of achieving a resource mix that is 65 percent clean energy, with 45 percent of our portfolio coming from renewable energy. APS will end all coal-fired generation by 2031, seven years sooner than previously projected.

"We see incredible things ahead for Arizona, and are excited to power our state's future with electricity that is 100 percent clean," said APS Chairman and CEO **Jeff Guldner**. "We're starting from an energy mix that is 50 percent clean today, including energy efficiency and electricity from one of the nation's largest solar fleets and the country's most powerful carbon-free and clean energy resource – the Palo Verde Generating Station.

"We see incredible things ahead for Arizona, and are excited to power our state's future with electricity that is 100 percent clean"

Jeff Guldner, Chairman and CEO

"This is an important day for APS, our customers and Arizona. Our clean energy plan will be guided by sound science, and will encourage market-based solutions to climate issues. Through increased collaboration with our customers, regulators and other stakeholders, we expect to achieve environmental and economic gains without undermining our commitment to affordable, reliable service," Guldner said.

Pathways to 100 Percent Clean

On the journey to a carbon-free future, APS plans to ensure reliability and affordability through intelligent investments in renewable resources and developing technologies, nuclear power produced at Palo Verde Generating Station and energy efficiency and other programs for customers. Achieving this 100 percent clean goal while maintaining reliability of service at affordable rates for customers also will rely on:

- **Existing power sources** in the near term, including some natural gas, as APS makes a sensible transition to clean generating resources. In time, APS expects technological advances to eliminate the need to supplement renewable energy with even low-emitting carbon resources like natural gas in order to maintain reliable service around the clock at reasonable prices.

- **Continued modernization of the electric grid** as APS builds an advanced infrastructure that is more responsive and resilient, supports more renewables, minimizes outages and provides customers more choice and control over their energy decisions.
- **Energy storage solutions** to increase the effectiveness of renewable resources and provide more clean energy to customers after the sun has set. These will include APS's previously announced plans for an 850-megawatt expansion of large-scale energy storage, mostly paired with the company's innovative solar farms.
- **Policy decisions** that leverage market-based technology and innovation and keep Arizona and its utility industry an attractive place to invest.
- **Electrification** of the state's different economic sectors, particularly the transportation sector and specific building applications. In addition to supporting affordability for utility customers, electrification will drive a cleaner environment and more energy-efficient operations throughout the economy.
- **Evolving regional and market-based solutions** such as participation in the Western Energy Imbalance Market, which is saving customers tens of millions of dollars each year.

Collaboration Will Be Fundamental to Success

After the Integrated Resource Plan process in 2018, Arizona's experience with Proposition 127 and the Arizona Corporation Commission's efforts to update the state's energy rules, APS took a hard look at its generation mix and future plans. APS spent more than a year engaged with a variety of stakeholders including customers, business organizations and non-governmental organizations. This plan reflects those experiences and discussions.

Collaboration with stakeholders and regulators will be key to the plan's ultimate success, with full transparency regarding APS's roadmap and progress through Arizona's established process of Integrated Resource Plans. Flexibility, reliability and affordability will remain fundamental planning principles that will guide the addition of carbon-free resources at a reasonable cost and on pace and scale with customers' growing and changing energy needs.

"Our existing generation facilities, employees and communities have made possible the

affordable and reliable energy APS has delivered to customers for decades," Guldner said. "As we set out to generate only clean power by 2050, it will mean transitioning away from coal. We do not take that transition lightly, and are committed to working with our employees and stakeholders on the economic and other effects of retiring those assets."

APS also acknowledges that some of the solutions needed to achieve the goal are in early stages or even yet to be developed, and that realizing the full potential and benefits of a completely clean energy mix will take partnership. APS's progress to date and developing this goal would not have been possible without the support from an array of stakeholders.

"As a leader in innovation, ASU is excited to see Arizona's largest electricity provider reimagine our state's energy sector with this bold commitment to clean power generation," said Dr. Michael M. Crow, President of Arizona State University. "We are excited to be among the early collaborators in APS's approach, which will include diverse stakeholders from across Arizona, in charting this course to a carbon-free future so imperative to our long-term quality of life."

"This is a bold and historic decision that is coming at an important time," said Patrick Graham, State Director, The Nature Conservancy."APS's commitment to a clean economy in Arizona demonstrates the kind of leadership that will create momentum to put us on a path where Arizonans, now and in the future, can thrive. Arizonans expect sustainable communities, a healthy environment and access to good jobs."

The benefits of a 100 percent clean power portfolio will include helping customers achieve their own sustainability goals and attracting more employers to Arizona who want to be served fully by carbon-free resources at a reasonable cost and without compromising reliability.

"This landmark clean energy goal helps further differentiate Arizona's leading position as a strategic, forward-thinking market to do business, especially with many companies placing emphasis on their own sustainability targets," said Chris Camacho, President and CEO of the Greater Phoenix Economic Council.

"Arizona Public Service is taking the lead among U.S. utility companies to achieve 100

percent carbon free energy," said Nat Kreamer, Chief Executive Officer, Advanced Energy Economy. "Advanced energy technologies like renewable energy, electric vehicles, storage, energy efficiency and nuclear will all play important roles. Advanced Energy Economy and its member companies are already working with APS to find innovative solutions that can help achieve its clean energy goals, and we look forward to continuing this work together."

"Our commitment is to maintain a leadership role in shaping a forward-thinking, healthy and prosperous Arizona where people can build a better life," said Guldner. "We believe this initiative will encourage economic development in clean and innovative industries, create thousands of jobs and advance a healthy environment. Now comes the hard work of making it happen, which we are excited to carry out with others dedicated to securing a bright future for Arizona."

APS serves about 2.7 million people in 11 of Arizona's 15 counties, and is the Southwest's foremost producer of clean, safe and reliable electricity. Using a balanced energy mix that is 50 percent carbon-free, APS has one of the country's most substantial renewable energy portfolios and is a proven leader in introducing technology and services that offer customers choice and control over their energy consumption. With headquarters in Phoenix, APS is the principal subsidiary of Pinnacle West Capital Corp. (NYSE: PNW).

Media Contact:
Suzanne Treviño
(602) 250-2277

Analyst Contact:
Stefanie Layton
(602) 250-4541

DOCKET NO. E-01345A-19-0236

Exhibit FWR-4 -- APS Response to Sierra Club discovery question 1.3

SIERRA CLUB'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
FEBRUARY 20, 2020

SC 1.3: For each of Four Corners Units 1 through 5 and Ocotillo plant, please provide the following information as of December 31 for each of the years 2010-2019 (inclusive):

a. Gross plant balance.

b. Accumulated depreciation balance.

c. Net plant balance.

d. Net salvage (or negative net salvage).

e. The identification and quantification of any other category of expense collected through depreciation expense (e.g. asset retirement obligations, remediation accounts, etc.).

f. Estimated end-of-useful life date for purposes of setting a depreciation schedule.

g. The then-applicable annual depreciation expense attributable to the generating unit.

h. Property taxes.

i. Property insurance.

j. To the extent that any of the values in (a) – (i) are quantified differently in base rates and any applicable rate riders, please include both amounts.

Response:

a. Please see APS19RC00709 page 1 for gross plant balances as of December 31 for each of the years 2010-2019 (inclusive).

b. Please see APS19RC00709 page 2 for accumulated depreciation balances as of December 31 for each of the years 2010-2019 (inclusive).

c. Please see APS19RC00709 page 3 for net plant balances as of December 31 for each of the years 2010-2019 (inclusive).

d. Please see APS19RC00709 page 4 for net salvage balances as of December 31 for each of the years 2010-2019 (inclusive).

Witness: Elizabeth Blankenship

Response to SC 1.3 (continued):

e. Aside from the categories describe in parts a – d, there are no other categories of expense related to these facilities collected through depreciation expense.

f. The actual and estimated end-of-useful life for the facilities above are as follows:

Location	**Year**
Four Corners Units 1-3	2012 (Actual)
Four Corners Units 4-5	2038 (Est.)
Ocotillo Steam Units 1-2	2018 (Actual)
Ocotillo CT Units 1-2	2030 (Est.)
Ocotillo CT Units 3-7	2051 (Est.)

The Four Corners Units 4 and 5 end-of-useful life represents the assumption that was filed in the rate case application. Since then, APS has announced it will close Four Corners Units 4 and 5 in 2031 as part of its clean energy commitment.

g. Please see APS19RC00709 page 5 for annual depreciation and amortization expense as of December 31 for each of the years 2010-2019 (inclusive).

h. Please see APS19RC00709 page 6 for property tax expense as of December 31 for each of the years 2010-2019 (inclusive).

i. Please see APS19RC00709 page 7 for property insurance expense as of December 31 for each of the years 2010-2019 (inclusive).

j. There are no values that are quantified differently.

Sierra Club 1.3 - Part a
Docket No. E-01345A-19-0236
As of February 28, 2020

Gross plant balance:

($ In Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-3	368,957	372,496	380,840	-	-	-	-	-	-	-
Four Corners Units 4-5	203,199	213,399	218,344	1,008,981	1,040,338	1,068,030	1,144,470	1,405,858	1,675,368	1,691,923
Ocotillo	77,833	79,519	90,076	104,505	103,637	104,216	107,893	107,856	108,263	653,236

Sierra Club 1.3 - Part b
Docket No. E-01345A-19-0236
As of February 28, 2020

Accumulated depreciation balance:

($ In Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-3	174,796	196,748	380,879	-	-	-	-	-	-	-
Four Corners Units 4-5	91,180	93,284	50,992	608,402	570,734	579,107	589,988	588,664	574,035	597,668
Ocotillo	59,824	61,909	48,419	49,480	52,383	55,600	58,885	70,043	70,572	33,439

Sierra Club 1.3 - Part c
Docket No. E-01345A-19-0236
As of February 28, 2020

Net plant balance:

($ in Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-3	194,161	175,748	(39)							
Four Corners Units 4-5	112,019	120,115	167,352	400,579	469,604	488,923	554,483	917,194	1,101,333	1,094,255
Ocotillo	18,009	17,610	41,650	65,025	51,264	48,617	49,007	37,212	31,691	619,797

Sierra Club 1.3 - Part d
Docket No. E-01345A-19-0236
As of February 28, 2020

Net salvage:

($ In Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-3	65,857	58,949	-	-	-	-	-	-	-	-
Four Corners Units 4-5	29,769	29,706	80,873	80,825	81,973	81,129	79,524	85,117	76,748	69,807
Ocotillo	2,707	3,242	12,040	10,111	9,971	10,009	9,308	575	741	(60)

Sierra Club 1.3 - Part g
Docket No. E-01345A-19-0236
As of February 28, 2020

Annual depreciation expense attributable to the generating unit:

($ in Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-3	21,616	22,090	11,378	-	-	-	-	-	-	-
Four Corners Units 4-5	4,747	4,856	6,323	7,787	9,915	21,501	23,456	25,943	35,575	37,355
Ocotillo	2,744	2,805	3,303	3,536	3,390	3,435	3,495	5,685	8,586	15,966

Sierra Club 1.3 - Part h
Docket No. E-01345A-19-0236
As of February 28, 2020

Property Taxes:

($ in Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-5	2,014	2,002	1,916	1,740	1,817	3,325	4,056	5,081	6,407	8,294
Ocotillo	526	609	720	814	927	1,087	1,144	1,168	1,232	1,287

Sierra Club 1.3 - Part i
Docket No. E-01345A-19-0236
As of February 26, 2020

Property Insurance:

($ in Thousands)

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Four Corners Units 1-5	918	770	667	698	485	580	562	506	521	502
Ocotillo	142	126	130	113	117	129	128	119	120	188

DOCKET NO. E-01345A-19-0236

Exhibit FWR-5 -- Commissioner Burns letter August 11, 2020

ORIGINAL

E000008353

COMMISSIONERS
ROBERT "BOB" BURNS
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

ROBERT "BOB" BURNS
Chairman

ARIZONA CORPORATION COMMISSION

August 11, 2020

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-19-0236

Arizona Public Service Company and Interested Parties:

In Arizona Public Service Company's ("APS") rate case, APS has indicated that it will be closing its Four Corners Generating Plant ("Four Corners") in 2031, which is 7 years before originally planned. With the early closure of Four Corners, there will be stranded costs that need to be recovered. Below are four methods that I would like APS to develop and submit for Commission consideration in this rate case. Each method below should be based on the APS's planned closure date. APS is free to submit alternative methods for the Commission to consider along with those listed below.

Method #1:
Recovery of the stranded costs through the use of accelerated depreciation. Please specify and discuss in detail the rate impact to customers. This method should also include a detailed transition plan for the local community impacted by the early closure of this generating plant.

Method #2:
Recovery of the stranded costs through securitization of those costs. Please specify the interest rate for the loan to be used and the length of the loan; and discuss how this interest rate was determined. Please specify and discuss in detail the rate impact to customers. This method should also include a detailed transition plan for the local community impacted by the early closure of this generating plant.

Method #3:
Same as Method #2, but with the interest rate 1% lower than Method #2.

Method #4:
Same as Method #2, but with the interest rate 1% higher than Method #2.

ACC - Docket Control - Received 8/11/2020 11:15 AM
ACC - Docket Control - Docketed 8/11/2020 11:29 AM

Each of the methods above should also be developed for a closure of Four Corners 2 years earlier than APS's planned closure date and 5 years earlier than the planned closure date (for a total of 12 plans).

Any other party in this rate case may also develop similar plans for the Commission's consideration.

Sincerely,

Bob Burns
Chairman

DOCKET NO. E-01345A-19-0236

Exhibit FWR-6 – APS Letter to Docket Control in Reply to Commission Burns 8-11-20 Letter

ORIGINAL

E000008762

Rodney J. Ross
Manager
State Regulatory Affairs

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-4944
Rodney.Ross@aps.com

September 3, 2020

Docket Control
Chairman Robert "Bob" Burns
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: Arizona Public Service Company (APS or Company)
Docket No. E-01345A-19-0236

Dear Chairman Burns,

This letter is in response to your letters of August 11, 2020 and September 1, 2020 to APS seeking analyses of methods for addressing stranded costs "that need to be recovered" associated with the closure of the Four Corners Power Plant and additional analyses for Cholla Units 1 and 3. Your letters requested, among other things, the calculation of the rate impacts of closure in twelve scenarios, including two alternative methods of cost recovery (accelerated depreciation and securitization); alternative closure dates of 2031, 2029 and 2026; and alternative interest rates.

This is a complex, data-driven request that requires multiple teams from throughout the Company, as well as external support. In order to perform the analysis you requested thoroughly and accurately, a reasonable amount of time is required to develop the assumptions, run the analyses, review the results, conduct quality assurance, make adjustments, and revise the analyses, as appropriate.

Upon receipt of your letters, APS immediately began conducting preliminary analyses of the scenarios you outlined. APS remains in the process of developing these analyses but will not be able to provide information you requested by October 2.

APS is working to develop the analysis of all the scenarios you requested and has begun a dialogue about Coal Community Transition with stakeholders and interested parties, including the Sierra Club, the Citizen Groups, and the Navajo Nation, among others. The Company anticipates being able to file its analysis and information about these efforts in connection with its rebuttal testimony in the Rate Case on November 6th.

Please let me know if you have any questions.

Sincerely,

/s/ Rod Ross

Rodney J. Ross
RJR/bgs

ACC - Docket Control - Received 9/3/2020 5:15 PM
ACC - Docket Control - Docketed 9/4/2020 8:08 AM

DOCKET NO. E-01345A-19-0236

Exhibit FWR-7 -- Excerpt from APS' 2019 FERC Form 1

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Arizona Public Service Company	02 Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 400 North 5th Street, Phoenix, AZ 85004	
05 Name of Contact Person Barbara D. Lockwood	06 Title of Contact Person Senior VP, Public Policy
07 Address of Contact Person *(Street, City, State, Zip Code)* 400 North 5th Street, Phoenix, AZ 85004	

08 Telephone of Contact Person, *Including Area Code* (602) 250-3361	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 03/23/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Elizabeth A. Blankenship	03 Signature	04 Date Signed *(Mo, Da, Yr)*
02 Title VP Controller & CAO APS/PNW	Elizabeth A. Blankenship	03/23/2020

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Cholla 1* (b)			Plant Name: *Cholla 3* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Over 50% Outdoors			Over 50% Outdoors		
3	Year Originally Constructed	1962			1980		
4	Year Last Unit was Installed	1981			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	113.60			312.30		
6	Net Peak Demand on Plant - MW (60 minutes)	110			269		
7	Plant Hours Connected to Load	4841			6697		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	116			271		
10	When Limited by Condenser Water	116			271		
11	Average Number of Employees	35			48		
12	Net Generation, Exclusive of Plant Use - KWh	291060079			1006969235		
13	Cost of Plant: Land and Land Rights	1425488			3922970		
14	Structures and Improvements	20744896			57333578		
15	Equipment Costs	145293049			403471982		
16	Asset Retirement Costs	7167870			16745629		
17	Total Cost	174631303			481474159		
18	Cost per KW of Installed Capacity (line 17/5) Including	1537.2474			1541.7040		
19	Production Expenses: Oper, Supv, & Engr	1170418			729704		
20	Fuel	8899582			34161508		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1305567			3820787		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	354860			245548		
26	Misc Steam (or Nuclear) Power Expenses	730429			1090151		
27	Rents	0			0		
28	Allowances	156986			543120		
29	Maintenance Supervision and Engineering	1623615			1441809		
30	Maintenance of Structures	631025			2864667		
31	Maintenance of Boiler (or reactor) Plant	4657898			3586448		
32	Maintenance of Electric Plant	3785799			737012		
33	Maintenance of Misc Steam (or Nuclear) Plant	93762			1341863		
34	Total Production Expenses	23409941			50562617		
35	Expenses per Net KWh	0.0804			0.0502		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Gas	Coal	Oil	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Bbls	MCF	Tons	Bbls	MCF
38	Quantity (Units) of Fuel Burned	177837	0	2838	626680	2185	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9256	0	769870	9013	129280	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	55.040	0.000	2.920	50.750	108.720	0.000
41	Average Cost of Fuel per Unit Burned	52.080	0.000	-68.990	53.400	217.980	0.000
42	Average Cost of Fuel Burned per Million BTU	2.810	0.000	-89.620	2.960	40.150	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	-1.010	0.030	0.450	0.000
44	Average BTU per KWh Net Generation	11318.688	0.000	11318.702	11229.958	11229.957	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Four Corners 4* (d)			Plant Name: *Four Corners 5* (e)			Plant Name: *Ocotillo 1* (f)			Line No.
Steam			Steam			Steam			1
Over 50% Outdoors			Over 50% Outdoors			Over 50% Outdoors			2
1969			1969			1960			3
1970			1970			1960			4
515.40			515.40			113.60			5
382			436			152			6
7876			6960			152			7
0			0			0			8
485			485			110			9
485			485			110			10
81			82			1			11
3026572962			2509098943			166700			12
31634			32412			152890			13
33602536			29812359			2131844			14
669103660			687259966			27049830			15
9671566			9678744			5186294			16
712409396			726783481			34520858			17
1382.2456			1410.1348			303.8808			18
2511246			1661834			0			19
101495611			86444561			9160			20
0			0			0			21
8806421			7529340			29291			22
0			0			0			23
0			0			0			24
241530			241530			170			25
3853501			3838988			71461			26
414984			414984			0			27
1632415			1353310			90			28
712196			747101			0			29
3036993			3368550			639			30
6495316			9748076			95406			31
1060105			1595370			0			32
1609584			1588000			37034			33
131869902			118531644			243251			34
0.0436			0.0472			1.4592			35
Coal		Gas	Coal		Gas			Gas	36
Tons		MCF	Tons		MCF			MCF	37
1617464	0	318296	1317250	0	330499	0	0	2389	38
8983	0	1018184	8979	0	1019292	0	0	1041021	39
59.320	0.000	2.510	60.730	0.000	5.540	0.000	0.000	2.930	40
62.100	0.000	3.280	63.810	0.000	7.240	0.000	0.000	3.830	41
3.460	0.000	3.220	3.550	0.000	7.110	0.000	0.000	3.680	42
0.030	0.000	0.030	0.030	0.000	0.070	0.000	0.000	0.050	43
9708.493	0.000	9708.493	9562.359	0.000	9562.359	0.000	0.000	14919.016	44

- Privileged Data

DOCKET NO. E-01345A-19-0236

Exhibit FWR-8 – Excerpt from APS 2017 IRP – Portfolio Summaries

2017 INTEGRATED RESOURCE PLAN

APRIL 2017 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

FLEXIBLE RESOURCE PORTFOLIO

The Flexible Resource Portfolio is designed to deliver an increasingly flexible set of resources that does not overly rely on one specific fuel source during the 15-year Planning Period. It incorporates a significant level of rooftop solar generation expected to be installed by APS customers, adds approximately 50 MW per year of peak demand reducing DSM programs, over 500 MW of energy storage systems, microgrids, demand response and flexible gas generation. It recognizes the economically and operationally challenging environment for coal power plants and accordingly assumes that APS will no longer receive coal-fired generation from the Navajo Generating Station after 2019, and no longer burn coal at Cholla Units 1 and 3 beyond 2024. The reduced coal capacity along with the increase in flexible energy storage and natural gas generation allows APS customers to benefit from the low wholesale market prices being created by neighboring states with high renewable mandates. The Loads & Resources table for this Portfolio can be found in Attachment F.1(a)(1).

FIGURE 7-5. FLEXIBLE RESOURCE PORTFOLIO – ENERGY MIX

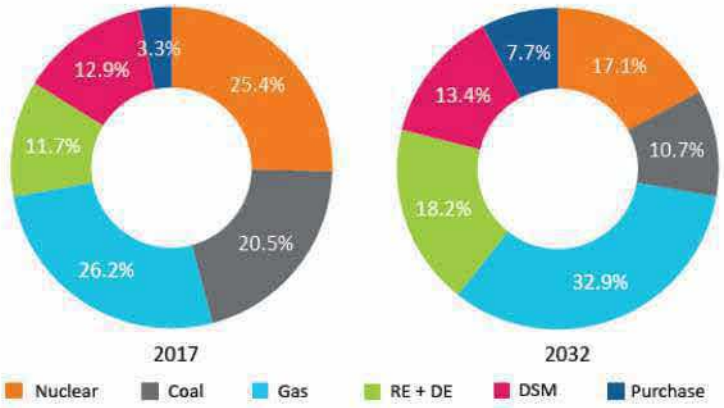
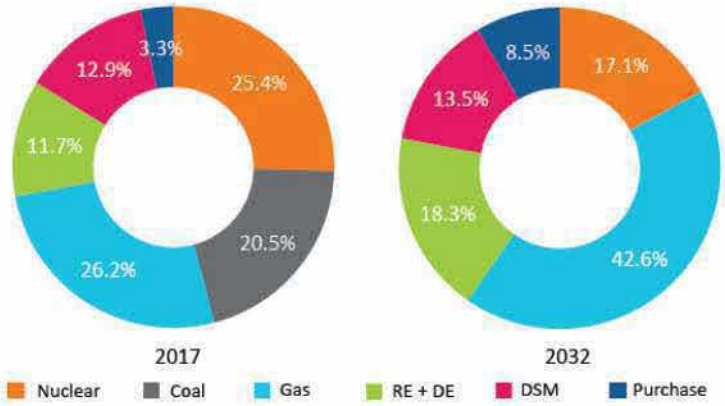


FIGURE 7-6. CARBON REDUCTION PORTFOLIO – ENERGY MIX



CARBON REDUCTION PORTFOLIO

The Carbon Reduction Portfolio was designed to reduce the level of carbon emissions in tons, not just the intensity, in order to evaluate the impacts of a mass-based carbon reduction goal that could potentially be mandated by the Environmental Protection Agency. One effective way to reduce carbon emissions is by reducing coal generation. In this Portfolio, that was accomplished by advancing the assumed retirement date of Cholla Units 1 and 3 from 2024 to 2022, and advancing the retirement date of Four Corners Units 4 and 5 to 2031 to coincide with the expiration of its current coal contract. Due to the operational challenges created by the amount of distributed generation in the resource mix, the lost generation was replaced with natural gas rather than additional renewable or base load nuclear generation. The Loads and Resources table for this Portfolio can be found in Attachment F.1(a)(2).

DOCKET NO. E-01345A-19-0236

Exhibit FWR-9 –Excerpt from APS 2017 IRP – Carbon Reduction Discussion

2017 INTEGRATED RESOURCE PLAN

APRIL 2017 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

DISCUSSION OF RESULTS

The results presented above illustrate the trade-offs in key metrics between the seven Portfolios under the base assumptions and are synopsized below.

The **Flexible Resource Portfolio** rates very well in terms of cost measures – both 15- and 30-year NPV, system cost, cost shift and capital expenditures. It has a reasonable energy mix with natural gas contributing about one third of its mix. Although it has slightly higher carbon emissions and uses slightly more water than some of the other Portfolios, its higher mix of flexible resources (natural gas and batteries) makes it a good fit for reliability, affordability and allows APS customers to benefit from market opportunities through its operation in the western wholesale energy market. Overall, this Portfolio is least-cost, best-fitting Portfolio of the seven evaluated.

The **Carbon Reduction Portfolio** has slightly higher costs than the Flexible Resource Portfolio in the 15-year NPV, and slightly lower in the 30-year NPV. It emits less carbon and uses less water than the other Portfolios; however, it also has significantly higher capital expenditure requirements and gas burn, with natural gas approaching 50% of the energy mix. APS will continue to evaluate operation of its coal resources and update future IRPs as appropriate.

The **Expanded DSM Portfolio** slightly reduces gas burn, carbon emissions and water use relative to the Flexible Resource Portfolio. However, the Portfolio does not compare well in terms of the economic analysis, especially when considering the size of the potential cost shift to non-participating customers and system average cost is 10% higher in this Portfolio than it is in the Flexible Resource Portfolio. The analysis confirms that the peak demand focused DSM represented in the Flexible Resource Portfolio is a more cost-effective option for all customers than continuation of today's GWH-focused EE programs.

The **Expanded Renewables Portfolio** reduces gas burn, carbon emissions and water use relative to the Flexible Resource Portfolio, but the Portfolio does not compare well to many of the other Portfolios in terms of the economic analysis. It is $100 million and $500 million more expensive than the Flexible Resource Portfolio in 15- and 30-year NPV of revenue requirements. Although the cost of renewable resources declines over the Planning Period, they do not provide enough value to offset their cost. Renewable resources provide limited summer peak capacity, so natural gas generation is still needed to meet the peak demand. Additionally, renewable resources provide a significant amount of energy in low-value, non-summer midday hours.

The **Energy Storage Systems Portfolio** is $300 million and $500 million more costly in 15- and 30-year NPV of revenue requirements, respectively, than the Flexible Resource Portfolio. Because of the limited number of hours per day that the storage systems can be used, increasing the amount of storage capacity results in reduced capacity value. In other words, the first 500 MW achieves approximately 80% capacity value, and the next 600 MW only achieves 60%. In this Portfolio, the addition of the extra 600 MW increases the amount of energy APS could purchase from the wholesale market, but the resources are also more costly and see diminishing returns on arbitrage opportunities. Gas burn, carbon emissions and water use were minimally impacted by the Energy Storage Systems Portfolio.

The **Resource Mandates Portfolio** combines elements of Expanded DSM, Expanded Renewables and Energy Storage Systems Portfolios. This Portfolio is extremely costly and is $500 million and $1.7 billion more expensive than the 15- and 30-year NPV values for the Flexible Resource Portfolio. It furthermore results in a cost shift of $2.8 billion to customers not participating in the EE programs embodied in the Portfolio. It raises system average costs more than 15% compared to the Flexible Resource Portfolio.

The **Small Modular Reactors Portfolio** is also a very costly Portfolio with 15- and 30-year NPV of revenue requirements $400 million and $1.7 billion higher than the Flexible Resource Portfolio. Due to the base load nature of the SMRs, the amount of energy that APS could purchase from the wholesale market in 2032, for example, is reduced by about 500 GWHs. Although it reduces gas burn and carbon emissions, both gas prices and carbon prices would have to be dramatically higher to make this a cost-effective option.

DOCKET NO. E-01345A-19-0236

Exhibit FWR-10 --Excerpt from APS 2017 IRP – Chart of 2032 System Average Costs by Portfolio

2017 INTEGRATED RESOURCE PLAN

APRIL 2017 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

FIGURE 7-19. SYSTEM AVERAGE COST IN 2032

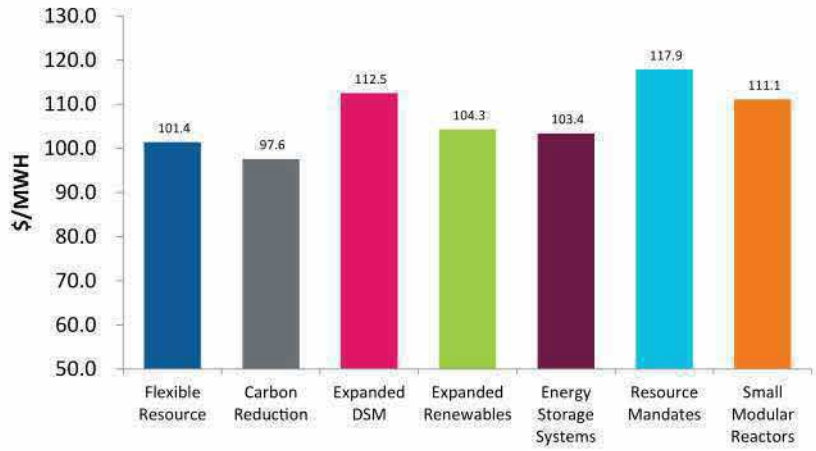


FIGURE 7-20. NPV OF COST SHIFT 2017-2032

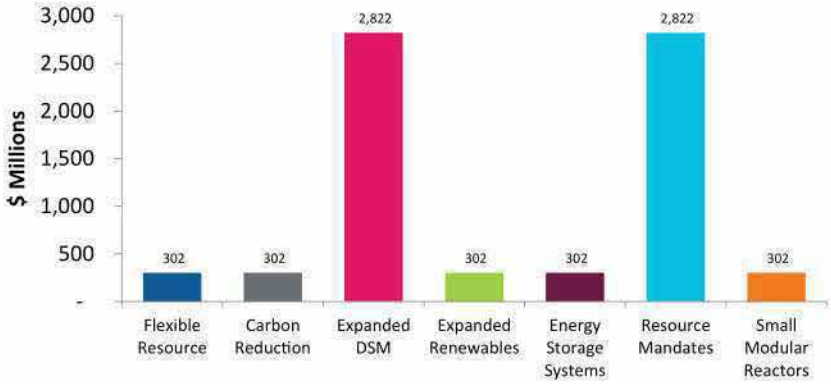
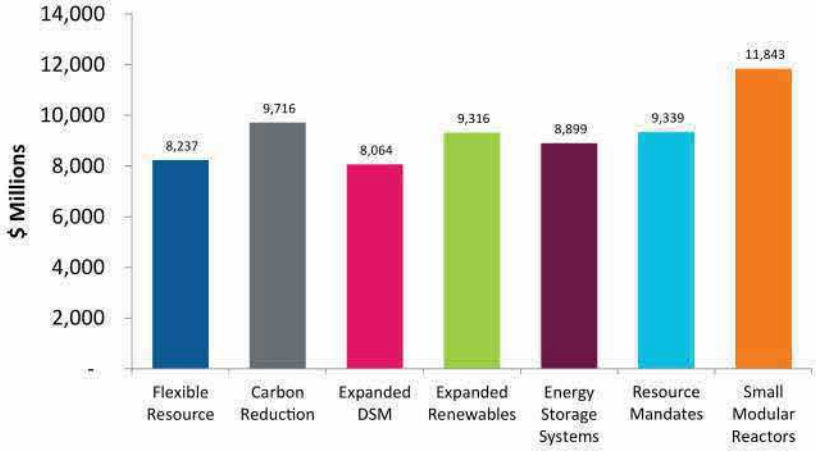


FIGURE 7-21. CAPITAL EXPENDITURES 2017-2032



The system average costs in 2032 show a similar trend with the Expanded Renewables, Resource Mandates and Small Modular Reactors Portfolios being significantly higher than the others. Although these are not projected customer rates, they do reflect that the cents per kWh will be higher under those Portfolios. This is what gives rise to the high cost shift in two of the Portfolios as indicated in Figure 7-19.

Cost shift in the two Portfolios with higher levels of EE is approximately $2.5 billion more than the Portfolios with the peak demand reducing DSM as shown in Figure 7-20.

The cumulative capital expenditures required to support the Flexible Portfolio are $8.2 billion over the Planning Period, as illustrated in Figure 7-21. It has the lowest capital requirements for APS of all of the Portfolios except the Expanded DSM.[5] All other Portfolios have higher capital requirements, with the Small Modular Reactors Portfolio requiring an additional $3.5 billion, or over 40% more than the Flexible Resource Portfolio. This is primarily due to the comparatively low cost of conventional peaking capacity included in the plans.

5 The customer cost of DSM totals about $600 million from 2017-2032 and is included in the capital expenditures for the Expanded DSM and Resource Mandates Portfolios shown on the chart.

DOCKET NO. E-01345A-19-0236

Exhibit FWR-11 – Calculation of APS Return of and Return on Four Corners Investment

Arizona Public Service Company
Calcuation of Retunr on and Retunr of Investment for Four Corners Generting Station

	Gross Plant 1/	Depr. Res. 1/	Net Plant 1/	Depr. Exp 1/ , 2/	APS requested Return	Return	Provisomn for income Taxes	Total
2019	$ 1,691,923	$ 597,668	$ 1,094,255	$ 37,355	7.41%	$ 81,084	$ 26,661	$ 145,100
2020	$ 1,691,923	$ 635,023	$ 1,056,900	$ 37,355	7.41%	$ 78,316	$ 25,750	$ 141,422
2021	$ 1,691,923	$ 672,378	$ 1,019,545	$ 63,722	7.41%	$ 75,548	$ 24,840	$ 164,110
2022	$ 1,691,923	$ 736,100	$ 955,823	$ 59,739	7.41%	$ 70,827	$ 23,288	$ 153,853
2023	$ 1,691,923	$ 795,839	$ 896,084	$ 59,739	7.41%	$ 66,400	$ 21,832	$ 147,971
2024	$ 1,691,923	$ 855,577	$ 836,346	$ 59,739	7.41%	$ 61,973	$ 20,377	$ 142,089
2025	$ 1,691,923	$ 915,316	$ 776,607	$ 59,739	7.41%	$ 57,547	$ 18,921	$ 136,207
2026	$ 1,691,923	$ 975,055	$ 716,868	$ 59,739	7.41%	$ 53,120	$ 17,466	$ 130,325
2027	$ 1,691,923	$ 1,034,794	$ 657,129	$ 59,739	7.41%	$ 48,693	$ 16,010	$ 124,443
2028	$ 1,691,923	$ 1,094,533	$ 597,390	$ 59,739	7.41%	$ 44,267	$ 14,555	$ 118,560
2029	$ 1,691,923	$ 1,154,272	$ 537,651	$ 59,739	7.41%	$ 39,840	$ 13,099	$ 112,678
2030	$ 1,691,923	$ 1,214,011	$ 477,912	$ 59,739	7.41%	$ 35,413	$ 11,644	$ 106,796
2031	$ 1,691,923	$ 1,273,750	$ 418,173	$ 59,739	7.41%	$ 30,987	$ 10,188	$ 100,914
2032	$ 1,691,923	$ 1,333,489	$ 358,434	$ 59,739	7.41%	$ 26,560	$ 8,733	$ 95,032
2033	$ 1,691,923	$ 1,393,228	$ 298,695	$ 59,739	7.41%	$ 22,133	$ 7,277	$ 89,150
2034	$ 1,691,923	$ 1,452,967	$ 238,956	$ 59,739	7.41%	$ 17,707	$ 5,822	$ 83,268
2035	$ 1,691,923	$ 1,512,706	$ 179,217	$ 59,739	7.41%	$ 13,280	$ 4,366	$ 77,385
2036	$ 1,691,923	$ 1,572,445	$ 119,478	$ 59,739	7.41%	$ 8,853	$ 2,911	$ 71,503
2037	$ 1,691,923	$ 1,632,184	$ 59,739	$ 59,739	7.41%	$ 4,427	$ 1,455	$ 65,621
2038	$ 1,691,923	$ 1,691,923	$ -	$ -	7.41%	$ -	$ -	$ 0
Total		2021-2038		$ 1,019,545		$ 677,574	$ 222,786	$ 1,919,906
Total		2032-2038		$ 358,434		$ 92,960	$ 30,565	$ 481,959

DOCKET NO. E-01345A-19-0236

Exhibit FWR-12 – APS DR Response confirming 2-Year lag on Property Tax for New Plant

ARIZONA CORPORATION COMMISSION STAFF'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 11, 2016

Staff 9.19: Refer to the direct testimony and workpapers of APS witness Snook concerning the Company's Ocotillo Deferral Request.

a. Show in detail how each amount on Mr. Snook's Ocotillo Deferral Request workpapers [LRS_WP01DR - Ocotillo deferral and SCR rev req.xlsx] on the "Ocotillo WPS" tab was derived.

b. Why are no "overhead loads" included in the plant costs?

c. What estimated "overhead loads" would be recorded by APS for:

   i. Units 3, 4 and 5?

   ii. Units 6 and 7?

d. Does the Company's accounting deferral request include any plant costs associated with "overhead loads"?

   i. If not, explain fully why not.

   ii. If so, how much?

e. What debt rate is used to compute the Debt Return?

f. Show in detail how the Debt Return amounts are calculated.

g. What depreciation rate and useful life are used for the Depreciation Expense?

h. Show in detail how the Depreciation Expense amounts are calculated.

i. Would any carrying charges be applied during the amortization period?

j. If the answer to part i is "yes" explain fully, and show in detail how the carrying charges curing the amortization period would be computed.

k. How are the "Average Rate Base - 2019" amounts

calculated? Show in detail.

l. The Company's proposed Commission Order language at page 14 of Mr. Snook's direct testimony does not specify an amortization period for the deferral. If that language were used, would the decision concerning the amortization period be reserved for the Commission to make in a future APS rate case?

m. Is the Company requesting to defer any equity return amounts for the OMP?

n. If the answer to part m is "yes" identify, quantify and explain all equity return deferrals related to the OMP that APS is proposing.

o. How will APS account for the revenue it receives from the generation of energy that is produced by the OMP during the accounting deferral period? Explain fully.

p. For each month of the anticipated accounting deferral period, identify the amount of energy generation anticipated from the OMP.

q. For each month of the anticipated accounting deferral period, identify the amount of revenue that APS expects from the energy generation anticipated from the OMP.

r. For each month of the OMP accounting deferral period, show and explain how the cost of power from the OMP compares with the amount of estimated payments for energy that APS would be making to obtain the energy from an alternative source.

s. Is the OMP anticipated to generate any savings in fuel or purchased power cost during the accounting deferral period?

    i. If not, explain fully why not.

    ii. If so, identify, quantify and explain the anticipated fuel and purchased power savings associated with the OMP.

t. Is the OMP anticipated to be eligible for accelerated tax depreciation and bonus tax depreciation?

   i. If not, explain fully why not.

   ii. If so, identify the amounts of accelerated tax depreciation and bonus tax depreciation in each tax year that is expected for the OMP.

u. Does APS agree that accelerated and bonus tax depreciation represents an important source of non-investor supplied cost-free financing? If not, explain fully why not.

Response:

a. Please see attachment APSRC01392 for additional details in support of LRS_WP01DR - Ocotillo deferral and SCR rev req.xlsx work paper "Ocotillo WPS" tab. Table A & B at lines 7 thru 60 relate to Ocotillo Modernization Project (OMP) cost deferrals.

b. Please note that Mr. Snook's testimony at page 12, line 20, states that the actual deferral will reflect the total ownership cost incurred in construction and operation of OMP project. Actual costs will include the actual direct and actual overhead loads for the project. Mr. Snook's work papers were prepared using only direct construction costs primarily for two reasons. First, the overhead loads that will apply to this project are not yet known. Overhead loads can be quite variable from year-to-year and business area to business area. Second, the amount of the Company's expected investment in OMP has previously been reported to the Commission and other external parties on the basis of direct costs only. To avoid confusion, the Company decided to use previously disclosed direct costs in its estimate. See Response to Staff 9.19(c) below for a rough estimate of the impact the inclusion of overhead loads may have on the annualized deferral.

c. Overhead loads are administrative and general (A&G) and engineering and supervision (E&S) costs allocated to capital projects. The actual overhead allocation ratio can vary from year to year depending on the level of A&G and E&S costs in a given year and the volume of capital projects subject to those allocations. The estimated overhead loads related to

OMP could be in the range of 6%, or approximately $30 million. On an annualized basis, this load rate would increase the cost deferral by approximately $2.5 million.

i. Overhead loads on OMP Units 3, 4 and 5 could be in the range of 6% or approximately $18M. On an annualized basis, this load rate would increase the cost deferral by approximately $1.5 million.

ii. Overhead loads on OMP Units 6 and 7 could be in the range of 6% or approximately $12M. On an annualized basis, this load rate would increase the cost deferral by approximately $1.0 million.

d. Yes, please see Response to Staff 9.19 (b) and (c) above.

e. Work paper LRS_WP01DR Page 2 of 2 used an incremental debt return of 6.75%.

f. Please see attachment APSRC01392 page 1 line 12 and line 41 for the calculation of the Debt Return amounts. A debt return is applied to 100% of the OMP in-service rate base for the number of months in deferral period. The expense associated with the debt return is deferred.

g. A depreciation rate of 3.125% with a useful life of 32 years was used to estimate the depreciation expense for OMP.

h. Please see attachment APSRC01392 page 1 line 9 & 38 for the calculation of the depreciation expense amounts.

i. After the costs of the OMP have been incorporated into the Company's base rates, which is likely to be at the conclusion of the Company's next rate case following the current case, cost deferrals for OMP will cease. Carrying charges for both debt and equity will be applied to the OMP rate base value at that time just as they apply to any other investment comprising the Company's rate base. Similarly, at the conclusion of the Company's next rate case, it is expected that the balance of the deferred expenses will start to be amortized and recovered in base rates. As with any other rate base item, the regulatory asset related to the accumulated deferred expenses will incur carrying charges

for both debt and equity.

j. Please see the Response to Staff 9.19(i) above. The carrying charges will be equal to the value of the regulatory asset in the Company's adjusted test year in (presumably) the Company's next rate case times the Company's weighted average cost of capital, including income taxes for the equity return portion, authorized by the Commission in that rate case.

k. Additional details on OMP average rate base estimates can be seen in attachment APSRC01392 page 1 line 31 and line 60.

l. Yes.

m. No.

n. Not applicable.

o. Customers will get the benefit of the OMP from the first day the units are in service. These benefits may occur as reduced fuel and purchased power expenses or as higher off-system margins. See the Response to Staff 9.19(s) below. In both cases, the changes in fuel and purchased power expenses will be reflected in lower PSA rates to customers once the units become operational.

p. The deferral period has not yet been determined, however, attachment APSRC01388 shows anticipated monthly generation from OMP from when it is expected to go in service through the end of 2022.

q. The OMP units are being developed to serve APS's native load requirements. To the extent that the units are available and market conditions are favorable, the units may be used to generate off system sales. These sales and associated revenues have not been estimated. Whatever they may be, they will be credited to APS customers.

r. OMP is being developed for capacity, reliability, quick start capability, fast-ramping and flexible operation purposes. Comparable resource alternatives were evaluated in a 2015

Peaking RFP. Results from that RFP showed that the OMP is less expensive than comparable alternative sources. Please refer to the independent monitor's letter provided in response to Staff 9.12a attachment APSRC01385.

s. OMP is expected to generate savings in fuel and purchase power costs during the accounting deferral period compared to not having OMP in service. The units are more efficient than the steam units currently at Ocotillo, more efficient than the other CTs on APS system, and provide added flexibility to the system. The flexibility including quick starting and fast-ramping of the OMP units allow APS to integrate greater amounts of solar renewable generation by ramping down as solar generation is added to the system and ramping up quickly to full load as solar generation falls sharply as the sun is setting. APS does not have an estimate of savings in fuel and purchase power that fully incorporates these benefits.

t. Yes, the capital investment in OMP is anticipated to be eligible for accelerated bonus tax depreciation based on current federal tax legislation.

   i. This question does not apply given that the response to 9.19 t. is yes.

   ii. Please see attachment APSRC01392 page 1 line 26 & 55 which indicate the estimated amounts of accelerated bonus tax depreciation related to OMP.

u. Yes. For this reason APS reduces rate base by the deferred tax impact associated with accelerated and bonus accelerated tax depreciation. This treatment will be applied to bonus accelerated tax depreciation on OMP.

OMP and SCR cost deferral detailed work paper - Staff Question 5.19 and 5.20

Supporting Details to LRS_WP01DR **Most Values are in $Millions**

Line #	TABLE - A : OMP U6 & U7				2016	2017	2018	2019	Totals	Comments & Notes
	OMP Costs - U6 & 7 in-service Nov & Dec 2018 deferrals begin Dec 2018									
7	*Deferral Months This period*				*0*	*0*	*1*	*12*		Number of months for deferrals
8	O&M				-	-	0.1	0.9	1.0	New CT unit "Fixed" O&M
9	Book Depreciation				-	-	0.5	6.6	7.2	Book depr. at book rate with calendar months factored into estimate
10	Other expense								-	Other expense
11	Property Taxes - 2 year lag				-	-	-	-	-	Property taxes normally have a two year lag before they are billed
12	Debt Return	100%	6.75%		-	-	1.0	11.4	12.4	Deferrals normally are allowed a 100% debt return
13	Equity Return	0%	10.5%		-	-	-	-	-	No equity return use 100% debt return for deferral period
14	Tax on Equity Return	40%	167%		-	-	-	-	-	Taxes result only when we are using an equity return
15	**Annual Deferrals - $Ms**				-	-	**1.6**	**19.0**	**20.6**	Sub-Total costs and return deferral amounts
16	**Annual Amortization - $Ms**			Years		-	-	-	-	
17	**Cumulative Deferrals Balance**				-	-	**1.6**	**20.6**		
18										
19	*Months in service*				*0*	*0*	*2*	*12*		**Construction Values - $Ms**
20	**Gross Plant**		Nov & Dec 2018		-	-	208.2	212.1		198.8 CapEx Total No AFUDC No Loads
21	Accum. Depr		32.0	3.1%		-	(1.1)	(7.7)		- Overhead costs assumed
22	**OCLD**					-	**207.1**	**204.4**		9.4 Estimated Capitalized AFUDC
23										208.2 Total Estimate for Plant in Service
24	Macrs Tax %s		B. Macrs 15 - Bonus 2018				43%	6%		Accelerated Bonus Depreciation Rates for 2018
25	Book Depreciation			3.1%			1.1	6.6		Book Depreciation at straight-line rate
26	Tax Depreciation						89.5	12.1		Tax Depreciation at accelerated tax rates
27	Tax Depr O/(U) Book Depr						88.4	5.5		Tax Depreciation Difference over book rate
28	Tax Depr Delta at marginal tax rate					-	(35.4)	(2.2)		Annual deferred tax at marginal tax rate
29	**Deferred Income Tax - Cumulative Balance**					-	**(35.4)**	**(37.6)**		Cumulative deferred tax and reduction to rate base
30	**Rate Base end of period**			**(line 22 + line29)**		-	**171.7**	**166.9**		
31	Rate Base average for return calc			(2 pt Ave)		-	190.0	169.3		Average rate base is 2pt - 100 % Return considers months in period

Line #	TABLE - B : OMP U6, U7 & U8				2016	2017	2018	2019	Totals	Comments & Notes
	OMP Costs - U5, U4 & U3 in-service Jan,Feb,Mar 2019 deferrals begin Feb 2019									
36	*Deferral Months This period*				*0*	*0*	*0*	*10*		Number of months for deferrals
37	O&M				-	-	-	1.4	1.4	New CT unit "Fixed" O&M
38	Book Depreciation				-	-	-	7.9	7.9	Book depr. at book rate with calendar months factored into estimate
39	Other expense								-	Other expense
40	Property Taxes - 2 year lag				-	-	-	-	-	Property taxes normally have a two year lag before they are billed
41	Debt Return	100%	6.75%			-	-	15.4	15.4	Deferrals normally are allowed a 100% debt return
42	Equity Return	0%	10.5%			-	-	-	-	No equity return use 100% debt return for deferral period
43	Tax on Equity Return	40%	167%		-	-	-	-	-	Taxes result only when we are using an equity return
44	**Annual Deferrals - $Ms**				-	-	-	**24.7**	**24.7**	Sub-Total costs and return deferral amounts
45	**Annual Amortization - $Ms**			Years			-	-	-	
46	**Cumulative Deferrals Balance**				-	-	-	**24.7**		
47										
48	*Months in service*				*0*	*0*	*0*	*10*		**Construction Values - $Ms**
49	Gross Plant		by Mar 2019		-	-	-	321.5		298.8 **CapEx Total No AFUDC No Loads**
50	Accum. Depr		32.0	3.1%		-	-	(7.9)		- Overhead costs assumed
51	**OCLD**					-	-	**313.6**		23.3 Estimated Capitalized AFUDC
52										321.5 Total Estimate for Plant in Service
53	Macrs Tax %s		B. Macrs 15 - Bonus 2019				0%	54%		Accelerated Bonus Depreciation Rates for 2018
54	Book Depreciation			2.9%			-	7.9		Book Depreciation at straight-line rate
55	Tax Depreciation						-	107.7		Tax Depreciation at accelerated tax rates
56	Tax Depr O/(U) Book Depr						-	99.8		Tax Depreciation Difference over book rate
57	Tax Depr Delta at marginal tax rate					-	-	(39.9)		Annual deferred tax at marginal tax rate
58	**Deferred Income Tax - Cumulative Balance**					-	-	**(39.9)**		Cumulative deferred tax and reduction to rate base
59	**Rate Base end of period**			**(line 51 + line58)**		-	-	**273.7**		
60	Rate Base average for return calc			(2 pt Ave)		-	-	297.6		Average rate base is 2pt - 100 % Return considers months in period

OMP and SCR cost deferral detailed work paper - Staff Question 5.19 and 5.20

Supporting Details to LRS_WP01DR **Most Values are in $Millions**

*Step Increase January 2019

Line #	TABLE - C - SCRs U4			2016	2017	2018	2019	Totals	Comments & Notes
	4C SCRs equipment costs for unit #4 - In-service Apr 2018, cost deferral thru Dec 2018 and Step increase in Jan 2019 and amortization begins Jan 2019								
65	*Surcharge Months This period*			*0*	*1*	*#*	*12*		Number of months for deferrals
66	O&M			-	-	-	-	-	No incremental OM
67	Book Depreciation			-	-	4.6	6.8	11.4	Book depr. at book rate at number of calendar months
68	Regulatory Asset Amortization						2.5	2.5	Regulatory Asset Amortization
69	Property Taxes - 2 year lag			-	-	-	-	-	Property taxes normally have a two year lag before they are billed
70	Debt Return	100%	6.75%		-	7.8	5.3	13.1	Deferral period at 100% debt - Jan 2019 on uses 54/46 Equity / Debt return
71	Equity Return starts Jan 2019	54%	10.5%		-	-	9.6	9.6	No equity return deferrals - Equity begins Jan 2019 with step increase
72	Tax on Equity Return	40%	167%	-	-	-	6.4	6.4	Taxes result only when we are using an equity return
73	**Annual Deferrals - $Ms**			-	-	12.4	-	**12.4**	Sub-total costs and return on capital for surcharge (with equity)
74	**Annual Amortization - $Ms**	5	Years			-	(2.5)		No amortization needed due to surcharge recovery
75	**Annual Revenue Req. - $Ms**		**(Sum line#67 to #72)**				**30.6**		**Annual Revenue Requirement - $Ms**
76	**Cumulative Deferrals Balance**			-	-	**12.4**	**9.9**		
77									
78	*Months in service*			*0*	*1*	*12*	*12*		**Construction Values - $Ms**
79	Gross Plant	Apr-18		-	-	213.6	213.6		200.0 **CapEx Total No AFUDC No Loads**
80	Accum. Depr	31	3.2%		-	(6.8)	(13.7)		- Overhead costs assumed
81	**OCLD**				-	**206.8**	**199.9**		13.6 Estimated Capitalized AFUDC
82									213.6 Total Estimate for Plant In Service
83	Macrs Tax Rates	B. Macrs 20 - Bonus 2018				42%	4%		Accelerated Bonus Depreciation Rates for 2018
84	Book Depreciation		3.2%		-	6.8	6.8		Book Depreciation at straight-line rate
85	Tax Depreciation				-	90.2	9.3		Tax Depreciation at accelerated tax rates
86	Tax Depr O/(U) Book Depr				-	83.4	2.4		Tax Depreciation Difference over book rate
87	Tax Depr Delta at marginal tax rate				-	(33.4)	(1.0)		Annual deferred tax at marginal tax rate
88	**Deferred Income Tax - Cumulative Balance**				-	**(33.4)**	**(34.3)**		Cumulative deferred tax and reduction to rate base
89	**Rate Base end of period**		**(line 81 + line 88)**		-	**173.4**	**165.6**		
90	Rate Base average for return calc		(2 pt Ave)		-	193.5	169.5		Average rate base is 2pt - 100 % Return considers months in period

*Step Increase January 2019

Line #	TABLE - D - SCRs U5			2016	2017	2018	2019	Totals	Comments & Notes
	4C SCRs equipment costs for unit #5 - In-service Dec 2017 with cost deferrals thru Dec 2018, Step increase Jan 2019 and amortization begins Jan 2019								
95	*Surcharge Months This period*			*0*	*1*	*12*	*12*		
96	O&M			-	-	-	-	-	New unit "Fixed" O&M from Resource Planning Work sheets
97	Book Depreciation			-	0.5	6.6	6.6	13.6	From CapEx module specific projects #55
98	Regulatory Asset Amortization						3.7	3.7	Regulatory Asset Amortization
99	Property Taxes - 2 year lag			-	-	-	1.3	1.3	Property taxes normally have a two year lag before they are billed
100	Debt Return	100%	6.75%		0.8	10.8	4.9	16.5	Deferral period at 100% debt - Jan 2019 on uses 54/46 Equity / Debt return
101	Equity Return starts Jan 2019	54%	10.5%		-	-	8.9	8.9	No equity return deferrals - Equity begins Jan 2019 with step increase
102	Tax on Equity Return	40%	167%	-	-	-	5.9	5.9	Taxes result only when we are using an equity return
103	**Annual Deferrals - $Ms**			-	**1.3**	**17.4**	-	**18.7**	Sub-total costs and return on capital for surcharge (with equity)
104	**Annual Amortization - $Ms**	5	Years			-	(3.7)		No amortization needed due to surcharge recovery
105	**Annual Revenue Req. - $Ms**		**(Sum line#95 to #102)**				**31.3**		**Annual Revenue Requirement - $Ms**
106	**Cumulative Deferrals Balance**			-	**1.3**	**18.7**	**15.0**		Cumulative Surcharge Recovery
107									
108	*Months in service*			*0*	*1*	*#*	*12*		**Construction Values - $Ms**
109	Gross Plant	Dec-17		-	185.4	204.7	204.7		197.9 CapEx Total No AFUDC No Loads
110	Accum. Depr	31	3.2%		(0)	(5)	(11)		- Overhead costs assumed
111	OCLD				185	200	193		6.8 Estimated Capitalized AFUDC
112									204.7 Total Estimate for Plant In Service
113	Macrs Tax %s	B. Macrs 20 - Bonus 2017			52%	4%	3%		Accelerated Bonus Depreciation Rates for 2018
114	Book Depreciation		3.2%		0	4	7		Book Depreciation at straight-line rate
115	Tax Depreciation				96	7	7		Tax Depreciation at accelerated tax rates
116	Tax Depr O/(U) Book Depr				96	3	0		Tax Depreciation Difference over book rate
117	Tax Depr Delta at marginal tax rate				(38)	(1)	(0)		Annual deferred tax at marginal tax rate
118	Deferred Income Tax - Cumulative Balance				(38)	(39)	(40)		Cumulative deferred tax and reduction to rate base
119	Other		0		-	-	-		
120	**Rate Base end of period**		**(line 111 + 118+119)**		**147**	**160**	**154**		
121	Rate Base average for return calc		(2 pt Ave)		147	160	157		Average rate base is 2pt - 100 % Return considers months in period

OMP and SCR cost deferral detailed work paper - Staff Question 5.19 and 5.20

Supporting Details to LRS_WP01DR **Most Values are in $Millions**

Macrs Tax Depreciation Tables - Normal

Line #	Tax Tables													
126														
127	A. Macrs 31.5	2%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
128	B. Macrs 20	4%	7%	7%	6%	4%	4%	4%	4%	4%	4%	4%	4%	4%
129	C. Macrs 15	5%	10%	9%	8%	6%	6%	6%	6%	3%				
130	D.. Macrs 10	10%	18%	14%	12%									
131	E. Macrs 7	14%	24%	17%	12%									
132	F. Macrs 5	20%	32%	19%	12%									
133	G. Macrs 3	33%	44%	15%	7%									
134														

Macrs Tax Depreciation - Bonus Accelerated (First year accelerated of 50% for 2017, 40% for 2018, 30% for 2019)

Line #	Tax Tables													
135														
136														
137	B. Macrs 15 - Bonus 2017	52.5%	4.8%	4.3%	3.9%	3.0%	3.0%	3.0%	3.0%	1.5%				
138	B. Macrs 20 - Bonus 2017	51.9%	3.6%	3.3%	3.1%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%
139														
140	B. Macrs 15 - Bonus 2018	43.0%	5.7%	5.1%	4.6%	3.5%	3.5%	3.5%	3.5%	1.8%				
141	B. Macrs 20 - Bonus 2018	42.3%	4.3%	4.0%	3.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
142														
143	B. Macrs 15 - Bonus 2019	33.5%	6.7%	6.0%	5.4%	4.1%	4.1%	4.1%	4.1%	2.1%				
144	B. Macrs 20 - Bonus 2019	32.6%	5.1%	4.7%	4.3%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%

TOTAL O&M Costs - $Millions

Line #				2016	2017	2018	2019
148	O&M Last Update - February 2016						
149	2	Units	LMS - CTs 2018	-	-	0.1	0.9
150	3	Units	LMS - CTs 2019	-	-	-	1.4
151			Fixed OM			0.1	2.3

TOTAL MONTHLY OCOTILLO MODERNIZATION PROJECT (OMP) GENERATION (MWH)

	Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
OCOTILLO CT 3-7	2018											4,211	52	4,263
OCOTILLO CT 3-7	2019	2,961	10,868	14,978	7,422	0	1,196	58,284	37,691	8,750	25,996	20,732	1,029	189,908
OCOTILLO CT 3-7	2020	1,323	7,926	11,383	6,884	0	1,309	51,812	35,416	10,096	39,748	20,442	1,221	187,560
OCOTILLO CT 3-7	2021	4,105	5,515	25,055	13,470	2,530	3,220	59,096	38,250	13,354	9,215	27,308	6,859	207,976
OCOTILLO CT 3-7	2022	0	2,549	21,557	5,424	9,191	291	51,426	39,217	8,256	9,783	5,260	2,288	155,243

NOTE: Source is the 2017 Preliminary IRP.

DOCKET NO. E-01345A-19-0236

Exhibit FWR-13 --APS Annual Incentive Award Plan - Redacted

DOCKET NO. E-01345A-19-0236

Exhibit FWR-14 Award Plan 2019 Results - Redacted

DOCKET NO. E-01345A-19-0236

Exhibit FWR-15 – APS Response to AECC Discovery Question on Cash Incentives

Rodney J. Ross
Manager
State Regulatory Affairs

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-4944
Rodney.Ross@aps.com

April 20, 2020

Patrick J. Black
Fennemore Craig, P.C.
2394 East Camelback, Suite 600
Phoenix, Arizona 85016-3429

RE: AECC's Sixteenth Set of Data Requests to
Arizona Public Service Company (APS or Company)
Docket No. E-01345A-19-0236

Dear Mr. Black:

Arizona Public Service Company's (APS or Company) responses to AECC's Sixteenth Set of Data Requests in the above docket are available on the APS 2019 Rate Case SharePoint Extranet Site.

Please let me know if you have any questions.

Sincerely,

/s/Rodney Ross

Rodney J. Ross

RJR/bgs

cc: Laura Ferrigni
Kevin Higgins

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SIXTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 6, 2020

AECC 16.1: **Cash Incentive.**

a. Please refer to APS's supplemental response to AECC 6.1 a. Please provide the breakout of the 2019 cash incentive dollars that were used to calculate the Test Year cash incentive between Company Performance and Business Performance, as APS provided for 2017 and 2018.

b. Please provide the derivation of the Test Year cash incentive using the 2018 and 2019 cash incentive amounts.

Response:

a. Please see the table below.

	Company Performance	Business Performance	Total
	(dollars in thousands)		
July-December 2018	$ 9,796	$ 12,606	$ 22,401
January-June 2019	$ 3,708	$ 12,370	$ 16,079
	$ 13,504	$ 24,976	$ 38,480

b. APS utilized the amounts reported in APS's Initial Data Request 15. Using the percentages contained therein, 58.2% of the costs are related to 2018 and 41.8% of the costs are related to 2019.

Witness: Elizabeth Blankenship

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SIXTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
APRIL 6, 2020

AECC 16.2: **Cash Incentive.** Please refer to APS's response to AECC 6.1 b. Please provide the average proportion of the Shareholder Value performance level to the total Business Unit Performance for the actual 2017, 2018, and 2019 cash incentives. For an example of the requested information, please see APS's response to AECC 6.1 b. in Docket No. E-01345A-19-0236:

> "b. Each Business Unit Performance plan contains a Shareholder Value component. Depending on the business unit the Shareholder Value components may be based on that business unit's O&M budget and/or capital budget. The performance level of the Shareholder Value metric varies across each business unit. On average, the proportion of the Shareholder Value performance level to the total Business Unit Performance is approximately 28% for 2013, 22% for 2014, and 28% for 2015. Please see Pre-filed 1.47 for business unit plan result for 2014 and 2015. Please see EFCA 12.3 for 2016 plan results."

Response: Each Business Unit Performance plan contains a Shareholder Value component. Depending on the business unit, the Shareholder Value components may be based on that business unit's O&M budget, capital budget, net operating expense, and/or value based maintenance savings. Although these components have been labeled as "Shareholder Value" in APS's incentive plan, they in fact provide equal if not greater value to APS customers.

The performance level of the Shareholder Value metric varies across each business unit. On average, the proportion of the Shareholder Value performance level to the total Business Unit Performance is approximately 28% for 2017, 22% for 2018, and 25% for 2019.

Witness: Elizabeth Blankenship

DOCKET NO. E-01345A-19-0236

Exhibit FWR-16 --APS Response to Initial Discovery Question 1.40 regarding Cash Incentive

ARIZONA PUBLIC SERVICE COMPANY
INITIAL SET OF DATA REQUESTS REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
OCT 31, 2019

Initial 1.40: Incentive Compensation.

a. Please identify all amounts of incentive compensation included in the Test Year by O&M subaccount.

b. Provide the amounts of ADIT associated with the incentive compensation expense included in the Test Year.

Response: a. Incentive compensation costs that are included in the Test Year are related to the Company's annual incentive plan, the Palo Verde outage plan, and the Palo Verde performance plan. See below for annual incentives.

Test Year July 2018-June 2019 Cash Incentive Amount

Account	($000)
426.4	296
506	2,878
519	(9)
524	3,133
549	2,143
556	(69)
557	551
566	1,665
588	4,824
903	2,198
908	138
916	751
920	13,906
928	351
930.2	33
Total:	32,789

The Test Year costs associated with stock compensation and SERP (the latter of which APS regards as a "benefit" as opposed to compensation) included in the revenue requirement for Total Company and ACC jurisdiction is zero, because the Company made pro forma adjustments to remove them from the Test Year.

Witness: Elizabeth Blankenship

DOCKET NO. E-01345A-19-0236

Exhibit FWR-17-- Commission Burns September 1, 2020 regarding APS Upper Management
Compensation

ORIGINAL

E000008699

MISSIONERS
ROBERT "BOB" BURNS
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

ROBERT "BOB" BURNS
Chairman

ARIZONA CORPORATION COMMISSION

September 1, 2020

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY RATE CASE
DOCKET NO. E-01345A-19-0236

Parties to the Case:

It has come to my attention that perhaps the amount of upper level management at Arizona Public Service Company ("APS") may be excessive and that the salary level of this upper level management may also be excessive when both levels are compared with other large utilities and other large corporations. It is with this backdrop that I would like the Arizona Corporation Commission's Utilities Division Staff ("Staff"), the Residential Utility Consumer Office ("RUCO"), and APS to respond (through written testimony in this docket) to the following questions:

1. How many Vice-President ("VP") positions did APS have in the years 2000, 2005, 2010, and 2015?
2. How many VP positions does APS have as of the date of this letter?
3. How does the number of VP positions listed above for each year compare with the number of VP positions in other utilities, specifically Salt River Project ("SRP"), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), San Diego Gas and Electric ("SDG&E"), Southwest Gas ("SWG"), Tucson Electric Power ("TEP") and UNS Electric ("UNSE") combined, Public Service of New Mexico ("PNM"), Los Angeles Department of Water and Power ("LADWP"), and any other utility or large corporation you believe is relevant to this comparison?
4. How many Senior Vice-President ("SVP") positions did APS have in the years 2000, 2005, 2010, and 2015?
5. How many SVP positions does APS have as of the date of this letter?
6. How does the number of SVP positions listed above for each year compare with the number of SVP positions in other utilities, specifically SRP, PG&E, SCE, SDG&E, SWG, TEP and

ACC - Docket Control - Received 9/1/2020 2:30 PM
ACC - Docket Control - Docketed 9/1/2020 2:46 PM

UNSE combined, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?

7. How many Executive Vice-President ("EVP") positions did APS have in the years 2000, 2005, 2010, and 2015?
8. How many EVP positions does APS have as of the date of this letter?
9. How does the number of EVP positions listed above for each year compare with the number of EVP positions in other utilities, specifically SRP, PG&E, SCE, SDG&E, SWG, TEP and UNSE combined, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?
10. For the VP positions listed above, what was the high, low and average annual salary for each year listed above?
11. For the SVP positions listed above, what was the high, low and average annual salary for each year listed above?
12. For the EVP positions listed above, what was the high, low and average annual salary for each year listed above?
13. For each salary for each year in questions #10, #11, and #12, how do those compare with the salaries of SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?
14. For the years 2000, 2005, 2010, and 2015, what was the annual salary for the President of APS?
15. How did the salary for the APS President compare to the salaries of the Presidents for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison for each year in question #14?
16. What is the current annual salary of the APS President and how does it compare to the current salaries of the Presidents for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?
17. For the years 2000, 2005, 2010, and 2015, what was the annual salary for the Chief Executive Officer ("CEO") of APS?
18. How did the salary for the APS CEO compare to the salaries of the CEOs for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison for each year in question #17?
19. What is the current annual salary of the APS CEO and how does it compare to the current salaries of the CEOs for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?
20. In addition to the salary information requested above for President and CEO, please provide the salaries of the President and CEO of APS for the year 2019, and how those salaries compared to the 2019 salaries of the President and CEO for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison.
21. For the years 2000, 2005, 2010, and 2015, what was the annual salary for the Chief Operating Officer ("COO") of APS?

22. How did the salary for the APS COO compare to the salaries of the COOs for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison for each year in question #21?
23. What is the current annual salary of the APS COO and how does it compare to the current salaries of the COOs for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?
24. For the years 2000, 2005, 2010, and 2015, what was the annual salary for the Chief Financial Officer ("CFO") of APS?
25. How did the salary for the APS CFO compare to the salaries of the CFOs for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison for each year in question #24?
26. What is the current annual salary of the APS CFO and how does it compare to the current salaries of the CFOs for SRP, PG&E, SCE, SDG&E, SWG, TEP, UNSE, PNM, LADWP, and any other utility or large corporation you believe is relevant to this comparison?

For each of the salary questions above, please include total compensation, not just the base salary, i.e., include any stocks, stock options, vehicles, and any other benefits that could be considered compensation that come with any of the above positions. In addition, please provide an organizational chart showing all the above positions for the years 2000, 2005, 2010, 2015 and 2020.

Although I have specifically requested that Staff, RUCO and APS respond to this letter, any other party to this case that believes it has relevant information to provide on the above questions should feel free to provide testimony in that regard.

I am requesting that APS provide responses to the above inquiries by no later than October 9, 2020. RUCO, Staff and any other interested party should provide their responses by November 6, 2020.

Sincerely,

Bob Burns
Chairman

DOCKET NO. E-01345A-19-0236

Exhibit FWR-18 -- APS Responses to various Discovery Responses on Membership Dues

VOTE SOLAR'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JUNE 5, 2020

Vote Solar 1.36:

a) Please identify each corporate membership dues paid, each contribution to a non-for-profit entity, and each contribution to an entity that engages in advocacy or public education of any type, that the Company includes in the revenue requirement to be recovered from ratepayers through rates. For purposes of this request, a contribution means cash payment, credit payment or extension of credit, in-kind contribution and/or conveyance of anything of value. This request encompasses, but is not limited to: All dues paid to Electric Power Research Institute, North American Electric Reliability Corporation, Edison Electric Institute, American Coalition for Clean Coal Electricity, Nuclear Energy Institute, American Gas Association, U.S. Chamber of Commerce, Republican Governors Association, Democratic Governors Association, any state legislative leadership committee, Utility Air Regulatory Group, Utility Water Act Group, Waters Advocacy Coalition, Utilities Solid Waste and Activities Group, American Legislative Exchange Council, National Conference of State Legislators, Third Way, Americans for Tax Reform, State Policy Network, Committee for a Constructive Tomorrow, Americans for Prosperity, the Thomas Alva Edison Foundation, and any similar organization(s); and each organization or entity receiving any amount of contribution recorded in account 426.4 "Political and Civil Activities" and account 930.2 "Miscellaneous General Expense."

b) For each contribution or dues identified in response to (a), above, please identify:

i. The total amount of membership dues or contribution.
ii. The amount of membership dues or contribution that is included in the revenue requirement in this case and the portion, if any, that the Company is not seeking to recover through rates.
iii. All services and value received by or accruing to ratepayers as a result of any portion of dues and/or contribution that the Company seeks to recover through rates.
iv. Whether the organization receiving the dues or contribution engages in any form of communication, advocacy, lobbying, litigation, public education and/or advertising paid for through dues and/or contributions.

Response:

a) For a listing of industry and trade association dues that were included in the Test Year, and a description of each entity, please see the Company's responses to Initial 1.33 and SEIA Data Request 1.2.

Witness: Elizabeth Blankenship

Response to Vote Solar 1.36 (continued):

For additional detail on Edison Electric Institute (EEI) expense and related subcommittee expense, and the amount of dues designated as lobbying, please see the Company's response to Initial 1.41. Dues to the Nuclear Energy Institute in 2019 were $1,878,538, of which $46,713 was designated by NEI as lobbying expense. No dues designated as lobbying have been included in the Test Year.

Also included in the Test Year revenue requirement as recorded in account 930.2 are various Chambers of Commerce dues, memberships, or sponsorships for cities and areas within the APS service territory. These Chambers are engaged primarily in economic development activities, and the related amount of expense for all Chamber dues, memberships, or sponsorships in the Test Year is less than $100,000.

Costs recorded in account 426.4 are not included in rates at any time, including the Test Year in this rate request.

For detailed information on organizations and APS expenses for lobbying, advertising and marketing, and contributions, please see the following letters in response to Commissioner inquiries:

https://docket.images.azcc.gov/0000198676.pdf
https://docket.images.azcc.gov/0000197833.pdf
https://docket.images.azcc.gov/E000007075.pdf

b) This information is provided in the documents cited in part a.

ARIZONA PUBLIC SERVICE COMPANY
INITIAL SET OF DATA REQUESTS REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
OCT 31, 2019

Initial 1.33: Industry Association Dues.

a. Are any amounts included in the test year for payments to industry associations, including but not limited to, amounts required as membership dues? If so, list the amounts and the accounts in which such contributions are recorded.

b. For each such dues payment of $10,000 or more, also state its purpose and describe how the Company perceives such expense to benefit ratepayers.

Response: a. Please see the table below.

Industry Association Dues		
Edison Electric Institute	9200000	$ 45,500
Electric Power Research Institute	5000000	$ 355,959
	5490000	$ 485,421
West Associates	9200000	$ 28,539
North American Transmission Forum	5600000	$ 80,702
RMEL	5660000	$ 18,000
Xenicus	5660000	$ 39,885
EUISSCA	9200000	$ 25,000
Chartwell Inc	9120000	$ 17,995
Center for Climate and Energy Solutions	9200000	$ 11,666
Smart Electric Power Alliance	5490000	$ 10,000
ARISEIA	5490000	$ 10,000
Other		$ 63,407
Grand Total		$1,192,077

b. Descriptions for associations with amounts of $10,000 or more are as follows:

Arizona Solar Energy Industries Association (AriSEIA) – Founded in 1997, AriSEIA is a non-profit organization representing the solar and storage industry, solar-friendly businesses, and others interested in advancing solar and storage technologies in Arizona. They focus on educating the public and key decision makers about solar, storage and technologies and energy efficiency.

Center for Climate and Energy Solutions (C2ES) – C2ES is an independent, nonpartisan, nonprofit organization working to forge practical solutions to climate change. They work with Fortune 500

Witness: Elizabeth Blankenship

Response to Initial 1.33 (cont):

companies to strengthen business action and business support for effective climate progress.

Chartwell, Inc – Chartwell, Inc. is a specialized information provider for the utility industry. Their resources are devoted to providing in-depth research and strategic industry contacts in customer-facing areas for electric, gas and water utilities.

Edison Electric Institute (EEI) – The Edison Electric Institute (EEI) is the association that represents all U.S investor-owned electric companies. EEI provides public policy leadership, strategic business intelligence and essential conferences and forums.

Electric Utility Industry Sustainable Supply Chain Alliance (EUISSCA) – Formed in 2008 in an effort to address common questions and challenges regarding how to address sustainability and become "more green". The group was formed by several electric utility supply chain executives who recognize the potential benefits of working together to green the electric utility supply chain.

Electric Power Research Institute (EPRI) – The Electric Power Research Institute is an independent, non-profit company performing research, development and demonstration in the electricity sector for the benefit of the public. They focus on the many specific technology challenges of helping members provide society with reliable, affordable, and environmentally responsible electricity.

North American Transmission Forum, Inc – North American Transmission Forum (NATF) members include investor-owned, state-authorized, municipal, cooperative, U.S. federal, and Canadian provincial utilities. NATF promotes excellence in the reliability ad resiliency of the electric transmission system. Members advance industry performance by sharing detailed and timely information, including lessons learned and superior practices.

RMEL – RMEL is a not-for-profit energy trade association that has served the electric utility industry with a variety of education and networking services since 1903. Dedicated to fostering a thriving community of electric energy professionals, RMEL's 300 corporate members share ideas, techniques and programs to better serve the industry and its customers.

Smart Electric Power Alliance (SEPA) – SEPA is a nonprofit organization that envisions a carbon-free energy system by 2050. They facilitate the electric power industry's smart transition to a clean and modern energy future through education, research, standards and collaboration.

Response to Initial 1.33 (cont):

WEST Associates - In the mid 1970's Southern California Edison (SCE) submitted a proposal to Western Energy Supply and Transmission (WEST) Associates to expand the solar monitoring effort outside of the SCE service territory in an effort to establish an accurate solar data base. The project, as approved, created the WEST Solar Monitoring network which eventually included 52 stations in six western states (Arizona, California, Colorado, Nevada, New Mexico and Wyoming).

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 10, 2020

SEIA 1.2: Please provide an itemization of the total amount of funds spent on an annual basis for the past five years for all trade association memberships, including but not limited to Edison Electric Institute, and advocacy groups. Please also indicate whether the Company is filing for recovery of these expenditures.

Response: Provided below is a listing of amounts paid for trade association memberships and advocacy groups in O&M expense for the years 2015 through 2019. Amounts reported for APS Total Company in the Test Year column were included in the filing for rate recovery. None of the expenses reflected below were used for lobbying purposes.

Business Unit	VENDOR NAME	2015	2016	2017	2018	6ME June 2019	Test Year (July 2018 to June 2019)
APSCO	AAED	12,000.00	500.00	-	-	-	-
APSCO	ACORE	-	7,125.00	-	7,500.00	-	7,500.00
APSCO	ADVANCED ENERGY ECONOMY	25,000.00	25,000.00	-	25,000.00	-	25,000.00
APSCO	ALLIANCE	-	25,000.00	-	-	-	-
APSCO	ALLIANCE FOR TRANSPORTATION	-	-	-	-	18,750.00	18,750.00
APSCO	AMERICAN LEGISLATIVE EXCHANGE COUNCIL	10,000.00	-	12,000.00	-	-	-
APSCO	ARISEIA	5,000.00	2,500.00	-	-	10,000.00	10,000.00
APSCO	ARIZONA TAX RESEARCH ASSOCIATION	14,750.00	5,530.00	9,500.00	12,000.00	3,500.00	9,500.00
APSCO	ASSOC OF EDISON ILLUMINATING COMPANIES	-	11,826.00	11,893.00	-	14,106.00	14,106.00
APSCO	ASSOC OF ENERGY SERVICES PROFESSIONALS	2,000.00	2,000.00	-	-	-	-
APSCO	ASSOCIATION OF ENERGY ENGINEERS	-	-	610.00	215.00	-	215.00
APSCO	CENTER FOR CLIMATE & ENERGY SOLUTIONS	-	-	17,500.00	17,500.00	11,666.00	11,666.00
APSCO	CENTER FOR ENERGY WORKFORCE DEVLOPMNT	6,250.00	6,250.00	-	6,250.00	6,250.00	6,250.00
APSCO	CENTER FOR RESOURCE SOLUTIONS	-	16,000.00	-	-	-	-
APSCO	CHARTWELL INC	-	-	17,295.00	17,995.00	-	17,995.00
APSCO	CONTINENTAL AUTOMATED BUILDINGS ASSOC	-	5,000.00	-	-	-	-
APSCO	CORPORATE EXECUTIVE BOARD	30,150.00	-	-	-	-	-
APSCO	CYBERTECH INC	19,995.00	-	-	-	-	-
APSCO	DISTRIBUTED ENERGY FINANCIAL GROUP	20,000.00	-	-	-	-	-
APSCO	EDISON ELECTRIC INSTITUTE	946,663.00	1,038,986.00	1,064,269.00	1,077,962.00	551,687.00	1,103,374.00
APSCO	ELECTRIC DRIVE TRANSPORTATION ASSOC	-	21,000.00	21,000.00	-	-	-
APSCO	ENERGY STORAGE ASSOCIATION INC	-	-	-	20,497.50	-	20,497.50
APSCO	EPRI	-	1,317,400.85	1,297,255.58	1,216,317.50	610,847.43	1,167,437.18
APSCO	EUISSCA	25,000.00	-	25,000.00	-	25,000.00	25,000.00
APSCO	GREENTECH MEDIA INC	-	47,500.00	-	60,500.00	-	-
APSCO	IHS GLOBAL INC	13,801.99	-	-	-	-	-
APSCO	ISH INC	5,000.00	-	-	-	-	-
APSCO	NATIONAL ASSOCIATION OF MANUFACTURERS	-	-	30,000.00	50,000.00	-	50,000.00
APSCO	NORTH AMERICAN ENERGY STANDARDS BOARD	7,000.00	-	-	7,000.00	7,500.00	14,500.00
APSCO	NORTH AMERICAN TRANSMISSION FORUM INC	-	-	-	-	80,702.00	80,702.00
APSCO	RMEL	18,000.00	18,000.00	-	18,000.00	18,000.00	18,000.00
APSCO	SMART ELECTRIC POWER ALLIANCE	-	-	-	10,000.00	10,000.00	20,000.00
APSCO	SOLAR ENERGY TRADE SHOWS LLC	6,800.00	-	-	-	-	-
APSCO	THE GRIDWISE ALLIANCE INC	20,000.00	-	20,000.00	20,000.00	-	-
APSCO	US GREEN BUILDING COUNCIL	-	1,050.00	-	-	-	-

Witness: Elizabeth Blankenship

SOLAR ENERGY INDUSTRIES ASSOCIATION'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 10, 2020

Response to
SEIA 1.2
(continued):

Business Unit	VENDOR NAME	2015	2016	2017	2018	6ME June 2019	Test Year (July 2018 to June 2019)
APSCO	UTILITY ECONOMIC DEVELOPMENT ASSOCIATION	1,980.00	3,130.00	3,580.00	9,850.00	-	6,715.00
APSCO	UTILITY VG INTEGRATION GROUP	5,000.00	7,500.00	7,500.00	-	-	-
APSCO	VALLEY OF THE SUN CLEAN CITIES COALITION	2,000.00	-	-	1,800.00	-	-
APSCO	WEST ASSOCIATES	28,539.00	-	-	28,539.00	-	28,539.00
APSCO	WESTERN ELECTRICITY COORDINATING COUNCIL	-	1,291,284.00	1,421,453.73	-	-	-
APSCO	WESTERN ENERGY INSTITUTE	68,323.01	46,040.42	45,970.00	45,911.00	-	45,911.00
APSCO	WREGIS	-	675.00	-	125.00	-	125.00
APSCO	XENICUS LLC	37,776.16	-	-	-	39,885.57	39,885.57
PVNGS*	ALLIANCE FOR TRANSPORTATION	-	-	-	-	1,818.75	1,818.75
PVNGS*	CENTER FOR CLIMATE & ENERGY SOLUTIONS	-	-	5,092.50	5,092.50	3,395.39	3,395.39
PVNGS*	CENTER FOR ENERGY WORKFORCE DEVLOPMNT	1,818.75	1,818.75	1,818.75	1,818.75	1,818.75	1,818.75
PVNGS*	EPRI	359,216.96	525,588.29	171,023.65	684,748.83	341,688.20	684,062.61
PVNGS*	EUCG	1,884.23	2,022.45	2,138.85	2,226.15	-	-
PVNGS*	STARS ALLIANCE	8,494.29	-	8,833.89	-	-	-
PVNGS*	WORLD NUCLEAR ASSOCIATION	15,759.14	15,163.25	13,425.79	15,488.93	-	-
FOURC*	EPRI	27,982.99	44,112.23	20,017.49	82,204.66	41,953.17	83,055.50
CHOLLA*	EPRI	22,417.50	35,338.78	16,036.24	65,855.06	33,609.15	66,536.68

*Plant amounts reported are for APS's Share only

Witness: Elizabeth Blankenship

DOCKET NO. E-01345A-19-0236

Exhibit FWR-19 -- Details on Membership dues

Arizona Pubic Service Company
Amounts Paid for Trade Association Memberships
For Test Year Ending June 2019

Trade Group	Total Amount Paid	EPRI and EEI share
Alliance for Transportation	$ 1,819	
Center for Climate & Energy Solutions	$ 3,395	
Center for Energy Workforce Development	$ 1,819	
EPRI	$ 684,063	$ 684,063
EPRI	$ 83,056	$ 83,056
EPRI	$ 66,537	$ 66,537
ACORE	$ 7,500	
Advanced Energy Economy	$ 25,000	
Alliance for Transportation	$ 18,750	
ARISEIA	$ 10,000	
Arizona Tax Research Association	$ 9,500	
Assoc of Edison Illuminating Companies	$ 14,106	
Association of Energy Engineers	$ 215	
Center for Climate & Energy Solutions	$ 11,666	
Center for Resource Solutions	$ 6,250	
Chartwell Inc.	$ 17,995	
EEI	$ 1,103,374	
Energy Storage Association	$ 20,498	
EPRI	$ 1,167,437	$ 1,167,437
EUISSCA	$ 25,000	
National Association Manufacturers	$ 50,000	
North American Standards Boards	$ 14,500	
North American Transmission Forum Inc.	$ 80,702	
RMEL	$ 18,000	
Smart Electric Power Alliance	$ 20,000	
Utility Economic Development Association	$ 6,715	
West Associates	$ 28,539	
Western Energy Institute	$ 45,911	
WREGIS	$ 125	
XENICUS LLC	$ 39,886	
Total	$ 3,582,356	$ 2,001,092
Adjustment 50/50 Sharing	$ 1,791,178	

DOCKET NO. E-01345A-19-0236

Exhibit FWR-20 -- APS response on Directors and Officers Liability Insurance

Staff 5.43: **Directors and Officers Liability Insurance.**

a. Has the Company included any amounts in rate base for Directors and Officers liability insurance? If so, please identify the total Company and ACC jurisdictional amounts by account.

b. Has the Company included any amounts in operating expense for Directors and Officers liability insurance? If so, please identify the total Company and ACC jurisdictional amounts by account.

c. Please identify the cost and coverage for each Directors and Officers liability insurance policy that was in effect during each year 2017, 2018, and 2019.

d. Does the Company record any amounts for Directors and Officers insurance as prepaids? If not, explain fully why not. If so, please show the monthly amounts for January 1, 2018 through the present.

Response:

a. Yes, Directors and Officers liability insurance is not capitalized, but it is a component of prepayments in working capital. The amount of D&O insurance in prepaid was about $306,697 as of June 30, 2019. See APS's response to subpart d.

b. Yes, APS has included the ACC jurisdictional amount which is $720,860 for the test year and charged to FERC account 925. The total company amount for the test year is $752,342. These expenses are customary and are necessary to attract and maintain qualified Directors and Officers.

c. The attached schedule, APS19RC00866, provides a breakdown of annual coverage amounts and premiums for 2017, 2018 and 2019. Please note that the attachment is Confidential and being provided pursuant to an executed Protective Agreement.

d. Yes, insurance policies over $50,000 covering one year or more are recorded in prepaid expense and are straight-line amortized monthly throughout the policy coverage period.

Witness: Elizabeth Blankenship

DOCKET NO. E-01345A-19-0236

Exhibit FWR-21 -- List of APS' regulatory assets

FREEPORT MINERALS CORPORATION AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-19-0236
JANUARY 30, 2020

AECC 2.5: **Regulatory Assets**. Please refer to SFR Schedule B-1. According to this schedule, APS's unadjusted test year includes $1,283,538,000 of regulatory assets.

a. Please provide a breakdown of this amount for each individual regulatory asset included in this total.
b. Please provide the original gross regulatory asset amount and the net regulatory asset amount (net of amortization) for each individual regulatory asset.
c. Please identify the amortization period starting date, the amortization period ending date, the amortization period, and the annual amortization amount being utilized for each individual regulatory asset.

Response:

a. A breakdown of the regulatory asset amounts included in rate base totaling $1,283,538,000 was provided in EAB-WP5DR (SFR Schedule B-1).
b. For each individual regulatory asset included in rate base, please see attachment ExcelAPS19RC00420 for the Test Year beginning balance, additions, amortization and ending balance for the Test Year period.
c. Please see attachment ExcelAPS19RC00420 for the amortization period and the annual amortization amount for each individual regulatory asset included in rate base for the Test Year.

Witness: Elizabeth Blankenship

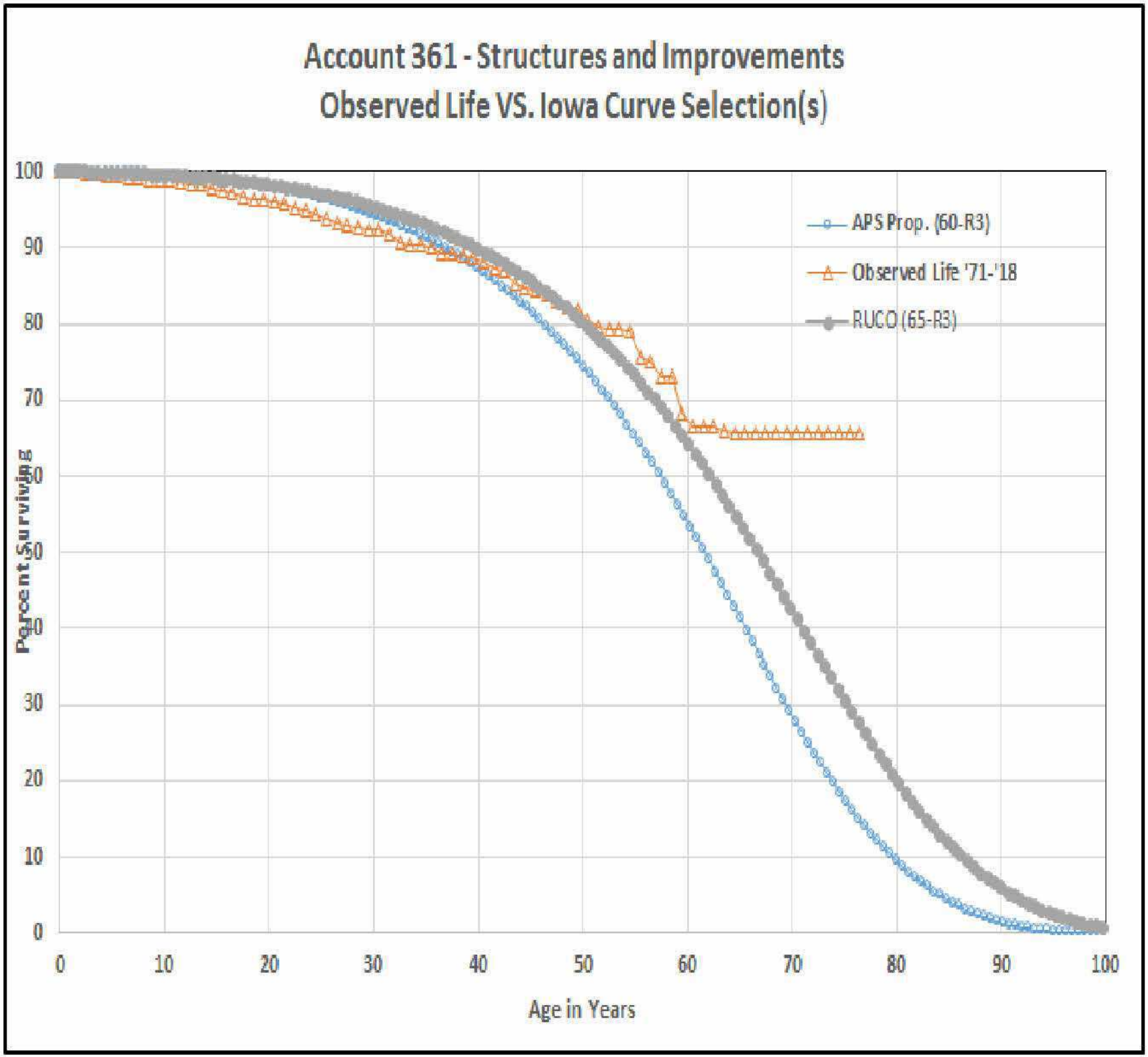
ARIZONA PUBLIC SERVICE COMPANY
NET REGULATORY ASSETS INCLUDED IN RATE BASE
TEST YEAR ENDED 6/30/2019
(dollars in thousands)

Line No.	Account Description	Total Beginning Balance 6/30/2018	Test Year Additions	Test Year Amortization	Total Ending Balance 6/30/2019	Amortization Period
	REGULATORY ASSETS					
1.	Pension	$ 604,556	$ 108,352	$ -	$ 712,908	N/A (a)
2.	Deferred Income Taxes on AFUDC	149,986	14,821	(5,962)	158,845	2003 - 2049
3.	Unrecovered Power Plant Costs-Navajo	92,439	-	(9,606)	82,833	2017 - 2026
4.	Unrecovered Power Plant Costs-Cholla	97,166	-	(16,103)	81,063	2017 - 2033 (b)
5.	Property Tax deferral	80,132	-	(9,491)	70,641	2017 - 2027
6.	Four Corners deferral	52,343	-	(8,077)	44,266	2017 - 2024
7.	SCR debt deferral	9,482	28,437	-	37,919	2021 - 2031 (b)
8.	Investment Tax Credit Basis Adjustment	26,916	-	(667)	26,249	2017 - 2047
9.	Navajo Coal Reclamation	13,388	5,477	(1,068)	17,797	2010 - 2026
10.	Regulatory Treatment of CIAC on the Mead-Phoenix Transmission Line	10,542	-	(332)	10,210	2005 - 2050
11.	Unrecovered Power Plant Costs-West Phx	9,982	-	-	9,982	2021 - 2031 (b)
12.	Ocotillo Deferral	-	9,495	-	9,495	2021 - 2031 (b)
13.	Unrecovered Power Plant Costs-Saguaro	224	9,468	(2,266)	7,426	2017 - 2022
14.	OPEB Subsidy PPACA	8,219	-	(1,212)	7,007	2010-2024
15.	AG-X deferral	9,799	-	(2,902)	6,897	2017 - 2022
	SUBTOTAL	$ 1,165,174	$ 176,050	$ (57,686)	$ 1,283,538	

(a) Future recovery of pension benefit obligations
(b) Proposed

DOCKET NO. E-01345A-19-0236

Exhibit FWR-22 -- Account 361 – Graph and deprecation data


Account 361 - Structures and Improvements
Observed Life VS. Iowa Curve Selection(s)
APS Prop. (60-R3)
Observed Life '71-'18
RUCO (65-R3)
Percent Surviving
Age in Years
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 361.00 Structures and Improvements

Placement Band: 1940 - 2017
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	89,978,270	0	0.00000	1.00000	1.00000
0.5	90,951,257	38,412	0.00042	0.99958	1.00000
1.5	88,070,778	124,081	0.00141	0.99859	0.99958
2.5	89,545,074	17,024	0.00019	0.99981	0.99817
3.5	82,444,921	220,423	0.00267	0.99733	0.99798
4.5	80,092,139	51,421	0.00064	0.99936	0.99531
5.5	75,561,133	254,918	0.00337	0.99663	0.99467
6.5	70,714,087	37,098	0.00052	0.99948	0.99132
7.5	64,089,903	16,754	0.00026	0.99974	0.99080
8.5	58,293,114	50,584	0.00087	0.99913	0.99054
9.5	51,684,245	86,681	0.00168	0.99832	0.98968
10.5	41,212,250	11,165	0.00027	0.99973	0.98802
11.5	38,879,222	161,520	0.00415	0.99585	0.98775
12.5	35,680,566	41,215	0.00116	0.99884	0.98365
13.5	31,761,152	150,365	0.00473	0.99527	0.98251
14.5	29,716,783	74,221	0.00250	0.99750	0.97786
15.5	27,890,191	80,582	0.00289	0.99711	0.97542
16.5	26,555,972	187,283	0.00705	0.99295	0.97260
17.5	24,263,809	57,814	0.00238	0.99762	0.96574
18.5	23,641,336	2,115	0.00009	0.99991	0.96344
19.5	21,748,437	75,325	0.00346	0.99654	0.96335
20.5	19,941,924	48,030	0.00241	0.99759	0.96002
21.5	19,339,492	124,882	0.00646	0.99354	0.95770
22.5	18,153,581	53,661	0.00296	0.99704	0.95152
23.5	16,743,376	67,244	0.00402	0.99598	0.94871
24.5	15,477,991	100,294	0.00648	0.99352	0.94490
25.5	14,579,103	82,697	0.00567	0.99433	0.93877
26.5	14,296,079	59,219	0.00414	0.99586	0.93345
27.5	13,471,165	41,173	0.00306	0.99694	0.92958
28.5	12,041,767	31,615	0.00263	0.99737	0.92674
29.5	11,078,959	20,668	0.00187	0.99813	0.92431
30.5	9,633,593	56,688	0.00588	0.99412	0.92258
31.5	6,522,387	66,831	0.01025	0.98975	0.91716
32.5	6,445,218	16,740	0.00260	0.99740	0.90776
33.5	5,864,321	15,178	0.00259	0.99741	0.90540
34.5	5,459,512	19,298	0.00353	0.99647	0.90306
35.5	4,903,625	31,385	0.00640	0.99360	0.89986

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 361.00 Structures and Improvements

Placement Band: 1940 - 2017
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	4,320,705	9,845	0.00228	0.99772	0.89411
37.5	4,016,254	8,344	0.00208	0.99792	0.89207
38.5	3,437,295	9,590	0.00279	0.99721	0.89021
39.5	2,687,404	16,155	0.00601	0.99399	0.88773
40.5	2,414,996	27,701	0.01147	0.98853	0.88239
41.5	2,218,456	9,017	0.00406	0.99594	0.87227
42.5	2,118,311	39,273	0.01854	0.98146	0.86873
43.5	1,997,025	13,200	0.00661	0.99339	0.85262
44.5	1,640,422	7,200	0.00439	0.99561	0.84699
45.5	1,366,279	9,461	0.00692	0.99308	0.84327
46.5	1,164,197	9,373	0.00805	0.99195	0.83743
47.5	1,109,962	12,956	0.01167	0.98833	0.83069
48.5	869,051	3,421	0.00394	0.99606	0.82099
49.5	790,281	11,405	0.01443	0.98557	0.81776
50.5	758,318	8,234	0.01086	0.98914	0.80596
51.5	631,724	2,688	0.00425	0.99575	0.79721
52.5	625,660	150	0.00024	0.99976	0.79381
53.5	603,063	1,368	0.00227	0.99773	0.79362
54.5	563,779	24,396	0.04327	0.95673	0.79182
55.5	500,188	3,643	0.00728	0.99272	0.75756
56.5	406,110	10,687	0.02632	0.97368	0.75204
57.5	362,448	413	0.00114	0.99886	0.73225
58.5	296,882	20,006	0.06739	0.93261	0.73142
59.5	248,899	6,078	0.02442	0.97558	0.68213
60.5	195,485	254	0.00130	0.99870	0.66547
61.5	131,555	0	0.00000	1.00000	0.66461
62.5	103,240	643	0.00622	0.99378	0.66461
63.5	71,583	492	0.00687	0.99313	0.66047
64.5	64,720	0	0.00000	1.00000	0.65593
65.5	61,656	0	0.00000	1.00000	0.65593
66.5	26,380	0	0.00000	1.00000	0.65593
67.5	26,380	0	0.00000	1.00000	0.65593
68.5	14,868	0	0.00000	1.00000	0.65593
69.5	8,365	0	0.00000	1.00000	0.65593
70.5	8,365	0	0.00000	1.00000	0.65593
71.5	8,365	0	0.00000	1.00000	0.65593
72.5	8,365	0	0.00000	1.00000	0.65593

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 361.00 Structures and Improvements

Placement Band: 1940 - 2017
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
73.5	6,496	0	0.00000	1.00000	0.65593
74.5	6,496	0	0.00000	1.00000	0.65593
75.5	6,496	0	0.00000	1.00000	0.65593
76.5	0	0	0.00000	1.00000	0.65593

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 361.00 Structures and Improvements

T-Cut: None

Placement Band: 1940-2017

Hazard Function: Proportion Retired

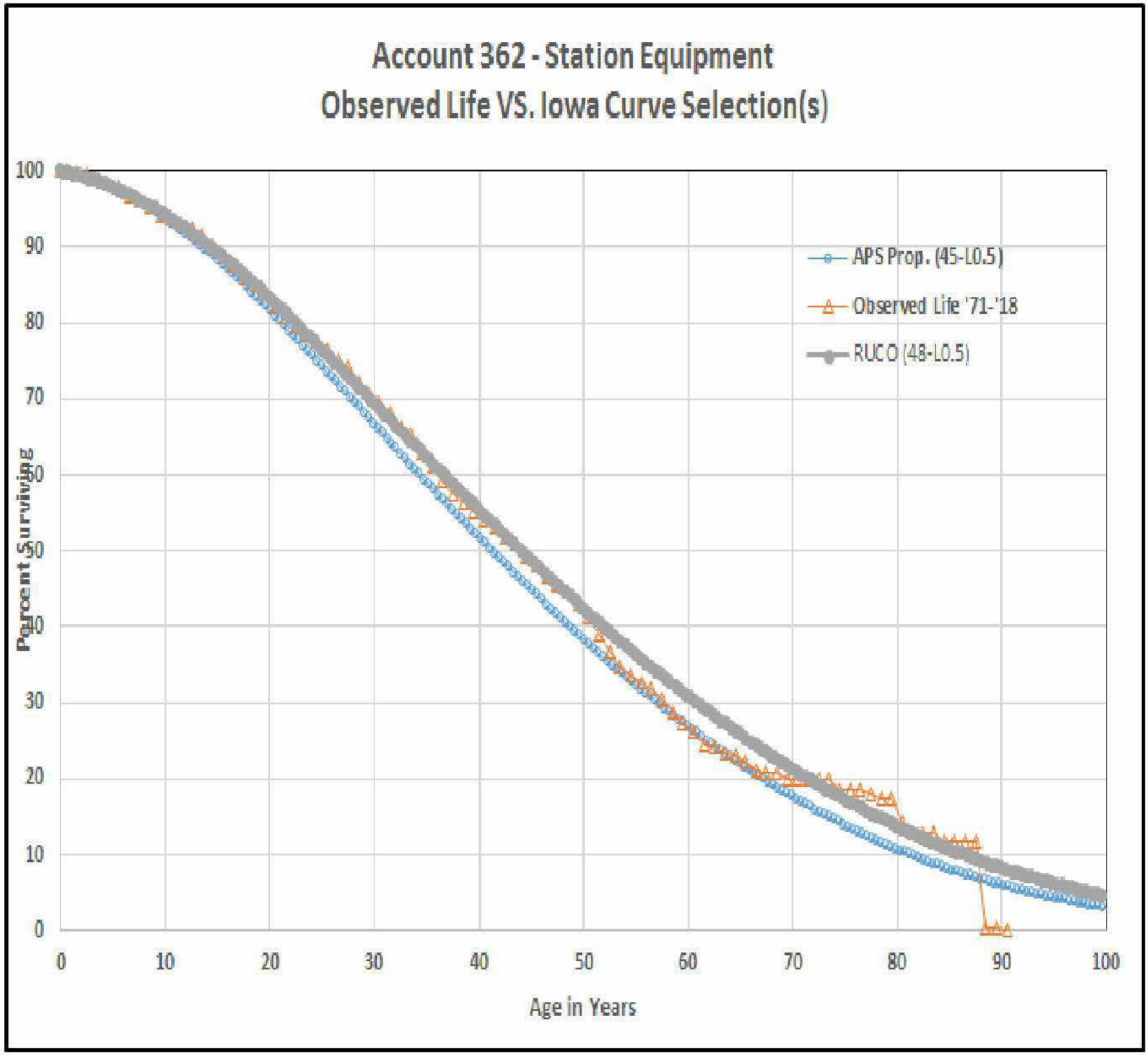
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	65.6	98.2	L1	2.16	85.1	S0.5	2.21	74.7	R2	3.42
1973-2018	65.6	98.4	L1	2.17	85.2	S0.5	2.21	74.6	R2	3.45
1975-2018	65.7	98.4	L1	2.18	85.2	S0.5	2.20	74.6	R2	3.46
1977-2018	65.8	98.9	L1	2.21	85.6	S0.5	2.19	74.5	R2	3.49
1979-2018	65.8	98.7	L1	2.19	85.6	S0.5	2.19	74.6	R2	3.47
1981-2018	65.8	98.6	L1	2.19	85.6	S0.5	2.19	74.6	R2	3.48
1983-2018	65.8	98.6	L1	2.18	85.7	S0.5	2.18	74.7	R2	3.46
1985-2018	66.6	100.4	L1	2.18	87.9	S0.5	2.09	75.3	R2	3.35
1987-2018	66.7	100.6	L1	2.18	88.0	S0.5	2.09	75.4	R2	3.35
1989-2018	67.1	101.2	L1	2.15	88.9	S0.5	2.06	75.9	R2	3.30
1991-2018	67.4	101.7	L1	2.21	86.9	S0.5	2.20	77.5	R2	3.09
1993-2018	67.5	101.4	L1	2.15	87.9	S0.5	2.14	77.0	R2	3.16
1995-2018	67.3	101.2	L1	2.14	87.9	S0.5	2.13	76.5	R2	3.24
1997-2018	67.2	100.7	L1	2.11	88.0	S0.5	2.12	76.0	R2	3.31
1999-2018	66.6	99.5	L1	2.09	87.9	S0.5	2.11	75.4	R2	3.35
2001-2018	66.2	98.8	L1	2.12	87.0	S0.5	2.14	74.8	R2	3.42
2003-2018	70.3	101.3	L1	1.68	93.6	L1.5	2.04	83.0	R1.5	2.63
2005-2018	69.4	99.2	L1	1.75	93.2	L1.5	2.04	81.5	R1.5	2.71
2007-2018	68.3	96.5	L1	1.83	93.2	L1	2.00	81.2	R1.5	2.62
2009-2018	67.8	95.7	L1	1.98	94.9	L1	2.01	77.4	R2	3.12
2011-2018	71.7	107.9	L1	2.00	97.2	S0.5	2.03	78.8	R2	3.34
2013-2018	74.3	122.1	S-.5	2.91	95.4	S1	2.32	82.1	R2.5	3.17
2015-2018	78.7	124.3	S0 *	2.05	104.5	S1	1.94	89.1	R2.5	2.57
2017-2018	83.7	134.1	S0 *	2.21	181.4	R3 *	3.06	183.1	R4 *	3.35

DOCKET NO. E-01345A-19-0236

Exhibit FWR-23 -- Account 362 – Graph and deprecation data


Account 362 - Station Equipment
Observed Life VS. Iowa Curve Selection(s)
APS Prop. (45-L0.5)
Observed Life '71-'18
RUCO (48-L0.5)
Percent Surviving
Age in Years
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Placement Band: 1929 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	709,561,984	510,981	0.00072	0.99928	1.00000
0.5	639,049,261	970,196	0.00152	0.99848	0.99928
1.5	589,207,108	1,746,359	0.00296	0.99704	0.99776
2.5	546,998,781	3,271,984	0.00598	0.99402	0.99481
3.5	517,424,768	2,008,830	0.00388	0.99612	0.98885
4.5	494,413,107	3,663,176	0.00741	0.99259	0.98502
5.5	479,500,973	5,133,345	0.01071	0.98929	0.97772
6.5	451,305,829	2,782,587	0.00617	0.99383	0.96725
7.5	428,169,908	4,205,831	0.00982	0.99018	0.96129
8.5	411,810,222	4,320,232	0.01049	0.98951	0.95184
9.5	380,860,156	1,916,616	0.00503	0.99497	0.94186
10.5	336,530,078	2,546,021	0.00757	0.99243	0.93712
11.5	315,979,507	1,931,305	0.00611	0.99389	0.93003
12.5	282,537,239	2,934,892	0.01039	0.98961	0.92434
13.5	247,228,267	3,489,406	0.01411	0.98589	0.91474
14.5	227,692,946	3,583,778	0.01574	0.98426	0.90183
15.5	208,820,821	2,700,613	0.01293	0.98707	0.88764
16.5	189,414,045	3,873,769	0.02045	0.97955	0.87616
17.5	167,011,583	1,751,327	0.01049	0.98951	0.85824
18.5	152,522,838	2,073,064	0.01359	0.98641	0.84924
19.5	133,494,097	2,554,497	0.01914	0.98086	0.83770
20.5	121,175,430	2,282,418	0.01884	0.98116	0.82167
21.5	112,759,787	1,521,663	0.01349	0.98651	0.80619
22.5	105,025,947	1,546,805	0.01473	0.98527	0.79531
23.5	99,878,340	993,862	0.00995	0.99005	0.78360
24.5	96,210,588	1,187,551	0.01234	0.98766	0.77580
25.5	90,678,336	1,824,902	0.02013	0.97987	0.76622
26.5	85,857,146	1,145,491	0.01334	0.98666	0.75080
27.5	81,003,202	1,993,434	0.02461	0.97539	0.74079
28.5	75,601,928	1,907,356	0.02523	0.97477	0.72256
29.5	69,979,518	1,040,435	0.01487	0.98513	0.70433
30.5	60,387,096	1,034,782	0.01714	0.98286	0.69386
31.5	54,623,514	1,480,203	0.02710	0.97290	0.68197
32.5	48,382,783	727,236	0.01503	0.98497	0.66349
33.5	41,496,808	1,588,959	0.03829	0.96171	0.65351
34.5	36,286,883	1,043,619	0.02876	0.97124	0.62849
35.5	32,287,694	926,222	0.02869	0.97131	0.61041

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Placement Band: 1929 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
36.5	28,456,833	850,982	0.02990	0.97010	0.59290
37.5	25,876,959	596,145	0.02304	0.97696	0.57517
38.5	23,699,742	370,008	0.01561	0.98439	0.56192
39.5	20,324,427	443,456	0.02182	0.97818	0.55315
40.5	18,034,563	318,460	0.01766	0.98234	0.54108
41.5	16,534,436	467,828	0.02829	0.97171	0.53153
42.5	15,517,622	224,162	0.01445	0.98555	0.51649
43.5	14,946,933	469,207	0.03139	0.96861	0.50903
44.5	12,787,435	329,292	0.02575	0.97425	0.49305
45.5	11,396,262	357,859	0.03140	0.96860	0.48035
46.5	9,569,309	226,832	0.02370	0.97630	0.46527
47.5	8,797,424	145,949	0.01659	0.98341	0.45424
48.5	6,895,923	252,037	0.03655	0.96345	0.44670
49.5	6,006,794	229,272	0.03817	0.96183	0.43038
50.5	5,451,528	309,642	0.05680	0.94320	0.41395
51.5	4,884,286	279,182	0.05716	0.94284	0.39044
52.5	4,292,623	231,249	0.05387	0.94613	0.36812
53.5	3,897,977	136,475	0.03501	0.96499	0.34829
54.5	3,677,849	83,837	0.02280	0.97720	0.33609
55.5	3,424,128	112,665	0.03290	0.96710	0.32843
56.5	2,550,135	101,403	0.03976	0.96024	0.31763
57.5	2,385,566	144,596	0.06061	0.93939	0.30500
58.5	1,974,616	92,603	0.04690	0.95310	0.28651
59.5	1,768,910	70,435	0.03982	0.96018	0.27307
60.5	1,483,758	99,606	0.06713	0.93287	0.26220
61.5	1,274,815	11,639	0.00913	0.99087	0.24460
62.5	1,066,074	32,468	0.03046	0.96954	0.24237
63.5	866,483	10,793	0.01246	0.98754	0.23498
64.5	741,719	29,971	0.04041	0.95959	0.23206
65.5	625,723	36,248	0.05793	0.94207	0.22268
66.5	508,819	4,065	0.00799	0.99201	0.20978
67.5	479,009	0	0.00000	1.00000	0.20810
68.5	397,725	16,455	0.04137	0.95863	0.20810
69.5	318,849	65	0.00021	0.99979	0.19949
70.5	179,621	0	0.00000	1.00000	0.19945
71.5	179,621	0	0.00000	1.00000	0.19945
72.5	174,959	1,010	0.00577	0.99423	0.19945

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

Placement Band: 1929 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
73.5	154,292	9,828	0.06370	0.93630	0.19830
74.5	144,464	1,008	0.00698	0.99302	0.18567
75.5	143,332	0	0.00000	1.00000	0.18437
76.5	40,258	1,053	0.02616	0.97384	0.18437
77.5	39,205	1,242	0.03168	0.96832	0.17955
78.5	37,963	0	0.00000	1.00000	0.17386
79.5	37,822	6,633	0.17537	0.82463	0.17386
80.5	31,189	2,927	0.09384	0.90616	0.14337
81.5	28,262	0	0.00000	1.00000	0.12992
82.5	28,262	0	0.00000	1.00000	0.12992
83.5	5,471	560	0.10236	0.89764	0.12992
84.5	4,911	0	0.00000	1.00000	0.11662
85.5	4,911	0	0.00000	1.00000	0.11662
86.5	4,911	0	0.00000	1.00000	0.11662
87.5	4,911	4,732	0.96350	0.03650	0.11662
88.5	179	0	0.00000	1.00000	0.00426
89.5	0	0	0.00000	1.00000	0.00426

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 362.00 Station Equipment

T-Cut: None

Placement Band: 1929-2018

Hazard Function: Proportion Retired

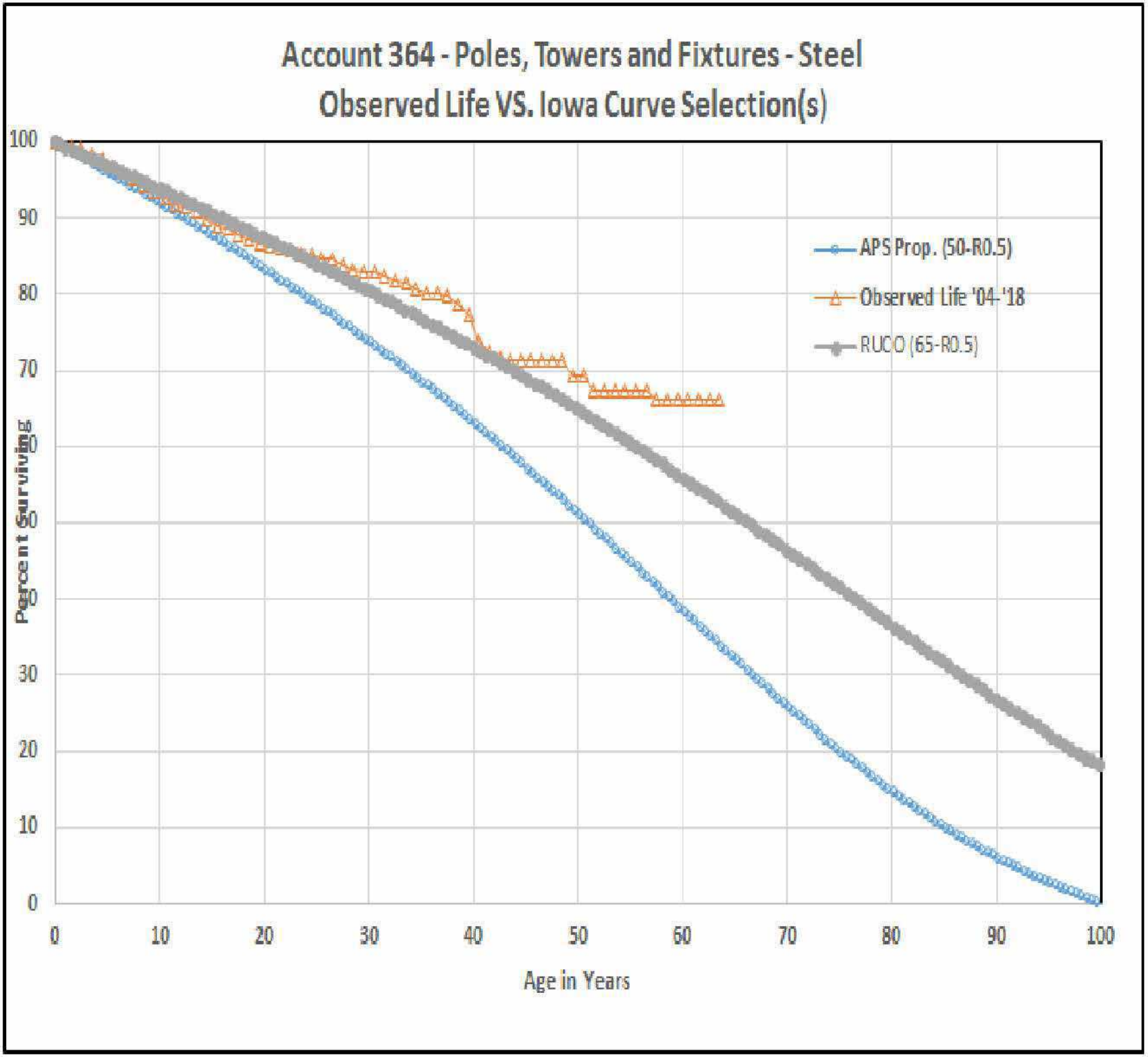
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	0.4	46.4	L0.5	2.09	47.4	L0.5	1.85	46.3	L0.5	2.08
1973-2018	0.4	46.4	L0.5	2.09	47.4	L0.5	1.85	46.3	L0.5	2.08
1975-2018	0.4	46.4	L0.5	2.09	47.4	L0.5	1.85	46.3	L0.5	2.08
1977-2018	0.4	46.4	L0.5	2.09	47.5	L0.5	1.85	46.3	L0.5	2.09
1979-2018	0.4	46.3	L0.5	2.09	47.5	L0.5	1.85	46.3	L0.5	2.09
1981-2018	0.4	46.3	L0.5	2.09	47.4	L0.5	1.84	46.2	L0.5	2.08
1983-2018	0.4	46.3	L0.5	2.10	47.4	L0.5	1.85	46.2	L0.5	2.08
1985-2018	0.4	46.3	L0.5	2.09	47.5	L0.5	1.86	46.3	L0.5	2.09
1987-2018	0.4	46.3	L0.5	2.09	47.4	L0.5	1.85	46.2	L0.5	2.09
1989-2018	0.4	46.9	L0.5	2.08	48.1	L0.5	1.89	46.6	L0.5	2.15
1991-2018	0.5	48.3	L0.5	2.03	48.9	L0.5	1.96	47.9	L0.5	2.14
1993-2018	0.5	48.3	L0.5	2.04	49.0	L0.5	1.95	47.7	L1	2.22
1995-2018	0.5	48.4	L0.5	2.04	49.1	L0.5	1.97	47.7	L1	2.25
1997-2018	0.4	47.6	L0.5	2.04	48.5	L0.5	1.92	47.1	L1	2.21
1999-2018	0.4	47.0	L0.5	2.03	48.0	L0.5	1.88	46.5	L0.5	2.23
2001-2018	0.4	48.0	L0.5	1.99	47.6	L1	2.03	47.0	L1	2.27
2003-2018	0.4	47.6	L0.5	2.02	47.1	L1	2.10	46.9	L1	2.19
2005-2018	0.4	47.4	L0.5	2.03	46.8	L1	2.11	46.6	L1	2.19
2007-2018	0.4	49.7	L0.5	2.42	47.9	L1	2.37	48.1	L1	2.28
2009-2018	0.6	52.2	L0.5	2.29	51.7	L1	2.31	52.1	L0.5	2.28
2011-2018	0.7	52.5	L0.5	2.90	52.5	L0.5	2.91	65.0	O3 *	2.80
2013-2018	0.1	55.5	L0.5	6.77	55.0	L0.5	6.48	53.8	L0.5	6.06
2015-2018	0.1	61.0	L0.5	8.50	65.2	L0.5	9.58	90.1	O3 *	11.22
2017-2018	0.0	72.8	L0.5	14.09	112.9	O3 *	18.32	77.5	S-.5	16.80

DOCKET NO. E-01345A-19-0236

Exhibit FWR-24 -- Account 364 Graph and deprecation data


Account 364 - Poles, Towers and Fixtures - Steel
Observed Life VS. Iowa Curve Selection(s)
APS Prop. (50-R0.5)
Observed Life '04-'18
RUCO (65-R0.5)
Percent Surviving
Age in Years
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 364.02 Poles, Towers and Fixtures - Steel

Placement Band: 1955 - 2018
Observation Band: 2004 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	278,726,886	578,477	0.00208	0.99792	1.00000
0.5	277,730,365	787,305	0.00283	0.99717	0.99792
1.5	270,801,845	1,341,459	0.00495	0.99505	0.99510
2.5	258,539,685	1,789,446	0.00692	0.99308	0.99017
3.5	245,382,721	1,657,932	0.00676	0.99324	0.98331
4.5	234,490,961	1,991,152	0.00849	0.99151	0.97667
5.5	215,241,462	1,722,733	0.00800	0.99200	0.96838
6.5	197,644,536	1,967,786	0.00996	0.99004	0.96063
7.5	177,571,043	1,434,384	0.00808	0.99192	0.95106
8.5	163,440,326	1,524,635	0.00933	0.99067	0.94338
9.5	148,527,121	1,195,163	0.00805	0.99195	0.93458
10.5	130,477,977	1,245,395	0.00954	0.99046	0.92706
11.5	107,179,326	579,121	0.00540	0.99460	0.91821
12.5	81,759,504	510,260	0.00624	0.99376	0.91325
13.5	64,344,518	673,787	0.01047	0.98953	0.90755
14.5	51,062,800	507,668	0.00994	0.99006	0.89805
15.5	38,989,057	154,408	0.00396	0.99604	0.88912
16.5	26,718,969	243,590	0.00912	0.99088	0.88560
17.5	21,835,540	172,099	0.00788	0.99212	0.87752
18.5	13,182,113	70,701	0.00536	0.99464	0.87061
19.5	8,633,667	35,891	0.00416	0.99584	0.86594
20.5	7,188,880	7,319	0.00102	0.99898	0.86234
21.5	7,090,177	24,358	0.00344	0.99656	0.86146
22.5	2,037,080	17,391	0.00854	0.99146	0.85850
23.5	1,727,192	443	0.00026	0.99974	0.85117
24.5	1,375,320	5,152	0.00375	0.99625	0.85095
25.5	1,362,546	4,244	0.00311	0.99689	0.84776
26.5	1,255,711	8,859	0.00706	0.99295	0.84512
27.5	1,211,551	8,559	0.00706	0.99294	0.83916
28.5	1,030,462	5,065	0.00492	0.99508	0.83323
29.5	796,471	1,120	0.00141	0.99859	0.82914
30.5	708,504	4,537	0.00640	0.99360	0.82797
31.5	520,913	2,148	0.00412	0.99588	0.82267
32.5	471,451	2,442	0.00518	0.99482	0.81928
33.5	394,409	3,479	0.00882	0.99118	0.81503
34.5	377,042	3,089	0.00819	0.99181	0.80784
35.5	331,906	360	0.00109	0.99891	0.80122

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 364.02 Poles, Towers and Fixtures - Steel

Placement Band: 1955 - 2018
Observation Band: 2004 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	314,408	490	0.00156	0.99844	0.80036
37.5	253,171	3,661	0.01446	0.98554	0.79911
38.5	237,752	4,838	0.02035	0.97965	0.78755
39.5	220,348	9,489	0.04307	0.95693	0.77153
40.5	171,642	3,461	0.02016	0.97984	0.73830
41.5	160,598	1,476	0.00919	0.99081	0.72341
42.5	133,057	517	0.00389	0.99611	0.71676
43.5	115,263	0	0.00000	1.00000	0.71398
44.5	101,120	53	0.00053	0.99947	0.71398
45.5	98,919	0	0.00000	1.00000	0.71360
46.5	115,380	140	0.00121	0.99879	0.71360
47.5	109,032	0	0.00000	1.00000	0.71274
48.5	108,721	2,856	0.02627	0.97373	0.71274
49.5	96,924	0	0.00000	1.00000	0.69401
50.5	91,758	2,743	0.02990	0.97010	0.69401
51.5	83,078	0	0.00000	1.00000	0.67326
52.5	81,314	0	0.00000	1.00000	0.67326
53.5	77,730	0	0.00000	1.00000	0.67326
54.5	71,377	0	0.00000	1.00000	0.67326
55.5	67,114	0	0.00000	1.00000	0.67326
56.5	62,013	1,117	0.01801	0.98199	0.67326
57.5	58,615	0	0.00000	1.00000	0.66114
58.5	51,616	0	0.00000	1.00000	0.66114
59.5	51,616	0	0.00000	1.00000	0.66114
60.5	44,333	0	0.00000	1.00000	0.66114
61.5	18,699	0	0.00000	1.00000	0.66114
62.5	13,187	0	0.00000	1.00000	0.66114
63.5	0	0	0.00000	1.00000	0.66114

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 364.02 Poles, Towers and Fixtures - Steel

T-Cut: None

Placement Band: 1955-2018

Hazard Function: Proportion Retired

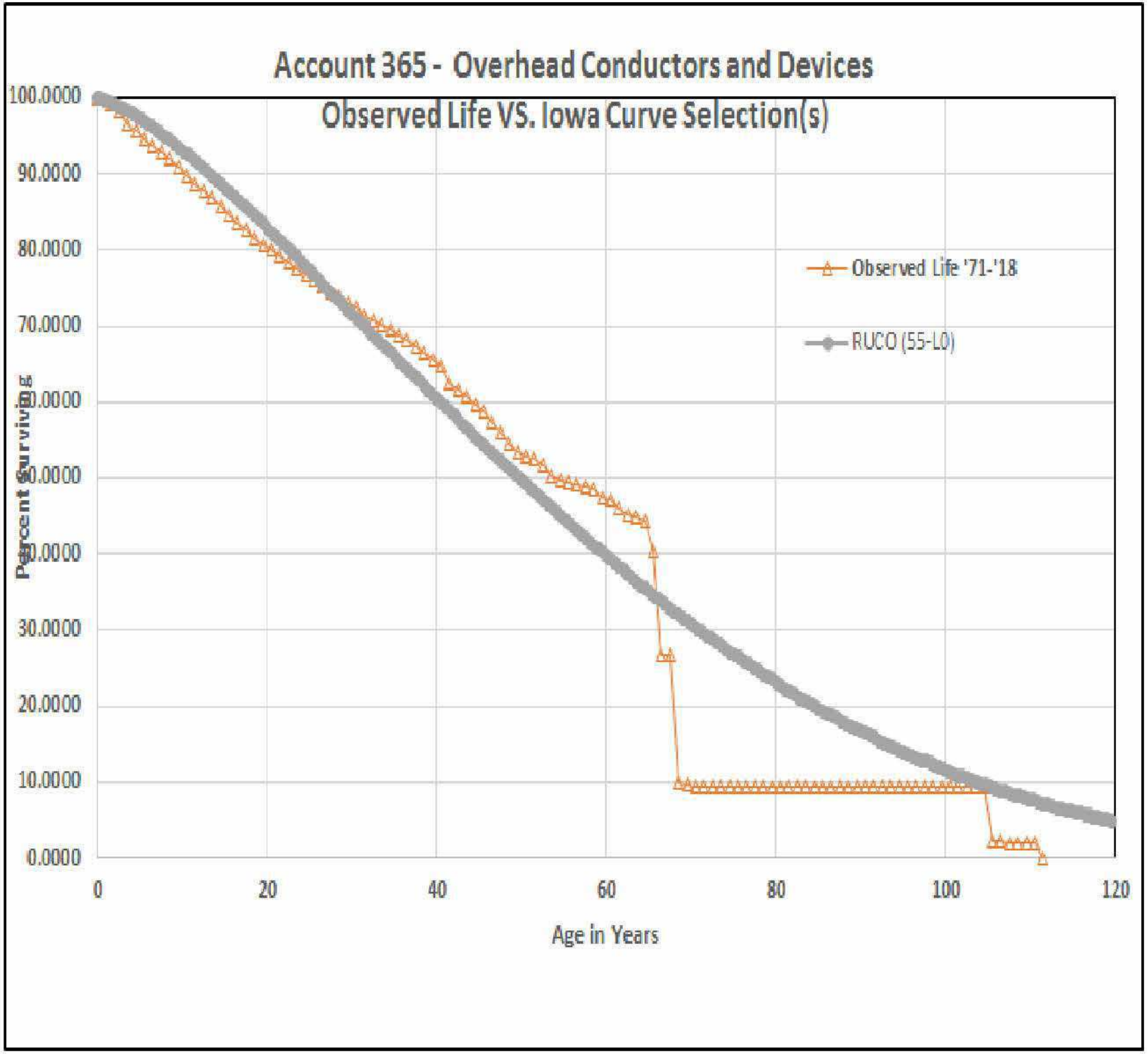
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2004-2018	66.1	68.2	L0	7.78	157.7	R0.5 *	5.62	60.2	R2.5 *	6.63
2006-2018	74.0	76.0	O2	10.55	161.2	R1 *	2.73	61.7	R2.5 *	3.48
2008-2018	83.4	74.4	O2	15.28	163.7	R1 *	2.94	64.0	R3 *	2.10
2010-2018	84.0	68.2	L0	16.94	164.3	R1 *	3.21	65.6	R3 *	1.58
2012-2018	87.0	61.6	L1	20.17	165.5	R1 *	4.94	89.3	R2.5 *	3.32
2014-2018	86.6	61.7	L1	20.34	167.2	R1 *	4.47	76.5	R3 *	1.94
2016-2018	91.5	77.9	L1	14.30	175.9	R2.5 *	3.06	99.5	R3 *	2.05
2018-2018	88.7	67.9	L1	16.83	163.1	R1 *	5.85	162.7	R1 *	6.10

DOCKET NO. E-01345A-19-0236

Exhibit FWR-25 -- Account 365 – Graph and deprecation data


Account 365 - Overhead Conductors and Devices
Observed Life VS. Iowa Curve Selection(s)
Observed Life '71-'18
RUCO (55-L0)
Percent Surviving
100.0000
90.0000
80.0000
70.0000
60.0000
50.0000
40.0000
30.0000
20.0000
10.0000
0.0000
0
20
40
60
80
100
120
Age in Years

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 365.00 OH Conductors and Devices

Placement Band: 1900 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	520,150,754	835,604	0.00161	0.99839	1.00000
0.5	450,516,615	3,334,511	0.00740	0.99260	0.99839
1.5	404,229,652	3,706,206	0.00917	0.99083	0.99100
2.5	393,240,861	6,399,976	0.01627	0.98373	0.98192
3.5	380,671,883	3,708,691	0.00974	0.99026	0.96594
4.5	367,250,037	4,010,773	0.01092	0.98908	0.95653
5.5	354,835,425	3,152,704	0.00888	0.99112	0.94608
6.5	336,625,753	2,854,691	0.00848	0.99152	0.93767
7.5	325,784,584	3,405,444	0.01045	0.98955	0.92972
8.5	312,376,001	3,897,564	0.01248	0.98752	0.92000
9.5	300,556,627	3,480,045	0.01158	0.98842	0.90853
10.5	290,231,990	3,543,193	0.01221	0.98779	0.89801
11.5	276,291,124	3,058,386	0.01107	0.98893	0.88704
12.5	263,391,822	2,663,543	0.01011	0.98989	0.87722
13.5	254,310,312	3,023,790	0.01189	0.98811	0.86835
14.5	241,711,342	3,245,602	0.01343	0.98657	0.85803
15.5	231,185,439	2,966,415	0.01283	0.98717	0.84651
16.5	219,763,260	2,676,655	0.01218	0.98782	0.83564
17.5	209,202,400	2,365,906	0.01131	0.98869	0.82547
18.5	195,712,001	2,127,767	0.01087	0.98913	0.81613
19.5	185,313,047	1,720,620	0.00928	0.99072	0.80726
20.5	175,247,448	1,784,565	0.01018	0.98982	0.79976
21.5	165,698,918	1,676,974	0.01012	0.98988	0.79162
22.5	155,744,280	1,838,412	0.01180	0.98820	0.78361
23.5	144,875,408	1,271,935	0.00878	0.99122	0.77436
24.5	135,834,982	1,199,912	0.00883	0.99117	0.76756
25.5	120,235,576	1,496,773	0.01245	0.98755	0.76078
26.5	113,846,069	950,036	0.00834	0.99166	0.75131
27.5	103,153,333	1,019,943	0.00989	0.99011	0.74504
28.5	90,805,997	1,029,060	0.01133	0.98867	0.73767
29.5	73,058,876	641,466	0.00878	0.99122	0.72931
30.5	63,539,091	801,357	0.01261	0.98739	0.72291
31.5	60,392,097	596,070	0.00987	0.99013	0.71379
32.5	53,723,751	453,901	0.00845	0.99155	0.70675
33.5	51,845,729	420,787	0.00812	0.99188	0.70078
34.5	47,767,718	461,607	0.00966	0.99034	0.69509
35.5	42,106,980	434,395	0.01032	0.98968	0.68837

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 365.00 OH Conductors and Devices

Placement Band: 1900 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	39,157,044	479,896	0.01226	0.98774	0.68127
37.5	32,723,815	402,983	0.01231	0.98769	0.67292
38.5	29,840,564	402,892	0.01350	0.98650	0.66463
39.5	27,128,192	328,340	0.01210	0.98790	0.65566
40.5	23,866,930	893,131	0.03742	0.96258	0.64772
41.5	21,168,996	241,530	0.01141	0.98859	0.62348
42.5	18,636,276	274,158	0.01471	0.98529	0.61637
43.5	16,841,695	312,686	0.01857	0.98143	0.60730
44.5	15,539,260	222,560	0.01432	0.98568	0.59603
45.5	14,388,554	325,308	0.02261	0.97739	0.58749
46.5	12,911,661	318,557	0.02467	0.97533	0.57421
47.5	11,605,050	324,668	0.02798	0.97202	0.56004
48.5	10,267,432	191,772	0.01868	0.98132	0.54437
49.5	9,063,474	81,501	0.00899	0.99101	0.53421
50.5	8,499,453	79,015	0.00930	0.99070	0.52940
51.5	4,857,144	82,430	0.01697	0.98303	0.52448
52.5	4,406,674	109,387	0.02482	0.97518	0.51558
53.5	3,906,896	37,217	0.00953	0.99047	0.50278
54.5	3,396,769	22,256	0.00655	0.99345	0.49799
55.5	3,026,916	22,981	0.00759	0.99241	0.49473
56.5	2,669,615	12,978	0.00486	0.99514	0.49097
57.5	2,433,984	17,997	0.00739	0.99261	0.48859
58.5	1,845,736	36,868	0.01997	0.98003	0.48497
59.5	1,796,471	10,494	0.00584	0.99416	0.47529
60.5	1,456,152	40,268	0.02765	0.97235	0.47251
61.5	647,930	9,605	0.01482	0.98518	0.45944
62.5	288,785	1,639	0.00568	0.99432	0.45263
63.5	2,557	40	0.01564	0.98436	0.45006
64.5	3,727	328	0.08800	0.91200	0.44302
65.5	3,399	1,142	0.33594	0.66406	0.40404
66.5	2,276	0	0.00000	1.00000	0.26831
67.5	2,276	1,441	0.63302	0.36698	0.26831
68.5	859	19	0.02211	0.97789	0.09846
69.5	840	24	0.02856	0.97144	0.09629
70.5	25,513	0	0.00000	1.00000	0.09354
71.5	25,513	0	0.00000	1.00000	0.09354
72.5	25,513	0	0.00000	1.00000	0.09354

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 365.00 OH Conductors and Devices

Placement Band: 1900 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	25,513	0	0.00000	1.00000	0.09354
74.5	25,513	0	0.00000	1.00000	0.09354
75.5	25,513	0	0.00000	1.00000	0.09354
76.5	25,549	0	0.00000	1.00000	0.09354
77.5	25,549	0	0.00000	1.00000	0.09354
78.5	25,549	0	0.00000	1.00000	0.09354
79.5	25,549	36	0.00141	0.99859	0.09354
80.5	25,513	0	0.00000	1.00000	0.09341
81.5	25,513	0	0.00000	1.00000	0.09341
82.5	25,513	0	0.00000	1.00000	0.09341
83.5	25,513	0	0.00000	1.00000	0.09341
84.5	25,513	0	0.00000	1.00000	0.09341
85.5	25,513	0	0.00000	1.00000	0.09341
86.5	25,513	0	0.00000	1.00000	0.09341
87.5	25,513	0	0.00000	1.00000	0.09341
88.5	25,513	0	0.00000	1.00000	0.09341
89.5	25,513	0	0.00000	1.00000	0.09341
90.5	25,513	0	0.00000	1.00000	0.09341
91.5	25,513	0	0.00000	1.00000	0.09341
92.5	25,513	0	0.00000	1.00000	0.09341
93.5	25,513	0	0.00000	1.00000	0.09341
94.5	25,513	0	0.00000	1.00000	0.09341
95.5	25,513	0	0.00000	1.00000	0.09341
96.5	25,513	0	0.00000	1.00000	0.09341
97.5	25,513	0	0.00000	1.00000	0.09341
98.5	25,513	0	0.00000	1.00000	0.09341
99.5	25,513	0	0.00000	1.00000	0.09341
100.5	25,513	0	0.00000	1.00000	0.09341
101.5	25,513	0	0.00000	1.00000	0.09341
102.5	25,513	0	0.00000	1.00000	0.09341
103.5	25,513	0	0.00000	1.00000	0.09341
104.5	25,513	19,314	0.75704	0.24296	0.09341
105.5	6,199	20	0.00330	0.99670	0.02269
106.5	6,178	979	0.15848	0.84152	0.02262
107.5	5,199	0	0.00000	1.00000	0.01903
108.5	5,199	0	0.00000	1.00000	0.01903
109.5	4,383	0	0.00000	1.00000	0.01903

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 365.00 OH Conductors and Devices

Placement Band: 1900 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
110.5	4,383	4,218	0.96246	0.03754	0.01903
111.5	165	165	1.00000	0.00000	0.00071
112.5	0	0	0.00000	1.00000	0.00000

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 365.00 OH Conductors and Devices

T-Cut: None

Placement Band: 1900-2018

Hazard Function: Proportion Retired

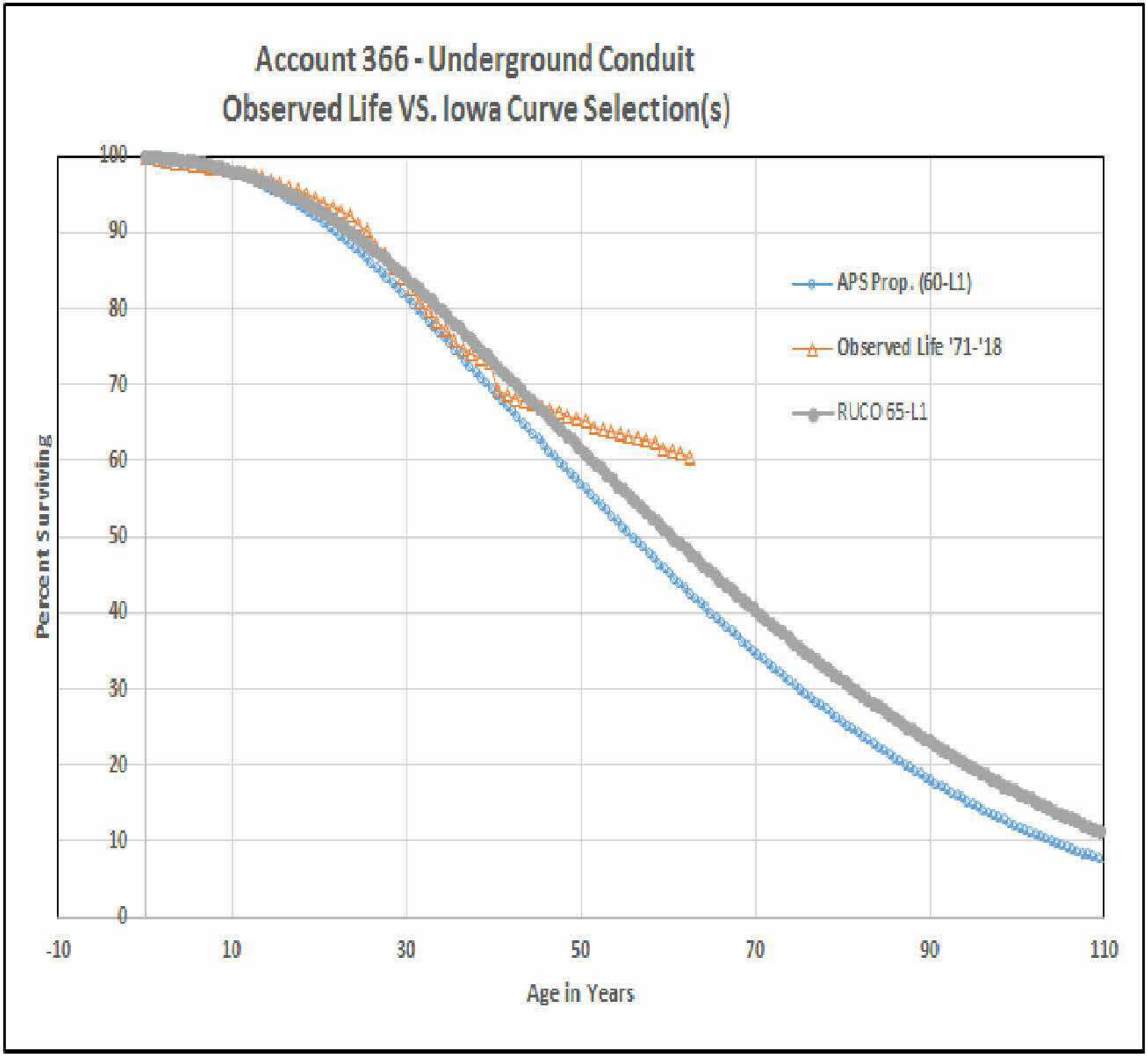
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	0.0	70.3	O2	15.22	60.0	L0	11.30	54.6	SC	8.46
1973-2018	0.0	70.2	O2	15.21	59.8	L0	11.25	54.5	SC	8.41
1975-2018	0.0	70.3	O2	15.43	59.7	L0	11.38	54.4	SC	8.52
1977-2018	0.0	70.2	O2	16.21	59.5	L0	12.17	54.2	SC	9.17
1979-2018	0.0	69.9	O3	20.05	59.4	O2	16.03	54.0	SC	12.48
1981-2018	0.0	69.7	O3	20.06	59.5	O2	16.14	53.8	SC	12.45
1983-2018	0.0	69.5	O3	19.95	59.2	O2	16.00	53.6	SC	12.33
1985-2018	0.0	69.0	O3	19.75	58.8	O2	15.78	53.4	SC	12.18
1987-2018	0.0	68.7	O3	19.61	58.3	O2	15.50	53.1	SC	12.04
1989-2018	0.0	69.0	O3	19.77	58.6	O2	15.72	53.2	SC	12.07
1991-2018	0.0	67.9	O2	19.29	58.5	O2	15.62	52.7	SC	11.70
1993-2018	0.0	66.9	O2	18.98	58.4	O2	15.58	52.5	SC	11.62
1995-2018	0.0	68.3	O3	20.46	57.2	L0	16.00	52.4	SC	12.71
1997-2018	0.0	69.8	O3	8.14	56.7	L0	12.06	51.7	SC	16.87
1999-2018	0.0	67.4	O2	9.01	59.6	O2	11.37	52.3	SC	17.93
2001-2018	0.0	67.7	O2	9.15	59.0	L0	12.15	52.3	R0.5	18.72
2003-2018	0.0	66.0	O2	9.98	61.5	L0	11.50	52.4	R0.5	19.75
2005-2018	0.0	74.1	O2	10.41	71.7	O2	10.87	55.3	R1	23.06
2007-2018	0.0	75.9	O2	10.84	93.5	O3 *	8.33	57.3	R1	23.82
2009-2018	0.0	76.1	O2	12.54	107.4	O3 *	7.95	59.1	R1	24.70
2011-2018	0.0	87.3	L0	11.92	135.9	SC *	8.15	62.0	R1.5	28.76
2013-2018	62.9	91.5	L0	10.52	143.4	SC *	2.96	63.5	R1.5	28.91
2015-2018	65.5	92.7	L0	11.62	148.4	SC *	3.34	65.2	R1.5	29.14
2017-2018	70.9	101.6	L0	11.37	157.3	R0.5 *	3.49	69.7	R2	29.03

DOCKET NO. E-01345A-19-0236

Exhibit FWR-26 -- Account 366 Graph and deprecation data


Account 366 - Underground Conduit
Observed Life VS. Iowa Curve Selection(s)
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
-10
10
30
50
70
90
110
Age in Years
APS Prop. (60-L1)
Observed Life '71-'18
RUCO 65-L1

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 366.00 Underground Conduit

Placement Band: 1940 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	768,801,797	814,651	0.00106	0.99894	1.00000
0.5	757,999,931	1,805,638	0.00238	0.99762	0.99894
1.5	739,190,933	1,680,501	0.00227	0.99773	0.99656
2.5	719,545,966	2,411,030	0.00335	0.99665	0.99430
3.5	698,146,571	1,082,846	0.00155	0.99845	0.99096
4.5	680,437,917	977,265	0.00144	0.99856	0.98943
5.5	666,623,519	1,024,439	0.00154	0.99846	0.98801
6.5	650,899,145	988,478	0.00152	0.99848	0.98649
7.5	636,538,486	1,081,378	0.00170	0.99830	0.98499
8.5	621,990,902	906,832	0.00146	0.99854	0.98332
9.5	608,097,125	1,084,685	0.00178	0.99822	0.98188
10.5	589,016,564	1,311,860	0.00223	0.99777	0.98013
11.5	563,292,419	1,330,657	0.00236	0.99764	0.97795
12.5	534,888,715	1,678,025	0.00314	0.99686	0.97564
13.5	507,142,318	2,101,091	0.00414	0.99586	0.97258
14.5	466,447,911	2,113,192	0.00453	0.99547	0.96855
15.5	428,150,660	1,719,199	0.00402	0.99598	0.96416
16.5	388,663,684	1,860,855	0.00479	0.99521	0.96029
17.5	346,801,190	1,665,135	0.00480	0.99520	0.95569
18.5	312,646,030	1,780,188	0.00569	0.99431	0.95110
19.5	277,218,320	1,509,888	0.00545	0.99455	0.94569
20.5	242,198,470	1,718,606	0.00710	0.99290	0.94054
21.5	209,800,987	1,412,462	0.00673	0.99327	0.93386
22.5	175,738,234	1,303,765	0.00742	0.99258	0.92757
23.5	150,378,562	1,405,291	0.00935	0.99066	0.92069
24.5	118,840,458	1,458,552	0.01227	0.98773	0.91209
25.5	64,918,597	1,334,880	0.02056	0.97944	0.90089
26.5	57,447,633	718,199	0.01250	0.98750	0.88237
27.5	46,456,962	900,833	0.01939	0.98061	0.87134
28.5	33,228,323	612,558	0.01843	0.98157	0.85444
29.5	28,684,102	465,290	0.01622	0.98378	0.83869
30.5	21,746,764	439,876	0.02023	0.97977	0.82509
31.5	19,112,429	285,908	0.01496	0.98504	0.80840
32.5	17,407,461	269,084	0.01546	0.98454	0.79630
33.5	16,620,282	265,073	0.01595	0.98405	0.78400
34.5	14,895,141	281,295	0.01888	0.98111	0.77149
35.5	13,187,327	178,961	0.01357	0.98643	0.75692

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 366.00 Underground Conduit

Placement Band: 1940 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
36.5	11,903,835	105,042	0.00882	0.99118	0.74665
37.5	10,572,752	82,263	0.00778	0.99222	0.74006
38.5	9,515,647	63,380	0.00666	0.99334	0.73430
39.5	8,966,091	447,108	0.04987	0.95013	0.72941
40.5	7,975,137	76,296	0.00957	0.99043	0.69304
41.5	7,504,406	49,371	0.00658	0.99342	0.68641
42.5	7,189,033	40,201	0.00559	0.99441	0.68189
43.5	6,680,591	30,901	0.00463	0.99537	0.67808
44.5	6,264,084	42,984	0.00686	0.99314	0.67494
45.5	5,932,648	38,153	0.00643	0.99357	0.67031
46.5	5,419,043	30,357	0.00560	0.99440	0.66600
47.5	4,569,133	23,207	0.00508	0.99492	0.66227
48.5	4,089,716	16,584	0.00406	0.99594	0.65891
49.5	3,828,459	24,851	0.00649	0.99351	0.65623
50.5	3,170,608	39,965	0.01260	0.98740	0.65198
51.5	2,376,164	10,118	0.00426	0.99574	0.64376
52.5	2,262,166	9,627	0.00426	0.99574	0.64102
53.5	2,139,840	6,069	0.00284	0.99716	0.63829
54.5	1,741,664	9,243	0.00531	0.99469	0.63648
55.5	1,626,546	11,573	0.00712	0.99288	0.63310
56.5	1,590,441	5,104	0.00321	0.99679	0.62860
57.5	688,920	4,352	0.00632	0.99368	0.62658
58.5	667,573	6,372	0.00955	0.99045	0.62262
59.5	661,201	4,314	0.00653	0.99347	0.61668
60.5	652,059	3,634	0.00557	0.99443	0.61265
61.5	633,275	4,386	0.00693	0.99307	0.60924
62.5	0	0	0.00000	1.00000	0.60502

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 366.00 Underground Conduit

T-Cut: None

Placement Band: 1940-2018

Hazard Function: Proportion Retired

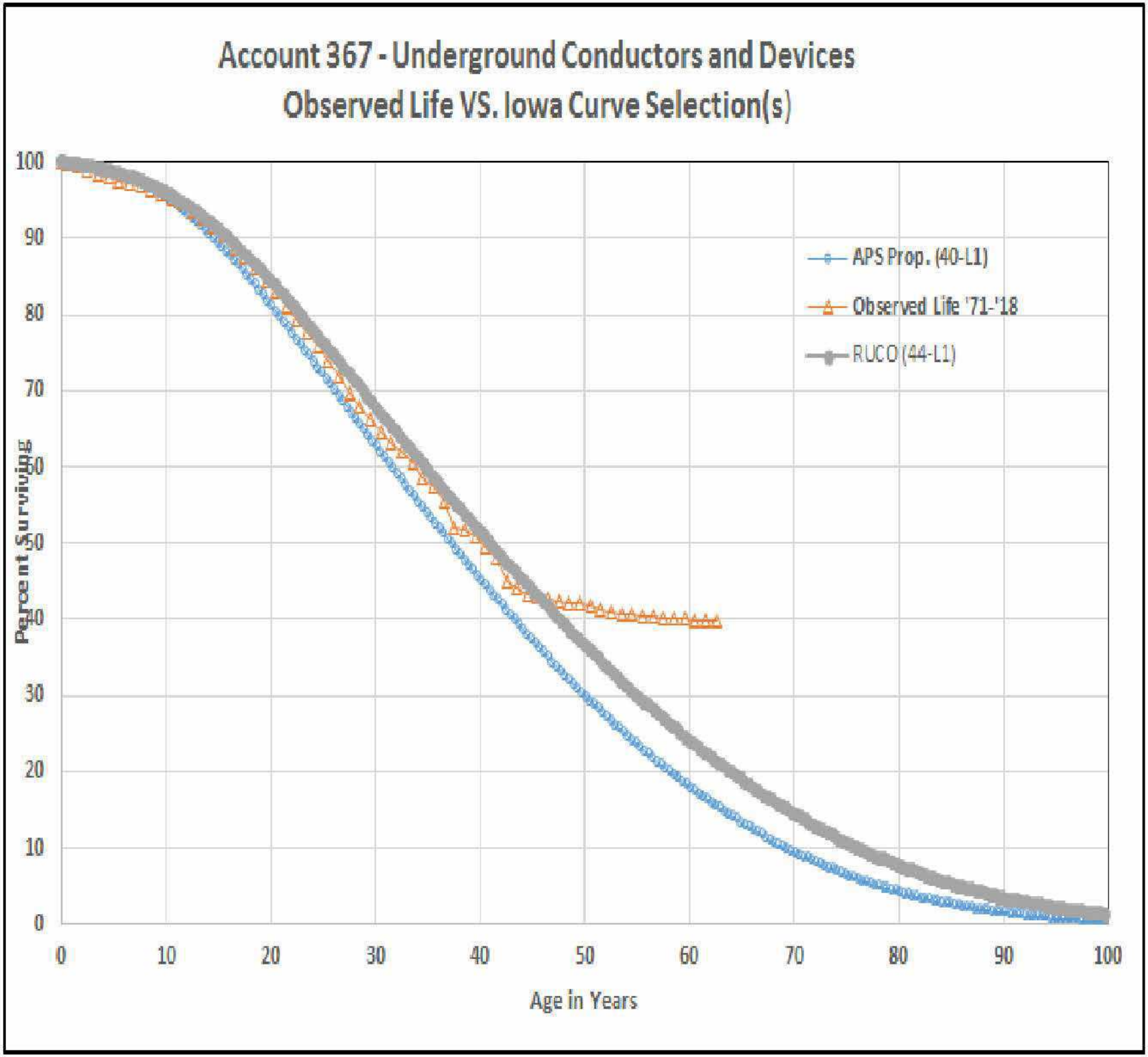
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	60.5	70.4	L1	3.47	62.6	S0.5	4.25	134.2	SC *	1.31
1973-2018	60.5	70.4	L1	3.47	62.7	S0.5	4.25	134.2	SC *	1.31
1975-2018	60.5	70.4	L1	3.47	62.7	S0.5	4.24	134.2	SC *	1.31
1977-2018	60.5	70.4	L1	3.47	62.7	S0.5	4.24	134.2	SC *	1.31
1979-2018	60.5	70.3	L1	3.47	62.7	S0.5	4.24	134.2	SC *	1.31
1981-2018	60.5	70.3	L1	3.47	62.7	S0.5	4.24	134.1	SC *	1.31
1983-2018	60.5	70.2	L1	3.48	62.7	S0.5	4.24	134.1	SC *	1.31
1985-2018	60.5	70.2	L1	3.49	62.7	S0.5	4.24	134.1	SC *	1.32
1987-2018	60.4	70.1	L1	3.50	62.7	S0.5	4.25	134.0	SC *	1.32
1989-2018	60.4	69.8	L1	3.54	63.0	S0.5	4.22	134.0	SC *	1.33
1991-2018	60.2	69.7	L1	3.59	62.9	S0.5	4.24	133.8	SC *	1.35
1993-2018	60.1	69.7	L1 *	3.66	62.8	S0.5	4.30	133.6	SC *	1.38
1995-2018	60.0	69.8	L1 *	3.78	62.6	S0.5	4.38	133.4	SC *	1.42
1997-2018	59.4	69.8	L1 *	3.96	62.3	S0.5	4.46	132.8	SC *	1.44
1999-2018	59.0	68.7	L1 *	4.11	62.6	S0.5	4.50	132.2	SC *	1.51
2001-2018	58.4	68.3	L1.5 *	4.37	62.2	S0.5	4.70	131.2	SC *	1.63
2003-2018	57.7	67.9	L1.5 *	4.76	61.9	S0.5 *	4.97	130.5	SC *	1.78
2005-2018	57.2	67.6	L1.5 *	5.06	61.9	S0.5 *	5.16	129.7	SC *	1.90
2007-2018	55.8	66.7	L1.5 *	5.47	61.1	S0.5 *	5.47	127.1	SC *	2.07
2009-2018	55.5	67.9	L1.5 *	5.88	61.3	S1 *	5.66	127.1	SC *	2.09
2011-2018	63.3	73.0	L1.5 *	3.78	67.4	L2 *	4.09	136.5	SC *	2.12
2013-2018	64.5	78.0	L1.5 *	3.42	68.9	S1 *	3.46	140.5	SC *	1.48
2015-2018	65.5	81.7	L1.5 *	3.53	70.6	S1 *	3.21	143.1	SC *	1.12
2017-2018	63.7	87.7	L1.5 *	4.25	71.6	S1	2.88	145.1	SC *	1.19

DOCKET NO. E-01345A-19-0236

Exhibit FWR-27 -- Account 367 – Graph and deprecation data


Account 367 - Underground Conductors and Devices
Observed Life VS. Iowa Curve Selection(s)
Percent Surviving
Age in Years
APS Prop. (40-L1)
Observed Life '71-'18
RUCO (44-L1)
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Placement Band: 1940 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	2,160,966,023	3,739,704	0.00173	0.99827	1.00000
0.5	2,036,672,231	7,591,835	0.00373	0.99627	0.99827
1.5	1,946,681,408	9,707,015	0.00499	0.99501	0.99455
2.5	1,852,973,552	9,088,515	0.00490	0.99510	0.98959
3.5	1,754,031,637	8,070,228	0.00460	0.99540	0.98474
4.5	1,688,910,505	7,200,281	0.00426	0.99574	0.98020
5.5	1,626,273,400	7,106,259	0.00437	0.99563	0.97603
6.5	1,571,299,186	4,708,488	0.00300	0.99700	0.97176
7.5	1,517,322,250	7,762,970	0.00512	0.99488	0.96885
8.5	1,453,391,376	6,841,300	0.00471	0.99529	0.96389
9.5	1,393,262,277	8,851,013	0.00635	0.99365	0.95935
10.5	1,300,729,058	9,747,137	0.00749	0.99251	0.95326
11.5	1,175,739,636	12,616,096	0.01073	0.98927	0.94612
12.5	1,050,463,684	10,492,370	0.00999	0.99001	0.93596
13.5	955,186,354	11,913,904	0.01247	0.98753	0.92662
14.5	879,497,055	10,884,179	0.01238	0.98762	0.91506
15.5	811,109,802	14,703,478	0.01813	0.98187	0.90373
16.5	740,914,634	10,143,880	0.01369	0.98631	0.88735
17.5	659,966,810	11,251,057	0.01705	0.98295	0.87520
18.5	585,623,466	11,092,922	0.01894	0.98106	0.86028
19.5	520,491,087	9,210,895	0.01770	0.98230	0.84399
20.5	444,988,676	9,935,404	0.02233	0.97767	0.82905
21.5	397,448,797	8,082,768	0.02034	0.97966	0.81054
22.5	348,541,840	8,289,783	0.02378	0.97622	0.79406
23.5	311,957,774	6,691,872	0.02145	0.97855	0.77517
24.5	282,933,907	6,799,094	0.02403	0.97597	0.75854
25.5	248,326,006	6,798,862	0.02738	0.97262	0.74031
26.5	207,433,346	6,471,305	0.03120	0.96880	0.72005
27.5	182,940,174	4,822,031	0.02636	0.97364	0.69758
28.5	142,886,015	3,285,739	0.02300	0.97700	0.67920
29.5	114,685,271	2,978,282	0.02597	0.97403	0.66358
30.5	103,103,659	2,178,601	0.02113	0.97887	0.64634
31.5	90,523,227	1,659,461	0.01833	0.98167	0.63269
32.5	81,802,967	2,031,130	0.02483	0.97517	0.62109
33.5	68,075,567	2,333,394	0.03428	0.96572	0.60567
34.5	58,108,906	1,101,882	0.01896	0.98104	0.58491
35.5	56,864,510	1,821,670	0.03204	0.96796	0.57382

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Placement Band: 1940 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	50,753,147	3,128,027	0.06163	0.93837	0.55543
37.5	41,035,808	368,871	0.00899	0.99101	0.52120
38.5	36,495,615	429,031	0.01176	0.98824	0.51652
39.5	33,974,397	963,629	0.02836	0.97164	0.51044
40.5	30,299,847	884,635	0.02920	0.97080	0.49597
41.5	27,686,296	1,868,185	0.06748	0.93252	0.48149
42.5	24,409,250	445,045	0.01823	0.98177	0.44900
43.5	22,051,082	368,462	0.01671	0.98329	0.44081
44.5	20,607,517	156,356	0.00759	0.99241	0.43344
45.5	19,341,581	134,865	0.00697	0.99303	0.43016
46.5	18,068,471	184,502	0.01021	0.98979	0.42716
47.5	17,279,595	72,526	0.00420	0.99580	0.42279
48.5	13,711,140	38,104	0.00278	0.99722	0.42102
49.5	12,751,106	75,987	0.00596	0.99404	0.41985
50.5	10,761,863	94,233	0.00876	0.99124	0.41735
51.5	7,894,059	84,743	0.01073	0.98927	0.41369
52.5	7,038,483	37,505	0.00533	0.99467	0.40925
53.5	5,746,398	12,112	0.00211	0.99789	0.40707
54.5	4,452,816	24,364	0.00547	0.99453	0.40621
55.5	4,129,150	1,318	0.00032	0.99968	0.40399
56.5	4,126,712	20,420	0.00495	0.99505	0.40386
57.5	1,645,424	2,760	0.00168	0.99832	0.40186
58.5	1,594,766	3,015	0.00189	0.99811	0.40119
59.5	1,591,751	5,087	0.00320	0.99680	0.40043
60.5	1,548,216	1,749	0.00113	0.99887	0.39915
61.5	1,546,467	847	0.00055	0.99945	0.39870
62.5	0	0	0.00000	1.00000	0.39848

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None

Placement Band: 1940-2018

Hazard Function: Proportion Retired

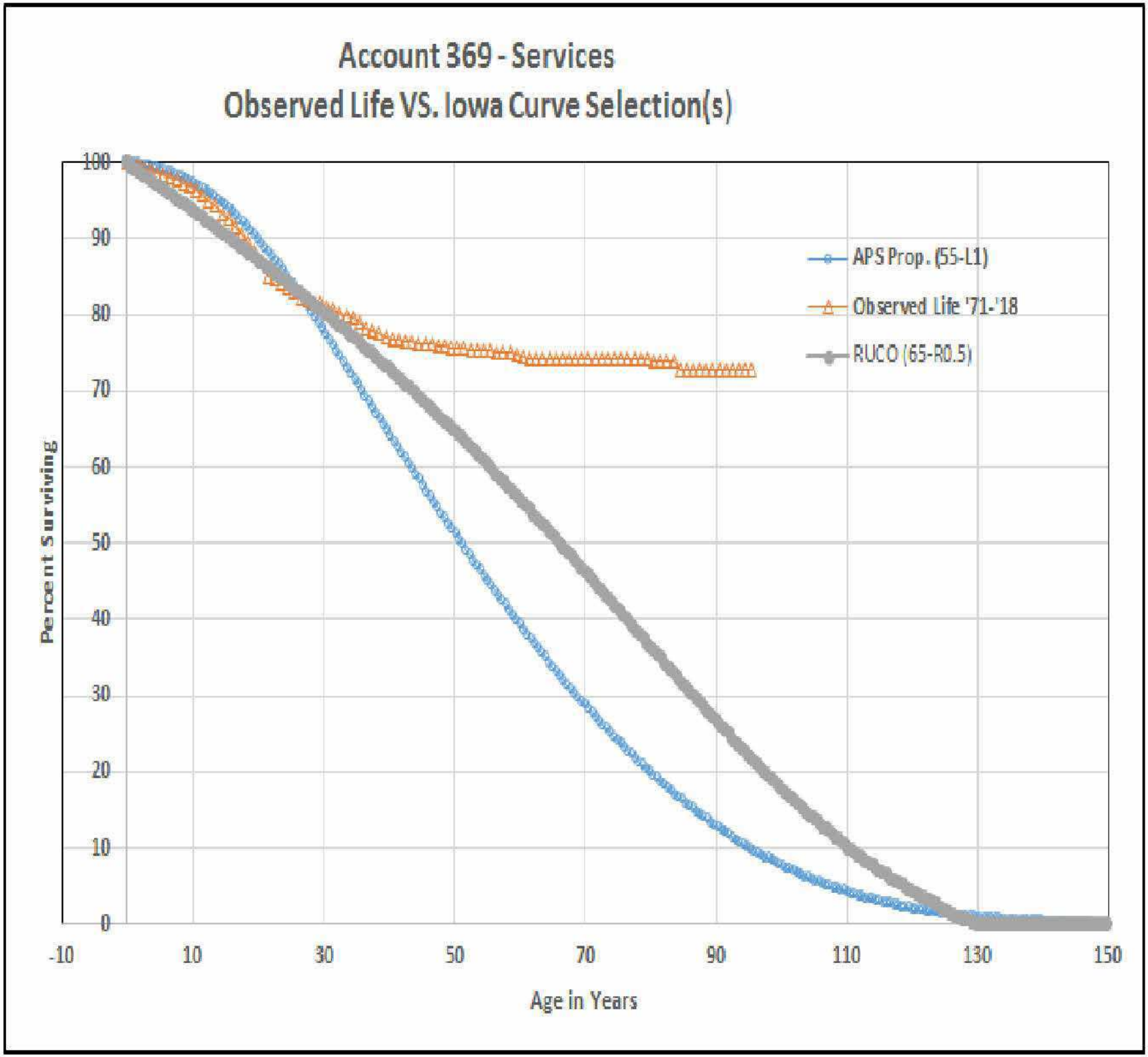
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	39.8	44.0	L1	6.04	66.1	O4 *	3.54	93.7	O4 *	1.12
1973-2018	39.8	44.0	L1	6.04	66.2	O4 *	3.54	93.7	O4 *	1.12
1975-2018	39.8	44.0	L1	6.04	66.2	O4 *	3.54	93.7	O4 *	1.12
1977-2018	39.8	44.0	L1	6.04	66.2	O4 *	3.54	93.7	O4 *	1.12
1979-2018	39.8	43.9	L1	6.04	66.3	O4 *	3.53	93.7	O4 *	1.12
1981-2018	39.8	43.9	L1	6.03	66.3	O4 *	3.53	93.7	O4 *	1.13
1983-2018	39.8	43.9	L1	6.02	66.4	O4 *	3.52	93.7	O4 *	1.12
1985-2018	39.8	43.9	L1	6.02	66.6	O4 *	3.51	93.7	O4 *	1.12
1987-2018	39.8	43.9	L1	6.01	66.9	O4 *	3.49	93.6	O4 *	1.12
1989-2018	39.8	43.9	L1	6.01	67.5	O4 *	3.46	93.7	O4 *	1.11
1991-2018	39.8	44.0	L1	6.00	67.8	O4 *	3.44	93.7	O4 *	1.12
1993-2018	40.0	44.2	L1	6.07	68.3	O4 *	3.48	94.2	O4 *	1.13
1995-2018	40.3	45.0	L1	5.78	61.1	O3 *	3.84	94.6	O4 *	1.18
1997-2018	40.0	45.1	L1	5.63	58.0	O3 *	3.94	93.9	O4 *	1.19
1999-2018	50.6	48.6	L1	7.99	99.3	O4 *	3.28	109.0	O4 *	2.72
2001-2018	50.9	49.3	L1	7.75	94.9	O4 *	3.72	108.9	O4 *	3.00
2003-2018	51.4	50.5	L1 *	7.25	86.5	O4 *	4.20	109.4	O4 *	3.19
2005-2018	52.6	52.4	L1 *	6.72	76.3	O3 *	4.56	111.4	O3 *	3.28
2007-2018	53.2	52.7	L1.5 *	6.85	74.9	O3 *	4.79	111.3	O3 *	3.59
2009-2018	53.5	53.4	L1.5 *	6.62	72.7	O3 *	4.77	111.9	O3 *	3.56
2011-2018	55.9	54.6	L1.5 *	6.99	74.4	O3 *	5.14	113.8	O3 *	4.38
2013-2018	55.7	55.7	L1.5 *	6.29	65.5	L0.5 *	5.02	114.6	O3 *	4.02
2015-2018	53.2	55.4	L1.5 *	5.55	60.5	L1 *	4.62	112.4	O3 *	3.54
2017-2018	54.0	59.3	L1.5 *	4.14	63.7	L1 *	3.68	119.6	SC *	1.61

DOCKET NO. E-01345A-19-0236

Exhibit FWR-28 -- Account 369 Graph and deprecation data


Account 369 - Services
Observed Life VS. Iowa Curve Selection(s)
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
-10
10
30
50
70
90
110
130
150
Age in Years
APS Prop. (55-L1)
Observed Life '71-'18
RUCO (65-R0.5)

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 369.00 Services

Placement Band: 1909 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	488,111,232	119,320	0.00024	0.99976	1.00000
0.5	469,383,232	1,163,804	0.00248	0.99752	0.99976
1.5	439,559,592	1,881,262	0.00428	0.99572	0.99728
2.5	434,306,986	1,341,898	0.00309	0.99691	0.99301
3.5	417,694,483	1,253,498	0.00300	0.99700	0.98994
4.5	401,084,767	1,298,275	0.00324	0.99676	0.98697
5.5	385,637,827	667,121	0.00173	0.99827	0.98377
6.5	381,291,736	1,663,939	0.00436	0.99564	0.98207
7.5	372,279,865	1,886,160	0.00507	0.99493	0.97779
8.5	364,485,854	1,622,945	0.00445	0.99555	0.97283
9.5	355,356,681	2,133,568	0.00600	0.99400	0.96850
10.5	338,498,405	1,986,257	0.00587	0.99413	0.96269
11.5	322,495,469	2,142,605	0.00664	0.99336	0.95704
12.5	305,641,874	2,532,053	0.00828	0.99172	0.95068
13.5	287,488,022	3,142,350	0.01093	0.98907	0.94280
14.5	267,288,264	1,995,254	0.00746	0.99254	0.93250
15.5	251,727,312	2,990,555	0.01188	0.98812	0.92554
16.5	233,370,641	1,770,859	0.00759	0.99241	0.91454
17.5	221,290,686	2,850,349	0.01288	0.98712	0.90760
18.5	207,467,776	2,774,256	0.01337	0.98663	0.89591
19.5	181,776,355	2,834,502	0.01559	0.98441	0.88393
20.5	165,764,687	3,688,743	0.02225	0.97775	0.87015
21.5	157,953,480	532,526	0.00337	0.99663	0.85079
22.5	148,490,160	880,414	0.00593	0.99407	0.84792
23.5	126,417,831	859,699	0.00680	0.99320	0.84289
24.5	113,695,949	799,710	0.00703	0.99297	0.83716
25.5	98,858,396	1,021,301	0.01033	0.98967	0.83127
26.5	91,827,388	359,485	0.00391	0.99609	0.82268
27.5	84,410,200	219,590	0.00260	0.99740	0.81946
28.5	75,418,857	237,558	0.00315	0.99685	0.81733
29.5	62,571,375	286,419	0.00458	0.99542	0.81475
30.5	54,697,602	251,762	0.00460	0.99540	0.81102
31.5	47,340,398	242,506	0.00512	0.99488	0.80729
32.5	42,387,429	225,244	0.00531	0.99469	0.80316
33.5	31,953,856	142,482	0.00446	0.99554	0.79889
34.5	24,422,078	191,841	0.00786	0.99214	0.79533
35.5	20,769,322	157,973	0.00761	0.99239	0.78908

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 369.00 Services

Placement Band: 1909 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	19,066,264	92,262	0.00484	0.99516	0.78308
37.5	15,614,291	67,707	0.00434	0.99566	0.77929
38.5	13,797,287	75,221	0.00545	0.99455	0.77591
39.5	12,358,930	51,824	0.00419	0.99581	0.77168
40.5	8,123,516	14,351	0.00177	0.99823	0.76844
41.5	7,674,534	20,662	0.00269	0.99731	0.76708
42.5	6,861,284	9,565	0.00139	0.99861	0.76502
43.5	5,745,237	6,180	0.00108	0.99892	0.76395
44.5	5,136,275	4,990	0.00097	0.99903	0.76313
45.5	4,696,352	9,119	0.00194	0.99806	0.76239
46.5	4,278,806	6,663	0.00156	0.99844	0.76091
47.5	3,985,037	6,496	0.00163	0.99837	0.75972
48.5	3,761,650	7,235	0.00192	0.99808	0.75849
49.5	3,390,335	4,483	0.00132	0.99868	0.75703
50.5	3,264,670	2,350	0.00072	0.99928	0.75603
51.5	3,002,998	2,148	0.00072	0.99928	0.75548
52.5	2,953,363	2,157	0.00073	0.99927	0.75494
53.5	2,795,921	2,784	0.00100	0.99900	0.75439
54.5	2,689,940	2,110	0.00078	0.99922	0.75364
55.5	2,543,738	3,693	0.00145	0.99855	0.75305
56.5	2,453,353	5,828	0.00238	0.99762	0.75195
57.5	2,290,587	2,586	0.00113	0.99887	0.75017
58.5	1,879,047	3,801	0.00202	0.99798	0.74932
59.5	1,803,092	5,782	0.00321	0.99679	0.74781
60.5	1,681,914	4,435	0.00264	0.99736	0.74541
61.5	1,429,760	512	0.00036	0.99964	0.74344
62.5	1,006,953	767	0.00076	0.99924	0.74318
63.5	1,943	0	0.00000	1.00000	0.74261
64.5	1,943	0	0.00000	1.00000	0.74261
65.5	1,943	0	0.00000	1.00000	0.74261
66.5	1,943	0	0.00000	1.00000	0.74261
67.5	1,943	0	0.00000	1.00000	0.74261
68.5	1,943	0	0.00000	1.00000	0.74261
69.5	1,943	0	0.00000	1.00000	0.74261
70.5	1,943	0	0.00000	1.00000	0.74261
71.5	1,943	0	0.00000	1.00000	0.74261
72.5	1,943	0	0.00000	1.00000	0.74261

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 369.00 Services

Placement Band: 1909 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	1,943	0	0.00000	1.00000	0.74261
74.5	1,943	0	0.00000	1.00000	0.74261
75.5	1,943	0	0.00000	1.00000	0.74261
76.5	1,954	0	0.00000	1.00000	0.74261
77.5	1,954	0	0.00000	1.00000	0.74261
78.5	1,954	0	0.00000	1.00000	0.74261
79.5	1,954	11	0.00563	0.99437	0.74261
80.5	1,971	0	0.00000	1.00000	0.73843
81.5	1,971	0	0.00000	1.00000	0.73843
82.5	1,971	0	0.00000	1.00000	0.73843
83.5	1,971	28	0.01421	0.98579	0.73843
84.5	1,943	0	0.00000	1.00000	0.72794
85.5	1,943	0	0.00000	1.00000	0.72794
86.5	1,943	0	0.00000	1.00000	0.72794
87.5	1,943	0	0.00000	1.00000	0.72794
88.5	1,943	0	0.00000	1.00000	0.72794
89.5	1,943	0	0.00000	1.00000	0.72794
90.5	1,943	0	0.00000	1.00000	0.72794
91.5	1,943	0	0.00000	1.00000	0.72794
92.5	1,943	0	0.00000	1.00000	0.72794
93.5	1,943	0	0.00000	1.00000	0.72794
94.5	1,943	0	0.00000	1.00000	0.72794
95.5	1,943	1,943	1.00000	0.00000	0.72794
96.5	0	0	0.00000	1.00000	0.00000

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 369.00 Services

T-Cut: None

Placement Band: 1909-2018

Hazard Function: Proportion Retired

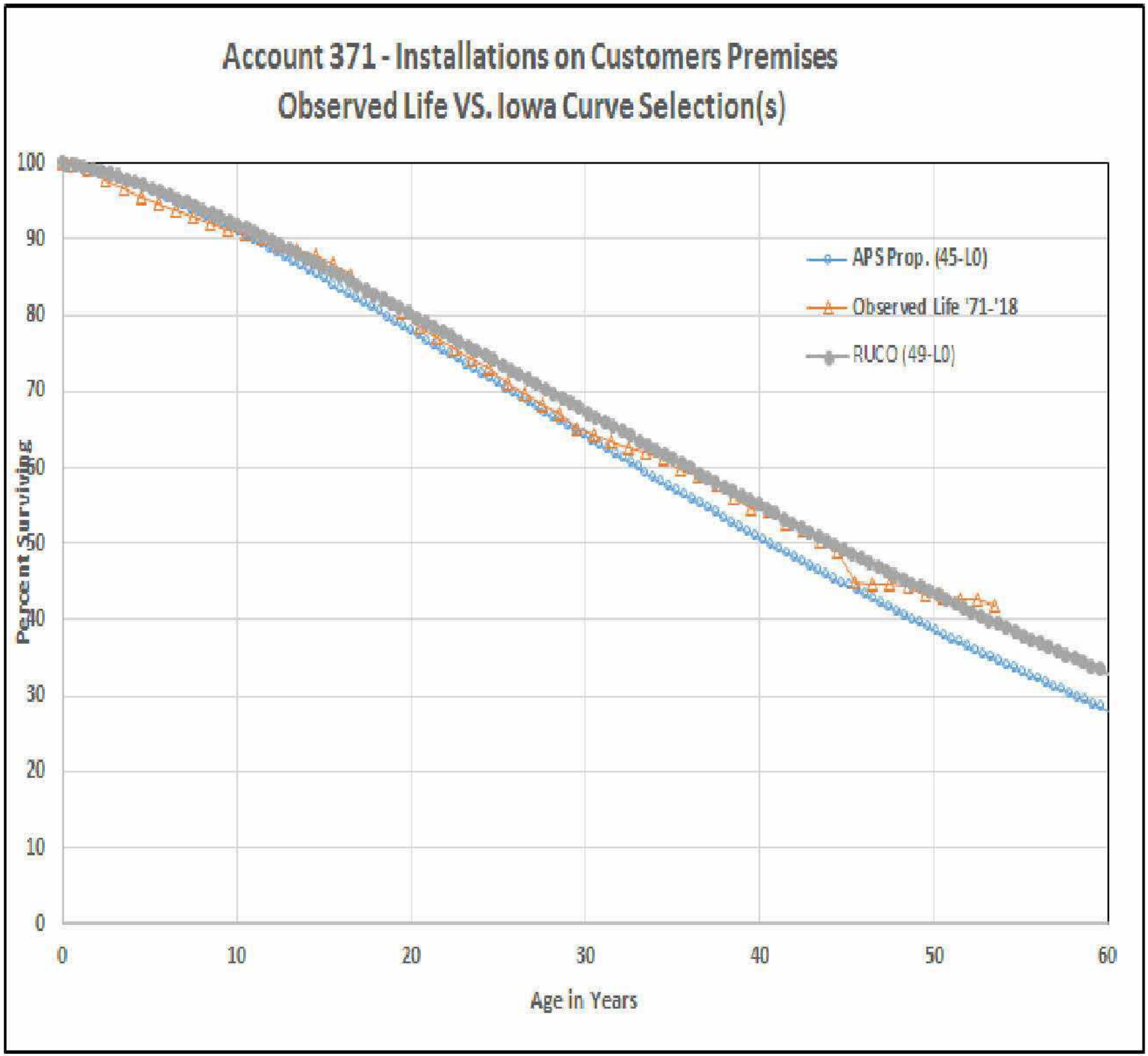
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	0.0	76.1	L0	19.44	152.4	SC *	7.53	84.5	R1.5 *	6.46
1973-2018	0.0	75.4	L0	19.83	152.7	SC *	7.54	81.3	R1.5 *	7.18
1975-2018	0.0	74.3	L0	20.45	153.0	SC *	7.56	79.2	R1.5 *	8.32
1977-2018	0.0	73.3	L0.5	21.08	153.5	SC *	7.59	79.4	R1.5 *	8.34
1979-2018	0.0	73.0	L0.5	21.37	153.8	SC *	7.61	81.2	R1.5 *	7.49
1981-2018	0.0	72.7	L0.5	21.88	154.6	R0.5 *	7.66	89.2	R1.5 *	6.71
1983-2018	0.0	73.1	L0.5	22.05	155.4	R0.5 *	7.71	107.4	R1.5 *	7.73
1985-2018	0.0	74.6	L0.5	21.76	156.8	R0.5 *	7.79	157.0	R0.5 *	7.79
1987-2018	0.0	77.7	L1	20.84	158.3	R0.5 *	7.90	157.9	R0.5 *	7.92
1989-2018	0.0	81.4	L1	19.59	159.5	R1 *	8.00	159.3	R1 *	8.04
1991-2018	0.0	88.1	L1	21.62	160.7	R1 *	32.20	161.9	R1 *	32.60
1993-2018	0.0	97.6	L1	23.51	160.5	R1 *	31.91	165.3	R1 *	33.39
1995-2018	0.0	98.1	L1	23.61	160.6	R1 *	31.94	165.5	R1 *	33.41
1997-2018	0.0	98.2	L1	14.77	160.5	R1 *	8.51	165.0	R1 *	8.30
1999-2018	0.0	98.6	L0.5	14.55	159.4	R1 *	8.55	164.5	R1 *	8.28
2001-2018	0.0	101.2	L0.5	13.81	155.2	R0.5 *	9.01	164.4	R1 *	8.30
2003-2018	0.0	105.5	L0.5	12.76	140.9	SC *	10.17	164.8	R1 *	8.36
2005-2018	0.0	124.5	S-.5	9.73	101.1	S0.5	12.36	169.7	R1.5 *	8.50
2007-2018	85.6	125.0	S-.5	1.42	99.4	S0.5	2.13	170.4	R1.5 *	1.67
2009-2018	85.0	126.0	S-.5	1.35	96.4	S0.5	2.19	168.8	R1.5 *	1.79
2011-2018	85.9	127.8	S-.5	1.19	99.0	S1	1.94	170.9	R1.5 *	1.60
2013-2018	85.1	127.0	S-.5	1.19	95.4	S1	2.09	168.8	R1.5 *	1.79
2015-2018	84.5	122.5	S-.5	1.29	97.4	S0.5	1.97	168.2	R1 *	1.65
2017-2018	81.1	113.4	S-.5	1.45	98.3	S0	1.83	163.2	R1 *	1.57

DOCKET NO. E-01345A-19-0236

Exhibit FWR-29 -- Account 371 Graph and deprecation data


Account 371 - Installations on Customers Premises
Observed Life VS. Iowa Curve Selection(s)
Percent Surviving
Age in Years
APS Prop. (45-L0)
Observed Life '71-'18
RUCO (49-L0)
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 371.00 Installations on Customers' Premises

Placement Band: 1951 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	56,752,631	113,324	0.00200	0.99800	1.00000
0.5	55,948,116	341,340	0.00610	0.99390	0.99800
1.5	54,772,047	781,029	0.01426	0.98574	0.99191
2.5	53,039,813	585,856	0.01105	0.98895	0.97777
3.5	51,944,246	622,122	0.01198	0.98802	0.96697
4.5	50,569,159	520,798	0.01030	0.98970	0.95539
5.5	48,959,379	390,789	0.00798	0.99202	0.94555
6.5	47,520,363	388,233	0.00817	0.99183	0.93800
7.5	45,925,389	440,745	0.00960	0.99040	0.93034
8.5	44,047,492	386,875	0.00878	0.99122	0.92141
9.5	42,536,062	326,482	0.00768	0.99232	0.91332
10.5	41,263,062	268,951	0.00652	0.99348	0.90631
11.5	37,597,060	317,879	0.00845	0.99155	0.90040
12.5	34,776,363	223,581	0.00643	0.99357	0.89279
13.5	32,569,018	266,942	0.00820	0.99180	0.88705
14.5	29,878,573	397,721	0.01331	0.98669	0.87978
15.5	26,666,696	429,340	0.01610	0.98390	0.86807
16.5	23,194,478	541,982	0.02337	0.97663	0.85409
17.5	20,468,556	294,305	0.01438	0.98562	0.83413
18.5	18,086,684	394,211	0.02180	0.97820	0.82214
19.5	16,720,562	410,363	0.02454	0.97546	0.80422
20.5	14,911,596	285,056	0.01912	0.98088	0.78448
21.5	12,692,411	223,541	0.01761	0.98239	0.76949
22.5	11,244,208	206,973	0.01841	0.98159	0.75593
23.5	10,092,830	146,382	0.01450	0.98550	0.74202
24.5	9,321,559	270,418	0.02901	0.97099	0.73126
25.5	7,992,787	155,556	0.01946	0.98054	0.71004
26.5	7,873,388	151,460	0.01924	0.98076	0.69622
27.5	6,986,469	121,434	0.01738	0.98262	0.68283
28.5	6,490,609	178,056	0.02743	0.97257	0.67096
29.5	5,859,460	85,571	0.01460	0.98540	0.65256
30.5	5,465,790	69,812	0.01277	0.98723	0.64303
31.5	5,201,278	70,230	0.01350	0.98650	0.63481
32.5	5,033,269	54,686	0.01086	0.98914	0.62624
33.5	4,613,675	63,530	0.01377	0.98623	0.61944
34.5	4,438,781	89,494	0.02016	0.97984	0.61091
35.5	4,230,739	72,985	0.01725	0.98275	0.59859

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 371.00 Installations on Customers' Premises

Placement Band: 1951 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
36.5	4,081,900	77,370	0.01895	0.98105	0.58827
37.5	3,605,934	104,320	0.02893	0.97107	0.57711
38.5	3,382,534	78,153	0.02310	0.97690	0.56042
39.5	3,245,343	32,704	0.01008	0.98992	0.54747
40.5	3,102,848	86,935	0.02802	0.97198	0.54195
41.5	2,959,616	52,347	0.01769	0.98231	0.52677
42.5	2,796,472	79,852	0.02855	0.97145	0.51745
43.5	2,519,533	70,163	0.02785	0.97215	0.50268
44.5	2,343,481	185,488	0.07915	0.92085	0.48868
45.5	2,031,761	9,621	0.00474	0.99526	0.45000
46.5	1,802,961	9,242	0.00513	0.99487	0.44787
47.5	1,609,090	3,276	0.00204	0.99796	0.44557
48.5	1,532,454	41,550	0.02711	0.97289	0.44466
49.5	1,235,948	8,671	0.00702	0.99298	0.43261
50.5	1,100,523	5,618	0.00511	0.99489	0.42957
51.5	880,428	3,565	0.00405	0.99595	0.42738
52.5	747,392	12,565	0.01681	0.98319	0.42565
53.5	0	0	0.00000	1.00000	0.41849

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 371.00 Installations on Customers' Premises

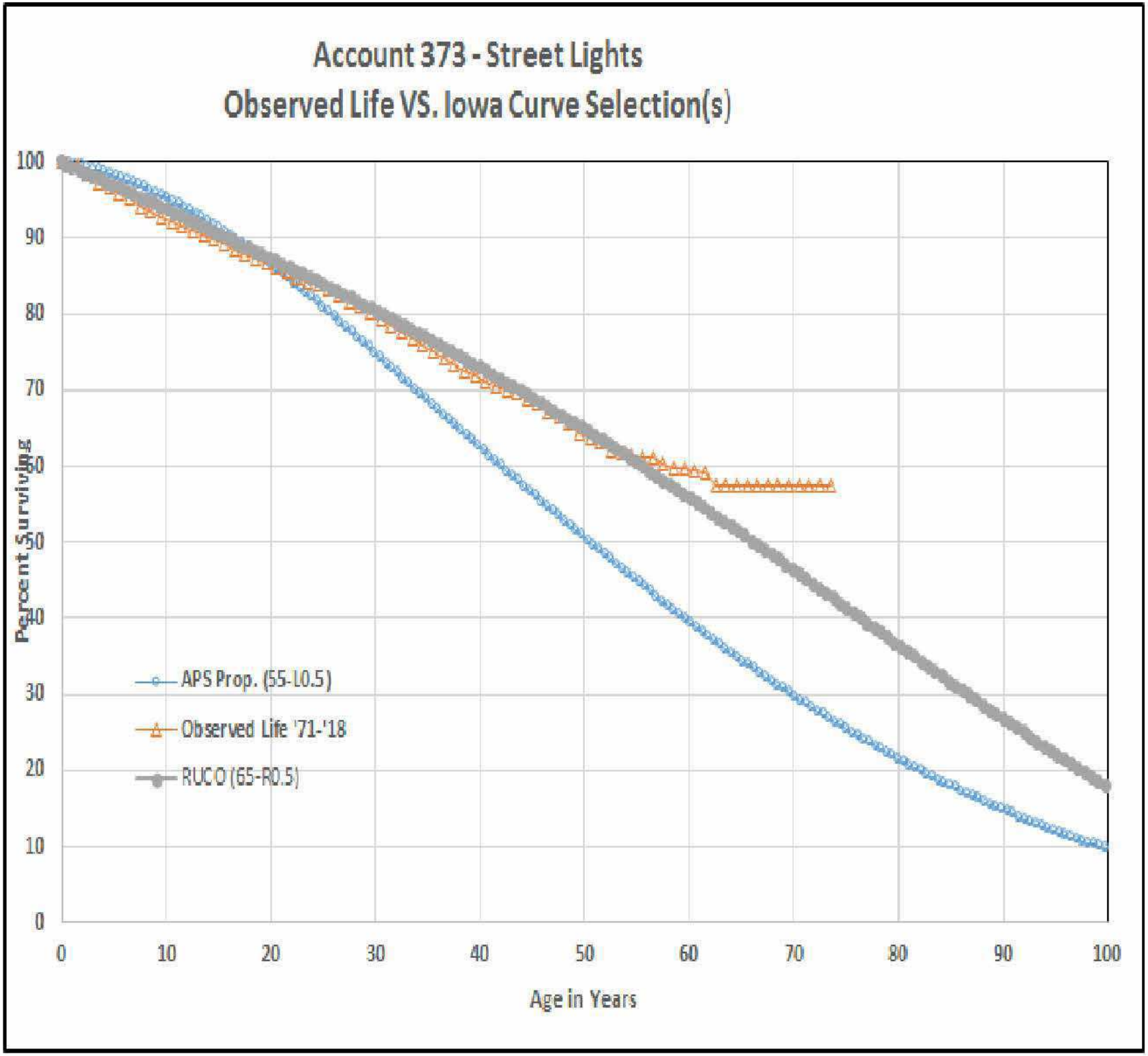
T-Cut: None
Placement Band: 1951-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	41.8	48.9	L0	1.29	52.7	O2	1.24	97.2	O4 *	1.15
1973-2018	41.8	48.9	L0	1.29	52.6	O2	1.24	97.2	O4 *	1.15
1975-2018	41.9	48.9	L0	1.30	53.1	O2 *	1.25	97.4	O4 *	1.16
1977-2018	42.1	48.9	L0	1.33	54.8	O2 *	1.25	97.8	O4 *	1.18
1979-2018	42.2	48.9	L0	1.35	55.6	O2 *	1.26	98.2	O4 *	1.20
1981-2018	42.3	48.9	L0	1.37	56.3	O2 *	1.26	98.5	O4 *	1.21
1983-2018	42.5	48.9	L0	1.40	57.1	O2 *	1.27	98.9	O4 *	1.23
1985-2018	42.6	49.1	L0	1.43	56.1	O2 *	1.31	99.3	O4 *	1.26
1987-2018	42.8	49.2	L0	1.47	55.4	O2 *	1.36	99.7	O4 *	1.28
1989-2018	42.7	49.2	L0	1.50	55.6	O2 *	1.39	99.7	O4 *	1.29
1991-2018	42.6	49.1	L0	1.60	57.3	O2 *	1.47	99.8	O4 *	1.32
1993-2018	42.5	48.9	L0	1.80	60.7	O3 *	1.61	100.0	O4 *	1.37
1995-2018	42.0	48.7	L0.5	2.08	62.8	O3 *	1.85	99.8	O4 *	1.41
1997-2018	41.2	48.1	L0.5	2.39	64.9	O3 *	2.11	98.6	O4 *	1.45
1999-2018	40.5	47.7	L0.5	2.61	63.8	O3 *	2.33	97.3	O4 *	1.51
2001-2018	40.0	47.4	L0.5	2.87	62.1	O3 *	2.59	96.1	O4 *	1.51
2003-2018	38.5	46.7	L0.5	3.28	60.0	O3 *	2.99	93.2	O4 *	1.46
2005-2018	37.4	46.3	L0.5	3.60	59.3	O3 *	3.32	90.9	O4 *	1.38
2007-2018	34.5	44.7	L0.5	4.02	55.5	O3 *	3.80	84.7	O4 *	1.39
2009-2018	30.9	43.1	L0.5	4.58	52.7	O3 *	4.42	77.7	O4 *	1.49
2011-2018	57.6	86.7	O2	4.18	61.8	R0.5	4.54	121.9	SC *	2.23
2013-2018	57.1	93.9	O3	3.97	58.3	R0.5	4.31	117.2	SC *	2.95
2015-2018	53.8	114.1	O3 *	4.24	52.8	R0.5	4.44	106.9	O4 *	4.34
2017-2018	48.9	129.0	SC *	7.33	46.6	SC	7.40	92.3	O4 *	4.83

DOCKET NO. E-01345A-19-0236

Exhibit FWR-30 -- Account 373 – Graph and deprecation data


Account 373 - Street Lights
Observed Life VS. Iowa Curve Selection(s)
Percent Surviving
Age in Years
APS Prop. (55-L0.5)
Observed Life '71-'18
RUCO (65-R0.5)
0
10
20
30
40
50
60
70
80
90
100

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 373.00 Street Lighting and Signal Systems

Placement Band: 1920 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	125,310,236	194,601	0.00155	0.99845	1.00000
0.5	124,266,904	597,075	0.00480	0.99520	0.99845
1.5	119,601,191	1,320,279	0.01104	0.98896	0.99365
2.5	113,050,971	1,165,686	0.01031	0.98969	0.98268
3.5	110,181,572	736,922	0.00669	0.99331	0.97255
4.5	104,150,773	816,927	0.00784	0.99216	0.96604
5.5	97,817,379	627,579	0.00642	0.99358	0.95847
6.5	92,812,651	977,283	0.01053	0.98947	0.95232
7.5	89,648,681	629,365	0.00702	0.99298	0.94229
8.5	86,709,045	695,582	0.00802	0.99198	0.93567
9.5	83,656,121	526,372	0.00629	0.99371	0.92817
10.5	80,358,855	483,677	0.00602	0.99398	0.92233
11.5	75,046,796	531,085	0.00708	0.99292	0.91678
12.5	71,488,921	431,599	0.00604	0.99396	0.91029
13.5	66,732,626	442,519	0.00663	0.99337	0.90479
14.5	63,171,918	496,208	0.00785	0.99215	0.89879
15.5	61,188,353	563,375	0.00921	0.99079	0.89173
16.5	58,002,767	415,510	0.00716	0.99284	0.88352
17.5	55,743,242	264,135	0.00474	0.99526	0.87719
18.5	53,478,217	278,546	0.00521	0.99479	0.87304
19.5	50,579,738	355,741	0.00703	0.99297	0.86849
20.5	46,531,016	395,863	0.00851	0.99149	0.86238
21.5	40,783,180	332,101	0.00814	0.99186	0.85504
22.5	36,844,532	227,970	0.00619	0.99381	0.84808
23.5	33,247,581	185,039	0.00557	0.99443	0.84283
24.5	30,696,617	168,567	0.00549	0.99451	0.83814
25.5	25,766,107	241,212	0.00936	0.99064	0.83354
26.5	24,483,656	274,042	0.01119	0.98881	0.82574
27.5	20,008,100	166,712	0.00833	0.99167	0.81650
28.5	17,556,852	150,093	0.00855	0.99145	0.80969
29.5	14,392,169	162,811	0.01131	0.98869	0.80277
30.5	12,746,464	135,980	0.01067	0.98933	0.79369
31.5	10,884,066	121,643	0.01118	0.98882	0.78522
32.5	10,509,524	110,484	0.01051	0.98949	0.77645
33.5	10,054,459	121,140	0.01205	0.98795	0.76828
34.5	9,084,345	103,545	0.01140	0.98860	0.75903
35.5	7,747,994	80,729	0.01042	0.98958	0.75038

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 373.00 Street Lighting and Signal Systems

Placement Band: 1920 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	6,973,843	81,123	0.01163	0.98837	0.74256
37.5	5,912,724	61,395	0.01038	0.98962	0.73392
38.5	5,233,780	44,818	0.00856	0.99144	0.72630
39.5	4,543,679	50,251	0.01106	0.98894	0.72008
40.5	3,896,008	34,769	0.00892	0.99108	0.71212
41.5	3,569,318	25,685	0.00720	0.99280	0.70576
42.5	3,312,162	17,791	0.00537	0.99463	0.70068
43.5	3,031,275	39,272	0.01296	0.98704	0.69692
44.5	2,732,301	24,316	0.00890	0.99110	0.68789
45.5	2,410,011	34,265	0.01422	0.98578	0.68177
46.5	2,227,012	24,877	0.01117	0.98883	0.67207
47.5	2,112,580	25,009	0.01184	0.98816	0.66457
48.5	1,879,596	42,268	0.02249	0.97751	0.65670
49.5	1,758,830	16,136	0.00917	0.99083	0.64193
50.5	1,603,538	12,244	0.00764	0.99236	0.63604
51.5	1,411,958	22,703	0.01608	0.98392	0.63119
52.5	1,385,515	9,138	0.00660	0.99340	0.62104
53.5	1,334,914	7,061	0.00529	0.99471	0.61694
54.5	1,083,870	2,123	0.00196	0.99804	0.61368
55.5	938,859	2,433	0.00259	0.99741	0.61247
56.5	883,597	12,473	0.01412	0.98588	0.61089
57.5	792,804	5,807	0.00732	0.99268	0.60226
58.5	554,451	1,121	0.00202	0.99798	0.59785
59.5	442,605	1,961	0.00443	0.99557	0.59665
60.5	224,153	568	0.00254	0.99746	0.59400
61.5	103,297	3,190	0.03088	0.96912	0.59250
62.5	0	0	0.00000	1.00000	0.57420
63.5	0	0	0.00000	1.00000	0.57420
64.5	0	0	0.00000	1.00000	0.57420
65.5	0	0	0.00000	1.00000	0.57420
66.5	0	0	0.00000	1.00000	0.57420
67.5	0	0	0.00000	1.00000	0.57420
68.5	0	0	0.00000	1.00000	0.57420
69.5	0	0	0.00000	1.00000	0.57420
70.5	0	0	0.00000	1.00000	0.57420
71.5	716	0	0.00000	1.00000	0.57420
72.5	716	0	0.00000	1.00000	0.57420

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 373.00 Street Lighting and Signal Systems

Placement Band: 1920 - 2018
Observation Band: 1971 - 2018

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion		Cumulative Proportion Surviving
			Retired	Surviving	
A	B	C	D=C/B	E=1-D	F
73.5	716	716	1.00000	0.00000	0.57420
74.5	0	0	0.00000	1.00000	0.00000

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 373.00 Street Lighting and Signal Systems

T-Cut: None
Placement Band: 1920-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2018	0.0	92.6	O2	6.25	67.9	S-.5	6.02	124.4	SC *	6.38
1973-2018	0.0	92.9	O2	6.26	67.8	S-.5	6.02	124.3	SC *	6.38
1975-2018	0.0	93.7	O2	6.30	67.7	R0.5	6.03	124.6	SC *	6.40
1977-2018	0.0	94.4	O2	6.32	67.4	R0.5	6.04	124.8	SC *	6.41
1979-2018	0.0	94.8	O2	6.33	67.2	R0.5	6.04	124.8	SC *	6.41
1981-2018	0.0	97.5	O2	6.44	67.1	R0.5	6.07	125.2	SC *	6.45
1983-2018	0.0	99.3	O2	6.52	66.8	R0.5	6.11	126.2	SC *	6.51
1985-2018	0.0	101.6	O2	6.61	66.6	R0.5	6.13	126.5	SC *	6.54
1987-2018	0.0	103.8	O2	6.69	67.5	R0.5	6.14	126.8	SC *	6.56
1989-2018	0.0	108.1	SC	6.89	68.8	R0.5	6.24	129.7	SC *	6.75
1991-2018	0.0	114.6	SC	7.19	68.2	R0.5	6.34	132.3	SC *	6.95
1993-2018	0.0	115.8	SC	7.24	69.4	R0.5	6.38	133.9	SC *	7.06
1995-2018	61.7	125.6	SC *	2.05	68.4	R0.5	1.06	135.7	SC *	0.38
1997-2018	61.4	135.4	SC *	2.48	66.8	R0.5	1.17	135.4	SC *	0.41
1999-2018	60.5	137.9	SC *	2.87	64.7	R0.5	1.39	134.2	SC *	0.54
2001-2018	59.5	139.3	SC *	3.36	63.0	R0.5	1.63	132.3	SC *	0.58
2003-2018	58.8	141.1	SC *	3.68	61.8	R0.5	1.75	130.2	SC *	0.70
2005-2018	59.7	145.3	SC *	4.20	61.8	R1	1.91	131.6	SC *	0.84
2007-2018	60.6	149.3	SC *	4.51	62.4	R1	1.85	132.7	SC *	0.94
2009-2018	59.9	138.4	SC *	3.82	63.9	R1	1.73	132.0	SC *	0.84
2011-2018	69.6	165.6	R1 *	4.61	71.3	R1.5	2.04	148.4	SC *	1.02
2013-2018	67.9	163.3	R1 *	5.38	69.5	R1.5	2.79	143.8	SC *	1.49
2015-2018	63.7	158.7	R1 *	6.93	65.6	R1	3.84	135.6	SC *	1.63
2017-2018	62.2	157.7	R0.5 *	7.21	61.3	R1	3.20	129.8	SC *	2.08

DOCKET NO. E-01345A-19-0236

Exhibit FWR-31 – Net Salvage Data for Accounts 365 and 367

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 365.00 OH Conductors and Devices

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1993	1,940,383	396,740	20.4		253,066	13.0		143,674	7.4	
1994	1,180,863	221,188	18.7		175,091	14.8		46,097	3.9	
1995	1,494,749	302,791	20.3		167,691	11.2		135,100	9.0	
1996	614,143	63,799	10.4		64,916	10.6		(1,117)	-0.2	
1997	1,799,020	237,174	13.2	17.4	114,620	6.4	11.0	122,555	6.8	6.3
1998	6,541,751	2,124,698	32.5	25.4	122,760	1.9	5.5	2,001,938	30.6	19.8
1999	2,415,704		0.0	21.2	851	0.0	3.7	(851)	0.0	17.5
2000	3,739,557	1,028,050	27.5	22.9	281,378	7.5	3.9	746,672	20.0	19.0
2001	2,983,572	584,241	19.6	22.7	535,926	18.0	6.0	48,315	1.6	16.7
2002	3,736,755	435,992	11.7	21.5	950,069	25.4	9.7	(514,077)	-13.8	11.8
2003	4,194,438	1,197,662	28.6	19.0	641,742	15.3	14.1	555,920	13.3	4.9
2004	7,462,299	1,281,038	17.2	20.5	636,489	8.5	13.8	644,549	8.6	6.7
2005	1,724,768	992,820	57.6	22.3	819,663	47.5	17.8	173,157	10.0	4.5
2006	2,536,170	1,455,433	57.4	27.3	1,817,373	71.7	24.8	(361,939)	-14.3	2.5
2007	3,465,559	3,645,794	105.2	44.2	2,336,146	67.4	32.3	1,309,648	37.8	12.0
2008	2,909,504	4,035,642	138.7	63.0	5,135,364	176.5	59.4	(1,099,722)	-37.8	3.7
2009	2,378,390	2,652,428	111.5	98.2	4,259,447	179.1	110.4	(1,607,019)	-67.6	-12.2
2010	5,658,919	2,028,761	35.9	81.5	3,538,672	62.5	100.8	(1,509,911)	-26.7	-19.3
2011	1,520,342	(183,027)	-12.0	76.4	1,233,168	81.1	103.6	(1,416,194)	-93.1	-27.1
2012	2,655,902	(4,595)	-0.2	56.4	1,345,506	50.7	102.6	(1,350,101)	-50.8	-46.2
2013	1,743,977	189,368	10.9	33.6	1,319,937	75.7	83.8	(1,130,570)	-64.8	-50.3
2014	2,070,051	186,957	9.0	16.2	1,973,208	95.3	68.9	(1,786,251)	-86.3	-52.7
2015	2,329,727	584,065	25.1	7.5	2,754,346	118.2	83.6	(2,170,280)	-93.2	-76.1
2016	2,027,215	775,932	38.3	16.0	1,841,080	90.8	85.3	(1,065,148)	-52.5	-69.3
2017	1,963,432	(2,451,504)	-124.9	-7.1	2,835,747	144.4	105.8	(5,287,250)	-269.3	-112.9
2018	1,700,837	1,536,540	90.3	6.3	4,333,556	254.8	136.1	(2,797,016)	-164.4	-129.9
Total	72,788,027	23,317,989	32.0		39,487,812	54.3		(16,169,822)	-22.2	

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1993	12,346,537	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,133,313	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,824	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,560,192	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,905,235	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,756,216		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,569,466		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,611,085	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,079,147	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,993	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,088,891	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,315,290	1,306,856	8.5	14.6	1,971,252	12.9	15.2	(664,396)	-4.3	-0.6
2005	7,426,563	1,536,983	20.7	13.0	3,342,225	45.0	20.3	(1,805,242)	-24.3	-7.3
2006	8,664,638	4,972,381	57.4	18.6	2,695,724	31.1	22.1	2,276,657	26.3	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
2008	9,083,916	3,764,197	41.4	30.0	4,689,426	51.6	32.5	(925,229)	-10.2	-2.4
2009	11,733,105	2,169,201	18.5	34.2	3,391,321	28.9	37.9	(1,222,120)	-10.4	-3.8
2010	7,660,141	12,570,515	164.1	57.2	4,986,596	65.1	41.2	7,583,919	99.0	16.0
2011	9,210,495	1,131,945	12.3	48.6	2,767,426	30.0	40.9	(1,635,481)	-17.8	7.7
2012	9,583,537	1,495,667	15.6	44.7	3,097,894	32.3	40.1	(1,602,227)	-16.7	4.7
2013	6,521,014	296,727	4.6	39.5	2,926,160	44.9	38.4	(2,629,433)	-40.3	1.1
2014	8,392,283	1,491,999	17.8	41.1	4,304,042	51.3	43.7	(2,812,043)	-33.5	-2.6
2015	9,727,135	1,295,380	13.3	13.2	4,942,304	50.8	41.5	(3,646,925)	-37.5	-28.4
2016	9,013,566	1,868,875	20.7	14.9	3,698,656	41.0	43.9	(1,829,781)	-20.3	-29.0
2017	8,170,347	842,738	10.3	13.9	4,101,514	50.2	47.8	(3,258,776)	-39.9	-33.9
2018	9,133,092	(133,705)	-1.5	12.1	4,047,542	44.3	47.5	(4,181,247)	-45.8	-35.4
Total	252,609,530	52,142,422	20.6		66,112,812	26.2		(13,970,390)	-5.5	

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-19-0236

DIRECT TESTIMONY

OF

JOHN CASSIDY, CRRA

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

OCTOBER 2, 2020

TABLE OF CONTENTS

		Page
I.	INTRODUCTION	3
II.	SUMMARY OF TESTIMONY AND RECOMMENDATIONS	4
III.	ECONOMIC/LEGAL PRINCIPLES APPLICABLE TO ARIZONA	7
IV.	GENERAL ECONOMIC CONDITIONS	9
V.	CAPITAL STRUCTURE AND COST OF DEBT	35
VI.	SELECTION OF PROXY GROUP	36
VII.	DCF ANALYSIS	43
VIII.	CAPM ANALYSIS	46
IX.	CE ANALYSIS	53
X.	RUCO RESPONSE TO COMPANY'S COST OF CAPITAL WITNESS MS. ANNE E. BULKLEY	55
XI.	CONCLUSION AND RECOMMENDATIONS	73

ATTACHMENTS

John A. Cassidy – Regulatory Experience ..... Attachment No. 1
Value Line Investment Survey Water Proxy Group ..... Attachment No. 2
Yahoo Analyst Estimates ..... Attachment No. 3

EXHIBITS

Path of Interest Rates in 2019 ..... JAC-A
Blue Chip Economic Indicators – Forecasts of 10-Year Treasury Rates ..... JAC-B

SCHEDULES

Weighted Average Cost of Capital ..... Schedule JAC-1
Cost of Common Equity ..... Schedule JAC-2
Discounted Cash Flow Model ..... Schedule JAC-3
Capital Asset Pricing Model ..... Schedule JAC-4
Comparable Earnings ..... Schedule JAC-5
Economic Indicators ..... Schedule JAC-6
RUCO Proxy Group – Common Equity Ratios ..... Schedule JAC-7

EXECUTIVE SUMMARY

RUCO recommends that the Commission adopt a 6.75 percent overall rate of return for Arizona Public Service Company ("APS," or "Company"), based upon (i) a capital structure comprised of 45.33 percent long-term debt and 54.67 percent common equity, (ii) the Company's proposed 4.10 percent cost of long-term debt, and (iii) RUCO's recommended 8.94 percent cost of common equity, as shown below:

	Weight	Cost	Weighted Cost
Long-Term Debt	45.33 %	4.10 %	1.86 %
Common Equity	54.67 %	8.94 %	4.89 %
Overall Rate of Return			6.75 %

RUCO obtained common equity cost estimates for a proxy group of twelve sample companies employing three cost of equity estimation models: the Constant Growth Discounted Cash Flow Model ("DCF"), the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings Model ("CE"). The range of estimates obtained from each of the three models employed by RUCO are as follows:

Cost of Equity Estimation Model	Range
Discounted Cash Flow ("DCF")	8.00% - 9.50% (8.75% mid-point)
Capital Asset Pricing Model ("CAPM")	7.64% - 7.73% (7.68% mid-point)
Comparable Earnings ("CE")	9.50% - 10.0% (9.75% mid-point)

RUCO's 8.94 percent recommended cost of equity represents a weighted cost rate obtained by assigning a 40.00 percent weighting factor to estimates obtained from the DCF and CE models, and a 20.00 percent weighting factor to estimates obtained from the CAPM, as follows:

	Indicated Cost	Weight Factor	Weighted Cost
Discounted Cash Flow	8.75 %	40.00 %	3.50%
Capital Asset Pricing Model	7.68 %	20.00 %	1.54 %
Comparable Earnings	9.75 %	40.00 %	3.90 %
Average Cost of Equity	8.73 %		
RUCO Recommended Cost of Common Equity			8.94 %

As a consequence of the Company's demonstrated poor customer service, in testimony to be filed by Director, Mr. Jordy Fuentes, RUCO recommends the Commission adopt a downward 20 basis point adjustment to the Company's ROE, from 8.94 percent to 8.74 percent.

I will also demonstrate that the 10.15 percent cost of equity recommendation of APS witness, Ms. Ann E. Bulkley, significantly over-states the Company's actual cost of equity for the following reasons:

1) Ms. Bulkley employs the results of a Bond Yield Plus Risk Premium method to corroborate the reasonableness of her DCF and CAPM results, and to inform

her ultimate ROE recommendation. However, Ms. Bulkley overstates the equity risk premium component obtained in her analysis by improperly employing yields on the 30-year long-term Treasury bonds rather than Moody's Baa-rated corporate utility bonds in her analysis.

2) Ms. Bulkley also employs the results of an Expected Earnings analysis to corroborate the reasonableness of her DCF and CAPM results, and to inform her ultimate ROE recommendation. However,

   (i) FERC has determined that rates established based upon estimates obtained from the Expected Earnings model are unjust and unreasonable; and

   (ii) Ms. Bulkley relies on the 11.15% sample mean estimate obtained from her Expected Earnings analysis--the single highest estimate obtained in her cost of equity analysis--rather than the 10.81% sample median estimate which is more representative of her proxy group.

3) The results obtained from Ms. Bulkley's Constant Growth DCF analysis are overstated through exclusive use of analysts' forecasts of EPS growth to estimate the dividend growth rate.

4) The results obtained from Ms. Bulkley's CAPM analyses are overstated through use of inflated estimates of the risk-free rate based on Blue Chip forecasts of 30-year Treasury yields.

I. INTRODUCTION

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

A. My name is John A. Cassidy. I am a Public Utilities Analyst V with the Residential Utility Consumers Office ("RUCO"). My business address is 1110 W. Washington Street, Suite 220, Phoenix, AZ.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in History from Arizona State University, a Master of Library Science degree from the University of Arizona, and a Master of Business Administration degree with an emphasis in Finance from Arizona State University. I have been awarded the professional designation Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA") based upon experience and the successful completion of a written examination. I have over twelve years of professional regulatory work experience as a Public Utilities Analyst, both with RUCO and the Arizona Corporation Commission ("ACC" or "Commission") Staff, and have testified in numerous rate proceedings as a cost of capital witness before this Commission. Additionally, I have attended utility related seminars sponsored by SURFA, the National Association of State Utility Consumer Advocates ("NASUCA"), and the National Association of Regulatory Utility Commissioners ("NARUC"). Attachment 1 contains a summary of my prior regulatory work experience.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations for the establishment of a fair value rate of return. For purposes of establishing a fair value rate of return on its invested capital in this proceeding, the Company has elected to

use its reconstruction cost new ("RCND") rate base as its fair value rate base ("FVRB").

Q. Will RUCO provide direct testimony on the rate base, operating income and rate design issues in this proceeding?

A Yes. RUCO witness, Mr. Frank Radigan will also file direct testimony in this proceeding. Mr. Radigan's testimony will address the rate base and operating income issues associated with the case, as well as RUCO's proposed rate design for APS..

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into twelve (12) different sections as identified in my "Table of Contents." In summary, I have derived cost of equity estimates obtained from both the Constant Growth Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"). The DCF and CAPM are market-based cost of equity estimation models, and both have consistently been employed by RUCO and ACC Staff in prior rate proceedings. Additionally, the DCF and CAPM are methodologies which the ACC has traditionally given the most weight when establishing authorized rates of return for utilities operating within its Arizona jurisdiction. In addition to cost of equity estimates obtained from the DCF and CAPM models, I have also prepared a Comparable Earnings ("CE") analysis which gives consideration to both (i) historical realized returns on equity ("ROE"), and (ii) projected ROEs for RUCO's proxy group of publicly-traded water utility companies. As will be discussed, RUCO's recommended cost of equity in this proceeding represents a weighted cost, with cost of equity estimates obtained from

the DCF and CE models assigned a 40.00 percent weighting, while estimates obtained from the CAPM are assigned a 20.00 percent weighting.

The Company's witness, Ms. Ann E. Bulkley, obtains equity cost estimates from both the Constant Growth DCF and CAPM models, as well as from a Bond Yield Plus Risk Premium method. My testimony will conclude with a discussion of Ms. Bulkley's cost of equity estimation analysis and I will demonstrate that her 10.15 percent recommendation significantly overstates the Company's actual cost of equity.

Q. Please summarize RUCO's cost of capital recommendations for APS in this rate proceeding.

A. Based on the results of my analysis, I recommend that the Commission adopt a 6.75 percent overall rate of return for the Company, based upon (i) a capital structure comprised of 45.33 percent long-term debt and 54.67 percent common equity, (ii) the Company's proposed 4.10 percent cost of long-term debt, and (iii) RUCO's recommended 8.94 percent cost of equity, as shown below:[1]

	Weight	Cost	Weighted Cost
Long-Term Debt	45.33 %	4.10 %	1.86 %
Common Equity	54.67 %	8.94 %	4.89 %
Overall Rate of Return			6.75 %

RUCO obtained common equity cost estimates for a proxy group of twelve (12) publicly-traded electric utility companies employing three cost of equity estimation models: the Constant Growth DCF model, the CAPM, and the CE Model. The range of estimates obtained from each model employed by RUCO are as follows:

[1] See JAC Schedule 1

Cost of Equity Estimation Model	Range
Discounted Cash Flow ("DCF")	8.00% - 9.50% (8.75% mid-point)
Capital Asset Pricing Model ("CAPM")	7.64% - 7.73% (7.68% mid-point)
Comparable Earnings ("CE")	9.50% - 10.00% (9.75% mid-point)

The computation of RUCO's recommended 8.94 percent common equity cost rate for AWC-West is presented below:

	Indicated Cost	Weight	Weighted Cost
Discounted Cash Flow (DCF)	8.75 %	40.00 %	3.50%
Capital Asset Pricing Model (CAPM)	7.68 %	20.00 %	1.54 %
Comparable Earnings (CE)	9.75 %	40.00 %	3.90 %
Average Cost of Equity	8.73 %		
RUCO Recommended Cost of Common Equity			**8.94 %**

As shown, RUCO obtained cost of equity ("COE") estimates of 8.75 percent from the Constant Growth DCF model, 7.68 percent from the CAPM, and 9.75 percent from the CE method for its proxy group of companies, which equates to an average (i.e., arithmetic mean) indicated cost of common equity of 8.73 percent. RUCO then assigned a weighting factor of 40.00 percent to COE results obtained from the DCF and CE models, and a 20.00 percent weighting factor to the results obtained from the CAPM. As shown, RUCO recommends an 8.94 percent weighted average cost of common equity for APS in this proceeding.

Q. You note above that RUCO Director, Mr. Jordy Fuentes, will be recommending that a downward 20 basis point adjustment be made to RUCO's 8.94 percent recommended ROE. Do the results obtained from your cost of capital models support such a downward adjustment?

A. Yes, they do. A downward adjustment of 20 basis points to my recommended 8.94 percent ROE would equate to an authorized ROE of 8.74 percent (8.94% -0.20% =

8.74%). As shown in Schedule JAC – 2 (Page1 of 1), assigning an equal weighting to the cost of equity results obtained from RUCO's DCF, CAPM, and CE models equates to an indicated cost of equity of 8.73 percent. Thus, an 8.74 percent authorized ROE after making a downward 20 basis point adjustment is supported by the results obtained from RUCO's models.

III. ECONOMIC/LEGAL PRINCIPLES APPLICABLE TO ARIZONA

Q. What are the basic economic principles which apply in the determination of a fair rate of return for regulated public utilities in Arizona?

A. For regulated public utilities in Arizona, rates are established in a manner designed to allow for recovery of the utility's costs, including capital costs. This is traditionally referred to as "cost of service" ratemaking. Rates are established using the "rate base – rate of return" concept, wherein utilities are allowed to recover specific operating expenses, taxes and depreciation, and granted an opportunity to earn a fair value rate of return on the assets utilized (i.e., fair value rate base) in providing service to ratepayers. Rate base is derived from the asset side of the utility's balance sheet, while rate of return is developed from the liability/stockholders' equity side of the balance sheet. The revenue impact of the cost of capital in rates is determined by multiplying rate base by rate of return. In the instant docket RUCO is recommending an overall rate of return for APS of 6.75 percent.

Q. Is the Company proposing that its original cost rate base also be used as its fair value rate base?

A. No. APS proposes that its reconstruction cost new ("RCND") rate base be used as its fair value rate base ("FVRB").

Q. What FVROR is the Company proposing?

A. APS proposes a FVROR of 5.62 percent, based on a Fair Value Increment ("FVI") cost rate of 1.00 percent.

Q. What is the meaning of a "fair rate of return" when analyzing a rate case application?

A. From an economic standpoint, a "fair rate of return" is one which allows an efficient and economically well managed utility the ability to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts. From a technical perspective, a "fair rate of return" is an ex post (after the fact) earned return on an asset base. Conversely, the cost of capital is an ex ante (before the fact) expected, or required, return on a capital base. In regulatory proceedings, the two terms are often used interchangeably.

Q. As regulated entities granted natural monopoly status, are public utilities guaranteed to earn their authorized rate of return?

A. No, they are not. Public utilities are granted an opportunity to earn their authorized rate of return; there is no guarantee that they will do so. Many factors are involved in determining a rate of return. However, investments in new plant assets made subsequent to a rate case and/or increases to operating expenses between rate cases can have a negative impact on a utility's realized rate of return. Conversely, an increase in revenues and/or a decrease in operating expenses can have a positive impact on the earned rate of return. In the former scenario, a public utility will generally file for a rate increase. In the latter scenario, should a public utility earn a rate of return in excess of that approved by a utility commission, then the

commission may instruct the utility to file a rate application in order that new rates be established to provide rate relief to ratepayers.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in the determination of the cost of capital for a regulated public utility such as APS?

A. Economic and financial conditions are important because the cost of capital, both fixed cost debt as well as common equity, is largely determined by current and future economic and financial conditions. At any given time, the cost of capital is influenced by each of the following: (i) the level of economic activity (i.e., economic growth), (ii) the stage of the business cycle, (iii) the rate of inflation, and (iv) expected future economic conditions. That current and future economic and financial conditions largely determine the cost of equity is consistent with the Court's ruling in *the Bluefield* decision, which held that

> "[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." Bluefield, 262 U.S. at 679.[2]

Measures of general economic indicators influencing the cost of capital are presented in Schedule JAC-6 (Pages 1-6).

[2] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia* (262 U.S. 679), as cited in Parcell, David C., *The Cost of Capital: A Practitioner's Guide*, prepared for the Society of Utility and Regulatory Financial Analysts (SURFA): 2010 Edition (p.26).

Q. On March 11, 2020, the World Health Organization ("WHO") formally declared the novel Coronavirus ("COVID-19") to be a global pandemic.[3] Since that time more than 200,000 Americans have died from Coronavirus, a figure which accounts for roughly 21.0 percent of confirmed COVID-19 deaths worldwide,[4] and the US economy has been in various stages of lockdown in an effort to mitigate the community spread of this highly communicable disease. Briefly describe what impact the Coronavirus pandemic has had upon the US domestic economy over the course of the last six months.

A. The onset of the Coronavirus pandemic has been sudden and its economic impact has been devastating, both to the U.S. domestic economy and the global economy, as well. Most significantly, efforts to mitigate the community spread of COVID-19 via mandated lockdown have resulted in unprecedented increases to the unemployment rate. As shown in the graph below,[5] the number of first time weekly applications for unemployment insurance began its precipitous rise in late March 2020. In the following month alone, the Labor Department reported that 20.5 million jobs were lost as the national unemployment rate soared to 14.7 percent in April 2020, a level not seen since the Great Depression of the 1930s.[6] As depicted in the graph, initial claims for unemployment insurance exceeded 1.0 million over a 23 consecutive week period, and it has only been in the last three weeks that the

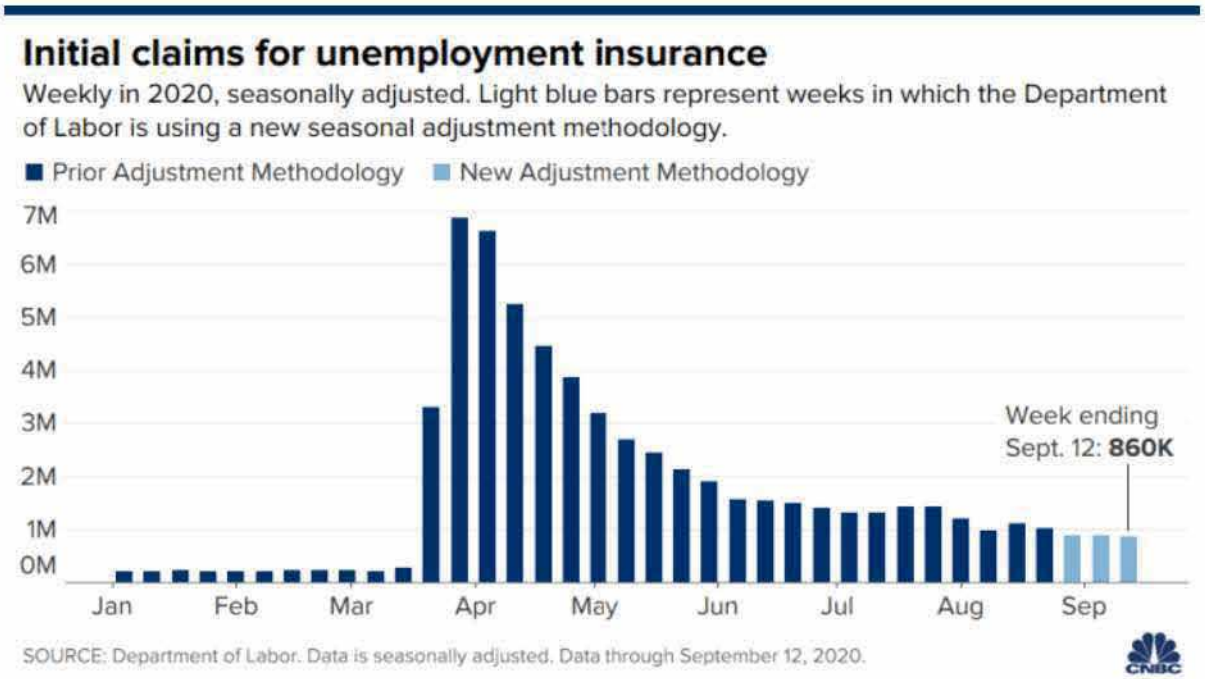
[3] Herman, Amy Orciari, "WHO Declares COVID-19 a Pandemic," New England Journal of Medicine, Journal Watch, *jwatch.org* (March 11, 2020). https://www.jwatch.org/fw116441/2020/03/11/who-declares-covid-19-pandemic

[4] Feuer, Will, "The U.S. Coronavirus Death toll tops 200,000, and it's just 'the Tip of the Iceberg,'" *cnbc.com* (September 22, 2020). https://www.cnbc.com/2020/09/22/us-coronavirus-death-toll-tops-200000-just-the-tip-of-the-iceberg-.html

[5] Picerno, James, "Is the U.S. Economic Recovery Fading?" *investing.com* (September 22, 2020). https://www.investing.com/analysis/is-the-us-economic-recovery-fading-200538441

[6] Bayly, Lucy, "Unemployment Rate Soars to 14.7 Percent, Highest Level since the Great Depression," *nbcnews.com* (May 8, 2020). https://www.nbcnews.com/business/economy/u-s-economy-shed-record-20-5-million-jobs-last-n1202696

number of initial claims has fallen below 1.0 million, with 860,000 applications filed for the week ending September 12.



Q. As discussed above, is the number of first time claims for unemployment insurance indicative of the number of American workers who have been laid off as a consequence of the Coronavirus pandemic?

A. Yes. The number of first time applications filed for unemployment insurance is "a rough measure of layoffs," and over the first 12 weeks the number of Americans filing initial claims rose "to a staggering 44.1 million."[7] When measured over a 14-week period, the number of first time unemployment claims had risen to 47.4 million."[8]

[7] Davidson, Paul, "1.5 Million more Workers File for Unemployment even as many Americans Return to Work amid COVID-19," *usatoday.com* (June 11, 2020). https://www.usatoday.com/story/money/2020/06/11/jobless-claims-report-another-million-file-unemployment-coronavirus/5338163002/

[8] Tappe, Anneken, and Luhby, Tami, "Unemployment Claims have Fallen for 3 Months, but Millions still Need Jobless Benefits," *cnn.com* (June 25, 2020). https://www.cnn.com/2020/06/25/economy/unemployment-benefits-coronavirus/index.html

Q. The above discussion addresses the number of American workers filing first-time claims for unemployment. Since the onset of the Coronavirus pandemic how many Americans have filed for continued jobless claims?

A. Continued regular jobless claims, which count people who have filed for unemployment benefits for at least two weeks in a row, peaked at a level of 24.91 million on May 9, 2020, and as of September 5, 2020 currently stands at 12.63 million.[9]

Q. How do the above referenced April (14.7 percent) and May (13.3 percent) unemployment rates compare to the annual unemployment rate experienced over the 10-year period 2010-2019, and the unemployment rate achieved during the First Quarter of 2020?

A. As shown in Schedule JAC-6 (Page 1 of 6), the US economy has experienced declining rates of unemployment each year over the 2010-2019 period. Despite the severity of the economic decline triggered by the subprime mortgage lending crisis in 2008 and 2009 (the "Great Recession"), the national unemployment rate peaked at a level of 9.6 percent in 2010, and fell to a level of 3.7 percent in 2019. As shown in Schedule JAC-6 (Page 2 of 6), the national unemployment rate in the First Quarter of 2020 averaged 3.8 percent, but rose precipitously in the Second Quarter to 13.0, as summarized below:

[9] https://ycharts.com/indicators/continued_claims_for_unemployment_insurance

National Unemployment Rate

January	3.6 %
February	3.5 %
March	4.4 %
Average Unemployment, Q1 2020	3.8 %
April	14.7 %
May	13.3 %
June	11.1 %
Average Unemployment, Q2 2020	13.0 %
July	10.2 %
August	8.4 %

As shown, the 3.5 percent rate in February 2020 matched the 50-year low 3.5 percent national unemployment rates experienced in November and December, 2019.[10] Thus, the deadly Coronavirus has caused the economy to move with alarming speed from 50-year lows in unemployment to levels not seen since the 1930s.

Q. Has the Federal Reserve Bank ("Fed") initiated accommodative monetary policies intended to stabilize labor markets and stimulate economic growth in response to the onset of the Coronavirus pandemic?

A. Yes, the Federal Open Market Committee ("FOMC") twice lowered the federal funds rate in March 2020 in response to the onset of the Coronavirus pandemic. On March 3, 2020, the FOMC lowered the federal funds rate by ½ percentage point, to a level of 1 to 1-1/4 percent, stating that while "the fundamentals of the U.S. economy remain strong...the coronavirus poses evolving risks to economic

[10] Bayly, Lucy, "Economy Added 145,000 Jobs in December," *nbcnews.com* (January 10, 2020). https://www.nbcnews.com/business/economy/economy-added-145-000-jobs-december-n1113401

activity."[11] Subsequently, on Sunday, March 15, 2020, on an emergency basis the FOMC lowered the federal funds rate by 1 percentage point, to a level of 0 to ¼ percent, stating the following:

> "The coronavirus outbreak has harmed communities and disrupted economic activity in many countries, including the United States. Global financial conditions have also been significantly affected. Available economic data show that the U.S. economy came into this challenging period on a strong footing. Information received since the Federal Open Market Committee met in January indicates that the labor market remained strong through February and economic activity rose at a moderate rate. Job gains have been solid, on average, in recent months, and the unemployment rate has remained low…"
>
> "Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The effects of the coronavirus will weigh on economic activity in the near term and pose risks to the economic outlook. In light of these developments, the Committee decided to lower the target range for the federal funds rate to 0 to 1/4 percent. The Committee expects to maintain this target range until it is confident that the economy has weathered recent events and is on track to achieve its maximum employment and price stability goals."[12]

Q. In lowering the federal funds rate to a level of 0 to ¼ percent, has the Fed reduced short-term interest rates to their Effective Lower Bound ("ELB")?

A. Yes. The federal funds rate is the interest rate the Fed charges banks for overnight deposits, and by lowering this short-term interest rate to a level of 0 to 1/4 percent, the federal funds rate has reached its ELB. Stated another way, the Fed has now exhausted its ability to further reduce short-term interest rates.

---

[11] Federal Reserve Press Release, *federalreserve.gov* (March 3, 2020). https://www.federalreserve.gov/monetarypolicy/files/monetary20200303a1.pdf

[12] Federal Reserve Press Release, *federalreserve.gov* (March 15, 2020). https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm

Q. By definition, a 'pandemic' is a global phenomenon affecting countries all over the world. Given the sudden onset of the Coronavirus pandemic, what is the outlook for the global economy?

A. In a newly issued mid-year report, the United Nations ("U.N.") now forecasts that "the COVID-19 pandemic will shrink the world economy by 3.2% this year, the sharpest contraction since the Great Depression in the 1930s." This outlook represents the U.N.'s best-case scenario; in its worst-case scenario, the U.N. believes the global economy could "shrink by 4.9% in 2020 if a second wave of COVID-19 infections flares up and lockdowns continue into the third quarter of the year." Additionally, the U.N. expects the Coronavirus "to slash global economic output by nearly $8.5 trillion over the next two years, wiping out nearly all gains of the last four years." It should be noted that in January 2020, prior to the onset of the COVID-19 pandemic, the U.N. had previously forecast a modest acceleration in global economic growth of 2.5% in 2020. According to U.N. chief economist Elliott Harris, however, the global economic outlook has "changed drastically" since then and "with the global economy ha[ving] come to a virtual standstill in the second quarter of 2020...we are now facing the grim reality of a severe recession of a magnitude not seen since the Great Depression."[13]

[13] "UN Forecasts Pandemic to Shrink World Economy by 3.2 Percent," Associated Press as reported in *nytimes.com* (May 13, 2020) https://www.nytimes.com/aponline/2020/05/13/world/bc-un-virus-outbreak-global-economy.html

Q. You noted above that in response to the economic weakness triggered by the Coronavirus pandemic the Fed lowered the federal funds rate to its ELB. As the nation's central bank, has the Fed taken additional steps to improve economic conditions?

A. Yes. In opening remarks at a recent Federal Reserve Press Conference,[14] Fed Chairman Mr. Jerome Powell summarized the additional monetary policy actions taken by the Fed in response to the Coronavirus pandemic:

> "To support the flow of credit to households and businesses, foster smooth market functioning, and promote effective transmission of monetary policy to broader financial conditions, we have been purchasing large amounts of Treasury and agency mortgage-backed securities. The markets for these securities play a critical role in the economy, and they came under great stress last month as the scale of economic disruption became clearer and as investors clamored for liquidity. Our purchases have helped market conditions improve substantially in recent weeks. In light of this improvement, we have slowed our pace of purchases. We will continue our purchases of Treasury and agency mortgage-backed securities as needed. While the primary purpose of these securities purchases is to preserve smooth market functioning and effective policy transmission, the purchases will also foster more accommodative financial conditioNs.
>
> We are also undertaking programs to provide stability to the financial system and to more directly support the flow of credit in the economy—for households, for businesses of all sizes, and for state and local governments. These programs benefit the economy by providing financing where it is not otherwise available. In addition, by serving as a backstop to key credit markets, the programs can improve market functioning by increasing the willingness of private lenders to extend credit. Many of these programs rely on emergency lending powers that are available only in very unusual circumstances, such as those we find ourselves in today. We are deploying these lending powers to an unprecedented extent, enabled in large part by the financial backing and support from Congress and the Treasury. We will continue to use these powers forcefully, proactively, and aggressively until we are confident that we are solidly on the road to recovery."

[14] "Transcript of Chair Powell's Press Conference," *federalreserve.gov* (April 29, 2020). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20200429.pdf

Q. Does Fed Chair Powell believe that the monetary policy action taken by the Fed will be sufficient to allow the US domestic economy to recover from the damage inflicted by the Coronavirus pandemic?

A. No, he does not. In remarks at the above referenced Press Conference, Fed Chair Powell emphasized that as a lending institution, the Fed was doing all it could to help American families and businesses weather this difficult period, but that only elected officials (i.e., Congress) having the power to tax and spend could provide the direct fiscal relief needed to ensure that the economy could recover without further long-term damage being done:

> "I would stress that these are lending powers, and not spending powers. The Fed cannot grant money to particular beneficiaries. We can only make loans to solvent entities with the expectation that the loans will be repaid. Many borrowers will benefit from our programs, as will the overall economy. But for many others, getting a loan that may be difficult to repay may not be the answer. In these cases, direct fiscal support may be needed. Elected officials have the power to tax and spend and to make decisions about where we, as a society, should direct our collective resources. The CARES Act [Coronavirus Aid, Relief, and Economic Security (CARES) Act] and other legislation provide direct help to people, businesses, and communities. This direct support can make a critical difference, not just in helping families and businesses in a time of need, but also in limiting long-lasting damage to our economy."[15]

To underscore this point, in response to a question posed to him at the Press Conference, Fed Chair Powell emphasized the importance of additional fiscal relief as follows:

> "This is the time to use the great fiscal power of the United States to do what we can to support the economy and try to get through this with as little damage to the longer run productive capacity of the economy as possible. The time will come, again, and reasonably

[15] Ibid.

> soon, I think, where we can think about a long-term way to get our fiscal house in order. And we absolutely need to do that. But this is not the time…in my personal view, this is not the time to let that concern, which is a very serious concern…get in the way of us winning this battle."[16]

Q. Does Fed Chair Powell express optimism for a rapid economic recovery?

A. No, I don't believe he does, for on April 29, 2020, the same day Mr. Kushner made the above prediction, Fed Chair Powell made the following statement, declaring the "depth and duration" of the economic downturn to be "*extraordinarily uncertain*" (emphasis added):

> "Both the depth and the duration of the economic downturn are extraordinarily uncertain and will depend in large part on how quickly the virus is brought under control. The severity of the downturn will also depend on the policy actions taken at all levels of government to cushion the blow and to support the recovery when the public health crisis passes."[17]

Pointing out that "many standard economic statistics have yet to catch up with the reality we are experiencing," Fed Chair Powell then cited to the following as evidence of the severe damage done to the U.S. economy by the Coronavirus pandemic:

> "Millions of workers are losing their jobs. Next week's jobs report is expected to show that the unemployment rate, which was at 50-year lows just two months ago, has surged into double-digits. Household spending has plummeted as people stay home, and measures of consumer sentiment have fallen precipitously. Hotels, airlines, restaurants, department stores, and other retailers have been particularly hard hit. Manufacturing output fell sharply in March and is likely to drop even more rapidly this month as many factories have temporarily closed. Overall, economic activity will likely drop at an

[16] Ibid.

[17] "Transcript of Chair Powell's Press Conference," *federalreserve.gov* (April 29, 2020). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20200429.pdf

> unprecedented rate in the second quarter. Inflation is also being held down, reflecting weaker demand as well as significantly lower energy prices."[18]

Q. The above quotation by Fed Chair Powell makes reference to 'consumer sentiment' and how it has fallen "precipitously." The University of Michigan regularly surveys American consumers and maintains a Consumer Sentiment Index ("CSI"), the results of which are published on a monthly basis. As measured by the CSI, what impact has the Coronavirus pandemic had on consumer sentiment in the U.S.?

A. The following are the University of Michigan's measures of consumer sentiment for the five month period, January 2020 – August 2020:[19]

2020	Index of Consumer Sentiment
January	99.8
February	101.0
March	89.1
April	71.8
May	72.3
June	78.1
July	72.5
August	74.1

As shown, prior to the onset of the Coronavirus pandemic, consumer sentiment began the year strong, increasing from a level of 99.8 in January to a level of 101.0 in February. However, with the onset of the pandemic consumer sentiment fell to a level of 89.1 in March, and plummeted to a level of 71.8 in April. It should be noted that the fall in the CSI from February (101.0) to March (89.1) represents "the

[18] Ibid.
[19] University of Michigan, Monthly Consumer Sentiment Index http://www.sca.isr.umich.edu/files/tbmics.pdf

fourth largest one-month decline in nearly a half century."[20] It should further be noted that the precipitous drop in the CSI from March (89.1) to April (71.8) is "the largest monthly decline ever recorded."[21]

Q. What conclusions can be drawn from the increase to the CSI in months May-August?

A. The increases suggest that consumer confidence remains highly tentative, for while the increase to the CSI in June (78.1) was higher than that for the month of May (72.3), those gains quickly disappeared in July (72.5), with the gain in August (74.1) once again being tentative. Thus, it appears the threats posed by the Coronavirus pandemic to both the public health and to the economy remain very much on the mind of consumers.

Q. Is consumer spending largely dependent upon the level of consumer sentiment?

A. Yes, it is. *Ceterus paribus*, holding all other factors constant, the higher the level of consumer sentiment, the higher the level of consumer spending, and *vice versa*.

[20] "U.S. Consumer Sentiment Falls the Most in Near 50 Years," *tradingeconomics.com* (March 27, 2020). https://tradingeconomics.com/united-states/consumer-confidence
[21] "U.S. Consumer Sentiment Falls at Record Pace," *tradingeconomics.com* (April 29, 2020). https://tradingeconomics.com/united-states/consumer-confidence

Q. Gross Domestic Product ("GDP") is a measure of the total value of goods produced and services provided in a country during one year.[22] Is GDP largely dependent upon the level of consumer spending?

A. Yes, because consumer spending "makes up about seventy percent of G.D.P."[23]

Q. As shown in Schedule JAC-6 (Page 2 of 6), Real (i.e., inflation adjusted) GDP growth declined by 5.0 percent in Q1 of 2020, and plummeted by 32.1 percent in Q2 of 2020. Is it reasonable to assume that much of the decline in Real GDP growth is attributable to the current weakness in consumer sentiment?

A. Yes.

Q. Is the U.S. economy currently in recession?

A. Yes, it is. By definition, a recession is "a period of temporary economic decline during which trade and industrial activity are reduced, generally identified by a fall in real (i.e., inflation adjusted) GDP in two successive quarters."[24] As noted above, and as shown in Schedule JAC-6 (Page 2 of 6), the two successive quarters of negative Real GDP growth in Q1 (5.0%) and Q2 (32.1%) of 2020 provide ample evidence that the U.S. economy is currently in recession.

---

[22] https://www.google.com/search?q=gross+domestic+product+definition&rlz=1C1GCEU_enUS893US893&oq=gross+domestic+product&aqs=chrome.1.69i57j0l7.15767j0j7&sourceid=chrome&ie=UTF-8

[23] Cassidy, John, "Who's Right about the Economy—Jared Kushner or the Chairman of the Federal Reserve?," *newyorker.com* (April 30, 2020). https://www.newyorker.com/news/our-columnists/whos-right-about-the-economy-jared-kushner-or-the-chairman-of-the-federal-reserve

[24] https://www.google.com/search?q=definition+of+a+recession&rlz=1C1GCEU_enUS893US893&oq=definition+of+a+&aqs=chrome.6.69i57j0l7.11991j1j7&sourceid=chrome&ie=UTF-8

Q. Has the Federal Reserve provided guidance to suggest that it plans to maintain an accommodative monetary policy going forward?

A. Yes, in a recent speech delivered by Federal Reserve Chairman Powell, it was announced that short-term interest rates will remain near zero at least through 2023. Thus, there is no reason to believe interest rates will be on the rise anytime soon.[25]

Q. Briefly describe the recent trends in economic conditions which preceded the onset of the Coronavirus pandemic and their impact on capital costs.

A. From the early 1980's through the end of 2007, the United States economy experienced a period of relative stability. This period was characterized by longer economic expansions, small contractions, low and/or declining inflation, and declining interest rates and other capital costs. However, in 2008 and 2009 the economy experienced a steep decline as a result of the subprime mortgage lending crisis and had a negative impact on the financial markets both in the U.S. and internationally. This economic decline is generally considered to be the worst financial crisis since the Great Depression, and is often referred to as, the 'Great Recession.' As a consequence, in 2008 central banks in the U.S. (i.e., the Federal Reserve Bank) and other foreign countries initiated accommodative monetary policies to stimulate economic growth and reduce unemployment in an effort to recover from this worldwide recession.

[25] Smialek, Jeanna, "Fed Pledges Low Rates for Years, and Until Inflation Picks Up," *nytimes.com* (September 16, 2020). https://www.nytimes.com/2020/09/16/business/economy/federal-reserve-interest-rates.html

The recession bottomed out in June 2009, with the national unemployment rate falling from a high of 9.6 percent in 2010 to a low of 3.7 percent in 2019, with the national unemployment rate in the fourth quarter of 2019 falling to a low of 3.5 percent.[26] At the State level, Arizona's unemployment rate has historically lagged that of the nation as a whole. As shown below, the State unemployment rate stood at 5.0 percent in Q1 2020, and more than doubled to a rate of 10.8 percent in Q2 2020. As of August 2020, Arizona's current unemployment rate stands at a preliminary 5.9 percent level, significantly lower than the 10.7 percent unemployment rate of July, 2020.[27]

2020	Arizona Unemployment Rate
January	4.5 %
February	4.5 %
March	6.1 %
Average Q1 2020	5.03 %
April	13.4 %
May	9.0 %
June	10.0 %
Average Q2 2020	10.8 %
July	10.7 %
August	5.9 % (P)

Q. Is there reason to believe that the current economic crisis brought on by the Coronavirus pandemic may be more severe than the economic decline brought on by the subprime mortgage lending crisis during the Great Recession of 2008 and 2009?

A. Yes. White House economic adviser, Mr. Kevin Hassett, recently (i.e., Sunday, April 26, 2020) appeared on ABC's, "This Week," and made the following

[26] *See* Schedule JAC-6 (Pages 1 and 2).
[27] U.S. Bureau of Labor Statistics. http://data.bls.gov/timeseries/LASST040000000000003

observation about the economic impact the Coronavirus pandemic is having on the U.S. economy:

> "This is the biggest negative shock that our economy, I think, has ever seen. We're going to be looking at an unemployment rate that approaches rates that we saw during the Great Depression," Hassett told ABC's "This Week." "During the Great Recession of 2008-2009… we lost [a total of] 8.7 million jobs. Right now, we're losing that many jobs about every 10 days."[28]

Fortunately, the rate of job loss has slowed from the levels seen in the month of April, 2020.

Q. Please describe how the economic and financial indicators were examined and how they relate generally to the cost of capital.

A. Schedules JAC-6 (Pages 1 and 2) present relevant economic data such as Real GDP Growth, Industrial Production Growth, Unemployment, Consumer Price Index ("CPI"), and Producer Price Index. As shown, 2007 marked the sixth year of economic expansion, but beginning in 2008 the economy entered into a significant decline, as indicated by negative real GDP and industrial production growth, as well as an increase in the unemployment rate. Since 2010 the economy has rebounded, with overall economic growth advancing at a slower pace than that of prior expansions following an economic downturn. Inflation, as measured by the CPI, has generally been declining over the past several business cycles. Since 2008, annual inflation has been 3.0 percent or lower, with average inflation being 1.76 percent over the 10-year period, 2010-2019,[29] and 1.82 percent over the most

[28] Davis, Richard and Bohn, Kevin, "White House Economic Advisers Express Contradictory Tones on Economic Impact of Coronavirus," *cnn.com* (April 26, 2020). https://www.cnn.com/2020/04/26/politics/coronavirus-economic-impact-kevin-hassett/index.html

[29] Schedule JAC-6 (Page 1) – average of CPI values shown for 10-year period, 2010-2019.

recent 5-year period, 2015-2019.[30] Thus, inflation continues to remain at the lowest levels experienced in the past 40+ years, and is indicative of lower capital costs.

Q. Is inflation expected to remain low over the next 10 years?

A. Yes. The 10-year breakeven inflation rate is a market-based measure of investor expectations of inflation over the next 10-years, computed as the difference between the current nominal yield on the 10-year Treasury Note and the current real (i.e., inflation adjusted) rate on the 10-year Treasury Inflation-Indexed Constant Maturity Securities, or TIPS. Below is the current 10-year breakeven inflation rate, measured as (i) a 3-month average (June - August, 2020), and (ii) the current spot 10-year breakeven inflation rate, measured as the close-of-market on September 11, 2020:[31]

	3-Mo. Avg. (June – Aug. 2020)	Current Spot Rate (Sept. 11, 2020)
10-Year Yield - Nominal	0.67 %	0.67 %
10-Year Yield – Real	-<0.79>%	- <0.98>%
10-Year Breakeven Inflation	**1.46** %	**1.65** %

As shown, both the 3-month average (1.46 percent) and current spot (1.65 percent) measures of 10-year projected breakeven inflation are well below the 2.0 percent rate of inflation targeted by the Fed, and as such both are suggestive of continued low inflation going forward.

[30] Schedule JAC-6 (Page 1) – average of CPI values shown for 5-year period, 2015-2019.
[31] U.S. Department of the Treasury, Daily Interest Rates. https://home.treasury.gov/policy-issues/financing-the-government/interest-rate-statistics

Q. How do the above (i) 1.46 percent (3-mo average) and (ii) 1.65 percent (current spot) projections of breakeven inflation compare to average 10-year historical inflation over the past forty years (i.e., 1980-2019)?

A. Based on the annual rates of inflation as presented in Schedule JAC-6 (Page 1), average inflation measured over a 10-year historical period going back to 1980 is as follows:

Historical 10-year inflation (1980-1989)	5.11 %
Historical 10-year inflation (1990-1999)	2.93 %
Historical 10-year inflation (2000-2009)	2.54 %
Historical 10-year inflation (2010-2019)	1.76 %
Projected 10-year inflation (2020-2029)	1.46 % - 1.65 %

As can be seen, inflation has fallen in each of the last four 10-year historical periods, with average inflation over the most recent 10-year period (i.e., 2010-2019) being 1.76 percent. Thus, based on the recent 3-month average (1.46 percent) and current spot (1.65 percent) 10-year breakeven estimates, 10-year inflation over the period 2020-2029 is not only expected to continue to fall, but to levels not previously seen at any time during the last 40 years, 1980-2019.

Q. What has been the trend in interest rates over the forty-five year period, 1975-2019?

A. As shown in Schedule JAC-6 (Pages 3 – 4), interest rates rose sharply to record levels during the period, 1975-1981, when inflation was high and generally rising. Interest rates declined substantially, as did inflation, during the remainder of the 1980s and throughout the 1990s. Interest rates declined further during the period 2000-2005, and after trending slightly upward in 2006-2008, continued on a downward path reaching levels in years 2009-2016 not previously seen since the early 1960s. In 2008, the Fed initiated an accommodative monetary policy by

lowering the federal funds rate, and in an effort to promote increased lending and liquidity, eventually initiated a policy of quantitative easing, an unconventional monetary policy used when short-term interest rates are at or approaching zero. As a consequence, in 2012-2016, both U.S. and corporate bond yields declined to their lowest levels in more than 40 years, with the yield on the benchmark 10-year Treasury Note falling to an all-time low in July 2016.[32] Beginning in December 2015, the Fed initiated a policy of gradually raising the federal funds rate, but through the end of 2018 long-term interest rates continued to remain at levels below those of 2010 and earlier.

Q. The above discussion addresses the path of interest rates through the end of 2018. What was the path of interest rates in 2019, the year immediately preceding the onset of the Coronavirus pandemic?

A. Interest rates, both short-, intermediate-, and long-term, fell significantly in 2019 relative to levels in 2018. To demonstrate just how significant this fall was, RUCO has prepared an Exhibit which presents monthly average yields on 5-, 7-, 10-, 20-, and 30-year U.S. Treasury securities, as well as Moody's Aa-, A-, and Baa-rated utility bonds covering the period, November 2018 – August 2020. As shown in RUCO Exhibit JAC-A, yields on each of these debt securities began to fall in December, 2018, well before the onset of the Coronavirus pandemic in March 2020.

[32] On July 5, 2016, on an intra-day basis the 10-year Treasury Note traded at an all-time low of 1.357 percent. http://www.wsj.com/articles/government-bond-yields-in-u-s-europe-hit-hertoric-lows-1467731411

Q. The yield on the benchmark 10-year Treasury hit an all-time low in July 2016. Do investors anticipate this previous low will soon be re-tested?

A. Yes, for the reasons noted below investors do anticipate new all-time lows for the 10-year Treasury Note:

> "The 10-year Treasury yield's slide has left a scorched path in its wake as bond-market forecasters struggle to make sense of its precipitous drop. Investors now say the 10-year Treasury yield only has one more psychological level to breach before it makes history — its all-time low of 1.32% established in mid-2016. The general consensus isn't will we see fresh record lows on the 10-year Treasury yield, but how soon will it happen," wrote Edward Moya, senior market analyst for OANDA, in a Thursday note.[33]

Q. Since the onset of the Coronavirus pandemic, has the yield on the 10-year Treasury Bond established a new all-time low?

A. Yes, in market trading on February 25, 2020, the yield on the 10-year Treasury Bond fell to a level of 1.31 percent."[34] Since that time, as shown in RUCO Exhibit JAC-A, the yield on the 10-year Treasury Bond has remained below 1.00 percent in each of the last six months, March – August, 2020.

Q. As shown in RUCO Exhibit JAC-A, yields on 30-year Treasury Bonds have also fallen significantly in 2019. Did the 30-year Treasury yield establish a new all-time low in 2019?

A. Yes, as evidenced by the following:

---

[33] Oh, Sunny, "All-time Low Stands as Last Hurdle for 10-year Treasury Yield Plunge," *marketwatch.com* (September 3, 2019). https://www.marketwatch.com/story/heres-the-last-hurdle-for-the-10-year-treasury-yields-spectacular-plunge-2019-08-29

[34] Oh, Sunny, "10-year U.S. Treasury Yield Falls to all-time Low as Stocks take a Beating," *marketwatch.com* (February 25, 2020). https://www.marketwatch.com/story/treasury-market-takes-a-breather-from-relentless-rally-stopping-short-of-record-2020-02-25

> "On Friday, the yield on a 30-year Treasury bond briefly dropped below 2% for the second time in history. The first was on Thursday."[35]

Q. Going forward, do investors expect yields on the 30-year Treasury Bond to retest their lows of August 2019?

A. Yes, and to many investors the downward trend is seen as the "end of the American Dream," one predicated on the idea that "ongoing growth will create social mobility and let your children do better than you." To this point, Lisa Shalett, chief investment officer for Morgan Stanley Wealth Management, makes the following observation:

> "We can talk about things that are technically influencing it, but the trend line is an extraordinarily sad and depressing state of affairs."[36]

A review of RUCO Exhibit JAC-A shows the 30-year Treasury yield has remained below 2.0 for the 7-month period, February – August, 2020.

Q. Is the decline in long-term interest rates since the mid-1980s something which the financial markets and professional forecasters saw coming and accurately predicted?

A. No, it is not. As reported in a study prepared by the Council of Economic Advisors,[37] "forecasters largely missed the secular decline of the last three decades" because "past forecasts of long-term nominal interest rates have tended to err on the side of mean reversion."[38] As evidence of such mean reversion, the authors of the study

---

[35] "Sherman, Erik, "Plunge in 30-Year Treasury Bond Yields Spells the End of America's Golden Age, to Some," *fortune.com* (August 16, 2019) https://fortune.com/2019/08/16/30-year-treasurys-plunge/
[36] *Ibid*.
[37] Executive Office of the President, Council of Economic Advisors, "Long-Term Interest Rates: A Survey," (July 2015), p. 11.
https://obamawhitehouse.archives.gov/sites/default/files/docs/interest_rate_report_final.pdf
[38] *Ibid*., p. 12.

prepared a graphic presentation (10-Year Treasury Rates and Historical Economist Forecasts) showing that forecasts made by a group of more than 50 private-sector economists of the benchmark 10-year Treasury rate, as reported by *Blue Chip Economic Indicators* ("*Blue Chip*"), had systematically been overstated. This graphic presentation is provided as RUCO Exhibit JAC-B. As shown, *Blue Chip* forecasts have consistently exceeded the actual path of nominal 10-year Treasury rates since 1995, and supports a conclusion that forecasters mistakenly believed the yield on the 10-year Treasury Note would—during the period(s) under study—revert back to a perceived historical mean. In the study, the authors further note the following:

> "Although economists' forecasts steadily declined after 1995, their pace of decline has lagged well behind the realized drop-off in interest rates. Indeed, since 1996, long-range private sector forecasts have exhibited a root mean square error of 2.7 percentage points relative to the nominal Treasury rate realized 10 years later."[39]

Q. What conclusions do the authors of the study to which you cite above draw regarding the decline in long-term interest rates?

A. As noted in the Executive Summary of the report, the authors state the following:

This report surveys the recent thinking on the many drivers of long-term interest rates in recent decades and going forward. It concludes:

1. **The decline in long-term interest rates over the past thirty years was real, global, and unexpected.** While lower inflation explains some of the decline in nominal interest rates, the downtrend is evident even when adjusting nominal interest rates for the rate of inflation. The decline has also

[39] *Ibid.*, p. 10. In a footnote, the authors describe the "root mean square error" as follows: "The root mean square error is a commonly used measure of the deviation between predicted and actual values. The difference between the two values is squared and then summed over time. The square root of that number is typically reported as a summary statistic, with large values indicating large prediction errors."

been evident across a wide range of countries, reflecting the increasing integration of the global economy. Financial markets and professional forecasters alike consistently failed to predict the secular shift, focusing too much on cyclical factors and missing the long-term trend.

2. **The decline is consistent with several theoretical frameworks economists have used to analyze interest rates.** The interest rate settles at the level that equates the supply of saving with the demand for investment, and innumerable factors affect both sides of the equation. Many frameworks suggest that long-term interest rates are closely related to productivity growth. Other factors such as the rate of population growth and technological advance, as well as aggregate demand and the stance of fiscal and monetary policy, also play a role.

3. **A number of factors, both transitory and longer-lived, have contributed to the decline—with many of these factors suggesting that long-run equilibrium interest rates have fallen.** Transitory factors include global fiscal and monetary policies, shifts in the term premium and inflation risk, and post-crisis private-sector deleveraging. More persistent factors include lower potential output and productivity growth, shifting demographics, and the global "saving glut."

4. Ultimately, **interest rates reflect underlying macroeconomic conditions**; there is no "optimal" long-term rate of interest. Rather, policy should support long-run growth, maintain price stability, and support a stable financial system.[40] (emphasis added)

Q. Has the secular decline in long-term interest rates, which has taken place over the last 30 years, proven beneficial to equity investors in the United States?

A. Yes. In a recent report published by McKinsey & Company,[41] the 30-year period, 1985-2014, was characterized as the "*golden era for investment returns*," as real (i.e., inflation adjusted) total returns on equities averaged 7.9 percent in the United States over this period, a figure 140 basis points higher than the 6.5 percent 100 year average, and 220 basis points higher than the 5.7 percent 50 year average

[40] *Ibid*., Executive Summary, p. 4.

[41] McKinsey Global Institute, "Diminishing Returns: Why Investors May Need to Lower their Expectations," May 2016. www.mckinsey.com/industries/.../why-investors-may-need-to-lower-their-sights

(emphasis added).[42] As noted in the report, the underpinnings of these above average equity returns were made possible by the confluence of the following four exceptional factors:

(i) A sharp decline in inflation from the unusually high levels of the late 1970s and early 1980s;
(ii) The resultant decline in nominal long-term interest rates,
(iii) Strong global GDP growth, lifted by positive demographics, productivity gains, and rapid growth in China; and
(iv) Even stronger corporate profit growth, reflecting revenue growth from new markets, declining corporate taxes, and advances in automation and global supply chains that contained costs.[43]

Q. Over this same 1985-2014 time period, did bond investors also achieve higher real returns on fixed-income investments?

A. Yes. As measured by returns on 10-year U.S. Treasury Bonds, fixed income investors achieved total real returns of 5.0 percent over the 30-year period, 1985-2014, a figure 330 basis points higher than the 1.7 percent 100 year average, and 250 basis points higher than the 2.5 percent 50 year average.[44]

Q. Going forward, does the McKinsey report anticipate this 'golden era' for investment returns to continue?

A. No. In fact, the purpose of the report was to place investors on notice that on a going-forward basis they should begin to lower their expectations regarding investment returns on both equity and debt securities, as "[t]his era is coming to an end."[45] Based upon its analysis, the McKinsey report lays out two scenarios as to

---

[42] *Ibid*., p. 2. As noted in the report, over the same 30-year period Western European investors also achieved real total returns on equity of 7.9 percent, a figure 300 basis points higher than the 4.9 percent 100 year average.
[43] *Ibid*., pp. 10-16.
[44] *Ibid*., pp. 2-3. As further noted in the report (p. 11), capital gains accounted for fully 1.9 percent (190 basis points) of their 5.0 percent real total return, as nominal interest rates fell from 9 percent to 2 percent.
[45] *Ibid*., p. 3.

what investors might expect over the 20-year period, 2016-2035; Scenario 1 being a *slow growth* scenario, and Scenario 2 being a *growth recovery* scenario. In the report, McKinsey points out that in both its *slow growth* and *growth recovery* scenarios, "U.S. and Western European equity and bond returns fail to match those of the past 30 years and could be lower than the 50- and 100-year averages."[46] Furthermore, under Scenario 1 "slow growth could reduce total U.S. equity returns by more than 250 basis points and bond returns[47] by 400 basis points or more below the 1985-2014 period (emphasis added)."[48] Under Scenario 2, "in a growth-recovery scenario, U.S. equity and bond returns would be 140-240 and 300-400 basis points, respectively, below the average of the 1985-2014 period."[49] As presented in the McKinsey report, the following is a summary of both historical real total investment returns on equities and 10-year U.S. Treasury Bonds over the 100-year period, 1915-2014, the 50-year period, 1965-2014, and the 30-year period, 1985-2014, as contrasted with the expected investment returns over the 20-year period, 2016-2035, under each of the above noted scenarios:[50]

Historical and Projected Investment Returns on U.S. Equities and 10-Year Treasury Bonds

	Historical Returns			Prospective Returns (2016-2035	
Investment	**1915-2014**	**1965-2014**	**1985-2014**	**Slow Growth**	**Growth Recovery**
U.S. Equities	6.5%	5.7%	7.9%	4.0-5.0%	5.5-6.5%
10-Year Treasuries	1.7%	2.5%	5.0%	0-1.0%	1.0-2.0%

[46] *Ibid.*, p. 21.
[47] For purposes of its analysis, investment returns on bonds are measured by the return on 10-year U.S. Treasury Bonds.
[48] *Ibid.*
[49] *Ibid.*, p. 22.
[50] *Ibid.*, p. 2, Exhibit 1.

Q. Briefly discuss the reasons cited in the McKinsey report for the expected decline in investment returns on equity and debt securities over the 20-year period, 2016-2035.

A. As noted earlier, the McKinsey report attributed the on-set of the so-called 'golden era' of investment returns to the confluence of four exceptional factors. The authors now view the fundamental economic and business conditions which contributed to above-average returns over the past 30 years to "have run out of steam, and in some cases are in the process of reversing."[51] Specifically, the report cites to the following three contributing factors as reasons for the expected decline in investment returns going forward:

1. the steep decline in interest rates over the past 30 years is unlikely to be repeated,
2. expected slower GDP growth, due to (i) an aging population and (ii) declining productivity growth, and
3. lower profit margins for businesses facing greater competition from (i) emerging markets, (ii) technology and tech-enabled firms, and (iii) small and medium-sized enterprises.[52]

Q. For purposes of its analysis the findings of the McKinsey report are based on aggregate returns of non-financial companies included in the Standard & Poor's 500 ("S&P 500").[53] Is the S&P 500 Index considered to be a proxy for the overall market, and if so why?

A. Yes, the S&P 500 Index is a broad proxy of the stock market, as it is based on a market capitalization of the 500 largest companies traded on the NYSE and NASDAQ stock exchanges. The S&P 500 Index is widely regarded as the best gauge of large-cap U.S. equities, and most agree that it is a better proxy than the

[51] *Ibid.*, p. 17.
[52] *Ibid.*, pp. 17-19.
[53] *Ibid.*, p. 5.

Dow Jones Industrial Average ("DJIA"), which arbitrarily uses nominal share prices to calculate the index value. It should be noted that among the 500 companies which currently comprise the S&P 500, 27 are regulated public utilities.[54]

Q. Is Pinnacle West Corporation, the holding company parent of APS, included in the S&P 500?

A. Yes. Pinnacle West was added to the S&P 500 effective October 1, 1999.[55]

Q. Based on the conclusions of the McKinsey report, is it reasonable to assume that equity investment returns for regulated public utilities might also be expected to decline on a going-forward basis?

A. Yes, as a broad based decline in investment returns would bring about a reduction in the opportunity cost of capital, or the expected return on alternative investment opportunities.

V. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the Company's proposed capital structure?

A. APS proposes a capital structure comprised of 45.33 percent long-term debt and 54.67 percent common equity.

Q. What is APS's proposed cost of debt?

A. As shown in Schedules D-1 and D-2, the Company proposes a cost of debt of 4.10 percent.

---

[54] https://en.wikipedia.org/wiki/List_of_S%26P_500_companies

[55] As noted in a news release, on October 1, 1999 trading volume of Pinnacle West stock exceeded five million shares compared to an historical average of 213,000 shares. http://www.pinnaclewest.com/newsroom/company-news/news-release-details/1999/Pinnacle-West-Added-to-SP-500-Index/default.aspx

Q. What cost of debt does RUCO recommend in this proceeding?

A. For purposes of its analysis, RUCO adopts the Company's proposed 4.10 percent cost of debt.

VI. SELECTION OF PROXY GROUP

Q. Was RUCO able to directly estimate APS's cost of common equity?

A. No. APS's common stock is not publicly-traded, and for this reason it is not possible to directly estimate the cost of the Company's common equity. Thus, RUCO employed a proxy group of publicly-traded electric utility companies to indirectly estimate the Company's cost of equity utilizing financial market data available for each sample company.

Q. What publicly-traded electric utility companies have RUCO selected for inclusion in its proxy group?

A. RUCO's proxy group consists of the following twelve (12) publicly-traded electric utility companies:

Company	Ticker
ALLETE, Inc.	ALE
Ameren Corporation	AEE
American Electric Power Company	AEP
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Exelon Corporation	EXC
Evergy, Inc.	EVRG
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
PNM Resources, Inc.	PNM
Southern Company	SO
Xcel Energy, Inc.	XEL

RUCO's proxy group of 12 companies are among the 39 publicly-traded electric utility companies followed by the *Value Line Investment Survey* ("*Value Line*"), and are included among the fourteen (14) companies comprising the proxy group employed by the Company's witness, Ms. Ann E. Bulkley. Attachment I contains the most recent *Value Line* quarterly update for each of RUCO's twelve proxy companies.

Q. For purposes of her analysis, what proxy group does the Company's cost of capital witness employ?

A. The company's witness, Ms. Bulkley, employs a proxy group of fourteen (14) companies; they include the above noted 12 companies included in RUCO's proxy group, plus the following two additional companies:

Company	Ticker
FirstEnergy Corporation	FE
PPL Corporation	PPL

Q. For ratemaking purposes in this proceeding, does RUCO believe inclusion of the above two companies in Ms. Bulkley's proxy group is appropriate?

A. No, as neither FirstEnergy Corporation ("FE") nor PPL Corporation ("PPL") are representative of companies within the domestic electric utility industry.

Q. Please explain why inclusion of FE in Ms. Bulkley's proxy group of companies is inappropriate.

A. As noted in its most recent quarterly update for FE,[56] recent legal developments have prompted *Value Line* to advise investors to "steer clear" of FE common stock, stating that FE's stock price "plummeted after five people, including the speaker of

[56] *Value Line Investment Survey*, Ratings & Reports (August 14, 2020).

the Ohio House of Representatives, were arrested on federal bribery charges," and the federal government plans to investigate the company's role in the alleged bribery. For the full-year, FE common stock has lost 40.0 percent of its value, and its dividend yield is "more than a percentage point above the utility average." Given these developments, *Value Line* considers FE common stock "suitable only for aggressive accounts stressing income."

Q. You note above that the dividend yield on FE common stock exceeds the electric utility average by 'more than a percentage point.' Does the dividend yield on PPL common stock exceed the electric utility average?

A. Yes. In its most recent quarterly update for PPL,[57] *Value Line* begins its discussion of the Company by stating that "[t]he dividend yield of PPL Corporation stock is *more than two percentage points* above the average for electric utility issues" (emphasis added).

Q. Is it reasonable to conclude that an electric utility company whose common stock dividend yield exceeds that of the industry average by more than two percentage points (i.e., 200+ basis points) is "representative" of companies within the electric utility industry?

A. No, it is not, and for that reason it is inappropriate for Ms. Bulkley to include PPL in her proxy group of companies.

[57] *Value Line Investment Survey*, Ratings & Reports (August 14, 2020).

Q. Is there an additional reason why PPL should not be included in Ms. Bulkley's proxy group of companies?

A. Yes. In a recent News Release,[58] PPL announced that it was initiating a formal process "to sell its United Kingdom ("U.K.") utility business in order to position PPL as a purely U.S.-focused utility holding company." In the News Release, Mr. Vincent Sorgi, PPL President and CEO stated:

> "We believe there is an opportunity to unlock significant value for PPL shareowners through the sale of Western Power Distribution (WPD) and the strategic repositioning of PPL's portfolio to be fully U.S.-based.
>
> WPD is a very strong business that continues to perform exceptionally well as the premier distribution network operator (DNO) group in the U.K., but we believe it continues to be undervalued by the market as part of PPL. We believe that greater value can be achieved for PPL shareowners through a sale of the U.K. business and use of proceeds that would be focused on strengthening PPL's balance sheet and enhancing the company's long-term earnings growth, which could include supporting strategic growth opportunities in the U.S. and returning capital to shareowners.
>
> Ultimately, we believe the divestment of WPD will simplify PPL's business mix, provide the company greater financial flexibility and create a sharpened focus on building tomorrow's energy infrastructure and advancing a cleaner energy future in the U.S."

[58] "PPL Corporation Launches Process to Sell U.K. Business, Reposition Itself as a U.S.-Focused Utility Company," *pplweb.mediaroom.com* (August 10, 2020). https://pplweb.mediaroom.com/2020-08-10-PPL-Corporation-Launches-Process-to-Sell-U-K-Business-Reposition-Itself-as-U-S-Focused-Utility-Company

Q. As noted, PPL plans to divest itself of its Western Power Distribution ("WPD") subsidiary, a distribution network operator ("DNO") group in the U. K. Does the WPD subsidiary represent a significant portion of PPL's electric utility operations?

A. Yes. In the News Release announcing the planned divestiture, PPL states that WPD "serves about 8 million customers in central and southwest England and south Wales." However, PPL's domestic U.S. operations appear to serve approximately only 2 million customers, for as noted in the News Release "PPL's seven high-performing, award-winning utilities serve more than 10 million customers in the U.S. and United Kingdom" (10 million – 8 million = 2 million). Thus, PPL's WPD subsidiary serves approximately 80.0 percent of PPL's customer base, while its domestic U.S. operations account for approximately 20.0 percent of PPL's customer base.

Q. Does an announcement by a publicly-traded utility company that it plans to divest itself of a subsidiary have the potential to alter investor behavior and market trading of the Company's common shares?

A. Yes, for if the divestiture is perceived to be favorable to the company, investors will bid up the market price of the company's common shares causing the dividend yield to fall. In the alternative, if the divestiture is perceived to be unfavorable, investors will sell their common shares, causing the market price to fall and the dividend yield to rise. For this reason, inclusion of a utility company making such an

announcement in a proxy group of companies deemed to be "representative" of the industry is improper.

Q. Would this be all the more true if the operations being divested represented 80.0 percent of a publicly-traded company's customer base?

A. Yes.

Q. In direct testimony,[59] the screening criteria employed by Ms. Bulkley in the selection of her proxy group includes consideration of whether a company has been "party to a merger or other transformative transaction." Does RUCO believe PPL's announced divestiture of its GDP subsidiary meets this criterion?

A. Yes, as the divestiture of 80.0 percent of its customer base would certainly be "transformative" to PPL.

Q. Has RUCO prepared an Exhibit which demonstrates that in addition to PPL's announced divestiture of its U.K. subsidiary there are other factors which warrant exclusion of PPL from Ms. Bulkley's proxy group?

A. Yes. Exhibit JAC-C presents a comparison of the DCF, CAPM and CE cost of equity results obtained from RUCO's proxy group of 12 companies with those obtained for PPL and FE. As shown, in the results obtained from RUCO's DCF analyses PPL's 6.13 percent expected dividend yield far exceeds RUCO's sample

[59] Bulkley Direct, pp. 31-32.

average 3.79 percent dividend yield (6.13% - 3.79% = 2.35%), while the results obtained from RUCO's CAPM analyses demonstrate that PPL's 1.10 beta coefficient exceeds that of both the market (i.e., 1.0) and RUCO's sample average 0.89 beta (1.10 – 0.89 = 0.21). Taken in isolation, these metrics are sufficient to conclude that PPL is not representative of the water utility industry. However, consideration of the results obtained from RUCO's CE analyses settles the matter. As shown, PPL's 15.60 percent 5-year historical ROE far exceeds the 9.30 percent historical sample average ROE (15.60% - 9.30% = 6.30)%, while PPL's 13.00 percent 5-year projected ROE far exceeds the 9.70 percent 5-year sample average projected ROE (13.00 – 9.70% = 3.30).

Q. Does the analysis presented in RUCO Exhibit JAC-C relating to FE further support a conclusion that FE, likewise, is not representative of the electric utility industry?

A. Yes. As shown in RUCO Exhibit JAC-C, the DCF, CAPM, and CE cost of capital metrics for FE are presented on Line 2, and the extent to which they exceed RUCO's sample average estimates is presented on Line 5. As shown, with the exception of the beta coefficient in the CAPM, a comparison of the DCF and CE metrics for FE clearly demonstrate that FE is not representative of the electric utility industry.

VII. DCF ANALYSIS

Q. What is the theory and methodological basis of the DCF model?

A. The DCF model is one of the oldest and most commonly used models for estimating the ROE for public utilities, and the only model which intrinsically takes into consideration the price investors are willing to pay for a given unit of return. The DCF is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate (the "constant growth" or "Gordon DCF model"). In this framework, the ROE is derived from the following formula:

$$K = \frac{D_0}{P_0} + g$$

Where: P_0 = current price

D_0 = current dividend rate

K = discount rate (cost of capital)

g = constant rate of expected growth

This formula essentially recognizes that the return expected, or required, by investors consists of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how RUCO employed the DCF model.

A. For purposes of its analysis, RUCO employs the constant growth DCF model. In doing so, RUCO combines the current dividend yield (D_0/P_0) for each proxy group company with several indicators of expected dividend growth to compute the expected dividend yield. The expected dividend yield (D_1/P_0) represents the anticipated dividend yield 12 months hence based upon the current (P_0) stock price.

Q. How did RUCO derive the expected dividend yield (D_1/P_0) component of the DCF equation?

A. Several different methods may be used to compute the expected dividend yield component. For purposes of its analysis RUCO employs the Gordon quarterly compounding method to compute the expected dividend yield component, as it gives recognition to the timing of dividend payments and dividend increases. The Gordon quarterly compounding method is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

The current (P_0) stock price in RUCO's yield calculation represents the average of the high and low stock price for each proxy company for the most recent three month period (June - August, 2020). The current (D_0) dividend is the indicated annualized dividend rate for each proxy company.

Q. How does RUCO estimate the dividend growth (g) component of the DCF equation?

A. In estimating the dividend growth rate in its DCF analysis, RUCO gives consideration to the following five indicators of growth:

1. Five-year average (2015-2019) earnings retention (i.e., fundamental) growth, as reported by *Value Line*;

2. Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS), as reported by *Value Line*;

3. Five-year projections of earnings retention growth in years 2020, 2021 and 2023-2025, as reported by *Value Line*;

4. Five-year projections of EPS, DPS, and BVPS as measured in years 2017-2019 to 2023-2025, as reported by *Value Line*; and,

5. Five - year projections of EPS growth, as reported by Yahoo Finance.

RUCO believes this combination of growth indicators to be a representative and appropriate set with which to estimate investor expectations of dividend growth for its proxy group of sample companies, as each is a determinant of dividend growth. Additionally, these growth indicators are reflective of the types of information that investors normally take into consideration when making an investment decision.

Q. Please describe RUCO's DCF calculations.

A. RUCO's DCF analysis is presented in Schedule JAC-3, Pages 1 through 4. Page 1 presents the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Page 2 presents historical and projected per share growth rates (i.e., EPS, DPS, and BVPS) for each proxy company. Page 3 presents historical and projected earnings retention (i.e., fundamental) growth rates for RUCO's proxy companies. Page 4 presents RUCO's DCF calculations, which are shown on several bases: mean / composite mean, and median / composite median. RUCO's DCF results can be summarized as follows:

	Mean	Median	Mean Low[60]	Mean High[61]	Median Low[62]	Median High[63]
Proxy Group	7.99 %	7.93 %	6.98 %	9.33 %	7.06 %	9.58 %

Q. What does RUCO conclude from its DCF cost of equity estimation analyses?

A. The DCF estimates obtained for RUCO's proxy group of companies fall into a range between 6.98 percent and 9.58 percent, with both the sample average mean and median estimates approximating 8.00 percent. On a composite mean and median basis, the highest DCF estimates are 9.33 percent and 9.58 percent, both of which were obtained from measures of projected earnings per share growth for RUCO's sample companies. RUCO concludes that the DCF derived cost of equity for its proxy group lies within the range, 8.00 percent to 9.50 percent. Given the current capital market environment, RUCO concludes that the mid-point of this range, 8.75 percent ((9.50% + 8.00%) / 2 = 8.75%), represents the current DCF-derived cost of equity for the proxy group. Accordingly, RUCO recommends a DCF-derived cost of equity of 8.75 percent for APS.

VIII. CAPM ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returNs. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return.[64]

[60] Reflects the single lowest average growth rate.
[61] Reflects the single highest average growth rate.
[62] Reflects the single lowest median growth rate.
[63] Reflects the single highest median growth rate.
[64] The CAPM makes the following assumptions: 1) single holding period; 2) perfect and competitive securities market; 3) no transaction costs; 4) no restrictions on short selling or borrowing; 5) the existence of a risk-free rate; and 6) homogeneous expectations.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta (R_m - R_f)$$

Where: K = *cost of equity*

R_f = *risk free rate*

R_m = *return on market*

β = *beta*

$R_m - R_f$ = *market risk premium*

The CAPM is a variant of the Risk Premium ("RP") method. They differ in the sense that the CAPM specifically recognizes the risk (i.e., beta) of a particular company or industry, whereas the simple RP method assumes the same ROE for all companies exhibiting similar bond ratings or other characteristics.

Q. Please identify the strengths of using the CAPM in a cost of equity estimation analysis.

A. The CAPM is cited as having the following strengths: (1) it is based on the concept of risk and return; (2) it is company specific as it relates to the specific beta's within the industry; (3) it has widespread use as it recognizes that investors can and do diversify; (4) it is highly structured and easy to apply when using the assumptions of the model; (5) the model is formulistic and the data used in the computations is readily available; (6) it is a forward looking concept; and (7) it is a method for converting changes in interest rates to the cost of equity.

Q. What risk-free (R_f) rate does RUCO use in its CAPM analysis?

A. For purposes of its CAPM analysis, RUCO employs a risk-free rate of 1.16 percent. RUCO's risk-free rate represents the 3-month average yield on the 20-year long-term U.S. Treasury Bond, measured over the 3-month period, June – August 2020. The computation of RUCO's 1.16 percent risk-free rate is presented in Schedule JAC-4, Page 1.

Q. Is it customary to use the yield on U.S. Treasury securities as the risk-free (R_f) rate in the CAPM?

A. Yes, because debt securities issued by the United States Department of the Treasury are considered to be free of default risk. Two general types of U.S. Treasury securities are most often used as the risk-free *(R_f)* rate component; short-term (i.e., 90-day) U.S. Treasury bills, and long-term U.S. Treasury bonds. RUCO employs yields on 20-year U.S. Treasury bonds since this matches the long-term investment perspective of ROE analyses.

Q. Did RUCO consider use of a forecasted long-term Treasury bond rate as the risk-free (R_f) rate in its CAPM analysis?

A. No. The appropriate interest rate to be used in the CAPM is the current rate borne by investors in the marketplace. The current rate is known and measurable, and thus reflects investors' current collective assessment of all capital market conditions. In contrast, prospective interest rates are neither measurable nor achievable; thus, they are speculative.

Q. How does the 1.16 percent risk-free (R_f) rate employed in RUCO's CAPM analyses compare to the risk-free rate used by the Company's witness, Ms. Bulkley, in her CAPM analyses?

A. For purposes of her CAPM analyses Ms. Bulkley employs three different risk-free rates, all of which are measures of the yield on the 30-year Treasury bond: (i) a current 2.57 percent rate, measured over a 30-day period; (ii) a 2.66 percent rate based on *Blue Chip* forecasts covering the period, Q4 2019 – Q4 2020; and (iii) a 3.60 percent *Blue Chip* forecast covering the 5-year period, 2021-2025.[65] Because RUCO's 1.16 percent risk-free rate is based on the 20-year Treasury yield (i.e., 3-month average yield, June - August 2020), a direct comparison is not possible. A proper comparison requires the computation of a current 3-month average yield on the 30-year Treasury bond measured over this same period.

As shown below, the current 3-month average yield on the 30-year Treasury Bond is 1.39 percent:

	30-Year Treasury Yield
June	1.49 %
July	1.31 %
August	1.36 %
3-Month Average	1.39 %

Thus, the overstatement to the three risk-free rates employed in Ms. Bulkley's CAPM analyses above the current 1.39 percent 3-month average yield on the 30-year Treasury bond are as follows:

[65] Bulkley Direct, p. 45, lines 1-6; and Schedule AEB-6DR (Page 1 of 1).

Ms. Bulkley's 3-month average yield	2.57% - 1.39% = 1.18%
Blue Chip forecast (Q4 2019 - Q4 2020)	2.66% - 1.39% = 1.27%
Blue Chip forecast (2021 - 2025)	3.60% - 1.39% = 2.21%

Q. Ms. Bulkley's direct testimony in this proceeding was filed October 31, 2019. Does RUCO know to what extent the above referenced *Blue Chip* forecasts of the 30-year Treasury yield which Ms. Bulkley relies upon may have changed?

A. Yes. Based upon *Blue Chip* updated forecasts, the forecasted yield on the 30-year Treasury covering the period, Q3 2020–Q3 2021 is 1.68 percent,[66] while the 5-year forecasted yield covering the period, 2022-2026 is 3.00 percent.[67] Thus, the 2.66 percent and 3.60 percent forecasts relied upon by Ms. Bulkley are overstated by 98 basis points (2.66% - 1.68% = 0.98%) and 60 basis points (3.60% - 3.00% = 0.60%), respectively.

Q. What is beta, and what beta coefficients does RUCO employ in its CAPM analysis?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks have traditionally had beta coefficients less than 1.0. For purposes of its CAPM analysis, RUCO employs the most recent *Value Line* beta reported for each company in the proxy group.[68]

[66] *Blue Chip Financial Forecasts*, Vol. 39, No. 6, June 1, 2020, p. 2.
[67] *Blue Chip Financial Forecasts*, Vol. 39, No. 6, June 1, 2020, p. 14.
[68] See Attachment 2 – Individual proxy companies beta's identified

Q. Were the beta values employed by RUCO in its CAPM analyses obtained from *Value Line's* most recent quarterly update for each proxy company?

A. They were for 10 of the 12 companies in RUCO's proxy group. *Value Line's* most recent quarterly update for both PNM Resources, Inc. (PNM) and Xcel Energy, Inc. (XEL) was issued on July 24, 2020.[69] Since that time, the *Value Line* beta coefficient for each company has risen slightly. As shown in RUCO Schedule JAC-4 (Page 1), the *Value Line* beta coefficient employed in RUCO's CAPM analyses for both PNM and XEL reflects the upward adjustment made by *Value Line*:[70]

	VL Beta Reported as of July 24,2020	VL Beta As updated Sept. 11, 2020
PNM	0.90	0.95
XEL	0.75	0.80

Q. You note above that the market beta is 1.0. What is the sample average *Value Line* beta for RUCO's 12-company proxy group, and how does it compare to the average *Value Line* beta for these same 12 companies included in Ms. Bulkley's proxy group of companies?

A. RUCO has prepared an exhibit which compares the *Value Line* betas for RUCO's proxy group to the same 12 companies as reported in Ms. Bulkley's direct testimony. As shown in Exhibit JAC-D, the sample average beta for RUCO's proxy group is 0.8875, while the average *Value Line* beta for these same 12 companies as reported in Ms. Bulkley's direct testimony proxy group is 0.6045. Due to the market volatility brought about by the Coronavirus pandemic, the *Value Line* beta coefficient for all 12 sample companies has increased significantly, with the beta of

[69] *Value Line Investment Survey, Ratings & Reports* (July 24, 2020).
[70] *Value Line Investment Survey, Summary & Index* (September 11, 2020).

2 proxy companies now equaling or exceeding the 1.0 market beta.[71] Overall, RUCO's sample average beta has increased in absolute terms by 0.2830 (0.8875 – 0.6045) since the filing of Ms. Bulkley's direct testimony, a figure which equates in relative terms to an increase of 46.80 percent (0.283 / 0.6045 = 46.80%).[72]

Q. How does RUCO estimate the market risk premium (R_m-R_f) component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For purposes of its analysis, RUCO estimated the market risk premium by comparing annual realized returns on equity for the S&P 500 (a broad based group of large U.S. companies) with the actual annual yields on 20-year long-term Treasury bonds over the period, 1978-2019. As shown in Schedule JAC-4, Page 2, the market risk premium component used in RUCO's CAPM represents the average of differential returns on equity for the S&P 500 index and the annual yields on 20-year U.S. Treasury bonds. Over the period 1978-2019, RUCO determined the average ROE on the S&P 500 to be 13.79 percent, and the average 20-year U.S. Treasury bond yield to be 6.39 percent. Thus, based upon these returns RUCO concluded the market risk premium (R_m-R_f) component in its CAPM analysis to be 7.40 percent (13.79% - 6.39% = 7.40%).

Q. What did RUCO conclude the overall CAPM cost of equity to be?

A. As shown in Schedule JAC-4, Page 1, RUCO determined the CAPM derived cost of equity to fall within the range of 7.64 percent to 7.73 percent for its proxy group of sample companies. RUCO concludes that the CAPM equity cost rate for APS is

[71] Evergy, Inc. (1.00), and OGE Energy (1.05).
[72] As shown in Column [D] of Exhibit JAC-D, the *Value Line* beta coefficients for Southern Company and Duke Energy experienced increases of 80.00% and 70.00%, respectively.

7.68 percent, a value representing the mid-point of this range ((7.64% + 7.73%) / 2 = 7.68%).

Q. How do RUCO's CAPM results compare to those obtained by the Company's witness, Ms. Bulkley?

A. Ms. Bulkley's CAPM results are presented in Schedule AEB-6DR (Page 1). As shown, she obtains two CAPM estimates, (i) a 10.20 percent mean ROE estimate employing a sample average 0.662 *Bloomberg* beta, and (ii) a 9.69 percent mean ROE estimate employing a sample average 0.615 *Value Line* beta. As shown below, each of Ms. Bulkley's CAPM estimates exceed by more than 200 basis points RUCO's 7.68 percent CAPM derived equity cost rate:

	[A] Bulkley CAPM Rate	[B] RUCO CAPM Rate	[A] – [B] Excess of Bulkley Rate
Bloomberg Beta	10.20 %	7.68 %	2.52 %
Value Line Beta	9.69 %	7.68 %	2.01 %

IX. CE ANALYSIS

Q. Please describe the basis of the Comparable Earnings (CE) methodology.

A. The CE method is derived from the "corresponding risk" concept discussed in the *Bluefield* and *Hope* cases; as such, the CE method is based on the economic concept of opportunity cost.

The CE method is designed to measure returns expected to be earned on the original cost book value of similar risk business enterprises, in this case RUCO's proxy group of companies. Thus, it provides a direct measure of the fair return,

since it translates into practice the competitive principle upon which regulation rests.

Q. How did RUCO apply the CE methodology?

A. RUCO applied the CE methodology by examining historical realized returns on equity for its proxy group of sample companies over both the 10-year period, 2010-2019, and 5-year period, 2015-2019, as well as 5-year projected equity returns in years 2020, 2021, and 2023-2025.

Q. What cost of equity results were obtained from RUCO's CE analysis?

A. As shown in Schedule JAC-5 (Page 1 of 1), RUCO calculated historical returns on equity for its sample companies over both a 5- and 10-year period, and projected returns on equity over the 5-year period, 2020-2024. Based upon its analysis, RUCO generated sample mean and median CE cost of equity estimates ranging from a low of 9.3 percent to a high of 10.0 percent. For purposes of its analysis, RUCO then computed a 5-Year combined historic and projected average ROE measure. The results of RUCO's CE analysis based on returns on equity for the proxy group can be summarized as follows:

	Historic ROE's		Projected ROE's	Avg. Historic & Projected
	10-Year	5-Year	5-Year	5-Year Combined
Mean	9.4 %	9.3 %	9.7 %	9.5 %
Median	9.7 %	9.8 %	10.0 %	10.0 %

For purposes of its analysis, RUCO concludes that 9.75 percent represents the CE-derived cost of equity estimate for its proxy group of companies. This figure represents the midpoint of the 9.5 percent mean and 10.0 percent median estimates obtained by averaging 5-year historic and projected ROEs ((9.5% + 10.0%) / 2 = 9.75%). RUCO adopts the 9.75 percent CE-derived equity cost estimate obtained

for its proxy group of companies as its recommended CE equity cost rate for the Company.

X. RUCO RESPONSE TO COMPANY'S COST OF CAPITAL WITNESS MS. ANNE E. BULKLEY

Q. Please summarize Ms. Bulkley's cost of capital analyses and recommendations.

A. Ms. Bulkley recommends adoption of a 10.15 percent common equity cost rate based on estimates derived from the Constant Growth DCF model, the CAPM, and a Bond Yield plus Risk Premium ("RP") method, using a sample group of fourteen (14) publicly-traded electric utility companies. Due to concerns that utility stocks are currently at unsustainably high prices, Ms. Bulkley also considers the results obtained from a Projected Constant Growth DCF model. Based upon her analyses, Ms. Bulkley determined the indicated cost of equity for her sample group falls in the range of 9.07 percent to 10.42 percent (midpoint 9.745 percent). Ms. Bulkley relies on the results obtained from her Bond Yield Less Risk Premium analysis only to corroborate the reasonableness of her DCF and CAPM results. To demonstrate that her recommended 10.15 percent equity cost rate is reasonable, Ms. Bulkley supplements her cost of equity analyses by incorporating estimates obtained from an Expected Earnings analysis. The results of Ms. Bulkley's cost of equity estimation analyses are summarized below:[73]

[73] Bulkley Direct, p. 5, *Figure 1- Summary of Cost of Equity Analytical Results.*

Constant Growth DCF

	Mean Low	Mean	Mean High
30-Day Average Price	8.09 %	9.07 %	10.21 %
90-Day Average Price	8.17 %	9.14 %	10.28 %
180-Day Average Price	8.17 %	9.26 %	10.40 %
Projected Constant Growth DCF[74]	8.51 %	9.66 %	10.75 %

Risk Premium Models

	Current R_f Rate (2.57%)	2019-2020 Projected R_f Rate (2.66%)	2021 - 2025 Projected R_f Rate (3.60%)
CAPM – Bloomberg Beta	10.07 %	10.11 %	10.42 %
CAPM – Value Line Beta	9.54 %	9.58 %	9.94 %
Bond Yield Plus Risk Premium	9.75 %	9.79 %	10.20 %

Expected Earnings Analysis

Value Line 2022-2024	11.15 %

Q. Briefly summarize Ms. Bulkley's Constant Growth DCF methodology.

A. In her constant growth DCF analyses, Ms. Bulkley employs exclusive use of analysts forecasts of earnings per share ("EPS") growth to estimate the dividend growth (g) rate, obtained from *Value Line*, *Yahoo Finance*, and *Zacks Investment Research*. To calculate the dividend yield in her DCF analyses, Ms. Bulkley obtains average stock prices for each of her 14 sample companies measured over a 30-, 90- and 180-trading day period ending July 31, 2019. Ms. Bulkley computes the current dividend yield (D_0 / P_0) for each sample company by dividing the current annualized dividend by the average stock price obtained from each of her three measurement periods (i.e., 30-, 90-, and 180-days). In calculating the expected dividend yield (D_1 / P_0), Ms. Bulkley applies one-half of the expected dividend

[74] The results of Ms. Bulkley's Projected Constant Growth DCF analysis do not appear in *Figure 1-Summary of Analytical Results*; they are presented in Attachment AEB-3DR (Page 1 of 1).

growth rate to the dividend yield to ensure that an increase made to the dividend is equally distributed across all calendar quarters.

The results of Ms. Bulkley's Constant Growth DCF analyses are presented in Attachment AEB-2DR (Pages 1-3).[75] As shown, Columns [1] - [4] present the annualized dividend, average stock price, current dividend (D_0 / P_0) yield, and expected dividend (D_1 / P_0) yield. Columns [5] – [7] present forecasts of EPS growth obtained from *Value Line*, *Yahoo! Finance*, and *Zack's*, with the average earnings growth rate for Ms. Bulkley's proxy group presented in Column [8]. Column [10] presents her DCF-derived sample average mean ROE estimates, while Columns [9] and [11] present low- and high-ROE estimates for each sample company based on the lowest / highest respective earnings growth rate for each. Finally, columns [12] – [14] present the same DCF equity cost rates, with exclusions. As discussed in direct testimony,[76] Ms. Bulkley excludes Constant Growth DCF results lower than 7.00 percent, as the 4.17 percent yield on Moody's Baa' rated utility bonds measured over the 30-day period ending July 31, 2019 would provide for an insufficient 283 basis point equity risk premium (7.00% - 4.17% = 2.83%).

Due to concerns that utility stocks are currently at unsustainably high prices, Ms. Bulkley also considers the results obtained from a Projected Constant Growth DCF model. In this DCF analysis, Ms. Bulkley employs projected average share prices and dividends obtained from *Value Line* for the period, 2022-2024, to compute the dividend yield, while utilizing the same sample average growth rate as that employed in her Constant Growth DCF analyses. As presented in Attachment AEB-3 (Page 1 of 1), Ms. Bulkley obtains a sample mean 9.66 percent ROE, a figure 78

[75] Ms. Bulkley's DCF results obtained using a 30-day average stock price appear on Page 1; the results obtained using 90- and 180-day average stock prices appear on Pages 2 and 3, respectfully.
[76] Bulkley Direct, p. 42, lines 9-18.

basis points higher than the 8.88 percent "mean results of [her] Constant Growth DCF model" (9.66% - 8.88% = 0.78%).[77]

Q. Based upon the results of her Constant Growth DCF analyses, what conclusions does Ms. Bulkley arrive at?

A. Ms. Bulkley concludes that reliance on "the historical average of abnormally high stock prices results in low dividend yields that are not expected to prevail over the period that new rates will be in effect… [which], in turn, underestimates the ROE for the rate period."[78] Thus, it appears Ms. Bulkley relies on the DCF results obtained from her Projected Constant Growth DCF analysis.

Q. Briefly summarize Ms. Bulkley's CAPM methodology.

A. In her CAPM analyses, Ms. Bulkley obtains estimates employing three measures of the risk-free (R_f) rate: (i) a current 2.57 percent 30-day average rate based on the 30-year U.S. Treasury yield, (ii) a 2.66 percent projected 30-year Treasury rate obtained from *Blue Chip* covering the period, Q4 2019 – Q4 2020, and (iii) a 3.60 percent projected 30-year Treasury rate obtained from *Blue Chip* covering the 5-year period, 2021-2025. As noted in direct testimony,[79] Ms. Bulkley places more weight on CAPM equity cost estimates obtained from *Blue Chip* projections of the 30-year Treasury yield, citing to the expectation by economists surveyed by *Blue Chip* that long-term interest rates will increase over the next five years.

Ms. Bulkley's CAPM analyses employs two measures of the Beta (β) coefficient for each of her 14 sample companies: (i) a *Value Line* beta based on five (5) years of

[77] Bulkley Direct, pp. 42-43, lines 19:4. The 8.88 percent mean DCF estimate referred to above is found in Attachment AEB-2DR (Page 1), Column [10].
[78] Ibid, p. 43, lines 5-15.
[79] Bulkley Direct, p. 45, lines 7-19.

weekly return data relative to the New York Stock Exchange Composite Index, and (ii) a *Bloomberg* beta calculated using ten (10) years of weekly return data relative to the S&P 500 Index. Ms. Bulkley justifies use of *Bloomberg's* ten-year beta on grounds that following the enactment of the TCJA in December 2017, "performance of the utility industry deviated significantly from the broader market, understating the Beta for utility companies as compared with historical averages."[80]

Ms. Bulkey employs a forward-looking market risk premium ("MRP") in her CAPM analysis based on estimates of the expected total return on the S&P 500 Index less the 30-year Treasury bond yield. Ms. Bulkley uses the Constant Growth DCF model to calculate rhe expected total return for companies in the S&P 500 Index for which dividend yields and long-term earnings projections are available. The results obtained are presented in Attachment AEB-5DR (Page 1 of 6). As shown, Ms. Bulkley obtains a 13.90 percent required market return estimate for the S&P 500 Index based upon (i) a 1.94 percent weighted average dividend yield, and (ii) an 11.84 percent weighted average long-term growth rate. When subtracting the risk-free rate measures employed in her analyses from the DCF derived 13.90 percent S&P 500 required market return, Ms. Bulkley obtains implied market risk premiums of 11.34 percent (13.90% - 2.57% = 11.34%), 11.24 percent (13.90% - 2.66% = 11.24%), and 10.30 percent (13.90% - 3.60% = 10.30%).

The results obtained from Ms. Bulkley's forward-looking CAPM analyses are presented in *Figure 13* of her direct testimony.[81] As shown, Ms. Bulkley derives a 10.20 percent mean CAPM estimate from use of *Bloomberg* betas, and a 9.69 percent mean CAPM estimate from use of *Value Line* betas.

[80] Bulkley Direct, pp. 45-47, lines 25:1.
[81] Bulkley Direct, p. 48, *Figure 13 – Forward Looking CAPM Results.*

Q. Based upon the results of her CAPM analyses, what conclusions does Ms. Bulkley arrive at?

A. Ms. Bulkley concludes that use of historical bond yields in the CAPM understates the CAPM-derived cost of equity, and that use of projected Treasury yields "results in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect."[82]

Q. Briefly summarize Ms. Bulkley's Bond Yield Plus Risk Premium approach.

A. To supplement her cost of capital analyses Ms. Bulkley obtains estimates from the Bond Yield Plus Risk Premium approach, which she describes as follows:

> "In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. Since returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds"[83]

For purposes of her analyses, Ms. Bulkley employs actual authorized equity returns derived from 615 integrated electric utility rate cases from 1992-July 2019 as the historical measure of the cost of equity, and selects the 30-year U.S. Treasury bond as the bond class with which to determine the equity risk premium, as follows:

Equity Risk Premium = Authorized ROE - 30-Year U.S. Treasury Yield

[82] Bulkley Direct, pp. 48-49, lines 22:5.
[83] Bulkley Direct, p.49, lines 9-15.

Ms. Bulkley believes that the results obtained from her Bond Yield Plus Risk Premium analysis have relevance to investors, for since it is "based on authorized ROEs for electric utilities *relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors* (emphasis added)."[84]

The results of Ms. Bulkley's Bond Yield Plus Risk Premium analysis are presented in Attachment AEB-7DR (Pages 2-3). As shown, Ms. Bulkley obtains a 5.90 percent average and 6.01 percent median estimate of the risk premium. Based on a regression analysis of the risk premium as a function of yields on the 30-year U.S. Treasury bond, Ms. Bulkley obtains a 9.91 percent average Risk Premium-derived ROE based on risk premiums of 7.19 percent, 7.13 percent, and 6.60 percent.

	30-Yr Treasury Yield	Risk Premium	ROE
Current 30-Day Avg. Yield	2.57 %	7.19 %	9.75 %
Blue Chip Forecast (Q4 '19-Q4 '20)	2.66 %	7.13 %	9.79 %
Blue Chip Forecast (2021-2025)	3.60	6.60 %	10.20 %
Average			9.91 %

Ms. Bulkley does not directly consider the results obtained from her Bond Yield Plus Risk Premium analyses; instead, she relies on the results to corroborate the reasonableness of her DCF and CAPM results and to inform her ultimate ROE recommendation.

Q. Briefly summarize Ms. Bulkley's Expected Earnings Analysis.

A. Ms. Bulkley also considers estimates obtained from an Expected Earnings analysis based on projected ROEs for each of her proxy companies. As justification for

[84] Bulkley Direct, p.50, lines 9-15.

doing so, Ms. Bulkley cites as authority to an Order issued by FERC[85] in October 2018 in which FERC elected to include estimates obtained from an Expected Earnings analysis in its cost of equity estimation methodology. As will be discussed, FERC has since reversed its position regarding the Expected Earnings method, due to a finding that reliance on estimates obtained therefrom result in unjust and unreasonable rates. The results obtained from Ms. Bulkley's Expected Earnings analysis are presented in Attachment AEB-8DR (Page 1 of 1). As shown, Ms. Bulkley's Expected Earnings approach produces mean results of 11.15 percent and a median estimate of 10.81 percent. As presented, the 10.81 percent median estimate appears to be more representative of her proxy group;[86] nevertheless, as presented in *Figure 1 - Summary of Cost of Equity Analytical Results* (Bulkley Direct, p. 5), Ms. Bulkley relies on the higher 11.15 percent mean Expected Earnings cost rate.

Ms. Bulkley's Constant Growth DCF Analyses

Q. Ms. Bulkley justifies consideration of estimates obtained from a Projected Constant Growth DCF analysis on grounds that "*abnormally high stock prices*" for her proxy companies result in "low dividend yields that are not expected to prevail over the period that new rates will be in effect" (emphasis added). What is the current sample average dividend yield for Ms. Bulkley's proxy group of companies and how does it compare to the current sample average dividend yield reported in Ms. Bulkley's direct testimony?

A. RUCO has prepared an exhibit which demonstrates that stock prices for Ms. Bulkley's proxy group of companies have fallen since the filing of Ms. Bulkley's

[85] Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, Issued October 16, 2018.

[86] As shown, Ms. Bulkley derives Expected Earnings equity cost rates of 16.78 percent for FirstEnergy Corporation, and 13.49 percent for PPL Corporation, neither of which are representative of estimates obtained for the other twelve companies in Ms. Bulkley's sample group.

direct testimony, resulting in a consequent rise to the current sample average dividend yield. As shown in RUCO Exhibit JAC-E (Lines 17-18), measured over the three month period, June-August 2020, the current sample average dividend yield for Ms.Bulkley's proxy group of 14 companies is 3.94 percent, a figure 67 basis points higher than the 3.27 percent sample average dividend yield obtained by Ms. Bulkley measured over the 30-trading day period ending July 31, 2019 (3.94% - 3.27% = 0.67%), which in relative terms equates to an increase of 20.58 percent ((3.94% / 3.27%) – 1 = 20.58%). As shown in RUCO Exhibit JAC-E (Lines 13-14), the sample average current dividend yield for RUCO's proxy group of 12 companies—all of which are included in Ms. Bulkley's proxy group—is 3.71 percent, a figure 63 basis points higher than the 3.08 percent current yield obtained by Ms. Bulkley for those measured over this same period (3.71% - 3.08% = 0.63%), an increase of 20.62 percent ((3.71% / 3.08%) – 1 = 20.62%).

Q. Given the increase to the dividend yield brought about by lower share prices, is Ms. Bulkley's reliance on estimates obtained from a Projected Constant Growth DCF analysis warranted in this proceeding?

A. No, for as shown in *Figure 4: Dividend Yields for Utility Stocks*,[87] both RUCO's 3.71 percent and Ms. Bulkley's 3.94 percent sample average dividend yield exceed the utility industry average over the six year period, 2014-2019.

[87] Bulkley Direct, p. 13.

Q. In direct testimony, Ms. Bulkley asserts that the Federal Reserve's accommodative monetary policy following the Great Recession of 2008-09 "artificially lowered government bond yields."[88] Would you care to respond?

A. Yes. While it is true that the Federal Reserve took aggressive action to stimulate economic growth by lowering short-term interest rates (i.e., the federal funds rate) to its ELB following the onset of the Great Recession, long-term interest rates are determined by investors in the marketplace based on expected growth and inflation. In a recent speech, Federal Reserve Chairman Powell made the following observation concerning the general level of interest rates here in the U.S. and globally:[89]

> "[T]he general level of interest rates has fallen both here in the United States and around the world. Estimates of the neutral federal funds rate, which is the rate consistent with the economy operating at full strength and with stable inflation, have fallen substantially, in large part reflecting a fall in the equilibrium real interest rate, or "r-star." *This rate is not affected by monetary policy but instead is driven by fundamental factors in the economy*, including demographics and productivity growth—the same factors that drive potential economic growth." (emphasis added)

Thus, contrary to Ms. Bulkley's assertion otherwise, the fall in long-term government bond yields was not "artificial," as the equilibrium real interest rate (i.e., r-star) is driven by fundamental factors in the economy, and not affected by monetary policy.

[88] Bulkley Direct, p. 12.
[89] *New Economic Challenges and the Fed's Monetary Policy Review*, a Speech by Mr. Jerome H. Powell, Chair, Board of Governors of the Federal Reserve System at "Navigating the Decade Ahead: Implications for Monetary Policy," an economic policy symposium sponsored by the Federal Reserve Bank of Kansas City, delivered at Jackson Hole, Wyoming (August 27, 2020). https://www.federalreserve.gov/newsevents/speech/powell20200827a.htm

Q. In the speech, did Chairman Powell discuss what impact persistent low inflation would have on the level of interest rates?

A. Yes, Chairman Powell described the dangers of persistent low inflation to the economy and interest rates as follows:

> "*Inflation that runs below its desired level can lead to an unwelcome fall in longer-term inflation expectations, which, in turn, can pull actual inflation even lower, resulting in an adverse cycle of ever-lower inflation and inflation expectations. This dynamic is a problem because expected inflation feeds directly into the general level of interest rates…* But if inflation expectations fall below our 2 percent objective, interest rates would decline in tandem. In turn, we would have less scope to cut interest rates to boost employment during an economic downturn, further diminishing our capacity to stabilize the economy through cutting interest rates. We have seen this adverse dynamic play out in other major economies around the world and have learned that once it sets in, it can be very difficult to overcome. We want to do what we can to prevent such a dynamic from happening here."[90] (emphasis added)

Following the speech, in response to a question posed to him, Chairman Powell made the following statement:

> "*To the extent that inflation gets lower and lower and lower, interest rates get lower and lower*," Mr. Powell said. "*This isn't some idle academic theory, this is what's happening all over the world* — if you look at many, many large jurisdictions around the world, you are seeing that phenomenon."[91] (emphasis added)

[90] Ibid.
[91] Smialek, Jeanna "Fed Pledges Low Rates for Years, and Until Inflation Picks Up," *nytimes.com* (September 16, 2020). https://www.nytimes.com/2020/09/16/business/economy/federal-reserve-interest-rates.html

Q. Does Ms. Bulkley's exclusive use of analysts' forecasts of earnings per share growth to estimate the dividend growth (g) rate overstate her Constant Growth DCF results?

A. Yes. For purposes of its Constant Growth DCF analyses, RUCO employs both historical and projected measures of (i) earnings retention (i.e., fundamental growth), (ii) EPS, (iii) DPS, and (iv) BVPS growth obtained from *Value Line*, as well as projected analyst forecasts of EPS growth from *Yahoo Finance* to estimate dividend growth, each of which are determinants of dividend growth. RUCO believes the growth indicators used in its analysis to be more representative of investor expectations of dividend growth, and that Ms. Bulkley's exclusive reliance upon analysts' forecasts of EPS growth overstates the dividend growth rate in her Constant Growth DCF analyses.

Q. As discussed in direct testimony,[92] Ms. Bulkley excludes from consideration DCF results less than 7.00 percent, for based on a 4.17 percent 30-trading day average yield on Moody's Baa-rated utility bonds measured as of July 31, 2019, equity investors would consider the resultant 283 basis point return increment above long-term debt costs to be insufficient (7.00% - 4.17% = 2.83%). To your knowledge, did the yield on Moody's Baa-rated utility bonds fall in the month of August 2019?

A. Yes, yields on Moody's Baa-rated utility bonds fell significantly. Schedule JAC-6 (Page 4) presents a variety of interest rates, including monthly average yields on Moody's Aa-, A-, and Baa-rated utility bonds, as reported by the *Mergent Bond Record*. Below are the monthly average yields on Moody's Baa-rated utility bonds for the months of July and August, 2019:

[92] Bulkley Direct, p.42 , lines 9-18.

Month	Moody's Baa-Rated Utility Bond Yield
July 2019	4.13 %
August 2019	3.63 %
1-Month Change	0.50 %

As shown, the yield on Moody's Baa-rated utility bonds fell by 50 basis points in the month of August 2019 from their level of July 2019 (4.13% - 3.63% = 0.50%).

Q. Ms. Bulkley's testimony was filed on October 31, 2019. Would it have been possible for Ms. Bulkley to perform her Constant Growth DCF analyses employing the 3.63 percent Moody's Baa-rated utility bond yield for the month of August, 2019?

A. Yes, and had she done so estimates excluded from her Constant Growth DCF analyses less than 7.00% appearing in Columns [9] – [11] might have been retained, thereby resulting in a reduction to her DCF-derived equity cost estimates.

Q. What is the current monthly yield on Moody's Baa-rated utility bonds?

A. As shown in Schedule JAC-6 (Page 4), as of August 2020 the current monthly yield on Moody's Baa-rated utility bonds is 3.06 percent, a figure 107 basis points lower than the 4.13 percent rate employed by Ms. Bulkley to establish a 7.00 percent threshold level her (4.13% - 3.06% = 1.07%).

Ms. Bulkley's Bond Yield Plus Risk Premium Approach

Q. Does Ms. Bulkley give direct consideration to equity cost estimates obtained from a Bond Yield Plus Risk Premium Approach?

A. No, she does not. As noted in direct testimony,[93] Ms. Bulkley states that she relies on the results obtained

> "to corroborate the reasonableness of my DCF and CAPM results and to inform my ultimate ROE recommendation, not as the primary basis for my recommendation."

Q. Does RUCO have reason to believe that it would be inappropriate for Ms. Bulkley to employ the results obtained from her Bond Yield Plus Risk Premium approach '*to corroborate the reasonableness*' of her DCF and CAPM equity cost results and '*inform*' her ROE recommendation?

A. Yes.

Q. Please explain.

A. In direct testimony,[94] Ms. Bulkley cites a FERC Order issued in 2018 proposing a new cost of equity estimation methodology giving equal weight to estimates obtained from multiple models: the DCF, CAPM, Expected Earnings and Risk Premium. On November 21, 2019, subsequent to the filing of Ms. Bulkley's direct testimony in this proceeding, FERC issued Order 569 amending its cost of equity estimation methodology. In doing so, FERC elected to remove both the Risk Premium and Expected Earnings models from its estimation methodology due to a finding that reliance on estimates obtained from those models led to the establishment of unjust and unreasonable rates. Subsequently, on May 21, 2020,

[93] Bulkley Direct, p. 50, lines 11-13.
[94] Bulkley Direct, p. 18, lines 1-8, and Footnote 13.

FERC Order 569-A was issued, and on appeal the Risk Premium model was restored to FERC's cost of equity estimation methodology.[95] The following is the relevant ordering paragraph from FERC Order 569-A discussing FERC's rationale for reinstating the Risk Premium model to its cost of equity estimation methodology:

> 105. In Opinion No. 569, the Commission expressed concerns that the Risk Premium model was an iteration of the CAPM, where both compared a derived return to a risk-free rate of return, affording too much weight to similar models. *Upon reconsideration, we agree* with the PJM TOs *that the Risk Premium model is sufficiently distinct from the CAPM to use in our ROE analysis.* ***The Risk Premium relies on corporate utility bonds while the CAPM uses Treasury Bond yields.*** Additionally, the Risk Premium model relies on the risk premiums implicit in regulatory judgements, including those using the DCF model, while the CAPM relies upon a different set of inputs, including S&P 500 dividend yields and growth rates as well as adjusted betas.[96] (emphasis added)

Q. Why is it important that corporate utility bond yields, rather than yields on U.S. Treasury securities, be employed as the debt component in the Risk Premium approach?

A. Use of corporate utility bond yields in a Bond Yield Plus Risk Premium analysis allows for the calculation of differential returns accruing to investors holding public utility equity securities (i.e., common stock) and those holding public utility debt securities (i.e., bonds). Ms. Bulkley should have properly employed the yield on Moody's Baa' rated corporate utility bonds to compute the equity risk premium component in her Bond Yield Plus Risk Premium analysis. In failing to do so, Ms.

[95] In doing so, FERC found "the flaws for the Risk Premium model, when mitigated by certain adjustments, do not render use of the model unreasonable…" FERC Order 569-A, Paragraph No. 45, issued in Docket Nos. EL14-12-004 and EL15-45-013 (May 21, 2020) https://ferc.gov/sites/default/files/2020-06/EL14-12-004_1.pdf Nos. EL14-12-004 and EL15-45-013 (May 21, 2020) https://ferc.gov/sites/default/files/2020-06/EL14-12-004_1.pdf

[96] FERC Order 569-A, Paragraph Nos 45 and 125, issued in Docket Nos. EL14-12-004 and EL15-45-013 (May 21, 2020) https://www.ferc.gov/whats-new/comm-meet/2020/052120/E-1.pdf

Bulkley overstates the equity risk premium in her analysis, as yields on corporate utility bonds exceed that of 30-year long-term Treasury bonds.

Q. Does an overstatement to the equity risk premium component in Ms. Bulkley's Bond Yield Plus Risk Premium analysis render the results obtained appropriate for purposes of *'corroborating the reasonableness of Ms. Bulkley's DCF and CAPM results and inform her overall recommendation?'*

A. No, to the contrary it renders them highly inappropriate for that purpose. The inputs employed in Ms. Bulkley's Bond Yield Plus Risk Premium analysis are presented in Attachment AEB—7DR (Pages 1 and 2). As shown, she derives the equity risk premium component by subtracting yields on 30-year Treasury bonds from authorized ROEs over the period 1992-2019. RUCO has prepared an Exhibit which provides evidence of the overstatement made to the equity risk premium in years 2007-2019[97] As shown, the yield on Moody's Baa-rated utility bonds exceeded those on 30-year treasury bonds by an average of 191 basis points (5.40% - 3.49% = 1.91%), which suggests that had Ms. Bulkley properly employed utility bond yields in her analysis, on an average annual basis the equity risk premium component obtained in her analysis would be 191 basis points lower.

Ms. Bulkley's Expected Earnings Approach

Q. Among the cost of equity estimates obtained from the various models employed by Ms. Bulkley in her analyses, from which model does she obtain the highest cost of equity estimate?

A. As presented in *Figure 1: Summary of Cost of Equity Analytical Results*, the highest estimate is an 11.15 percent sample mean estimate obtained from Ms. Bulkley's

[97] RUCOs' analysis was limited to this period, as RUCO did have Moody's Baa-rated utility bond yield data for years preceding 2007.

Expected Earnings Analysis. As presented in Attachment AEB-8DR, the 10.81 percent sample median is more representative of the sample.

Q. As noted in direct testimony,[98] Ms. Bulkley states that the results obtained from her Expected Earnings analysis will, likewise, be used to corroborate the range established for her recommendation. Would you care to comment?

A. Yes, but only to point out that the Expected Earnings model was rejected by FERC, with Paragraph 45 of Opinion 569-A finding "the flaws of the Expected Earnings model [to be] significant enough to render the model inappropriate for ROE calculations." Paragraph 125 of Opinion 569-A provides evidence that FERC is not inclined to be swayed from that position, as evidenced by the following:

> 125. "*We deny requests for rehearing* of the Commission's decision to exclude the Expected Earnings model from its base ROE analysis under section 206 of the FPA. As an initial matter, we note that the requests for rehearing largely repeat arguments parties previously made and which the Commission addressed in Opinion No. 569. *Nothing in the rehearing requests persuades us to alter our decision here*."[99] (emphasis added)

XI. FAIR VALUE RATE OF RETURN

Q. What Fair Value Rate of Return ("FVROR") does Ms. Bulkley propose for APS in this proceeding?

A. The Company proposes a FVROR of 5.62 percent. The FVROR proposed by Ms. Bulkley incorporates a 1.00 percent Fair Value Increment ("FVI") cost rate applied to the fair value increment of SWG's proposed FVRB.

[98] Bulkley Direct, pp. 6-7, lines 25:2.
[99] FERC Order 569-A, Paragraph Nos 45 and 125, issued in Docket Nos. EL14-12-004 and EL15-45-013 (May 21, 2020) https://www.ferc.gov/whats-new/comm-meet/2020/052120/E-1.pdf

Q. What FVROR does RUCO recommend for SWG in this proceeding?

A. As shown in Schedule JAC-1 (Page 2 of 2), RUCO recommends a FVROR of 4.69 percent.

Q. Did RUCO compute a fair value increment ("FVI") cost rate for the Company?

A. Yes.

Q. Is the FVI cost rate computed by RUCO the same as the FVI cost rate RUCO recommends for the Company?

A. No. The FVI cost rate computed by RUCO is 0.18 percent, calculated as follows:

Nominal Risk-Free Rate - Forecasted	1.58 %
Less: CPI Inflation Component - Forecasted	1.30 %
Real Risk-Free Rate	0.28 %
Fair Value Increment Cost Rate	**0.28 %**

In computing this 0.28 percent FVI cost rate RUCO uses the following inputs: (i) a nominal risk free rate of 1.58 percent, based on forecasts of the 30-year Treasury yield in Q2 2021, and (ii) a CPI inflation component of 1.30 percent, based on forecasts of Consumer Price Index (CPI) inflation for Q4 2021. RUCO's recommended FVI cost rate for APS in this proceeding is 0.0 percent.

Q. Please explain why RUCO elected to apply a 0.0 percent cost rate to the FVI rather than the 0.28 percent cost rate computed above.

A. In accordance with financial theory, a utility is entitled to a return on investment for prudent investments made in plant and infrastructure needed to provide service to ratepayers. The FVI cost rate, however, makes provision for a return on investment in the absence of an investment having been made; a circumstance which not only

conflicts with financial theory, but is patently unfair to ratepayers. It should be noted that the "cost" contemplated in the FVI is inflation, and because the rates a utility may charge is based on the book value of plant, RUCO believes that recovery of this cost in rates is inappropriate. It is for this reason that RUCO recommends a FVI cost rate of 0.00 percent in this proceeding.

XI. CONCLUSION AND RECOMMENDATIONS

Q. Please summarize RUCO's cost of capital recommendations in this proceeding.

A. RUCO recommends that the Commission adopt the following:

1) A capital structure comprised of 45.33 percent long-term debt and 54.67 percent common equity;
2) A cost of debt of 4.10 percent;
3) A cost of common equity of 8.94 percent;
4) An overall rate of return of 6.75 percent;
5) A fair value increment cost rate of 0.00 percent; and
6) A fair value rate of return of 4.69 percent.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT NO. 1

JOHN A. CASSIDY

REGULATORY EXPERIENCE

Attachment 1

John A. Cassidy, CRRA

EDUCATION

Arizona State University -- Master of Business Administration-Finance	(May 1987)
University of Arizona -- Master of Library Science	(August 1980)
Arizona State University -- B.A. History, Latin American Studies	(May 1976)

EXPERIENCE

Public Utilities Analyst V – Residential Utility Consumer Office (RUCO), Phoenix, AZ (July 2015-Present)

Public Utilities Analyst III -- Arizona Corporation Commission, Phoenix, AZ (March 2013-July 2015)

Public Utilities Analyst II -- Arizona Corporation Commission, Phoenix, AZ (May 2012-March 2013)

Public Utility Consultant -- Arizona Corporation Commission, Phoenix, AZ (Jan. 2012-May 2012)

Regulatory Utility Consultant – Self-Employed, Tempe, AZ (2009-2010)

- Assisted in the preparation of testimony filed by the Residential Utility Consumer Office (RUCO) in the Litchfield Park W/WW rate case (Docket No. SW-01428A-09-0103, et al)

Regulatory Utility Consultant – Self-Employed, Tempe, AZ (2007-2008)

- Filed formal cost of capital testimony/schedules on behalf of intervener, Anthem Town Council, and testified at evidentiary hearing in the Arizona-American Water Co., Anthem Water and Anthem/Agua Fria WW rate case (Docket No. WS-01303A-06-0403)

Utilities Auditor II -- Arizona Corporation Commission, Phoenix, AZ (Aug. 1993-Nov. 1997)

PROFESSIONAL DEVELOPMENT

Certified Rate of Return Analyst (CRRA) (May 2016)

Annual Regulatory Studies Program ("Camp NARUC"), Institute of Public Utilities, Michigan State University, East Lansing, MI (August 4-15, 2014)

Annual Financial Forum, Society of Utility and Regulatory Financial Analysts (SURFA) Indianapolis, IN (April 2013 and April 2016); New Orleans, LA (April 2017)

NARUC Utility Rate School, San Diego, CA (May 13-17, 2013)

HONORS

CPA Candidate - Passed the CPA exam (1997), but opted not to pursue certification

Beta Gamma Sigma - National Honor Society in Business Administration

Rate Dockets Testified - Cost of Capital:

Arizona Water Company – Western Group	Docket No. W-01445A-19-0278
Liberty Utilities (Black Mountain Sewer)	Docket No. SW-02361A-19-0139
Southwest Gas Corporation	Docket No. G-01551A-19-0055
Tucson Electric Power Company	Docket No. E-01933A-19-0028
Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164
EPCOR Water Arizona, Inc.	Docket No. WS-01303A-17-0257, et al
Liberty Utilities (Litchfield Park Service Co.)	Docket No. SW-01428A-17-0058, et al.
Pima Water Company	Docket No. W-02199A-16-0421, et al.
Arizona Public Service Company	Docket No. E-01345A-16-0036
EPCOR Water Arizona, Inc.	Docket No. WS-01303A-16-0145
Southwest Gas Corporation	Docket No. G-01551A-16-0107
Liberty Utilities (Bella Vista W / Rio Rico W/WW)	Docket Nos. W-02465A-15-0367, et al.
Arizona Water Company	Docket No. W-01445A-15-0277
Liberty Utilities (Black Mountain Sewer)	Docket Nos. SW-02361A-15-0206, et al.
Quail Creek Water Company	Docket No. W-02514A-14-0343
EPCOR Water Arizona	Docket No. WS-01303A-14-0010
Utility Source, L.L.C.	Docket No. WS-04235A-13-0331
Verde Santa Fe Wastewater Company	Docket No. SW-03437A-13-0292
Chaparral City Water Company	Docket No. W-02113A-13-0118
Payson Water Company	Docket No. W-03514A-13-0111
Lago Del Oro Water Company	Docket No. W-01944A-13-0215
Las Quintas Serenas Water Company	Docket No. W-01583A-13-0117
Litchfield Park Service Company	Docket Nos. SW-01428A-13-0042, et al.
Adaman Mutual Water Company	Docket No. W-01997A-12-0501
Global Water Utilities	Docket Nos. W-01212A-12-0309, et al.
New River Utility Company	Docket No. W-01737A-12-0478
Arizona Water Company	Docket No. W-01445A-12-0348
Far West Water & Sewer, Inc.	Docket No. WS-03478A-12-0307
Cordes Lakes Water Company	Docket No. W-02060A-12-0356

Rio Rico Utilities, Inc.	Docket No. WS-02676A-12-0196
Ray Water Company	Docket No. W-01380A-12-0254
Vail Water Company	Docket No. W-01651B-12-0339
Valley Water Company	Docket No. W-01412A-12-0195
Arizona Water Company	Docket No. W-01445A-11-0310
Pima Utility Company	Docket Nos. W-02199A-11-0329, et al.

Rate Dockets Testified - Revenue Requirement/Rate Design:

Pima Water Company	Docket No. W-02199A-16-0421, et al.
Arizona Water Company	Docket No. W-01445A-15-0277
Quail Creek Water Company	Docket No. W-02514A-14-0343
Beaver Dam Water Company	Docket No. W-03067A-12-0232
Eden Water Company	Docket No. W-02068A-11-0471
Great Prairie Oasis, dba Sunland Water Co.	Docket No. W-04015A-12-0051

Financing Dockets - Responsible for ACC Staff Report:

Arizona Public Service Company	Docket No. E-01345A-11-0423
Tucson Electric Power Company	Docket No. E-01933A-12-0176
Chaparral City Water Company	Docket No. W-02113A-13-0047
Payson Water Company	Docket No. W-03514A-13-0142
Lago Del Oro Water Company	Docket No. W-01944A-13-0242
Duncan Valley Electric Cooperative, Inc.	Docket No. E-01703A-13-0272
Sulphur Springs Valley Electric Cooperative, Inc.	Docket No. E-01575A-12-0457
Trico Electric Cooperative, Inc.	Docket No. E-01461A-12-0056
Great Prairie Oasis, dba Sunland Water Co.	Docket No. W-04015A-12-0050
Columbus Electric Cooperative, Inc.	Docket No. E-01851A-11-0415
Pima Utility Company	Docket Nos. W-02199A-11-0403, et al.

ATTACHMENT NO. 2

VALUE LINE INVESTMENT SURVEY

WATER PROXY GROUP

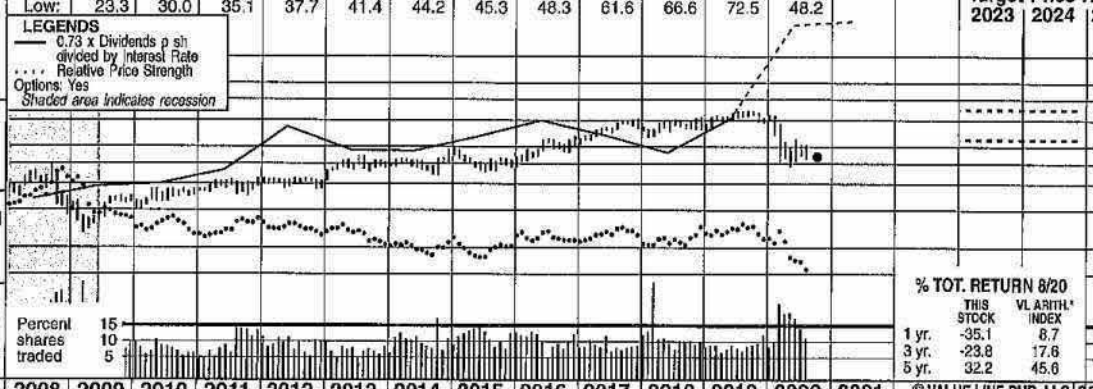
ALLETE NYSE-ALE

RECENT PRICE **53.96** | P/E RATIO **17.9** (Trailing: 16.9 Median: 18.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **4.7%** | VALUE LINE

TIMELINESS **3** Lowered 4/5/19
SAFETY **2** New 10/1/04
TECHNICAL **3** Raised 9/11/20
BETA .85 (1.00 = Market)

High:	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7
Low:	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2

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



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$47-$104	$76 (40%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+65%)	17%
Low	65	(+20%)	9%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	158	124	141
to Sell	120	154	136
Hld's(000)	38235	38410	37540

Percent shares traded 15 10 5

% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-35.1	8.7
3 yr.	-23.8	17.6
5 yr.	32.2	45.6

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
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	29.10	23.99	*21.05*	*22.35*	Revenues per sh	*25.00*
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	7.37	7.24	*7.10*	*7.70*	"Cash Flow" per sh	*9.25*
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	3.38	3.33	*3.10*	*3.50*	Earnings per sh A	*4.25*
.30	1.25	1.45	1.64	1.72	1.76	1.78	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	2.35	*2.47*	*2.58*	Div'd Decl'd per sh B ■ †	*2.90*
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	4.06	6.07	11.55	*14.80*	*11.20*	Cap'l Spending per sh	*3.25*
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	41.86	43.17	*46.35*	*47.75*	Book Value per sh C	*51.75*
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	51.70	*52.75*	*53.50*	Common Shs Outst'g D	*54.25*
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	22.2	24.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	*Value Line*		Relative P/E Ratio	*1.05*
.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.5%	3.0%	3.0%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $1890.7 mill. Due in 5 Yrs $562.6 mill.
LT Debt $1381.0 mill. LT Interest $60.1 mill.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $6.6 mill.

Pension Assets-12/19 $699.6 mill. Oblig $854.0 mill.

Pfd Stock None

Common Stock 51,880,664 shs.

MARKET CAP: $2.8 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	*1110*	*1195*	Revenues ($mill)	*1350*
75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	174.1	172.4	*165*	*190*	Net Profit ($mill)	*230*
37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	14.8%	NMF	*NMF*	*NMF*	Income Tax Rate	*NMF*
8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
44.2%	44.3%	43.7%	44.8%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	*41.0%*	*40.0%*	Long-Term Debt Ratio	*41.0%*
55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	*59.0%*	*60.0%*	Common Equity Ratio	*59.0%*
1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	*4145*	*4255*	Total Capital ($mill)	*4775*
1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	*4945*	*5320*	Net Plant ($mill)	*5575*
5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	*4.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	*6.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	*6.5%*	*7.5%*	Return on Com Equity E	*8.0%*
1.5%	2.9%	2.3%	2.2%	2.5%	3.8%	2.8%	2.4%	2.7%	2.3%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
81%	66%	71%	72%	67%	60%	66%	68%	66%	70%	*79%*	*73%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+8.4	-.2	-1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	1599	1589	1573
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	339	296	277

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	1.0%	2.0%	*-1.5%*
"Cash Flow"	5.5%	6.0%	*4.5%*
Earnings	2.5%	4.0%	*4.5%*
Dividends	3.0%	3.5%	*4.5%*
Book Value	5.0%	5.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2017	365.6	353.3	362.5	337.9	1419.3
2018	358.2	344.1	348.0	448.3	1498.6
2019	357.2	290.4	288.3	304.6	1240.5
2020	311.6	243.2	*275*	*280.2*	*1110*
2021	*325*	*285*	*285*	*300*	*1195*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2017	.97	.72	.88	.56	3.13
2018	.99	.61	.59	1.18	3.38
2019	1.18	.64	.60	.92	3.33
2020	1.28	.39	*.57*	*.86*	*3.10*
2021	*1.20*	*.70*	*.65*	*.95*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175	.6175		

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 (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal & lignite, 30%; wind, 11%; other, 5%; purchased, 54%. Fuel costs: 31% of revs. '19 deprec. rate: 3.3%. Has 1,400 employees. Chairman: Alan R. Hodnik. President & CEO: Bethany M. Owen. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

We expect an earnings decline for ALLETE in 2020. In the second quarter, the company took an aftertax charge of $8.3 million ($0.16 a share) for a refund to customers of previously collected revenues. This was part of an order that allowed the company's primary utility subsidiary, Minnesota Power, to effect a $25.5 million rate hike, effective May 1st. The utility may not file a rate application until November 1, 2021, unless specified conditions occur that permit it to file as early as March 1, 2021. (If and when Minnesota Power will file next year remains to be determined.) We *include* the $0.16-a-share charge in our earnings presentation. ALLETE's 2020 earnings guidance (on a GAAP basis) is $3.09-$3.29 a share. Note that management has cut expenses to offset the costs associated with the coronavirus.

There is mixed news on the state of the economy in the utility's service area. Most of Minnesota Power's large industrial customers expect to operate at full capacity for the remainder of 2020 (and will pay demand charges in accordance with this expectation). However, two plants (one taconite, one paper) remain shut indefinitely.

We think earnings will recover next year. The absence of the charge should be a key factor. We figure the economy will be in better condition in 2021, as well, although there is more uncertainty than usual in this regard.

ALLETE Clean Energy is building a large wind project in Oklahoma. The 300-megawatt, $450 million facility is expected to be completed by yearend. A similar project is planned for 2021. Note that ALLETE has a negative tax rate thanks to significant tax credits arising from this subsidiary's investments in renewable energy.

The price of ALLETE stock has fallen 34% this year. Investors are worried about the effects of the weak economy on Minnesota Power's heavily industrial service territory. This might well persist into 2021. The dividend yield is almost a percentage point above the utility mean. Total return potential is attractive for the next 18 months. For the 3- to 5-year period, total return potential is modest, but still better than that of most utility equities.

Paul E. Debbas, CFA *September 11, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; '19, 28¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '18 & '19 EPS don't sum due to rounding. Next earnings report due early Nov. (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 '19: $8.15/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., '19: 7.9%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	85

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

AMEREN NYSE-AEE

RECENT PRICE **79.11** | P/E RATIO **22.2** (Trailing: 23.1 / Median: 17.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **2.6%** | VALUE LINE

TIMELINESS **2** Raised 9/11/20
SAFETY **2** Raised 8/20/14
TECHNICAL **2** Lowered 6/19/20
BETA .80 (1.00 = Market)

High:	35.3	29.9	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7
Low:	19.5	23.1	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$61-$123	$92 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+5%)	5%
Low	60	(-25%)	-3%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	266	242	220
to Sell	265	273	301
Hld's(000)	186367	187833	196379

Target Price Range
2023 | 2024 | 2025

% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.2	8.7
3 yr.	43.3	17.6
5 yr.	129.2	45.6

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
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	25.73	24.00	*22.85*	*23.65*	Revenues per sh	*25.50*
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	7.64	7.83	*8.20*	*8.75*	"Cash Flow" per sh	*10.75*
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	3.32	3.35	*3.50*	*3.70*	Earnings per sh A	*4.50*
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	1.92	*2.01*	*2.11*	Div'd Decl'd per sh B ■	*2.45*
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	9.56	9.92	*15.85*	*11.65*	Cap'l Spending per sh	*11.00*
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	31.21	32.73	*35.75*	*37.75*	Book Value per sh C	*44.50*
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	244.50	248.20	*254.00*	*258.00*	Common Shs Outst'g D	*270.00*
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	18.3	22.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	*Value Line*		Relative P/E Ratio	*.90*
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%	3.0%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $10648 mill. **Due in 5 Yrs** $2165 mill.
LT Debt $10171 mill. **LT Interest** $456 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $8 mill.
Pension Assets-12/19 $4564 mill.
Oblig $4967 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 247,079,529 shs. as of 7/31/20
MARKET CAP: $20 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	*5800*	*6100*	Revenues ($mill)	*6900*
669.0	602.0	589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	*875*	*960*	Net Profit ($mill)	*1225*
36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	*15.5%*	*12.5%*	Income Tax Rate	*12.5%*
7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	*54.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	*45.5%*	*47.0%*	Common Equity Ratio	*49.0%*
15185	14738	13384	12190	12975	13968	13840	14420	15632	17116	*20000*	*20675*	Total Capital ($mill)	*24500*
17853	18127	16096	16205	17424	18799	20113	21466	22810	24376	*27200*	*28900*	Net Plant ($mill)	*33300*
6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	*9.5%*	*10.0%*	Return on Com Equity E	*10.0%*
3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	63%	66%	76%	67%	70%	64%	64%	56%	57%	*57%*	*57%*	All Div'ds to Net Prof	*54%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.4	+5.6	-3.5
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. (%)	350	313	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-3.0%	-.5%	*.5%*
"Cash Flow"	1.5%	5.5%	*6.5%*
Earnings	1.0%	6.5%	*6.0%*
Dividends	-2.0%	3.0%	*5.0%*
Book Value	-.5%	2.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1514	1538	1723	1402	6177.0
2018	1585	1563	1724	1419	6291.0
2019	1556	1379	1659	1316	5910.0
2020	1440	1398	*1650*	*1312*	*5800*
2021	*1600*	*1450*	*1700*	*1350*	*6100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.42	.79	1.18	.39	2.77
2018	.62	.97	1.45	.28	3.32
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	*1.53*	*.40*	*3.50*
2021	*.65*	*.85*	*1.70*	*.45*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.425	.425	.425	.44	1.72
2017	.44	.44	.44	.4575	1.78
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495		

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 43%; commercial, 32%; industrial, 8%; other, 17%. Generating sources: coal, 63%; nuclear, 23%; hydro & other, 6%; purchased, 8%. Fuel costs: 24% of revenues. '19 reported deprec. rates: 3%-4%. Has 9,300 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, Missouri 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We have boosted our 2020 and 2021 earnings estimates for Ameren by a nickel a share each year. Second-quarter earnings were better than our estimate of $0.80 a share because Ameren was able to cut expenses more than we expected in order to offset the effects of the slump in kilowatt-hour sales resulting from the weak economy. Our revised 2020 share-net estimate is at the midpoint of Ameren's targeted range of $3.40-$3.60. Our 2021 estimate would produce profit growth of 6%, within the company's targeted range of 6%-8% annually.

A gas rate case is pending in Illinois. The utility is seeking a base rate increase of $96 million (including $46 million that would otherwise be recovered through riders in 2021), based on a 10.5% return on equity and a 54.1% common-equity ratio. The staff of the Illinois Commerce Commission is recommending a hike of $67 million, based on a 9.32% ROE and a 50.43% common-equity ratio. Various intervenors are proposing an increase of $66 million, based on a 9.2% ROE and a 50% common-equity ratio. A ruling is required by January, with new tariffs taking effect in February. This is one source of the profit growth that is likely in 2021.

Ameren is building a wind project. The utility is spending $1.2 billion to add 700 megawatts of capacity. Most of this will be in service by yearend, but about $100 million of this spending is expected to slip into 2021. This will not affect the production tax credits associated with the project, however.

We expect a dividend increase in the fourth quarter. This is the usual timing. We estimate an increase of $0.025 a share (5.1%) in the quarterly disbursement, but wouldn't be surprised by a larger hike, given that the payout ratio is near the lower end of Ameren's target of 55%-70%.

Ameren stock is timely, but has a high valuation. The stock price has risen 3% in what has been a bad year for most utility issues, as the market likes the company's status as a fully regulated utility. The dividend yield is a percentage point below the utility mean. Total return potential for the 18-month span is only about average. The recent quotation is near the upper end of our 3- to 5-year Target Price Range.

Paul E. Debbas, CFA *September 11, 2020*

(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¢. '17 EPS don't sum due to rounding. Next egs. report due early Aug. (B) Div'ds pd. late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $5.70/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '20: elec., none; in '11: gas, none; in IL in '14: elec., 8.7%, in '18: gas, 9.87%; earned on avg. com. eq., '19: 10.6%. Reg. Climate: MO, Avg.; IL, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

AMERICAN ELEC. PWR. NYSE-AEP

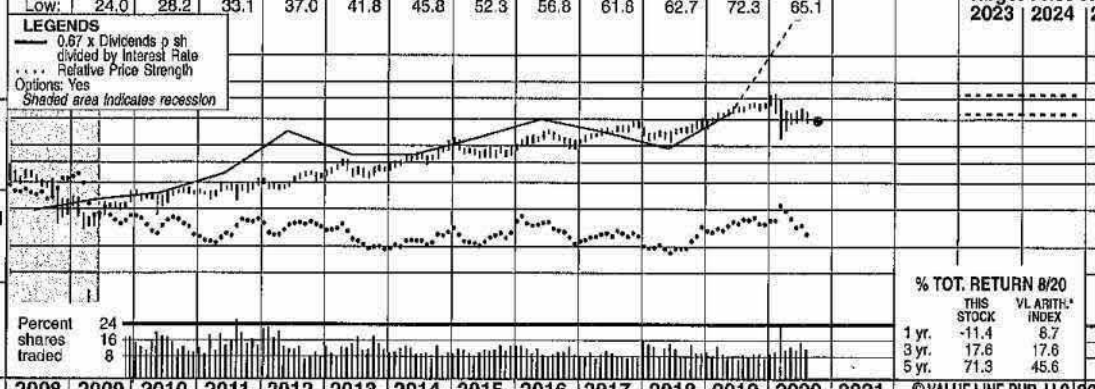
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
78.83	17.9	(Trailing: 19.5 Median: 15.0)	0.84	3.8%	VALUE LINE

TIMELINESS 3 Lowered 9/6/19
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Lowered 6/12/20
BETA .75 (1.00 = Market)

High:	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	
Low:	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	

Target Price Range 2023 | 2024 | 2025

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



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$66-$136	$101 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+35%)	11%
Low	85	(+10%)	6%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	549	483	496
to Sell	459	594	508
Hld's(000)	370323	370792	366307

Percent shares traded 24 16 8

% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.4	8.7
3 yr.	17.6	17.6
5 yr.	71.3	45.6

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
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	32.84	31.49	*30.20*	*30.30*	Revenues per sh	*31.50*
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	8.77	9.35	*9.75*	*10.20*	"Cash Flow" per sh	*11.50*
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	4.08	*4.25*	*4.65*	Earnings per sh A	*5.50*
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	2.53	2.71	*2.84*	*3.00*	Div'd Decl'd per sh B ■	*3.55*
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	12.89	12.43	*12.40*	*16.45*	Cap'l Spending per sh	*12.00*
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	38.58	39.73	*41.40*	*44.45*	Book Value per sh C	*53.00*
395.86	393.72	396.57	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	*497.00*	*515.00*	Common Shs Outst'g D	*555.00*
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	18.0	21.4	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	*Value Line*		Relative P/E Ratio	*.95*
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%	3.6%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $31852 mill. **Due in 5 Yrs** $11290 mill.
LT Debt $26638 mill. **LT Interest** $1113 mill.
Incl. $918 mill. securitized bonds. Incl. $307 mill. capitalized leases.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $269.9 mill.
Pension Assets-12/19 $5015.4 mill. Oblig $5236.8 mill.
Pfd Stock None

Common Stock 496,155,436 shs. as of 8/6/20
MARKET CAP: $39 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
14427	15116	14945	15357	17020	16453	16380	15425	16196	15561	*15000*	*15600*	Revenues ($mill)	*17500*
1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	*2120*	*2330*	Net Profit ($mill)	*3035*
34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	*2.0%*	*2.0%*	Income Tax Rate	*2.0%*
10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	*13.0%*	*13.0%*	AFUDC % to Net Profit	*9.0%*
53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	*56.0%*	*54.0%*	Long-Term Debt Ratio	*52.0%*
46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	*44.0%*	*46.0%*	Common Equity Ratio	*48.0%*
29184	29747	30823	32913	33001	35633	34775	37707	40677	44759	*46975*	*50050*	Total Capital ($mill)	*61200*
35674	36971	38763	40997	44117	46133	45639	50262	55099	60138	*63575*	*69125*	Net Plant ($mill)	*79500*
5.7%	6.3%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	*10.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	*10.5%*	*10.0%*	Return on Com Equity E	*10.5%*
3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
66%	60%	63%	62%	61%	60%	54%	67%	65%	67%	*69%*	*68%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-1.6	+3.0	-2.2
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)	NA	NA	+.3
Fixed Charge Cov. (%)	354	254	234

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	--	-.5%	*Nil*
"Cash Flow"	2.5%	4.0%	*5.0%*
Earnings	3.0%	4.0%	*6.0%*
Dividends	4.5%	5.5%	*5.5%*
Book Value	4.0%	3.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3933	3576	4104	3810	15424
2018	4048	4013	4333	3801	16195
2019	4056	3573	4315	3616	15561
2020	3748	3494	*4258*	*3500*	*15000*
2021	*4100*	*3600*	*4300*	*3600*	*15600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.94	.76	1.11	.81	3.62
2018	.92	1.07	1.17	.74	3.90
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	*1.45*	*.75*	*4.25*
2021	*1.15*	*1.10*	*1.60*	*.80*	*4.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70		

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 42%; commercial, 24%; industrial, 19%; wholesale, 11%; other, 4%. Sold Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '19 reported depreciation rates (utility): 1.8%-9.5%. Has 17,400 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 will build the wind project it proposed. The company will spend $2 billion to add 1,485 megawatts of capacity to serve Oklahoma, Louisiana, and Arkansas. (The Texas commission rejected the proposal, but the capacity that would have served the state will be used to serve customers in Louisiana and Arkansas.) The project will come on line in three phases, one in the first quarter of 2021, the other two in late 2021. AEP plans to finance this conservatively, with $1.3 billion of common stock and $700 million of long-term debt. We think the project will boost the company's annual earning power by $0.25 a share, beginning in 2022.

Our 2020 earnings estimate is at the low end of the company's targeted range of $4.25-$4.45 a share. We *include* some expenses, such as an upcoming charge for an early retirement program, that AEP excludes from its guidance. Aside from this, the company is benefiting from rate relief and increased transmission spending.

We raised our 2021 profit estimate by $0.10 a share, to $4.65. We figure AEP will get some benefit from the wind project next year. The growth we estimate for next year is above the company's annual goal of 5%-7% due to the unusual expenses AEP booked in 2020.

Rate cases are pending in three states. In Ohio, AEP is seeking $41 million, based on a 10.15% return on equity. The utility awaits a procedural schedule. In Kentucky, the company filed for $65 million, based on a 10% ROE. New rates are expected to take effect in January. A decision should come by yearend. In Virginia, the utility requested $65 million, based on a 9.9% ROE. New tariffs are expected to go into effect in the first quarter.

A dividend increase is likely in the fourth quarter. We estimate a boost of $0.04 a share (5.7%) in the quarterly disbursement. AEP's goals are 5%-7% yearly dividend growth and a payout ratio in a range of 60%-70%.

The dividend yield of this top-quality stock is about average, by utility standards. Total return potential is above average for the next 18 months, but just modest for the 3- to 5-year period.

Paul E. Debbas, CFA *September 11, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); disc. ops.: '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due early Nov. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '19: $13.39/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '19: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	90

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

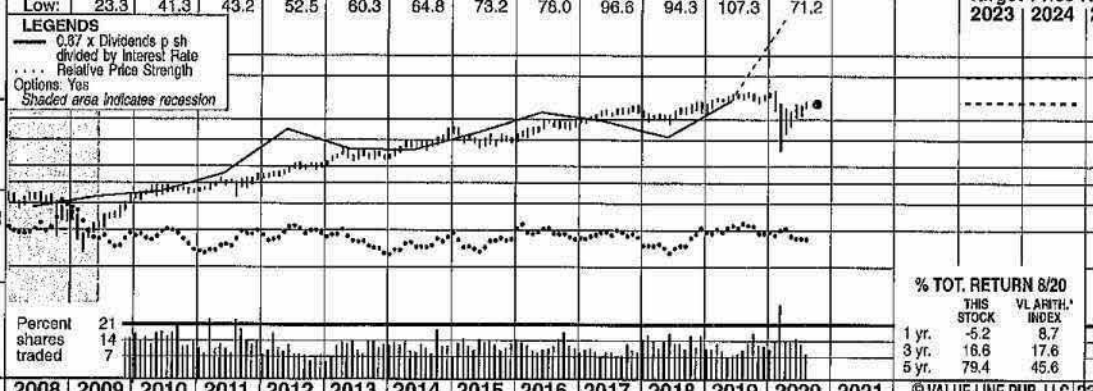
DTE ENERGY CO. NYSE-DTE

RECENT PRICE **118.67** | P/E RATIO **17.1** (Trailing: 18.7 / Median: 17.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **3.7%** | VALUE LINE

TIMELINESS **3** Lowered 6/14/19
SAFETY **2** Raised 12/21/12
TECHNICAL **4** Lowered 5/12/20
BETA .90 (1.00 = Market)

High:	45.0	49.1	55.3	62.6	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7
Low:	23.3	41.3	43.2	52.5	60.3	64.8	73.2	76.0	96.6	94.3	107.3	71.2

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



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$82-$187 $135 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+35%)	11%
Low	120	(Nil)	4%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	365	279	261
to Sell	245	345	318
Hld's(000)	140654	140354	141501

Percent shares traded 21 14 7

% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.2	8.7
3 yr.	16.6	17.6
5 yr.	79.4	45.6

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	78.12	65.91	*60.10*	*62.55*	Revenues per sh	*68.25*
6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	12.58	12.97	*14.45*	*15.30*	"Cash Flow" per sh	*18.00*
2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	6.17	6.31	*6.70*	*7.15*	Earnings per sh A	*8.50*
2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	3.59	3.85	*4.12*	*4.42*	Div'd Decl'd per sh B ■	*5.20*
5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	14.91	15.59	*19.95*	*18.45*	Cap'l Spending per sh	*13.50*
31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	56.27	60.73	*63.60*	*66.95*	Book Value per sh C	*79.25*
174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	181.93	192.21	*193.00*	*195.00*	Common Shs Outst'g D	*205.00*
16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	17.4	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.85	.73	.94	.97	.89	.69	.76	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	*Value Line*		Relative P/E Ratio	*.90*
5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $18925 mill. Due in 5 Yrs $7387 mill.
LT Debt $17341 mill. LT Interest $685 mill.

(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $38 mill.

Pension Assets-12/19 $4993 mill.
Oblig $5810 mill.

Pfd Stock None
Common Stock 192,650,741 shs.

MARKET CAP: $23 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
8557.0	8897.0	8791.0	9661.0	12301	10337	10630	12607	14212	12669	*11600*	*12200*	Revenues ($mill)	*14000*
630.0	624.0	666.0	661.0	905.0	796.0	868.0	1029.0	1120.0	1169.0	*1295*	*1390*	Net Profit ($mill)	*1755*
32.7%	35.9%	29.8%	27.5%	26.5%	25.6%	24.5%	21.8%	8.1%	11.5%	*8.0%*	*8.0%*	Income Tax Rate	*8.0%*
1.6%	1.6%	3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
51.3%	50.6%	48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	*60.0%*	*60.0%*	Long-Term Debt Ratio	*58.5%*
48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	*40.0%*	*40.0%*	Common Equity Ratio	*41.5%*
13811	14196	14387	15135	16670	17607	20280	21697	22371	27607	*30750*	*32525*	Total Capital ($mill)	*39000*
12992	13746	14684	15800	16820	18034	19730	20721	21650	25317	*28275*	*30275*	Net Plant ($mill)	*33500*
6.3%	5.9%	6.1%	5.7%	8.6%	5.7%	5.3%	5.9%	6.1%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
4.0%	3.4%	3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
57%	62%	61%	67%	52%	63%	61%	58%	55%	59%	*61%*	*62%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.1	+3.5	-3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
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. (%)	300	278	260

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	3.0%	4.0%	*-1.0%*
"Cash Flow"	3.5%	3.5%	*6.5%*
Earnings	8.0%	7.5%	*6.0%*
Dividends	5.5%	7.0%	*6.5%*
Book Value	4.5%	5.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	3236	2855	3245	3271	12607
2018	3753	3159	3550	3750	14212
2019	3514	2888	3119	3148	12669
2020	3022	2583	*2950*	*3045*	*11600*
2021	*3300*	*2700*	*3050*	*3150*	*12200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2.23	.99	1.51	1.00	5.73
2018	2.00	1.29	1.84	1.05	6.17
2019	2.19	.99	1.73	1.40	6.31
2020	1.76	1.44	*2.00*	*1.50*	*6.70*
2021	*2.00*	*1.55*	*2.10*	*1.50*	*7.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.73	.73	.73	.77	2.96
2017	.825	.825	.825	.825	3.30
2018	.8825	.8825	.8825	.8825	3.53
2019	.945	.945	.945	.945	3.78
2020	1.0125	1.0125	1.0125		

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.2 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 46%; commercial, 34%; industrial, 13%; other, 7%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 54% of revenues. '19 reported deprec. rates: 4.0% electric, 2.7% gas. Has 10,700 employees. Chairman: Gerard M. Anderson. President & CEO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's gas utility received a rate order. The Michigan Public Service Commission approved a settlement for DTE Gas calling for an increase of $110 million, based on a 9.9% return on equity and a 52% common-equity ratio. Earnings will also be augmented by $20 million of accelerated amortization to income of deferred taxes. New tariffs will take effect on October 1st. Separately, DTE Electric will delay its next rate application until 2021, but will also benefit from the accelerated amortization of deferred taxes.

Earnings in 2020 are likely to end up near the upper end of DTE Energy's targeted range of $6.47-$6.75 a share. The negative effects of the weak economy have been less than the company feared, as residential kilowatt-hour sales have risen even more than expected from people working from home. Favorable weather patterns have helped, too. On the nonutility side, the Gas Pipeline and Storage segment has fared better than expected as the demand for natural gas remains healthy. A pipeline began service on August 1st, completed on schedule and below the $600 million budget. The Energy Trading business is trending at the high end of DTE Energy's expectation. Second-quarter profits exceeded our estimate, so we boosted our 2020 share-net expectation by $0.20, to $6.70. Note that we raised the Financial Strength rating a notch, to A.

Earnings will likely improve in 2021. The economy should be better by then. DTE Electric and DTE Gas will benefit from a full year's effect of rate increases obtained in 2020. DTE Gas also recovers certain capital spending through a rider on customers' bills. We expect continued growth from the nonutility operations, especially Gas Pipeline and Storage. Our estimate of $7.15 a share, which we raised by $0.25, would produce a 7% increase.

We think the board of directors will boost the dividend in the fourth quarter, effective with the January payment. DTE Energy's goal for dividend growth is 7%, and we estimate a hike of $0.29 a share (7.2%) in the annual payout.

This stock's dividend yield is average, by utility standards. Total return potential does not stand out, either for the 18-month span or the 3- to 5-year period.

Paul E. Debbas, CFA *September 11, 2020*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, (2¢); '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on disc. ops.: '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '17-'18 EPS don't sum due to rounding. Next earnings report due late Oct. (B) Div'ds pd. mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '19: $47.33/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '20: 9.9% elec.; in '20: 9.9% gas; earned on avg. com. eq., '19: 10.8%. Regulat. Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	85

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

DUKE ENERGY NYSE-DUK

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
83.81	16.1	(Trailing: 16.5 / Median: 18.0)	0.75	4.6%	VALUE LINE

TIMELINESS **3** Lowered 3/13/20
SAFETY **2** New 6/1/07
TECHNICAL **3** Raised 8/14/20
BETA .85 (1.00 = Market)

High:	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.6	91.8	91.4	97.4	103.8
Low:	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1

18-Month Target Price Range

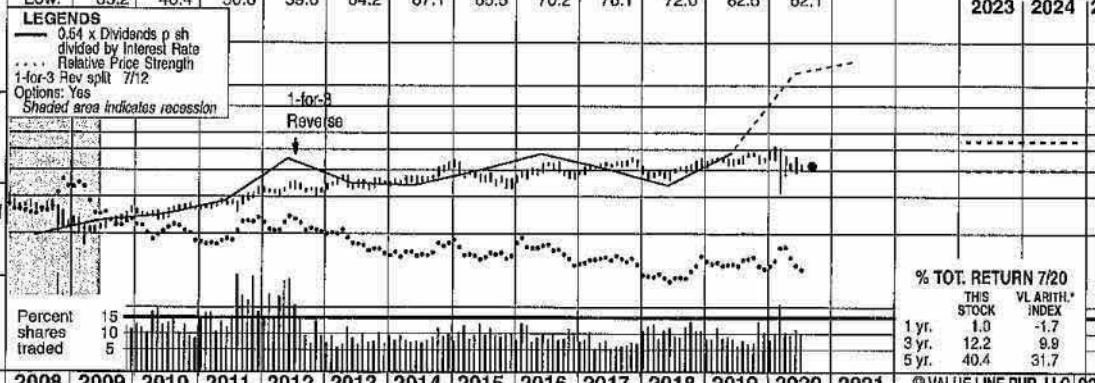
Low-High	Midpoint (% to Mid)
$62-$138	$100 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+30%)	11%
Low	80	(-5%)	4%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	711	806	682
to Sell	582	557	723
Hld's(000)	445072	476731	473369



% TOT. RETURN 7/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.0	-1.7
3 yr.	12.2	9.9
5 yr.	40.4	31.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
--	--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	*30.95*	*32.15*	Revenues per sh	*34.50*
--	--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	10.49	12.13	*12.10*	*12.75*	"Cash Flow" per sh	*14.50*
--	--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.13	5.07	*5.10*	*5.30*	Earnings per sh A	*6.00*
--	--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	*3.82*	*3.90*	Div'd Decl'd per sh B ■	*4.15*
--	--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	*15.50*	*14.70*	Cap'l Spending per sh	*13.75*
--	--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	*63.80*	*65.35*	Book Value per sh C	*71.00*
--	--	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	733.00	*764.00*	*770.00*	Common Shs Outst'g D	*785.00*
--	--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	19.4	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
--	--	--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	1.05	.95	*Value Line*		Relative P/E Ratio	*.85*
--	--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $64421 mill. Due in 5 Yrs $20638 mill.
LT Debt $56311 mill. LT Interest $2191 mill.
Incl. $969 mill. capitalized leases.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $268 mill.
Pension Assets-12/19 $8910 mill. Oblig $8231 mill.
Pfd Stock $1962 mill. Pfd Div'd $58 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 734,852,532 shs. as of 4/30/20
MARKET CAP: $62 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
14272	14529	19624	24598	23925	23459	22743	23565	24521	25079	*23650*	*24750*	Revenues ($mill)	*27000*
1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	2928.0	3755.0	*3865*	*4175*	Net Profit ($mill)	*4750*
32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.2%	12.7%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	13.0%	7.9%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	*52.5%*	*53.0%*	Long-Term Debt Ratio	*53.5%*
55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	*45.5%*	*45.5%*	Common Equity Ratio	*45.0%*
40457	41451	77307	79482	78088	77222	86609	90774	94940	101807	*106650*	*110725*	Total Capital ($mill)	*123600*
40344	42661	68558	69490	70046	75709	82520	86391	91694	102127	*108475*	*114050*	Net Plant ($mill)	*128400*
5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.2%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.3%	*7.5%*	*8.0%*	Return on Com Equity E	*8.5%*
2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	1.2%	1.0%	2.4%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
73%	72%	82%	78%	76%	79%	91%	83%	84%	71%	*77%*	*74%*	All Div'ds to Net Prof	*71%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.0	+3.9	-.9
Avg. Indust. Use (MWH)	2914	2953	2934
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.)	+1.3	+1.4	+1.5
Fixed Charge Cov. (%)	272	218	233

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	1.0%	1.0%	*.5%*
"Cash Flow"	3.5%	6.0%	*5.0%*
Earnings	3.0%	2.5%	*5.0%*
Dividends	3.0%	3.0%	*2.5%*
Book Value	2.0%	1.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	5729	5555	6482	5799	23565
2018	6135	5643	6628	6115	24521
2019	6163	5873	6940	6103	25079
2020	5949	*5300*	*6600*	*5801*	*23650*
2021	*6200*	*5650*	*6850*	*6050*	*24750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	1.02	.98	1.36	.86	4.22
2018	1.17	.71	1.63	.61	4.13
2019	1.24	1.12	1.82	.89	5.07
2020	1.24	*1.05*	*1.86*	*.95*	*5.10*
2021	*1.35*	*1.10*	*1.90*	*.95*	*5.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018	.89	.89	.927	.928	3.64
2019	.927	.928	.945	.945	3.75
2020	.945	.945	.965		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 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, 44%; commercial, 28%; industrial, 14%; other, 14%. Generating sources: gas, 29%; nuclear, 29%; coal, 22%; other, 1%; purchased, 19%. Fuel costs: 30% of revs. '19 reported deprec. rate: 3.1%. 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.

The Atlantic Coast Pipeline project, 47%-owned by Duke Energy, has been canceled. The project was plagued by delays and cost overruns stemming from litigation. This wasn't expected to be completed until early 2022, more than three years after the original target. The total cost had risen to an expected $8.0 billion, from $4.5 billion-$5.0 billion initially. Two unfavorable rulings from U.S. courts convinced Duke and its partner, Dominion Energy, to pull the plug. As a result, the company will take a nonrecurring, noncash pretax charge of $2.0 billion-$2.5 billion, most of which will be recorded against June-quarter results. However, the cancelation will also affect ongoing earnings because Duke will no longer record the Allowance for Funds Used During Construction, a noncash credit to earnings. Accordingly, management is now guiding analysts toward the low end of its 2020 earnings target of $5.05-$5.45 a share. The project was expected to contribute $0.30-$0.35 a share to profits in 2021. However, we did not change our expectations because our 2020 estimate of $5.10 a share was already near the low end of the range.

Duke received a rate increase in Indiana and reached partial settlements in North Carolina. The commission granted the utility an increase of $146 million, based on a return on equity of 9.7% and a common-equity ratio of 53%. About 75% of the increase took effect last month, with the remainder set to take effect in the first quarter of 2021. The company's two utilities in North Carolina reached partial settlements of their rate cases, subject to approval by the state commission. When new tariffs will take effect is unknown.

The board of directors raised the dividend this quarter. The quarterly increase was two cents a share (2.1%). This growth rate is less than half the utility average, which is a result of Duke's high payout ratio.

Duke stock has an above-average dividend yield for a utility. The write-off of the pipeline project did not surprise Wall Street, and the stock price has fallen at a low double-digit percentage this year—less than many utility equities. Total return potential is attractive for the 18-month span, but not for the 3- to 5-year period.

Paul E. Debbas, CFA *August 14, 2020*

(A) Diluted EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 41¢; losses on disc. ops.: '14, 80¢; '16, 60¢; '18 EPS don't sum due to rounding. Next earnings report due early Nov. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $44.37/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '18 in NC: 9.9%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '04 in IN: 10.5%; earned on avg. com. eq., '19: 8.3%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

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

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

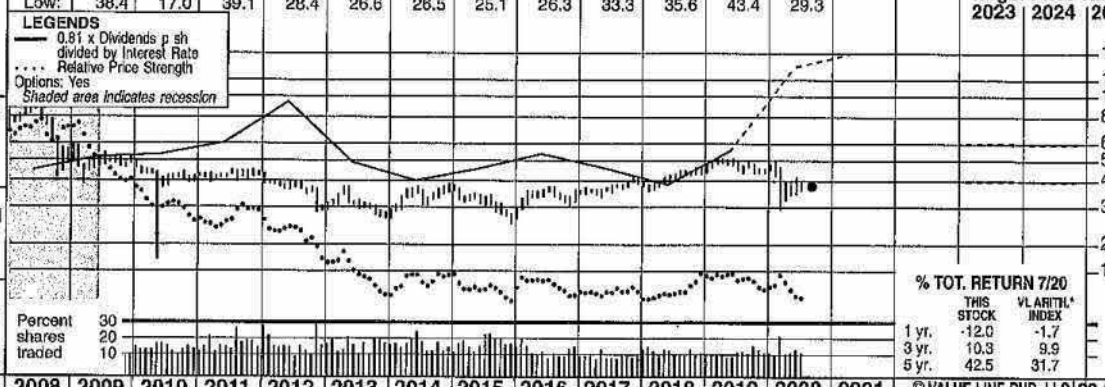
EXELON CORP. NDQ-EXC

RECENT PRICE **37.99** | P/E RATIO **12.9** (Trailing: 13.1 / Median: 15.0) | RELATIVE P/E RATIO **0.60** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS **3** Lowered 6/7/19
SAFETY **3** Lowered 5/15/20
TECHNICAL **3** Raised 8/14/20
BETA .95 (1.00 = Market)

High:	59.0	49.9	45.4	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5
Low:	38.4	17.0	39.1	28.4	26.6	26.5	25.1	26.3	33.3	35.6	43.4	29.3

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



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$29-$61 $45 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+60%)	15%
Low	40	(+5%)	6%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	423	428	361
to Sell	451	478	493
Hld's(000)	767278	768153	765293

Percent shares traded 30 20 10

% TOT. RETURN 7/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.0	-1.7
3 yr.	10.3	9.9
5 yr.	42.5	31.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
21.85	23.05	23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	35.39	*32.80*	*34.75*	Revenues per sh	*40.50*
5.68	6.19	6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	8.37	8.24	8.96	*8.90*	*9.50*	"Cash Flow" per sh	*11.00*
2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	2.78	2.07	3.01	*2.70*	*3.00*	Earnings per sh A	*3.50*
1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	1.38	1.45	*1.53*	*1.61*	Div'd Decl'd per sh B ■	*1.90*
2.89	3.25	3.61	4.05	4.74	4.96	5.03	5.09	6.77	6.29	7.07	8.29	9.26	7.87	7.84	7.45	*8.30*	*7.25*	Cap'l Spending per sh	*7.50*
14.19	13.69	14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	31.77	33.12	*34.10*	*35.55*	Book Value per sh C	*40.25*
664.19	665.37	669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	963.34	968.19	973.00	*976.00*	*979.00*	Common Shs Outst'g D	*990.00*
13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	13.4	20.1	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	.67	1.09	.84	*Value Line*		Relative P/E Ratio	*.80*
3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $40025 mill. Due in 5 Yrs $13745 mill.
LT Debt $35198 mill. LT Interest $1478 mill.
Includes $390 mill. nonrecourse transition bonds.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $287 mill.

Pension Assets-12/19 $18590 mill. Oblig $22868 mill.

Pfd Stock None

Common Stock 974,407,848 shs.

MARKET CAP: $37 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
18644	18924	23489	24888	27429	29447	31360	33531	35985	34438	*32000*	*34000*	Revenues ($mill)	*40000*
2567.0	2499.0	1579.0	1999.0	1826.0	2282.0	1677.0	2636.0	2010.0	2936.0	*2615*	*2925*	Net Profit ($mill)	*3510*
39.2%	36.8%	32.4%	36.5%	27.2%	32.2%	38.5%	34.2%	5.4%	19.4%	*19.5%*	*19.5%*	Income Tax Rate	*19.5%*
2.1%	3.0%	5.8%	4.5%	5.5%	5.4%	12.3%	6.5%	7.0%	5.3%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
46.8%	45.7%	45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	*52.0%*	*50.5%*	Long-Term Debt Ratio	*50.0%*
52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	*48.0%*	*49.5%*	Common Equity Ratio	*50.0%*
25651	26661	40057	41196	42811	50272	58053	62422	65229	63943	*68075*	*70000*	Total Capital ($mill)	*80300*
29941	32570	45186	47330	52087	57439	71555	74202	76707	80233	*82800*	*84025*	Net Plant ($mill)	*86400*
11.4%	10.6%	5.1%	5.9%	5.3%	5.5%	4.1%	5.3%	4.2%	5.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
18.8%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	*8.0%*	*8.5%*	Return on Com Equity E	*9.0%*
8.7%	7.7%	NMF	3.2%	3.3%	4.5%	1.9%	4.7%	2.2%	4.7%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	56%	109%	63%	59%	49%	70%	47%	66%	48%	*51%*	*49%*	All Div'ds to Net Prof	*52%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-3.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	NA	NA
Fixed Charge Cov. (%)	282	236	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	2.5%	4.0%	*2.0%*
"Cash Flow"	1.0%	5.0%	*4.5%*
Earnings	-4.5%	4.5%	*5.0%*
Dividends	-3.5%	-3.0%	*5.5%*
Book Value	6.5%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	8757	7623	8769	8382	33531
2018	9693	8076	9403	8813	35985
2019	9477	7689	8929	8343	34438
2020	8747	7322	*8231*	*7700*	*32000*
2021	*9450*	*7500*	*8850*	*8200*	*34000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.83	.44	.95	.56	2.78
2018	.60	.56	.76	.16	2.07
2019	.93	.50	.79	.79	3.01
2020	.60	.73	*.75*	*.62*	*2.70*
2021	*.85*	*.60*	*.90*	*.65*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.31	.318	.318	.318	1.26
2017	.3275	.3275	.3275	.3275	1.31
2018	.345	.345	.345	.345	1.38
2019	.3625	.3625	.3625	.3625	1.45
2020	.3825	.3825			

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 8.9 mill. elec., 1.3 mill. gas customers. Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: res'l, 54%; small comm'l & ind'l, 16%; large comm'l & ind'l, 17%; other, 13%. Generating sources: nuclear, 65%; other, 10%; purch., 25%. Fuel costs: 45% of revs. '19 depr. rates: 2.8%-7.4% elec., 2.0% gas. Has 32,700 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon's Commonwealth Edison unit reached a deal with the U.S. Attorney's Office to resolve an investigation of lobbying activities in Illinois. As part of a deferred prosecution agreement, ComEd will pay a $200 million fine as a result of a bribery allegation involving the state government. This resolved some uncertainty that was overhanging the stock, although investors should note than an SEC investigation is ongoing. We *excluded* the fine from our earnings presentation as a nonrecurring item.

This has been a difficult year for Exelon for other reasons. Unusually mild winter weather hurt the company's earnings — not just at the utility, but at the nonutility operations as well. The coronavirus will have just a modest negative effect on the bottom line because 70% of Exelon's utility businesses operate under regulatory mechanisms that decouple revenues and volume. Management has cut capital and operating costs in response. All told, we think earnings will fall well short of the 2019 tally. Note that our estimate is well below Exelon's guidance of $2.80-$3.10 a share (reduced from the initial $3.00-$3.30) because we include some items that the company excludes from its definition of operating earnings.

As usual, some rate cases are pending. In Maryland, Baltimore G&E is seeking multiyear increases totaling $235.0 million, based on a 10.1% return on equity. An order is expected in December. In Washington, D.C., Pepco is seeking multiyear increases totaling $135.9 million, based on a 9.7% ROE. A ruling is expected in November or December. In Delaware, Delmarva filed for electric and gas hikes totaling $32.8 million, based on a 10.3% ROE. Decisions are due in 2021. Rate relief and a better economy should produce higher profits in 2021. We figure share net will rebound to about the 2019 level.

We suggest investors look elsewhere. Exelon's nonregulated businesses are operating in a tough environment. The dividend yield, just slightly above the industry average, does not offer enough compensation for the risks. The stock price has declined 17% this year, in line with many electric companies. Total return potential is just modest to 2023-2025.

Paul E. Debbas, CFA *August 14, 2020*

(A) Diluted egs. Excl. nonrec. gain (losses): '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, $1.19; 2Q '20, (20¢). '18 EPS don't sum due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. deferred charges. In '19: $15.43/sh. (D) In mill. (E) Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earned on avg. com. eq., '19: 9.3%. Reg. Climate: PA, NJ Avg.; IL, MD, Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	60

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

EVERGY, INC. NYSE-EVRG

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
53.22	18.4	(Trailing: 19.4 / Median: NMF)	0.86	4.0%	VALUE LINE

TIMELINESS **3** New 9/11/20
SAFETY **2** New 9/14/18
TECHNICAL **5** New 9/11/20
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$39-$95	$67 (25%)

2023-25 PROJECTIONS

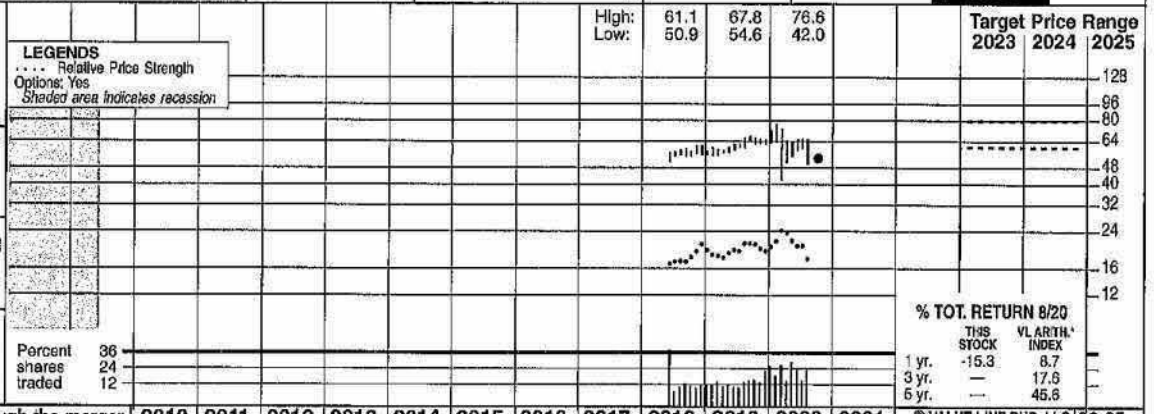
	Price	Gain	Ann'l Total Return
High	80	(+50%)	14%
Low	60	(+15%)	7%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	263	232	216
to Sell	278	302	312
Hld's(000)	191230	185949	184926

	2018	2019	2020
High:	61.1	67.8	76.6
Low:	50.9	54.6	42.0

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-15.3	8.7
3 yr.	—	17.6
5 yr.	—	45.8

Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
--	--	--	--	--	--	--	--	16.75	22.71	*21.80*	*22.25*	Revenues per sh	*24.50*
--	--	--	--	--	--	--	--	4.89	7.18	*7.05*	*7.65*	"Cash Flow" per sh	*9.00*
--	--	--	--	--	--	--	--	2.50	2.79	*2.75*	*3.10*	Earnings per sh A	*3.50*
--	--	--	--	--	--	--	--	1.74	1.93	*2.05*	*2.17*	Div'd Decl'd per sh B ■	*2.55*
--	--	--	--	--	--	--	--	4.19	5.34	*7.00*	*7.60*	Cap'l Spending per sh	*6.50*
--	--	--	--	--	--	--	--	39.28	37.82	*38.45*	*39.40*	Book Value per sh C	*42.25*
--	--	--	--	--	--	--	--	255.33	226.64	*227.00*	*227.00*	Common Shs Outst'g D	*227.00*
--	--	--	--	--	--	--	--	22.7	21.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
--	--	--	--	--	--	--	--	1.23	1.17	*Value Line*		Relative P/E Ratio	*1.10*
--	--	--	--	--	--	--	--	3.1%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
--	--	--	--	--	--	--	--	4275.9	5147.8	*4950*	*5050*	Revenues ($mill)	*5550*
--	--	--	--	--	--	--	--	535.8	669.9	*640*	*685*	Net Profit ($mill)	*775*
--	--	--	--	--	--	--	--	9.8%	12.6%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
--	--	--	--	--	--	--	--	2.5%	2.5%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
--	--	--	--	--	--	--	--	40.0%	50.6%	*51.5%*	*52.5%*	Long-Term Debt Ratio	*53.5%*
--	--	--	--	--	--	--	--	60.0%	49.4%	*48.5%*	*47.5%*	Common Equity Ratio	*46.5%*
--	--	--	--	--	--	--	--	16716	17337	*17950*	*18750*	Total Capital ($mill)	*20500*
--	--	--	--	--	--	--	--	18952	19346	*19950*	*20650*	Net Plant ($mill)	*22700*
--	--	--	--	--	--	--	--	4.0%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
--	--	--	--	--	--	--	--	5.3%	7.8%	*7.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
--	--	--	--	--	--	--	--	5.3%	7.8%	*7.0%*	*8.0%*	Return on Com Equity E	*8.5%*
--	--	--	--	--	--	--	--	.6%	2.4%	*2.0%*	*2.5%*	Retained to Com Eq	*2.5%*
--	--	--	--	--	--	--	--	89%	69%	*73%*	*68%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $10415 mill. Due in 5 Yrs $3294.4 mill.
LT Debt $9281.2 mill. LT Interest $378.3 mill.
Incl. $47.9 mill. capitalized leases.
(LT interest earned: 3.1x)

Leases, Uncapitalized Annual rentals $20.5 mill.

Pension Assets-12/19 $1732.8 mill.
Oblig $2718.2 mill.

Pfd Stock None

Common Stock 226,827,540 shs.
as of 7/31/20
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	7.11	7.25
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. (%)	NA	322	305

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd 2019 to '23-'25
Revenues	--	--	*1.5%*
"Cash Flow"	--	--	*4.5%*
Earnings	--	--	*4.5%*
Dividends	--	--	*5.5%*
Book Value	--	--	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	--	--	--	--	--
2018	600.2	893.4	1582.5	1199.8	4275.9
2019	1216.9	1221.7	1577.6	1131.6	5147.8
2020	1117	1185	*1548*	*1100*	*4950*
2021	*1200*	*1200*	*1550*	*1100*	*5050*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	--	--	--	--	--
2018	.42	.56	1.32	.07	2.50
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	*1.55*	*.30*	*2.75*
2021	*.45*	*.65*	*1.65*	*.35*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	--	--	--	--	--
2017	--	--	--	--	--
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505			

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 37%; commercial, 35%; industrial, 12%; wholesale, 7%; other, 9%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 25% of revenues. '19 reported deprec. rate: 3%. Has 4,600 employees. Chairman: Mark A. Ruelle. President & Chief Executive Officer: Terry Bassham. Incorporated: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergyinc.com.

Evergy has announced the result of its strategic review. This arose from the stake (equivalent to 11.3 million shares) Elliott Management, an activist investor group, took in January. Elliott pushed Evergy to explore options such as a sale or merger of the company, or an increase in capital spending aimed at adding renewable generation. Evergy chose the latter option. The company increased its five-year capital budget by $1.4 billion, to $8.9 billion. This will boost annual rate-base growth to 5%-6% from 3%-4% previously, which is lower than that of most utilities.

Wall Street was disappointed by the news. It's not that increased capital spending, and much-greater rate-base growth, is bad. The problem is that the market was hoping for a takeover. The stock price has declined 15% since August 3rd, the day before news broke about the company's decision. This is unrelated to the upcoming retirement of Evergy's chief executive officer, Terry Bassham.

The regulatory commissions in Missouri and Kansas have opened investigations into Evergy's plan. The regulators want to ensure this won't lead to unnecessarily higher rates or a lower quality of service. Whether this will affect the plan remains to be seen.

We raised our 2020 and 2021 share-earnings estimates by $0.10 and $0.15, respectively. June-quarter profits topped our estimate by $0.10 a share, due in part to favorable weather patterns. Our revised estimate of $2.75 a share is within Evergy's targeted range of $2.66-$2.96 a share (on a GAAP basis). Our estimate, and this guidance, includes adviser fees and a charge for an early retirement program, which together are expected to amount to $0.24 a share. Without these costs in 2021, profits should top the $3.00-a-share mark.

We expect a dividend hike in the fourth quarter. We look for a boost of $0.03 a share (5.9%) in the quarterly payout, and project healthy dividend growth over the 3- to 5-year period.

The stock's dividend yield is about average for a utility. Total return potential is more attractive for the 18-month span than for the 2023-2025 period. Note that the equity has a Timeliness rank now that its trading history is long enough.

Paul E. Debbas, CFA *September 11, 2020*

(A) Diluted EPS. '19 earnings don't sum to full-year total due to rounding. Next earnings report due early Nov. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '19: $4077.1 mill., $17.99/sh. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%. Earned on average common equity, '19: 7.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	60
Price Growth Persistence	NMF
Earnings Predictability	NMF

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

OGE ENERGY CORP. NYSE-OGE

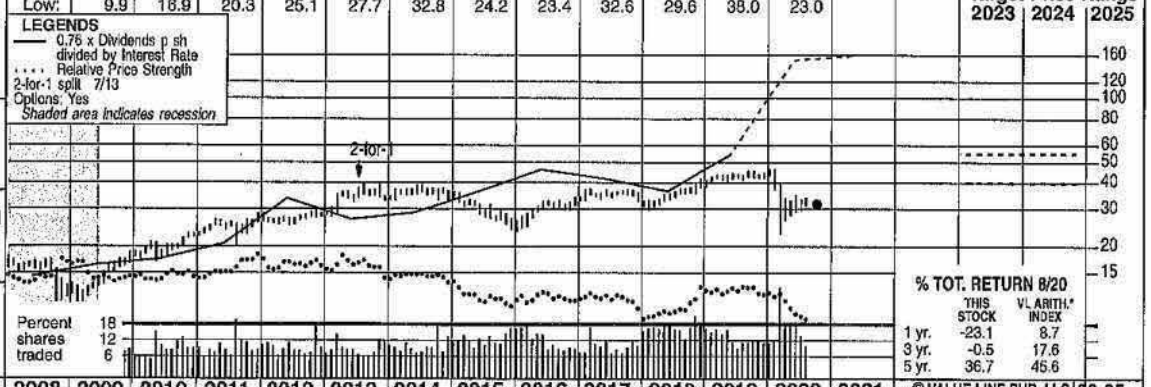
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
31.86	15.0	(Trailing: 14.2) (Median: 17.0)	0.70	5.1%	VALUE LINE

TIMELINESS 3 Lowered 3/6/20
SAFETY 2 Lowered 12/18/15
TECHNICAL 3 Lowered 5/1/20
BETA 1.05 (1.00 = Market)

High:	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4
Low:	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0

Target Price Range 2023 | 2024 | 2025

LEGENDS
— 0.75 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$23-$61	$42 (30%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+75%)	18%
Low	40	(+25%)	10%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	205	176	203
to Sell	185	221	182
Hld's(000)	133273	128589	129209

% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-23.1	8.7
3 yr.	-0.5	17.6
5 yr.	36.7	45.6

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
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	11.37	11.15	*10.50*	*11.50*	Revenues per sh	*13.75*
1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.89	3.46	3.40	3.23	3.31	3.34	3.74	4.02	*4.05*	*4.35*	"Cash Flow" per sh	*5.00*
.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	2.12	2.24	*2.10*	*2.25*	Earnings per sh A	*2.50*
.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	*1.60*	*1.68*	Div'd Decl'd per sh B ■	*1.95*
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	2.87	3.18	*2.90*	*3.65*	Cap'l Spending per sh	*3.75*
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	20.06	20.69	*18.25*	*18.85*	Book Value per sh C	*20.50*
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	200.10	*200.00*	*200.00*	Common Shs Outst'g D	*200.00*
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	16.5	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.02	*Value Line*		Relative P/E Ratio	*1.10*
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%	4.0%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $3568.4 mill. Due in 5 Yrs $75.0 mill.
LT Debt $3493.4 mill. LT Interest $154.4 mill.
(LT interest earned: 4.2x)

Leases, Uncapitalized Annual rentals $6.2 mill.

Pension Assets-12/19 $530.3 mill. Oblig $616.9 mill.

Pfd Stock None

Common Stock 200,169,838 shs.

MARKET CAP: $6.4 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	*2100*	*2300*	Revenues ($mill)	*2750*
295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	*420*	*450*	Net Profit ($mill)	*505*
34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	*1.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	*49.0%*	*48.0%*	Long-Term Debt Ratio	*49.0%*
49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	*51.0%*	*52.0%*	Common Equity Ratio	*51.0%*
4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	*7150*	*7265*	Total Capital ($mill)	*8050*
6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	*9235*	*9545*	Net Plant ($mill)	*10325*
7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.0%*
12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	*11.5%*	*12.0%*	Return on Com Equity E	*12.0%*
6.7%	7.7%	7.2%	7.3%	6.6%	4.0%	3.3%	3.5%	3.8%	3.6%	*3.0%*	*3.0%*	Retained to Com Eq	*2.5%*
48%	43%	44%	43%	47%	61%	67%	64%	64%	67%	*76%*	*74%*	All Div'ds to Net Prof	*78%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.2	+6.8	+1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.30	4.86	4.69
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6456	6863	6817
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.9	+1.0
Fixed Charge Cov. (%)	315	292	335

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-5.0%	-5.5%	*3.5%*
"Cash Flow"	4.0%	1.0%	*5.0%*
Earnings	5.0%	2.0%	*3.0%*
Dividends	7.0%	10.0%	*6.0%*
Book Value	7.0%	5.5%	*.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	456.0	586.4	716.8	501.9	2261.1
2018	492.7	567.0	698.8	511.8	2270.3
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	*715.2*	*450*	*2100*
2021	*500*	*550*	*750*	*500*	*2300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.18	.52	.92	.30	1.92
2018	.27	.55	1.02	.27	2.12
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	*1.13*	*.23*	*2.10*
2021	*.25*	*.55*	*1.20*	*.25*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.3875	1.48
2020	.3875	.3875	.3875		

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 858,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.5% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 10%; oilfield, 9%; other, 18%. Generating sources: gas, 35%; coal, 15%; wind, 5%; purchased, 45%. Fuel costs: 35% of revenues. '19 reported depreciation rate (utility): 2.7%. 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.

The price of Enable Midstream Partners stock continues to affect the price of OGE Energy stock. OGE has a 25.5% stake in the midstream natural gas master limited partnership. Enable has been hurt by reduced activity in the gas and oil sector this year, so its units have lost nearly 50% of their value since the start of 2020. The distributions that OGE receives from Enable have been halved. In addition, OGE took a pretax charge of $780 million in the first quarter to write down the value of its stake in Enable. (There will be tax adjustments throughout the remainder of 2020, and the company expects the aftertax nonrecurring charge for the full year to amount to $590 million.) The price of OGE stock has fallen 28% this year, making this one of the worst-performing equities in the electric utility industry.

We cut our 2020 earnings estimate by $0.05 a share, to $2.10. June-quarter profits were a bit below our estimate. Our revised estimate is near the low end of OGE's targeted range of $2.08-$2.18 a share, which is unchanged. Earnings are likely to fall short of the 2019 tally due to a decline in equity income from OGE's stake in Enable. Oklahoma Gas and Electric has held up well despite the coronavirus problem. Oklahoma has a relatively low unemployment rate, and OG&E received permission to defer for future recovery its coronavirus-related costs in Oklahoma and Arkansas. A better economy ought to help earnings rebound in 2021.

OG&E is awaiting a regulatory decision in Oklahoma. The utility is asking the state regulators to approve an $810 million grid modernization plan. The company wants to recover the costs through a rider (surcharge) on customers' bills. A ruling is expected by yearend.

A dividend increase is likely later this month, effective with the October payment. We estimate a boost of $0.09 a share (5.8%) in the annual disbursement, and project similar dividend growth over the 3- to 5-year period.

This stock has an attractive yield. This is more than one percentage point above the utility average. Total return potential is strong for the 18-month period and respectable for the pull to 2023-2025.

Paul E. Debbas, CFA *September 11, 2020*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '04, (3¢); '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); gains on discont. ops.: '05, 25¢; '06, 20¢. '18 & '19 EPS don't sum due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '19: $1.53/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '19: 11.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	40
Earnings Predictability	85

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE **38.85** | P/E RATIO **17.4** (Trailing: 18.1; Median: 22.0) | RELATIVE P/E RATIO **0.81** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS **4** Lowered 9/11/20
SAFETY **2** Raised 6/17/16
TECHNICAL **3** Raised 5/8/20
BETA .85 (1.00 = Market)

High:	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9					
Low:	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0					

18-Month Target Price Range

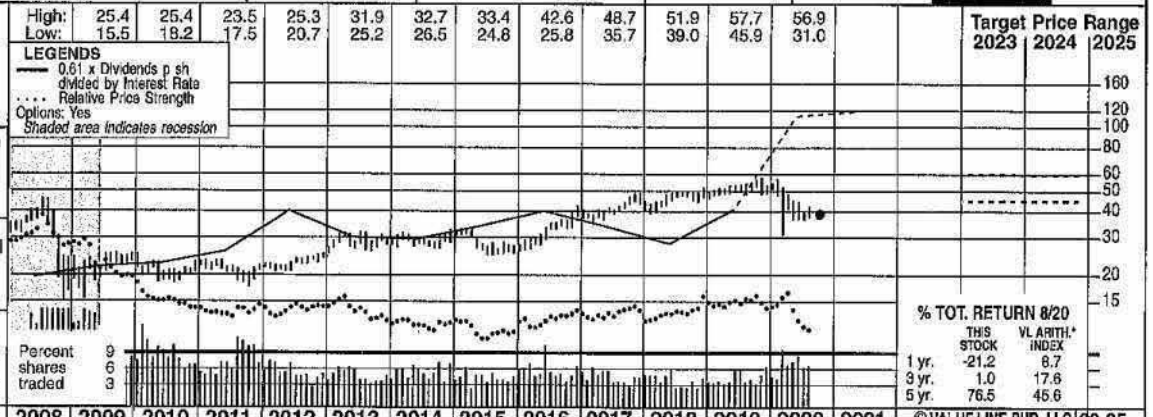
Low-High	Midpoint (% to Mid)
$31-$67	$49 (25%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+55%)	14%
Low	45	(+15%)	8%

Institutional Decisions

	4Q2019	1Q2020	2Q2020
to Buy	85	78	75
to Sell	69	84	82
Hld's(000)	18484	18228	18869



% TOT. RETURN 8/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-21.2	8.7
3 yr.	1.0	17.6
5 yr.	76.5	45.6

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	23.10	22.90	*20.50*	*22.60*	Revenues per sh	*26.50*
2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	4.11	*4.05*	*4.35*	"Cash Flow" per sh	*5.25*
1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	2.17	*2.15*	*2.30*	Earnings per sh A	*2.75*
1.10	1.12	1.16	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	1.40	*1.48*	*1.56*	Div'd Decl'd per sh B ■	*1.80*
1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	5.16	*9.15*	*3.75*	Cap'l Spending per sh	*3.00*
14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	19.46	*20.70*	*21.40*	Book Value per sh C	*23.75*
28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	40.16	*41.50*	*41.60*	Common Shs Outst'g D	*42.00*
17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	.92	1.06	1.11	1.20	1.26	*Value Line*		Relative P/E Ratio	*1.05*
4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $765.9 mill. **Due in 5 Yrs** $190.3 mill.
LT Debt $724.4 mill. **LT Interest** $33.8 mill.
(LT interest earned: 4.1x)

Leases, Uncapitalized Annual rentals $22.3 mill.
Pension Assets-12/19 $329.8 mill.
Oblig $384.8 mill.

Pfd Stock None

Common Stock 40,872,064 shs.
as of 7/31/20

MARKET CAP: $1.6 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1119.1	1077.9	859.2	893.3	799.3	779.8	803.5	849.4	916.4	919.5	*850*	*940*	Revenues ($mill)	*1115*
13.6	16.4	39.0	50.2	56.9	58.6	62.0	73.9	82.3	86.8	*90.0*	*95.0*	Net Profit ($mill)	*110*
--	14.5%	5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
.6%	3.8%	1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	*9.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	*42.0%*	*45.0%*	Long-Term Debt Ratio	*47.0%*
58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	*58.0%*	*55.0%*	Common Equity Ratio	*53.0%*
1083.3	1058.9	959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	*1485*	*1625*	Total Capital ($mill)	*1850*
1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	*2055*	*2125*	Net Plant ($mill)	*2275*
2.7%	3.2%	5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	*10.0%*	*11.0%*	Return on Shr. Equity E	*11.5%*
2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	*10.0%*	*11.0%*	Return on Com Equity	*11.5%*
NMF	NMF	NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
NMF	NMF	113%	87%	78%	79%	78%	69%	65%	64%	*69%*	*67%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+1.4	+3.4	-.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.26	5.97	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	917	912	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.2	+.1
Fixed Charge Cov. (%)	608	409	407

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-4.5%	-.5%	*3.0%*
"Cash Flow"	2.5%	6.0%	*5.0%*
Earnings	5.5%	9.0%	*5.0%*
Dividends	1.5%	2.5%	*5.0%*
Book Value	--	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	214.1	212.1	216.5	206.7	849.4
2018	241.2	226.3	227.7	221.2	916.4
2019	246.0	229.2	228.6	215.7	919.5
2020	234.7	192.8	*212.5*	*210*	*850*
2021	*250*	*235*	*235*	*220*	*940*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.49	.42	.45	.50	1.86
2018	.66	.47	.58	.35	2.06
2019	.66	.39	.62	.51	2.17
2020	.60	.42	*.63*	*.50*	*2.15*
2021	*.68*	*.47*	*.65*	*.50*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.3125	.3125	.3125	.3125	1.25
2017	.32	.32	.32	.32	1.28
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	1.40
2020	.37	.37	.37		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 132,000 customers in Minnesota (52% of retail electric revenues), North Dakota (38%), and South Dakota (10%). Electric rev. breakdown: residential, 32%; commercial & farms, 36%; industrial, 30%; other, 2%. Generating sources: coal, 45%; wind & hydro, 8%; other, 1%; purchased, 46%. Fuel costs: 14% of revenues. Also has operations in manufacturing and plastics (38% of '18 income). '19 reported deprec. rate (utility): 2.8%. Has 2,300 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Inc.: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

Otter Tail Corporation raised its earnings guidance for 2020 upon reporting June-quarter results. Profits of $0.42 a share topped the year-ago tally and were above our estimate of $0.35. The Plastics segment is faring better than expected. Market conditions suggest that volume and (possibly) pricing will improve in the second half of 2020. Management now estimates that this operation will generate a profit of $0.50-$0.54 this year, versus $0.51 in 2019 and its previous expectation of just $0.43-$0.47. This is the primary reason why Otter Tail revised its targeted range for 2020 from $2.00-$2.25 a share to $2.10-$2.30 a share. (This is still below the company's original guidance of $2.23-$2.37, issued in February.) Another reason is the negative effect on earnings from declines in commercial and industrial kilowatt-hour sales at Otter Tail Power will probably be less than expected three months ago: $0.04-$0.06, versus $0.06-$0.10. We raised our 2020 and 2021 estimates by $0.10 each year, to $2.15 and $2.30, respectively. The stock's reaction was positive, but modest. The share price is still down 24% for the year.

The weak economy has hurt Otter Tail. Besides the negative effect of the sales decline on utility income, the company's Manufacturing segment has been hit hard, as many customers closed facilities due to the coronavirus. A slowdown in sales of oil and gas fracking equipment is another factor. In response, the company has cut operating and maintenance costs in each division. Otter Tail Power has also asked the regulators in each state to allow the utility to defer for future recovery costs associated with the coronavirus. We expect a stronger economy in 2021, which points to higher earnings next year.

Two significant projects are under construction. Otter Tail Power is building a 245-megawatt gas-fired plant at an expected cost of $154 million and a 150-mw wind farm at an expected cost of $260 million. The projects should be completed in late 2020 or early 2021.

The dividend yield of this untimely stock is about equal to the utility average. The equity offers attractive total return potential for the 18-month span, but isn't as high for the 2023-2025 period.

Paul E. Debbas, CFA *September 11, 2020*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS don't sum due to rndg. Next egs. rept. due early Nov. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $4.67/sh. (D) In mill. (E) Rate all'd on com. eq. in MN in '17: 9.41%; in ND in '18: 9.77%; in SD in '19: 8.75%; earn. avg. com. eq., '19: 11.6%. Reg. Clim.: MN, ND, Avg.; SD, Above Avg.

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

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

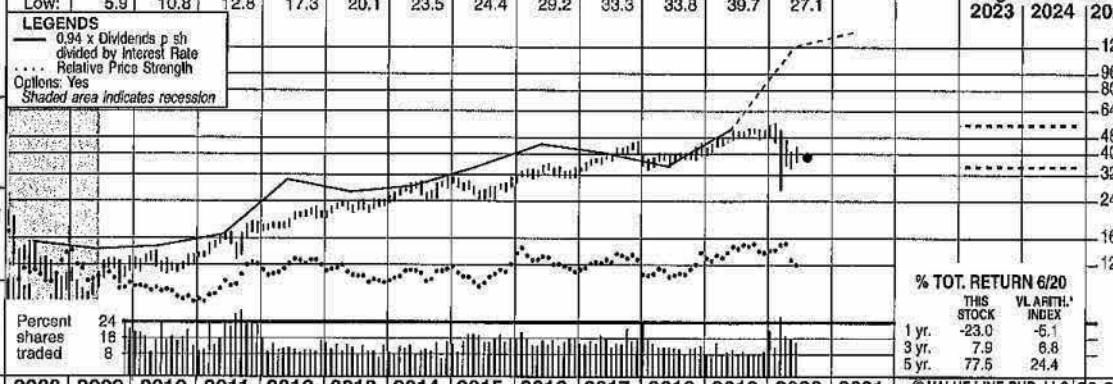
PNM RESOURCES NYSE-PNM

RECENT PRICE **38.86** | P/E RATIO **20.5** (Trailing: 20.9 / Median: 18.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **3.2%** | VALUE LINE

TIMELINESS **3** Lowered 4/24/20
SAFETY **3** Lowered 5/9/08
TECHNICAL **3** Raised 7/24/20
BETA .90 (1.00 = Market)

High:	13.1	14.0	19.2	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1
Low:	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1

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



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range
Low-High: $29-$75 — Midpoint (% to Mid): $52 (35%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	12%
Low	35	(-10%)	1%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	116	135	110
to Sell	130	116	144
Hld's(000)	72521	73262	79315

Percent shares traded: 24 / 16 / 8

% TOT. RETURN 6/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-23.0	-5.1
3 yr.	7.9	6.8
5 yr.	77.5	24.4

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
28.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	18.04	18.30	*16.30*	*16.90*	Revenues per sh	*18.00*
3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.13	6.07	*5.45*	*6.15*	"Cash Flow" per sh	*7.25*
1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	1.66	2.28	*1.90*	*2.25*	Earnings per sh A	*2.75*
.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	*1.24*	*1.30*	Div'd Decl'd per sh B ■ †	*1.50*
2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	7.74	*9.95*	*11.55*	Cap'l Spending per sh	*6.00*
18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	21.08	*23.50*	*24.45*	Book Value per sh C	*29.25*
60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	*85.83*	*85.83*	Common Shs Outst'g D	*92.00*
15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	23.4	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.26	1.14	*Value Line*		Relative P/E Ratio	*.90*
2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.8%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $3308.9 mill. **Due in 5 Yrs** $1778.9 mill.
LT Debt $2468.7 mill. **LT Interest** $112.3 mill.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $30.7 mill.
Pension Assets-12/19 $590.8 mill.
Oblig $671.3 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 5/1/20
MARKET CAP: $3.1 billion (Mid Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	*1400*	*1450*	Revenues ($mill)	*1650*
80.5	97.1	108.1	114.0	116.8	118.8	117.4	154.4	133.4	182.8	*170*	*210*	Net Profit ($mill)	*265*
32.6%	38.8%	31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	13.8%	9.4%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
7.1%	8.7%	7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	14.5%	9.2%	*12.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	*48.5%*	*54.0%*	Long-Term Debt Ratio	*50.5%*
49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	*51.0%*	*46.0%*	Common Equity Ratio	*49.0%*
3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	*3950*	*4575*	Total Capital ($mill)	*5475*
3444.4	3827.1	3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	*6005*	*6660*	Net Plant ($mill)	*7500*
4.2%	4.5%	5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	4.3%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	7.8%	10.8%	*7.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	10.9%	*7.5%*	*9.0%*	Return on Com Equity E	*9.5%*
2.2%	3.3%	3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	2.9%	5.4%	*2.5%*	*4.0%*	Retained to Com Eq	*4.5%*
57%	47%	43%	45%	51%	54%	61%	51%	64%	51%	*67%*	*58%*	All Div'ds to Net Prof	*54%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	+.3	+7.3	+5.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2580	2661	2761
Peak Load, Summer (Mw)	1843	1885	1937
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+1.1	NA
Fixed Charge Cov. (%)	243	218	228

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-2.0%	1.0%	*Nil*
"Cash Flow"	9.5%	8.5%	*4.5%*
Earnings	15.0%	7.0%	*6.0%*
Dividends	5.0%	10.0%	*5.5%*
Book Value	.5%	--	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	330.2	362.3	419.9	332.6	1445.0
2018	317.9	352.3	422.7	343.7	1436.6
2019	349.7	330.2	433.6	344.1	1457.6
2020	333.6	*320*	*415*	*331.4*	*1400*
2021	*345*	*330*	*430*	*345*	*1450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.29	.47	.92	.25	1.92
2018	.19	.48	1.09	d.10	1.66
2019	.23	.36	1.29	.40	2.28
2020	d.19	*.52*	*1.24*	*.33*	*1.90*
2021	*.18*	*.47*	*1.30*	*.30*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.22	.22	.22	.22	.88
2017	.2425	.2425	.2425	.2425	.97
2018	.265	.265	.265	.265	1.06
2019	.29	.29	.29	.29	1.16
2020	.3075	.3075			

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 532,000 customers in north central New Mexico, incl. Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 257,000 customers in Texas. Electric revenue breakdown: residential, 40%; commercial, 35%; industrial, 6%; other, 19%. Generating sources not available. Fuel costs: 26% of revenues. '19 reported deprec. rates: 2.5%-7.9%. Has 1,700 employees. Chairman, President & CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' utility subsidiary in New Mexico delayed the filing of a general rate case, but there are still some regulatory matters pending. Public Service of New Mexico had planned to file an application in the second quarter, but decided not to do so due to the state of the economy. PNM did request a regulatory mechanism that would decouple revenues and volume for residential and small commercial customers. Currently, the fixed charges billed to these users aren't high enough to reflect the fixed costs of serving them. The company expects an order by yearend. By October 1, the New Mexico commission is expected to rule on PNM's plan to replace the capacity of a coal-fired facility that is scheduled for a shutdown (well before the end of its useful life). The utility would build 280 megawatts of gas-fired capacity and 70 mw of battery storage, a total investment of $278 million. The regulators have already approved the issuance of up to $361 million of securitized bonds so that PNM can recover the cost of the plant.

We raised our 2020 earnings estimate by $0.10 a share. Although kilowatt-hour sales declines stemming from the recession are hurting the company, PNM benefited from hotter-than-normal weather in the second quarter. The company has also cut certain expenses, such as executive travel. We are sticking with our 2021 estimate of $2.25 a share.

The company's TNMP subsidiary in Texas received some rate relief. Each year, TNMP gets revenues to recover transmission and distribution expenditures. In March, the utility was granted $7.8 million for transmission costs, and another such filing was expected this month. For distribution, TNMP reached a settlement calling for a $14.3 million increase, effective September 1st.

The share count will increase, probably in late 2020. In early 2020, PNM Resources raised $290 million through a forward sale of 6.18 million common shares.

Although the stock price has declined 23% this year, the dividend yield is still below the utility mean. The equity offers good total return potential for the next 18 months, but not for the period to 2023-2025.

Paul E. Debbas, CFA — *July 24, 2020*

(A) Dil. EPS. Excl. nonrec. gain (losses): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (59¢); '19, ($1.31). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. '17 EPS don't sum due to rounding. Next egs. report due late July. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. intang. In '19: $11.81/sh. (D) In mill., adj. for split. (E) Rate base: net orig. cost. Rate all'd on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; earned on avg. com. eq., '19: 10.2%. Regulatory Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	90
Earnings Predictability	70

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

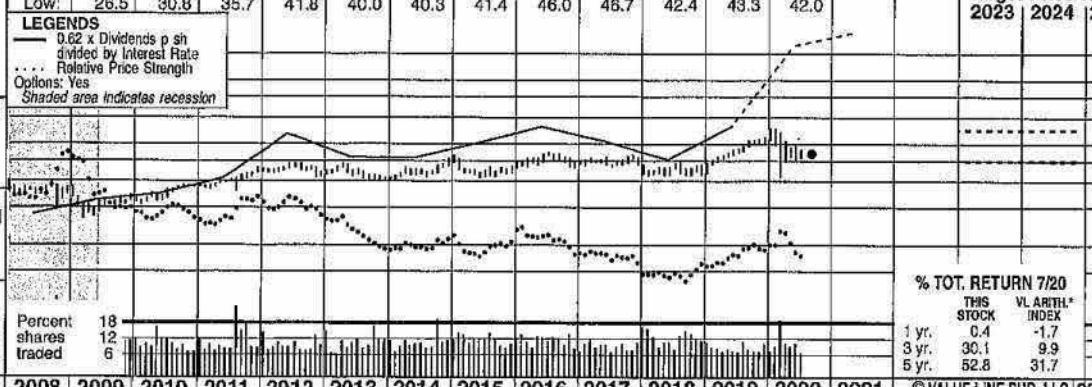
SOUTHERN COMPANY NYSE-SO

RECENT PRICE **54.01** | P/E RATIO **17.2** (Trailing: 17.3; Median: 16.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **4.8%** | VALUE LINE

TIMELINESS **3** Raised 3/2/18
SAFETY **2** Lowered 2/21/14
TECHNICAL **4** Lowered 8/14/20
BETA .90 (1.00 = Market)

High:	37.6	38.6	46.7	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1
Low:	26.5	30.8	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0

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



Target Price Range 2023 | 2024 | 2025

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$40-$92	$66 (20%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+30%)	11%
Low	50	(-5%)	3%

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	592	661	585
to Sell	531	564	730
Hld's(000)	623689	633480	626906

Percent shares traded 18 12 6

% TOT. RETURN 7/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.4	-1.7
3 yr.	30.1	9.9
5 yr.	52.8	31.7

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	*18.95*	*19.80*	Revenues per sh	*22.25*
3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	*6.45*	*6.70*	"Cash Flow" per sh	*7.75*
2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	*3.10*	*3.25*	Earnings per sh A	*3.75*
1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	*2.54*	*2.62*	Div'd Decl'd per sh B ■	*2.86*
2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	*8.70*	*7.45*	Cap'l Spending per sh	*6.50*
13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	*26.45*	*27.15*	Book Value per sh C	*30.50*
741.50	741.45	746.27	763.10	777.19	819.85	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	*1060.0*	*1060.0*	Common Shs Outst'g D	*1090.0*
14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.95	*Value Line*		Relative P/E Ratio	*.90*
4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 6/30/20
Total Debt $47919 mill. **Due in 5 Yrs** $12296 mill.
LT Debt $45138 mill. **LT Interest** $1711 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $289 mill.
Pension Assets-12/19 $14057 mill.
Oblig $14788 mill.
Pfd Stock $291 mill. **Pfd Div'd** $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).

Common Stock 1,056,130,748 shs.
MARKET CAP: $57 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
17456	17657	18537	17087	18467	17489	19896	23031	23495	21419	*20100*	*21000*	Revenues ($mill)	*24300*
2040.0	2268.0	2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	*3325*	*3485*	Net Profit ($mill)	*4200*
33.5%	35.0%	35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	*15.5%*	*15.5%*	Income Tax Rate	*15.5%*
13.7%	10.2%	9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	*8.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
51.2%	50.0%	49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	*61.0%*	*61.5%*	Long-Term Debt Ratio	*60.0%*
45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	*38.5%*	*38.0%*	Common Equity Ratio	*39.5%*
35438	37307	38653	41483	42142	46788	69359	68953	65750	69594	*73075*	*75800*	Total Capital ($mill)	*84000*
42002	45010	48390	51208	54868	61114	76446	79872	80797	83080	*88775*	*93025*	Net Plant ($mill)	*103500*
7.0%	7.2%	7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.8%	12.2%	12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	*12.0%*	*12.0%*	Return on Com Equity E	*12.5%*
3.0%	3.4%	3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
77%	73%	73%	75%	75%	76%	78%	72%	79%	77%	*81%*	*80%*	All Div'ds to Net Prof	*75%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-2.6	+3.6	-8.5
Avg. Indust. Use (MWH)	3016	3048	2947
Avg. Indust. Revs. per KWH (¢)	6.18	6.04	6.03
Capacity at Yearend (Mw)	46936	45824	41940
Peak Load, Summer (Mw) F	34874	36429	34209
Annual Load Factor (%)	61.4	61.2	60.3
% Change Customers (yr-end)	+1.0	+1.0	-8.9
Fixed Charge Cov. (%)	318	280	281

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	.5%	2.5%	*Nil*
"Cash Flow"	4.0%	4.5%	*3.0%*
Earnings	3.0%	3.0%	*3.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	3.5%	3.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	5771	5430	6201	5629	23031
2018	6372	5627	6159	5337	23495
2019	5412	5098	5995	4914	21419
2020	5018	4620	*5500*	*4962*	*20100*
2021	*5200*	*4800*	*5800*	*5200*	*21000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.73	.73	1.08	.67	3.21
2018	.99	.71	1.13	.17	3.00
2019	.75	.85	1.25	.32	3.17
2020	.81	.75	*1.15*	*.39*	*3.10*
2021	*.85*	*.75*	*1.25*	*.40*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.5425	.56	.56	.56	2.22
2017	.56	.58	.58	.58	2.30
2018	.58	.60	.60	.60	2.38
2019	.60	.62	.62	.62	2.46
2020	.62	.64			

BUSINESS: The Southern Company, through its subs., supplies electricity to 4.3 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.3 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric rev. breakdown: residential, 37%; commercial, 30%; industrial, 19%; other, 14%. Retail revs. by state: GA, 56%; AL, 38%; MS, 6%. Generating sources: gas, 47%; coal, 20%; nuclear, 15%; other, 9%; purchased, 9%. Fuel costs: 34% of revs. '19 reported depr. rates (util.): 2.6%-3.7%. Has 27,900 empls. Chairman, Pres. and CEO: Thomas A. Fanning. Inc.: DE. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary still believes it can complete the construction of two nuclear units to meet the regulatory schedule, but costs have risen. The utility is adding two units at the site of the Vogtle station, which are scheduled to come on line by November of 2021 and 2022. However, the coronavirus has disrupted construction, so Georgia Power exceeded the contingency that was included in the budget. Because this will not be recoverable in rates, the company took an aftertax charge of $111 million ($0.10 a share) against June-period results, which we *excluded* from our earnings presentation as a nonrecurring item. All told, Georgia Power raised its estimate of the cost of its 45.7% stake by $150 million, to $8.5 billion. Of this amount, about $2 billion remains. This excludes $3.0 billion of financing costs, of which $2.4 billion has been spent.

We think earnings in 2020 will fall a bit short of the 2019 tally. On the positive side, some of Southern Company's utilities are benefiting from rate relief. However, weather patterns were milder than normal in the first six months of 2020. As for the effects of the coronavirus on kilowatt-hour sales, management still expects a revenue loss of $250 million-$400 million, but expects to offset this through cost-cutting measures. Our estimate is at the low end of the company's $3.10-$3.22 guidance, issued in February.

We look for an earnings recovery in 2021. We figure that the economy will be in better shape. Georgia Power will also get $181 million of rate relief in the second phase of a three-year rate plan. Also . . .

Two gas rate cases are pending. Virginia Natural Gas filed for $49.6 million, based on a 10.35% return on equity and a 54% common-equity ratio. A ruling is expected in the second period of 2021, retroactive to this November. Atlanta Gas Light sought $37.6 million. New tariffs are expected to take effect at the start of 2021.

This stock's dividend yield is a percentage point above the utility average. However, investors must be willing to accept the risks associated with the nuclear construction project. Total return potential is attractive for the 18-month span, but not for the 3- to 5-year period.

Paul E. Debbas, CFA *August 14, 2020*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢). Next earnings report due late Oct. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd charges. In '19: $17.64/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common equity (blended): 12.5%; earned on avg. com. eq., '19: 13.0%. Regulatory Climate: GA, AL Above Average; MS, FL Average. (F) Winter peak in '18.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	85

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

XCEL ENERGY NDQ-XEL

RECENT PRICE **64.17** | P/E RATIO **23.3** (Trailing: 24.8 Median: 16.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **2.8%** | VALUE LINE

TIMELINESS **3** Lowered 9/20/19
SAFETY **1** Raised 5/1/15
TECHNICAL **1** Raised 7/24/20
BETA .75 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
High:	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	72.1
Low:	16.0	19.8	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6

18-Month Target Price Range

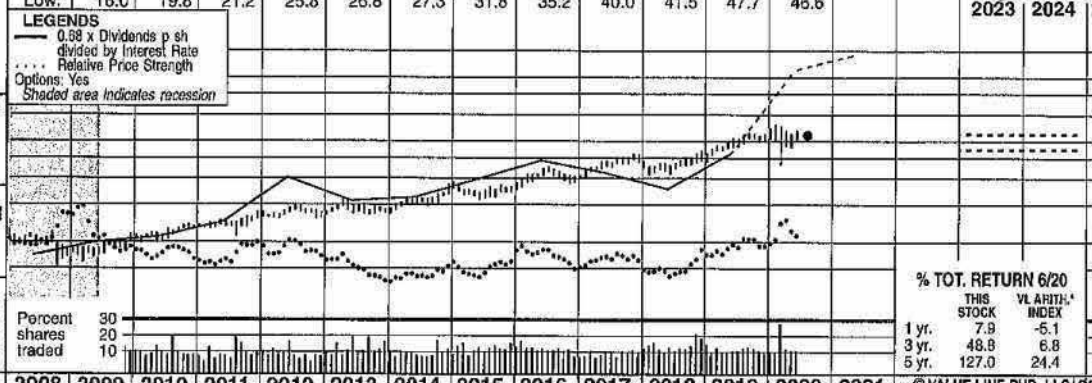
Low-High	Midpoint (% to Mid)
$47-$99	$73 (15%)

2023-25 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(Nil)	4%
Low	55	(-15%)	Nil

Institutional Decisions

	3Q2019	4Q2019	1Q2020
to Buy	347	395	365
to Sell	333	320	378
Hld's(000)	407757	409339	407479



% TOT. RETURN 6/20

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.9	-5.1
3 yr.	48.8	6.8
5 yr.	127.0	24.4

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	© VALUE LINE PUB. LLC	23-25
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	22.44	21.98	*19.10*	*20.30*	Revenues per sh	*22.75*
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	5.92	6.25	*6.50*	*7.05*	"Cash Flow" per sh	*8.50*
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	2.47	2.64	*2.75*	*2.90*	Earnings per sh A	*3.50*
.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	*1.72*	*1.82*	Div'd Decl'd per sh B ■	*2.15*
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	7.70	8.05	*6.70*	*7.05*	Cap'l Spending per sh	*8.50*
12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.99	21.73	22.56	23.78	25.24	*27.20*	*28.45*	Book Value per sh C	*32.25*
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	514.04	524.54	*539.00*	*542.00*	Common Shs Outst'g D	*548.00*
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	18.9	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.21	*Value Line*		Relative P/E Ratio	*.95*
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%	3.3%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 3/31/20
Total Debt $19877 mill. Due in 5 Yrs $4990 mill.
LT Debt $17010 mill. LT Interest $721 mill.
Incl. $77 mill. capitalized leases.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $262 mill.
Pension Assets-12/19 $3184 mill.
Oblig $3701 mill.

Pfd Stock None

Common Stock 525,170,820 shs.
as of 4/30/20
MARKET CAP: $34 billion (Large Cap)

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		23-25
10311	10655	10128	10915	11686	11024	11107	11404	11537	11529	*10300*	*11000*	Revenues ($mill)	*12500*
727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	*1445*	*1570*	Net Profit ($mill)	*1865*
37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	*Nil*	*Nil*	Income Tax Rate	*Nil*
11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	*10.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	*57.0%*	*57.0%*	Long-Term Debt Ratio	*57.5%*
46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	*43.0%*	*43.0%*	Common Equity Ratio	*42.5%*
17452	17331	19018	20477	21714	23092	25216	25975	28025	30646	*34175*	*35950*	Total Capital ($mill)	*41700*
20663	22353	23809	26122	28757	31206	32842	34329	36944	39483	*41025*	*42600*	Net Plant ($mill)	*48300*
5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
59%	56%	54%	54%	55%	57%	61%	62%	58%	58%	*63%*	*63%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2017	2018	2019
% Change Retail Sales (KWH)	-.7	+3.2	-1.2
Large C & I Use (MWH)	22642	23004	NA
Large C & I Revs. per KWH (¢)	6.36	5.91	5.96
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19591	20293	20146
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.1	+1.0
Fixed Charge Cov. (%)	330	281	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '23-'25
Revenues	-.5%	.5%	*.5%*
"Cash Flow"	5.5%	7.5%	*6.5%*
Earnings	5.5%	5.0%	*6.0%*
Dividends	5.0%	6.5%	*6.0%*
Book Value	4.5%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	2946	2645	3017	2796	11404
2018	2951	2658	3048	2880	11537
2019	3141	2577	3013	2798	11529
2020	2811	*2189*	*2700*	*2600*	*10300*
2021	*3000*	*2400*	*2850*	*2750*	*11000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.47	.45	.97	.42	2.30
2018	.57	.52	.96	.42	2.47
2019	.61	.46	1.01	.56	2.64
2020	.56	*.54*	*1.10*	*.55*	*2.75*
2021	*.65*	*.55*	*1.15*	*.55*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43		

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; P.S. of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.7 mill. elec., 2.1 mill. gas. Elec. rev. breakdown: res'l, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not avail. Fuel costs: 39% of revs. '19 reported depr. rate: 3.3%. Has 11,300 empls. Chairman & CEO: Ben Fowke. President & COO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utilities have reached settlements on pending rate cases. The New Mexico commission approved a settlement calling for a $31 million electric increase for Southwestern Public Service, based on a 9.45% return on equity and a 54.8% common-equity ratio. New tariffs took effect on May 28th. In Texas, SPS reached a "black box" agreement calling for an $88 million hike without specifying an allowed ROE or common-equity ratio. A ruling from the state regulators is expected in the current quarter, with the increase retroactive to September of 2019. Public Service of Colorado, the state commission's staff, and intervenors have reached a settlement calling for a gas rate increase of $76.9 million, based on a 9.2% ROE and a 55.6% common-equity ratio. If the regulators approve the agreement, new tariffs will be implemented on April 1, 2021, retroactive to November of 2020.

Xcel believes it can reduce expenses enough to offset the effects of the recession on kilowatt-hour sales. Cost cuts should enable operating and maintenance expenses to decline 4%-5% in 2020. Accordingly, management did not adjust its earnings guidance of $2.73-$2.83 a share for this year. Our estimate of $2.75 a share is unchanged. We have also stuck with our 2021 estimate of $2.90 a share. This would produce profit growth of 5%, which is within the company's annual goal of 5%-7%.

At least one rate case is upcoming. P.S. of Colorado plans to put forth an electric application later this summer. Northern States Power is considering filing for new electric and gas tariffs in Minnesota in November, but might well postpone its case if it can reach an agreement with the commission that compensates the utility for the decline in volume.

This high-quality stock has been one of the top performers in the electric utility industry in 2020. While the prices of most electric equities have fallen more than 10%, Xcel is almost unchanged from yearend 2019, thanks in part to its maintaining profit guidance. The dividend yield is a percentage point below the industry average, and with the recent quotation near the top of our 2023-2025 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *July 24, 2020*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '17 EPS don't sum due to rounding. Next earnings report due late July. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '19: $5.60/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '19: 10.8%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

© 2020 Value Line, Inc. All rights reserved. Factual material is obtained from sources believed to be reliable and is provided without warranties of any kind. THE PUBLISHER IS NOT RESPONSIBLE FOR ANY ERRORS OR OMISSIONS HEREIN. This publication is strictly for subscriber's own, non-commercial, internal use. No part of it may be reproduced, resold, stored or transmitted in any printed, electronic or other form, or used for generating or marketing any printed or electronic publication, service or product.

To subscribe call 1-800-VALUELINE

ATTACHMENT NO. 3

YAHOO ANALYST ESTIMATES

ALLETE, Inc. (ALE)
NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist Visitors trend 2W ↑ 10W ↑ 9M ↑ Quote Lookup

51.84 -0.26 (-0.50%)

As of 9:56AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	5	4	6
Avg. Estimate	0.66	0.84	3.33	3.59
Low Estimate	0.62	0.8	3.32	3.45
High Estimate	0.71	0.86	3.35	3.79
Year Ago EPS	0.6	0.96	3.59	3.33

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	2	2	4	4
Avg. Estimate	292.9M	300.2M	1.17B	1.23B
Low Estimate	289.8M	295.4M	1.14B	1.2B
High Estimate	296M	305M	1.22B	1.27B
Year Ago Sales	288.3M	304.6M	1.24B	1.17B
Sales Growth (year/est)	1.60%	-1.40%	-5.80%	5.20%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	0.63	0.92	1.14	0.67
EPS Actual	0.6	0.96	1.28	0.39
Difference	-0.03	0.04	0.14	-0.28
Surprise %	-4.80%	4.30%	12.30%	-41.80%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	0.66	0.84	3.33	3.59
7 Days Ago	0.66	0.84	3.33	3.59
30 Days Ago	0.65	0.84	3.34	3.62
60 Days Ago	0.64	0.74	3.36	3.75
90 Days Ago	0.64	0.74	3.36	3.75

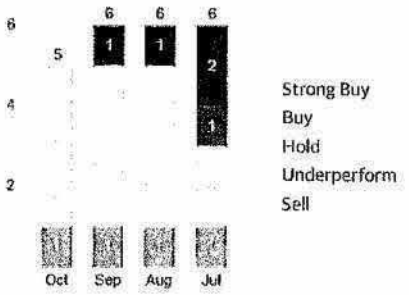
EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A

Sponsored by

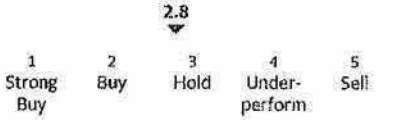
People Also Watch

Symbol	Last Price	Change	% Change
BKH Black Hills Corporation	53.65	-0.30	-0.56%
AVA Avista Corporation	34.13	-0.28	-0.81%
LNT Alliant Energy Corporation	52.58	+0.24	+0.47%
IDA IDACORP, Inc.	81.59	-0.27	-0.33%
NWE NorthWestern Corporation	48.41	-0.60	-1.22%

Recommendation Trends >



Recommendation Rating >



Up Last 30 Days	1	1	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Current 51.84 Low 55.00 High 88.00

Growth Estimates	ALE	Industry	Sector(s)	S&P 500
Current Qtr.	10.00%	N/A	N/A	N/A
Next Qtr.	-12.50%	N/A	N/A	N/A
Current Year	-7.20%	N/A	N/A	N/A
Next Year	7.80%	N/A	N/A	N/A
Next 5 Years (per annum)	7.00%	N/A	N/A	N/A
Past 5 Years (per annum)	1.25%	N/A	N/A	N/A

Upgrades & Downgrades ›

Maintains	Mizuho: to Neutral	8/26/2020
Maintains	JP Morgan: to Underweight	6/1/2020
Maintains	Wells Fargo: to Equal-Weight	5/7/2020
Upgrade	Mizuho: Underperform to Neutral	3/3/2020
Upgrade	Guggenheim: Neutral to Buy	1/8/2020
Downgrade	Mizuho: Neutral to Underperform	2/11/2019

More Upgrades & Downgrades

Advertise With Us

Data Disclaimer Help Suggestions
Do Not Sell My Personal Information
Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

Ameren Corporation (AEE)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

79.67 -0.19 (-0.24%)

As of 9:59AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	10	10	14	14
Avg. Estimate	1.52	0.38	3.47	3.76
Low Estimate	1.49	0.33	3.41	3.66
High Estimate	1.56	0.42	3.52	3.86
Year Ago EPS	1.47	0.38	3.35	3.47

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	4	4	8	8
Avg. Estimate	1.69B	1.38B	5.99B	6.32B
Low Estimate	1.63B	1.31B	5.79B	6.03B
High Estimate	1.75B	1.49B	6.25B	6.71B
Year Ago Sales	1.66B	1.32B	5.91B	5.99B
Sales Growth (year/est)	2.10%	4.60%	1.40%	5.50%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.45	0.31	0.7	0.87
EPS Actual	1.47	0.38	0.59	0.98
Difference	0.02	0.07	-0.11	0.11
Surprise %	1.40%	22.60%	-15.70%	12.60%

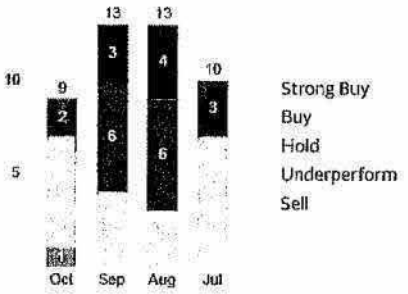
EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.52	0.38	3.47	3.76
7 Days Ago	1.52	0.38	3.47	3.76
30 Days Ago	1.52	0.39	3.48	3.77
60 Days Ago	1.56	0.43	3.45	3.76
90 Days Ago	1.55	0.41	3.42	3.75

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	1	N/A	1	1

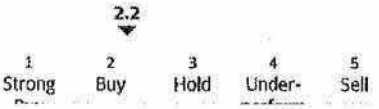
People Also Watch

Symbol	Last Price	Change	% Change
DTE DTE Energy Company	112.30	-1.14	-1.00%
AJG Arthur J. Gallagher & Co.	105.36	-0.25	-0.24%
CMS CMS Energy Corporation	61.42	-0.26	-0.42%
ABC AmerisourceBergen Corporation	95.99	+0.63	+0.66%
ETR Entergy Corporation	101.03	-0.25	-0.25%

Recommendation Trends ›



Recommendation Rating ›



Up Last 30 Days	1	N/A	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	1	N/A	1

Growth Estimates	AEE	Industry	Sector(s)	S&P 500
Current Qtr.	3.40%	N/A	N/A	N/A
Next Qtr.	N/A	N/A	N/A	N/A
Current Year	3.60%	N/A	N/A	N/A
Next Year	8.40%	N/A	N/A	N/A
Next 5 Years (per annum)	6.00%	N/A	N/A	N/A
Past 5 Years (per annum)	8.24%	N/A	N/A	N/A

Average 85.20

Low 79.00 Current 79.67 High 93.00

Upgrades & Downgrades ›

Downgrade	Barclays: Equal-Weight to Underweight	9/21/2020
Maintains	Morgan Stanley: to Equal-Weight	9/18/2020
Downgrade	B of A Securities: Buy to Neutral	8/13/2020
Maintains	BMO Capital: to Outperform	8/10/2020
Maintains	B of A Securities: to Buy	7/7/2020
Maintains	Morgan Stanley: to Equal-Weight	6/17/2020

More Upgrades & Downgrades

Advertise With Us

Data Disclaimer Help Suggestions
Do Not Sell My Personal Information
Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

American Electric Power Company, Inc. (AEP)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

Add to watchlist

Visitors trend 2W ↑ 10W ↑ 9M ↑

Quote Lookup

83.30 +0.24 (+0.29%)

As of 10:00AM EDT. Market open.

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials | Analysis | Options | Holders | Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	9	9	15	16
Avg. Estimate	1.45	0.78	4.33	4.65
Low Estimate	1.36	0.68	4.27	4.51
High Estimate	1.57	0.88	4.41	4.72
Year Ago EPS	1.46	0.6	4.24	4.33

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	3	3	8	8
Avg. Estimate	4.41B	3.88B	15.67B	16.6B
Low Estimate	4.26B	3.8B	14.95B	15.94B
High Estimate	4.49B	4B	16.3B	17.43B
Year Ago Sales	4.3B	3.65B	15.6B	15.67B
Sales Growth (year/est)	2.40%	6.30%	0.50%	5.90%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.32	0.58	1.09	1.06
EPS Actual	1.46	0.6	1.02	1.08
Difference	0.14	0.02	-0.07	0.02
Surprise %	10.60%	3.40%	-6.40%	1.90%

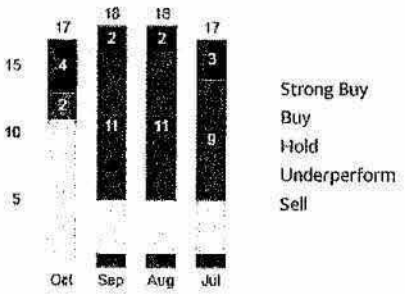
EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.45	0.78	4.33	4.65
7 Days Ago	1.45	0.78	4.33	4.65
30 Days Ago	1.45	0.78	4.32	4.65
60 Days Ago	1.44	0.76	4.28	4.63
90 Days Ago	1.43	0.79	4.27	4.63

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)

People Also Watch

Symbol	Last Price	Change	% Change
SO Southern Company (The)	54.81	+0.19	+0.36%
ED Consolidated Edison, Inc.	79.50	+0.46	+0.58%
D Dominion Energy, Inc.	79.37	+0.78	+0.99%
DUK Duke Energy Corporation (Holdin	90.12	+0.07	+0.08%
FE FirstEnergy Corp.	28.79	+0.03	+0.10%

Recommendation Trends ›



Recommendation Rating ›

2.3

Finance Home | 2020 Election | Watchlists | My Portfolio | Screeners | Premium | Markets | News | ... | Premium - Try it free

Buy | Perform

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 30 Days	1	N/A	N/A	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	1	N/A

Growth Estimates	AEP	Industry	Sector(s)	S&P 500
Current Qtr.	-0.70%	N/A	N/A	N/A
Next Qtr.	30.00%	N/A	N/A	N/A
Current Year	2.10%	N/A	N/A	N/A
Next Year	7.40%	N/A	N/A	N/A
Next 5 Years (per annum)	5.63%	N/A	N/A	N/A
Past 5 Years (per annum)	6.58%	N/A	N/A	N/A

Analyst Price Targets (16) >

Average 92.38

Low 78.00 Current 83.30 High 108.00

Upgrades & Downgrades >

Maintains	Morgan Stanley: to Overweight	9/18/2020
Maintains	KeyBanc: to Overweight	7/21/2020
Maintains	Morgan Stanley: to Overweight	6/17/2020
Maintains	UBS: to Buy	6/5/2020
Maintains	Morgan Stanley: to Overweight	5/15/2020
Upgrade	Evercore ISI Group: In-Line to Outperform	4/20/2020

More Upgrades & Downgrades

Today's Refinance Rat

15-YR FIXED 30-Y

2.14% APR 2.28

$300,000 $30

Calculate Payment

Terms & Conditions apply. NMLS#713

Advertise With Us

Data Disclaimer Help Suggestions

Do Not Sell My Personal Information

Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

DTE Energy Company (DTE)
NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑ | Quote Lookup

112.50 -0.94 (-0.83%)

As of 10:04AM EDT. Market open.

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials | **Analysis** | Options | Holders | Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	15	15	19	19
Avg. Estimate	1.89	1.64	6.67	7.11
Low Estimate	1.54	1.3	6.5	6.97
High Estimate	2.14	2	6.76	7.3
Year Ago EPS	1.91	1.35	6.3	6.67

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	11	11
Avg. Estimate	3.1B	3.31B	12.6B	13.06B
Low Estimate	2.93B	3B	11.44B	11.91B
High Estimate	3.32B	3.96B	14.22B	15.2B
Year Ago Sales	3.12B	3.15B	12.67B	12.6B
Sales Growth (year/est)	-0.70%	5.00%	-0.50%	3.60%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.97	1.3	1.74	1.28
EPS Actual	1.91	1.35	1.66	1.53
Difference	-0.06	0.05	-0.08	0.25
Surprise %	-3.00%	3.80%	-4.60%	19.50%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.89	1.64	6.67	7.11
7 Days Ago	1.89	1.64	6.67	7.11
30 Days Ago	1.89	1.63	6.67	7.11
60 Days Ago	1.89	1.7	6.65	7.1
90 Days Ago	1.92	1.86	6.57	7.08

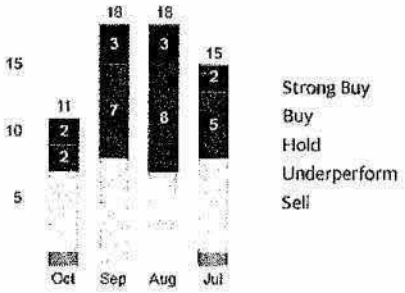
EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)

30 Second "Miracle Stretch" Leaves Chiropractors Baffled! (Watch)
Sponsored by WeeklyPenny.com

People Also Watch

Symbol	Last Price	Change	% Change
CMS CMS Energy Corporation	61.57	-0.11	-0.18%
ETR Entergy Corporation	101.32	+0.04	+0.04%
AEE Ameren Corporation	79.80	-0.06	-0.08%
PNW Pinnacle West Capital Corporati	75.48	+0.16	+0.21%
EIX Edison International	50.88	+0.44	+0.86%

Recommendation Trends >



Recommendation Rating >

2.3

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 30 Days	1	1	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	DTE	Industry	Sector(s)	S&P 500
Current Qtr.	-1.00%	N/A	N/A	N/A
Next Qtr.	21.50%	N/A	N/A	N/A
Current Year	5.90%	N/A	N/A	N/A
Next Year	6.60%	N/A	N/A	N/A
Next 5 Years (per annum)	5.95%	N/A	N/A	N/A
Past 5 Years (per annum)	7.07%	N/A	N/A	N/A

Analyst Price Targets (16) >

Average 128.72

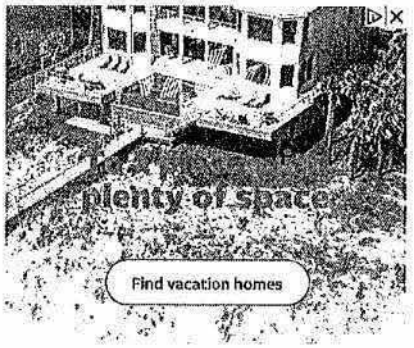
Low 118.00 High 155.00

Current 112.50

Upgrades & Downgrades >

Maintains	Morgan Stanley: to Equal-Weight	9/18/2020
Maintains	Morgan Stanley: to Equal-Weight	8/14/2020
Maintains	Citigroup: to Buy	8/4/2020
Downgrade	KeyBanc: Overweight to Sector Weight	7/21/2020
Reiterates	B of A Securities: to Buy	7/13/2020
Maintains	Morgan Stanley: to Equal-Weight	6/17/2020

More Upgrades & Downgrades



Advertise With Us

© 2020 Verizon Media. All rights reserved.

Duke Energy Corporation (DUK)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

90.09 +0.04 (+0.04%)

As of 10:03AM EDT. Market open.

Currency in USD

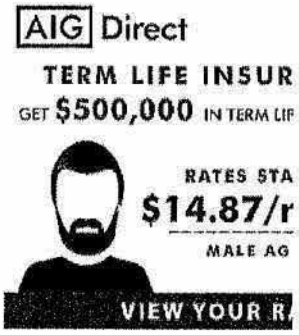
Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	10	10	13	14
Avg. Estimate	1.82	1.04	5.08	5.21
Low Estimate	1.7	0.93	5.03	5.15
High Estimate	1.93	1.17	5.15	5.32
Year Ago EPS	1.79	0.91	5.06	5.08

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	5	9	9
Avg. Estimate	6.98B	6.52B	25.17B	26.16B
Low Estimate	6.71B	5.85B	24.29B	25.15B
High Estimate	7.07B	7.98B	26.45B	27.45B
Year Ago Sales	6.94B	6.1B	25.08B	25.17B
Sales Growth (year/est)	0.60%	6.80%	0.40%	4.00%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.67	0.87	1.19	1.03
EPS Actual	1.79	0.91	1.14	1.08
Difference	0.12	0.04	-0.05	0.05
Surprise %	7.20%	4.60%	-4.20%	4.90%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.82	1.04	5.08	5.21
7 Days Ago	1.82	1.04	5.08	5.21
30 Days Ago	1.82	1.04	5.09	5.22
60 Days Ago	1.83	1.1	5.08	5.31
90 Days Ago	1.86	1.14	5.17	5.45

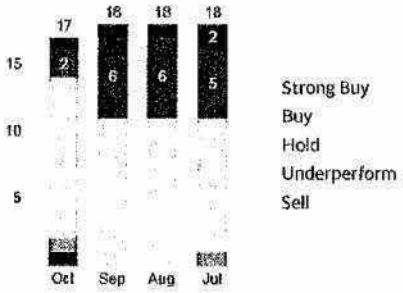
EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	1	N/A



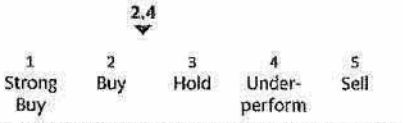
People Also Watch

Symbol	Last Price	Change	% Change
SO Southern Company (The)	54.89	+0.27	+0.49%
D Dominion Energy, Inc.	79.36	+0.77	+0.98%
AEP American Electric Power Company	83.44	+0.38	+0.46%
ED Consolidated Edison, Inc.	79.43	+0.39	+0.49%
EXC Exelon Corporation	35.74	-0.09	-0.25%

Recommendation Trends >



Recommendation Rating >



Up Last 30 Days	2	N/A	3	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	1

Growth Estimates	DUK	Industry	Sector(s)	S&P 500
Current Qtr.	1.70%	N/A	N/A	N/A
Next Qtr.	14.30%	N/A	N/A	N/A
Current Year	0.40%	N/A	N/A	N/A
Next Year	2.60%	N/A	N/A	N/A
Next 5 Years (per annum)	1.60%	N/A	N/A	N/A
Past 5 Years (per annum)	0.38%	N/A	N/A	N/A

Low 85.00 Current 90.11 High 106.00

Upgrades & Downgrades >

Downgrade	ScotiaBank: Sector Outperform to Sector Perform	10/1/2020
Upgrade	B of A Securities: Neutral to Buy	9/9/2020
Maintains	Morgan Stanley: to Equal-Weight	6/17/2020
Maintains	Wells Fargo: to Equal-Weight	5/20/2020
Maintains	Morgan Stanley: to Equal-Weight	5/15/2020
Reiterates	B of A Securities: to Neutral	5/13/2020

More Upgrades & Downgrades

Advertise With Us

Data Disclaimer Help Suggestions
Do Not Sell My Personal Information
Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

Exelon Corporation (EXC)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

Add to watchlist

Visitors trend 2W ↑ 10W ↑ 9M ↑

Quote Lookup

35.76 -0.07 (-0.20%)

As of 10:05AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	11	11	17	18
Avg. Estimate	0.84	0.71	2.96	2.95
Low Estimate	0.78	0.64	2.8	2.79
High Estimate	0.88	0.79	3.03	3.3
Year Ago EPS	0.92	0.83	3.22	2.96

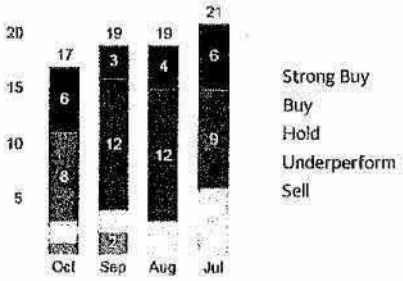
Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	10	11
Avg. Estimate	8.43B	7.63B	30.77B	30.99B
Low Estimate	6.75B	6.26B	25.5B	24.35B
High Estimate	10.14B	8.75B	34.96B	35.18B
Year Ago Sales	8.93B	8.34B	34.44B	30.77B
Sales Growth (year/est)	-5.60%	-8.60%	-10.70%	0.70%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	0.89	0.73	0.85	0.43
EPS Actual	0.92	0.83	0.87	0.55
Difference	0.03	0.1	0.02	0.12
Surprise %	3.40%	13.70%	2.40%	27.90%

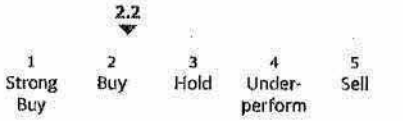
EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	0.84	0.71	2.96	2.95
7 Days Ago	0.84	0.71	2.96	2.95
30 Days Ago	0.84	0.71	2.96	2.92
60 Days Ago	0.91	0.76	2.95	2.92
90 Days Ago	0.91	0.73	2.96	2.95

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	1

Recommendation Trends ›



Recommendation Rating ›



Analyst Price Targets (16) ›

Average 46.63

Low 36.00 High 58.00

Current 35.75

Upgrades & Downgrades ›

Maintains	Wells Fargo: to Overweight	8/24/2020
Maintains	Morgan Stanley: to Overweight	8/11/2020
Maintains	UBS: to Buy	6/22/2020

Up Last 30 Days	N/A	N/A	N/A	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	1	N/A

Growth Estimates	EXC	Industry	Sector(s)	S&P 500
Current Qtr.	-8.70%	N/A	N/A	N/A
Next Qtr.	-14.50%	N/A	N/A	N/A
Current Year	-8.10%	N/A	N/A	N/A
Next Year	-0.30%	N/A	N/A	N/A
Next 5 Years (per annum)	-3.48%	N/A	N/A	N/A
Past 5 Years (per annum)	5.11%	N/A	N/A	N/A

Maintains	UBS: to Buy	6/5/2020
Maintains	Morgan Stanley: to Overweight	5/15/2020
Maintains	BMO Capital: to Outperform	5/11/2020

More Upgrades & Downgrades

Square Terminal
Take payments for one low rate.
Learn more

Advertise With Us

© 2020 Verizon Media. All rights reserved.

Evergy, Inc. (EVRG)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

51.17 +0.35 (+0.68%)

As of 10:06AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	5	8	8
Avg. Estimate	1.61	0.31	3.01	3.24
Low Estimate	1.55	0.15	2.97	3.17
High Estimate	1.72	0.36	3.06	3.29
Year Ago EPS	1.57	0.32	2.89	3.01

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	2	2	5	5
Avg. Estimate	1.56B	1.17B	5.06B	5.12B
Low Estimate	1.54B	1.12B	4.96B	5.05B
High Estimate	1.58B	1.23B	5.14B	5.23B
Year Ago Sales	1.58B	1.13B	5.15B	5.06B
Sales Growth (year/est)	-1.20%	3.40%	-1.70%	1.10%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.57	0.31	0.42	0.68
EPS Actual	1.57	0.32	0.41	0.68
Difference	0	0.01	-0.01	0
Surprise %	0.00%	3.20%	-2.40%	0.00%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.61	0.31	3.01	3.24
7 Days Ago	1.61	0.31	3.01	3.24
30 Days Ago	1.61	0.31	3.01	3.24
60 Days Ago	1.65	0.37	3.05	3.22
90 Days Ago	1.65	0.38	3.05	3.22

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A

Today's Refinance Rat

30-YR FIXED 2.28% APR $300,000

15-YI 2.14 $30

Calculate Payment

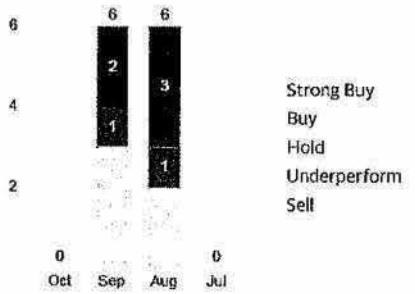
Terms & Conditions apply. NMLS#113

yahoo/finance
Trade like it's not your first rodeo

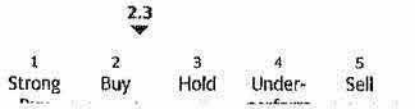
People Also Watch

Symbol	Last Price	Change	% Change
ES Eversource Energy (D/B/A)	86.59	+1.14	+1.33%
CBRE CBRE Group Inc	46.69	-0.71	-1.50%
WLTW Willis Towers Watson Public Lim	209.44	-0.64	-0.30%
LNT Alliant Energy Corporation	52.81	+0.48	+0.92%
LW Lamb Weston Holdings, Inc.	66.40	-0.27	-0.40%

Recommendation Trends ›



Recommendation Rating ›



Up Last 30 Days	N/A	N/A	1	2
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	EVRG	Industry	Sector(s)	S&P 500
Current Qtr.	2.50%	N/A	N/A	N/A
Next Qtr.	-3.10%	N/A	N/A	N/A
Current Year	4.20%	N/A	N/A	N/A
Next Year	7.60%	N/A	N/A	N/A
Next 5 Years (per annum)	6.80%	N/A	N/A	N/A
Past 5 Years (per annum)	-0.13%	N/A	N/A	N/A

Average 59.57

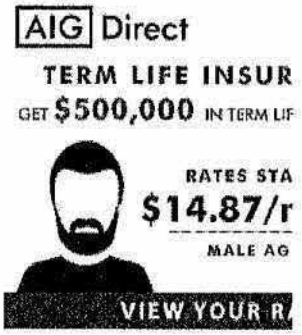
Low 56.00 High 62.00

Current 51.17

Upgrades & Downgrades >

Maintains	Wells Fargo: to Equal-Weight	8/6/2020
Downgrade	Wolfe Research: Outperform to Peer Perform	8/3/2020
Maintains	UBS: to Neutral	6/5/2020
Upgrade	Evercore ISI Group: In-Line to Outperform	6/4/2020
Maintains	CFRA: to Hold	5/7/2020
Maintains	Wells Fargo: to Equal-Weight	5/7/2020

More Upgrades & Downgrades



Advertise With Us

© 2020 Verizon Media. All rights reserved.

OGE Energy Corp. (OGE)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

30.26 +0.06 (+0.20%)

As of 10:06AM EDT. Market open.

Currency in USD

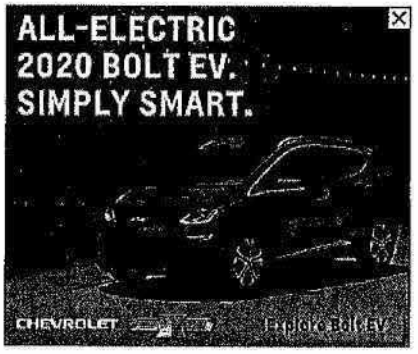
Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	11	11
Avg. Estimate	1.18	0.23	2.13	2.21
Low Estimate	1.03	0.16	2.11	2.15
High Estimate	1.25	0.39	2.16	2.25
Year Ago EPS	1.25	0.18	2.16	2.13

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	2	2	7	7
Avg. Estimate	756.56M	529.19M	2.31B	2.37B
Low Estimate	741.31M	467.76M	2.19B	2.26B
High Estimate	771.81M	590.62M	2.51B	2.61B
Year Ago Sales	755.4M	472.5M	2.23B	2.31B
Sales Growth (year/est)	0.20%	12.00%	3.40%	2.70%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.11	0.28	0.2	0.49
EPS Actual	1.25	0.18	0.23	0.51
Difference	0.14	-0.1	0.03	0.02
Surprise %	12.60%	-35.70%	15.00%	4.10%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.18	0.23	2.13	2.21
7 Days Ago	1.18	0.23	2.13	2.21
30 Days Ago	1.18	0.23	2.14	2.2
60 Days Ago	1.2	0.21	2.15	2.24
90 Days Ago	1.19	0.66	2.15	2.23

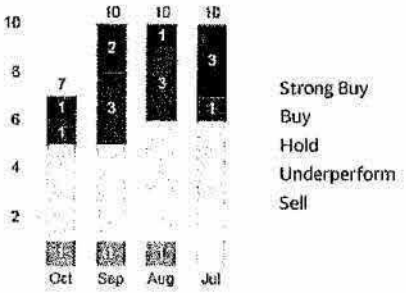
EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A



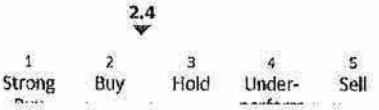
People Also Watch

Symbol	Last Price	Change	% Change
LNT Alliant Energy Corporation	52.77	+0.44	+0.84%
PNW Pinnacle West Capital Corporati	75.46	+0.14	+0.19%
PNM PNM Resources, Inc. (Holding Co	41.92	+0.02	+0.05%
IDA IDACORP, Inc.	81.94	+0.08	+0.10%
BKH Black Hills Corporation	54.12	+0.17	+0.32%

Recommendation Trends ›



Recommendation Rating ›



Up Last 30 Days	N/A	N/A	1	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	1	1

Growth Estimates	OGE	Industry	Sector(s)	S&P 500
Current Qtr.	-5.60%	N/A	N/A	N/A
Next Qtr.	27.80%	N/A	N/A	N/A
Current Year	-1.40%	N/A	N/A	N/A
Next Year	3.80%	N/A	N/A	N/A
Next 5 Years (per annum)	2.40%	N/A	N/A	N/A
Past 5 Years (per annum)	9.96%	N/A	N/A	N/A

Average 34.89

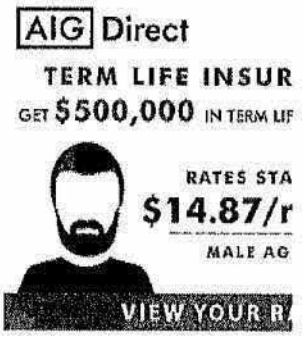
Low 33.00 High 37.00

Current 30.26

Upgrades & Downgrades ›

Maintains	Wells Fargo: to Equal-Weight	8/24/2020
Upgrade	Guggenheim: Neutral to Buy	8/20/2020
Reiterates	B of A Securities: to Buy	7/8/2020
Upgrade	UBS: Neutral to Buy	7/7/2020
Upgrade	Mizuho: Neutral to Buy	6/10/2020
Upgrade	Evercore ISI Group: In-Line to Outperform	4/20/2020

More Upgrades & Downgrades



Advertise With Us

© 2020 Verizon Media. All rights reserved.

Otter Tail Corporation (OTTR)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

Add to watchlist Visitors trend 2W ↑ 10W ↑ 9M ↑

Quote Lookup

36.57 +0.02 (+0.05%)

As of 10:14AM EDT. Market open.

Currency in USD

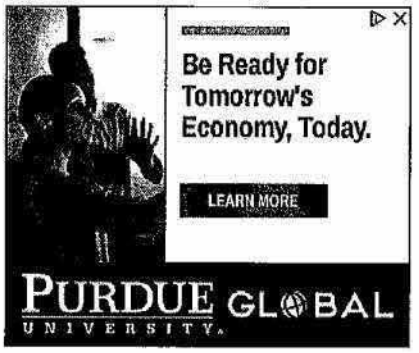
Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	4	4	4	4
Avg. Estimate	0.64	0.57	2.22	2.39
Low Estimate	0.6	0.55	2.2	2.32
High Estimate	0.65	0.59	2.23	2.46
Year Ago EPS	0.62	0.51	2.17	2.22

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	3	3	3	3
Avg. Estimate	229.85M	224.15M	881.5M	937.2M
Low Estimate	226.2M	216.9M	874.9M	897.1M
High Estimate	232.86M	233M	886.7M	966.2M
Year Ago Sales	228.65M	215.68M	919.5M	881.5M
Sales Growth (year/est)	0.50%	3.90%	-4.10%	6.30%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	0.64	0.5	0.67	0.32
EPS Actual	0.62	0.51	0.6	0.42
Difference	-0.02	0.01	-0.07	0.1
Surprise %	-3.10%	2.00%	-10.40%	31.20%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	0.64	0.57	2.22	2.39
7 Days Ago	0.64	0.57	2.22	2.39
30 Days Ago	0.63	0.57	2.2	2.37
60 Days Ago	0.61	0.57	2.17	2.32
90 Days Ago	0.61	0.57	2.17	2.32

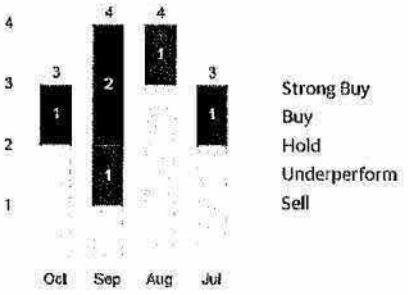
EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A



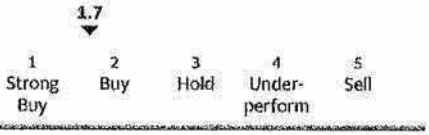
People Also Watch

Symbol	Last Price	Change	% Change
BKH Black Hills Corporation	53.86	-0.09	-0.17%
ALE Allete, Inc.	52.21	+0.11	+0.20%
PNM PNM Resources, Inc. (Holding Co	41.87	-0.03	-0.07%
MGEE MGE Energy Inc.	63.10	-0.21	-0.32%
IDA IDACORP, Inc.	81.72	-0.14	-0.17%

Recommendation Trends ›



Recommendation Rating ›



Up Last 30 Days	1	N/A	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Current 36.57 Low 45.00 High 51.00

Growth Estimates	OTTR	Industry	Sector(s)	S&P 500
Current Qtr.	3.20%	N/A	N/A	N/A
Next Qtr.	11.80%	N/A	N/A	N/A
Current Year	2.30%	N/A	N/A	N/A
Next Year	7.70%	N/A	N/A	N/A
Next 5 Years (per annum)	9.00%	N/A	N/A	N/A
Past 5 Years (per annum)	7.60%	N/A	N/A	N/A

Upgrades & Downgrades >

Upgrade	Sidoti & Co.: Neutral to Buy	8/5/2020
Downgrade	KeyBanc: Overweight to Sector Weight	3/13/2020
Maintains	Sidoti & Co.: to Neutral	2/19/2020
Maintains	KeyBanc: to Overweight	1/17/2020
Upgrade	Williams Capital: Sell to Hold	11/6/2019
Downgrade	Williams Capital: Hold to Sell	5/31/2018

More Upgrades & Downgrades

Advertise With Us

Data Disclaimer Help Suggestions
Do Not Sell My Personal Information
Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

PNM Resources, Inc. (PNM)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑ | Quote Lookup

41.90 -0.01 (-0.01%)

As of 10:10AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	8	10
Avg. Estimate	1.19	0.24	2.2	2.33
Low Estimate	1.13	0.16	2.16	2.26
High Estimate	1.27	0.29	2.22	2.38
Year Ago EPS	1.29	0.36	2.16	2.2

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	3	3	6	7
Avg. Estimate	522.04M	390.88M	1.52B	1.61B
Low Estimate	444.23M	267.99M	1.46B	1.56B
High Estimate	669.99M	552.06M	1.7B	1.78B
Year Ago Sales	N/A	344.14M	1.46B	1.52B
Sales Growth (year/est)	N/A	13.60%	4.40%	5.70%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.27	0.33	0.17	0.49
EPS Actual	1.29	0.36	0.18	0.55
Difference	0.02	0.03	0.01	0.06
Surprise %	1.60%	9.10%	5.90%	12.20%

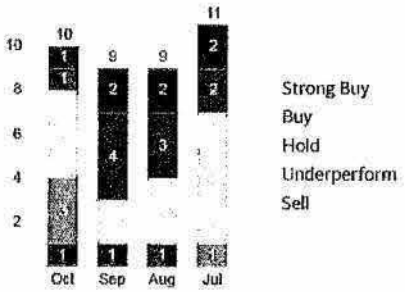
EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.19	0.24	2.2	2.33
7 Days Ago	1.19	0.24	2.2	2.33
30 Days Ago	1.19	0.24	2.2	2.33
60 Days Ago	1.19	0.3	2.19	2.34
90 Days Ago	1.28	0.35	2.18	2.34

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	N/A	N/A	N/A

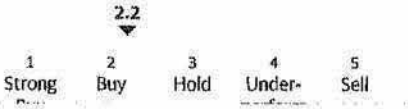
People Also Watch

Symbol	Last Price	Change	% Change
IDA IDACORP, Inc.	81.75	-0.11	-0.13%
PNW Pinnacle West Capital Corporati	75.47	+0.15	+0.20%
POR Portland General Electric Co	36.19	+0.21	+0.58%
BKH Black Hills Corporation	53.93	-0.02	-0.04%
OGE OGE Energy Corp	30.30	+0.10	+0.33%

Recommendation Trends >



Recommendation Rating >



Up Last 30 Days	N/A	N/A	2	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	N/A	N/A

Growth Estimates	PNM	Industry	Sector(s)	S&P 500
Current Qtr.	-7.80%	N/A	N/A	N/A
Next Qtr.	-33.30%	N/A	N/A	N/A
Current Year	1.90%	N/A	N/A	N/A
Next Year	5.90%	N/A	N/A	N/A
Next 5 Years (per annum)	4.95%	N/A	N/A	N/A
Past 5 Years (per annum)	4.02%	N/A	N/A	N/A

Average 46.78

Low 44.00 High 49.00

Current 41.90

Upgrades & Downgrades >

Maintains	UBS: to Buy	6/5/2020
Maintains	Mizuho: to Buy	6/3/2020
Upgrade	Barclays: Equal-Weight to Overweight	5/15/2020
Maintains	B of A Securities: to Buy	5/4/2020
Maintains	Wells Fargo: to Equal-Weight	4/2/2020
Upgrade	UBS: Neutral to Buy	4/1/2020

More Upgrades & Downgrades

Advertise With Us

Data Disclaimer Help Suggestions
Do Not Sell My Personal Information
Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

The Southern Company (SO)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

54.84 +0.22 (+0.40%)

As of 10:14AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	12	12	18	18
Avg. Estimate	1.23	0.38	3.16	3.32
Low Estimate	1.15	0.17	3.1	3.26
High Estimate	1.4	0.47	3.22	3.4
Year Ago EPS	1.34	0.27	3.11	3.16

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	6	6	12	12
Avg. Estimate	6.39B	5.17B	21.54B	22.37B
Low Estimate	5.55B	4.86B	20.04B	20.74B
High Estimate	8.97B	5.75B	23.61B	24.26B
Year Ago Sales	6B	4.91B	21.42B	21.54B
Sales Growth (year/est)	6.60%	5.20%	0.60%	3.90%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.14	0.27	0.71	0.67
EPS Actual	1.34	0.27	0.78	0.78
Difference	0.2	0	0.07	0.11
Surprise %	17.50%	0.00%	9.90%	16.40%

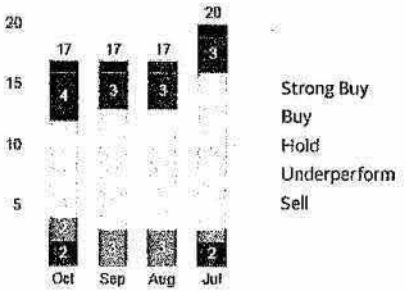
EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.23	0.38	3.16	3.32
7 Days Ago	1.23	0.38	3.16	3.32
30 Days Ago	1.25	0.37	3.16	3.32
60 Days Ago	1.25	0.4	3.15	3.3
90 Days Ago	1.28	0.39	3.14	3.3

EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	1	N/A	N/A

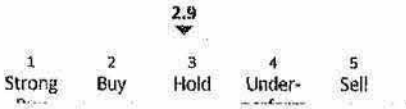
People Also Watch

Symbol	Last Price	Change	% Change
DUK Duke Energy Corporation (Holdin	89.69	-0.36	-0.40%
D Dominion Energy, Inc.	79.06	+0.47	+0.60%
AEP American Electric Power Company	83.28	+0.22	+0.27%
ED Consolidated Edison, Inc.	79.12	+0.08	+0.10%
EXC Exelon Corporation	35.65	-0.19	-0.52%

Recommendation Trends >



Recommendation Rating >



Up Last 30 Days	N/A	1	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	N/A	N/A

Growth Estimates	SO	Industry	Sector(s)	S&P 500
Current Qtr.	-8.20%	N/A	N/A	N/A
Next Qtr.	40.70%	N/A	N/A	N/A
Current Year	1.60%	N/A	N/A	N/A
Next Year	5.10%	N/A	N/A	N/A
Next 5 Years (per annum)	4.55%	N/A	N/A	N/A
Past 5 Years (per annum)	3.96%	N/A	N/A	N/A

Average 59.60

Low 48.00 Current 54.84 High 67.00

Upgrades & Downgrades >

Upgrade	Barclays: Equal-Weight to Overweight	9/21/2020
Maintains	Morgan Stanley: to Underweight	9/18/2020
Downgrade	Mizuho: Neutral to Underperform	9/10/2020
Maintains	UBS: to Neutral	9/1/2020
Maintains	Mizuho: to Neutral	7/22/2020
Maintains	KeyBanc: to Overweight	7/21/2020

More Upgrades & Downgrades

Today's Refinance Rat

15-YR FIXED 30-Y
2.14% APR 2.28
$300,000 $30

Calculate Payment

Terms & Conditions apply. NMLS#112

Advertise With Us

Data Disclaimer Help Suggestions
Do Not Sell My Personal Information
Privacy (Updated) About Our Ads Terms (Updated) Sitemap

© 2020 Verizon Media. All rights reserved.

Xcel Energy Inc. (XEL)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

Add to watchlist

Visitors trend 2W ↑ 10W ↑ 9M ↑

Quote Lookup

70.01 -0.37 (-0.53%)

As of 10:14AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	9	9	15	15
Avg. Estimate	1.09	0.59	2.78	2.97
Low Estimate	1.05	0.52	2.73	2.91
High Estimate	1.18	0.63	2.83	3.02
Year Ago EPS	1.01	0.56	2.64	2.78

Revenue Estimate	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
No. of Analysts	5	5	11	11
Avg. Estimate	3.39B	2.85B	11.75B	12.29B
Low Estimate	2.99B	2.44B	11.2B	11.68B
High Estimate	4.42B	3.21B	12.4B	12.95B
Year Ago Sales	3.01B	2.8B	11.53B	11.75B
Sales Growth (year/est)	12.60%	1.90%	1.90%	4.60%

Earnings History	9/29/2019	12/30/2019	3/30/2020	6/29/2020
EPS Est.	1.03	0.53	0.6	0.48
EPS Actual	1.01	0.56	0.56	0.54
Difference	-0.02	0.03	-0.04	0.06
Surprise %	-1.90%	5.70%	-6.70%	12.50%

EPS Trend	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Current Estimate	1.09	0.59	2.78	2.97
7 Days Ago	1.09	0.59	2.78	2.97
30 Days Ago	1.1	0.59	2.78	2.97
60 Days Ago	1.1	0.6	2.76	2.96
90 Days Ago	1.09	0.62	2.76	2.95

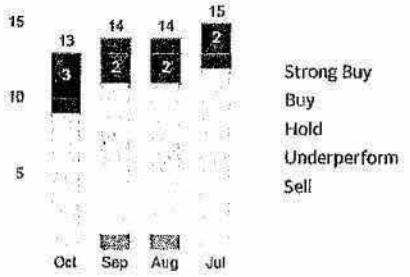
EPS Revisions	Current Qtr. (Sep 2020)	Next Qtr. (Dec 2020)	Current Year (2020)	Next Year (2021)
Up Last 7 Days	N/A	1	1	N/A

30 Second "Miracle Stretch" Leaves Chiropractors Baffled! (Watch)
Sponsored by WeeklyPenny.com

People Also Watch

Symbol	Last Price	Change	% Change
WEC WEC Energy Group, Inc.	97.55	-0.70	-0.71%
PNW Pinnacle West Capital Corporati	75.29	-0.03	-0.04%
SRE Sempra Energy	119.29	+0.16	+0.13%
PEG Public Service Enterprise Group	54.72	-0.35	-0.63%
CNP CenterPoint Energy, Inc (Holdin	19.38	-0.02	-0.10%

Recommendation Trends ›



Recommendation Rating ›

Up Last 30 Days	N/A	1	1	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	N/A	1

Growth Estimates	XEL	Industry	Sector(s)	S&P 500
Current Qtr.	7.90%	N/A	N/A	N/A
Next Qtr.	5.40%	N/A	N/A	N/A
Current Year	5.30%	N/A	N/A	N/A
Next Year	6.80%	N/A	N/A	N/A
Next 5 Years (per annum)	5.85%	N/A	N/A	N/A
Past 5 Years (per annum)	5.68%	N/A	N/A	N/A

Average 68.08

Low 60.00 High 74.00

Current 70.01

Upgrades & Downgrades ›

Downgrade	Argus Research: Buy to Hold	8/25/2020
Maintains	KeyBanc: to Overweight	7/21/2020
Maintains	Morgan Stanley: to Underweight	6/17/2020
Downgrade	Morgan Stanley: Equal-Weight to Underweight	5/13/2020
Downgrade	Wells Fargo: Overweight to Equal-Weight	4/24/2020
Maintains	Mizuho: to Neutral	4/15/2020

More Upgrades & Downgrades

Advertise With Us

© 2020 Verizon Media. All rights reserved.

EXHIBIT JAC-A

Arizona Public Service Company
Test Year Ended June 30, 2019
Docket No. E-01345A-19-0236

Exhibit JAC-A

Monthly Average Treasury Yields
Intermediate and Long-Term Treasury Securities
November 2018 -- August 2020

Monthly Average Yields
Moody's 'Aa,' 'A,' and 'Baa' Rated Utility Bonds
November 2018 -- August 2020

Line No.	Year	Month	Monthly Average Treasury Yields					Monthly Average Utility Bond Yields		
			5 Yr	7 Yr	10 Yr	20 Yr	30 Yr	Aa	A	Baa
1	**2018**	November	2.95%	3.04%	3.12%	3.27%	3.36%	4.40%	4.52%	5.03%
2		December	2.68%	2.75%	2.83%	2.98%	3.10%	4.24%	4.37%	4.92%
3	**2019**	January	2.54%	2.61%	2.71%	2.89%	3.04%	4.18%	4.35%	4.91%
4		February	2.49%	2.57%	2.68%	2.87%	3.02%	4.05%	4.25%	4.76%
5		March	2.37%	2.47%	2.57%	2.80%	2.98%	3.98%	4.16%	4.65%
6		April	2.33%	2.43%	2.53%	2.76%	2.94%	3.91%	4.08%	4.55%
7		May	2.19%	2.29%	2.40%	2.63%	2.82%	3.84%	3.98%	4.47%
8		June	1.83%	1.95%	2.07%	2.36%	2.57%	3.65%	3.82%	4.31%
9		July	1.83%	1.93%	2.06%	2.36%	2.57%	3.53%	3.69%	4.13%
10		August	1.49%	1.55%	1.63%	1.91%	2.12%	3.17%	3.29%	3.63%
11		September	1.57%	1.64%	1.70%	1.97%	2.16%	3.24%	3.37%	3.71%
12		October	1.53%	1.62%	1.71%	2.00%	2.19%	3.24%	3.39%	3.72%
13		November	1.64%	1.74%	1.81%	2.13%	2.28%	3.25%	3.43%	3.76%
14		December	1.68%	1.79%	1.86%	2.16%	2.30%	3.22%	3.40%	3.73%
15	**2020**	January	1.56%	1.67%	1.76%	2.07%	2.22%	3.12%	3.29%	3.60%
16		February	1.32%	1.42%	1.50%	1.81%	1.97%	2.96%	3.11%	3.42%
17		March	0.59%	0.78%	0.87%	1.26%	1.46%	3.30%	3.50%	3.96%
18		April	0.39%	0.55%	0.66%	1.06%	1.27%	2.93%	3.19%	3.82%
19		May	0.34%	0.53%	0.67%	1.12%	1.38%	2.89%	3.14%	3.63%
20		June	0.34%	0.55%	0.73%	1.27%	1.49%	2.80%	3.07%	3.44%
21		July	0.28%	0.46%	0.62%	1.09%	1.31%	2.46%	2.74%	3.09%
22		August	0.27%	0.46%	0.65%	1.14%	1.36%	2.49%	2.73%	3.06%

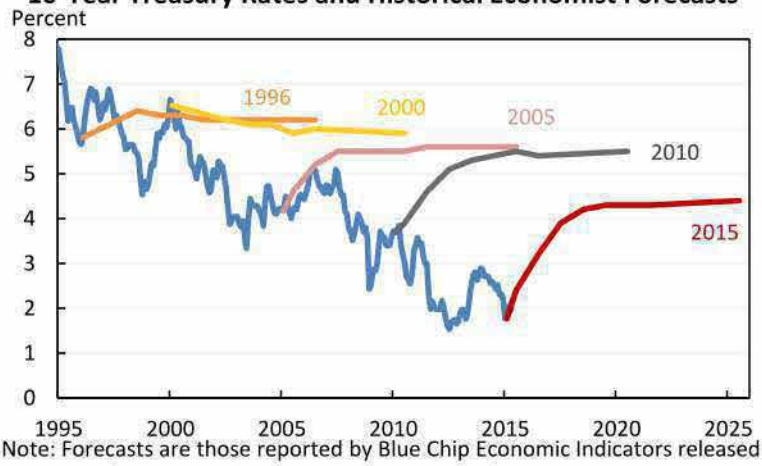
Source:
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

EXHIBIT JAC-B

have tended to be inaccurate. Between 1984 and 2012, CBO, private-sector forecasters, and the Administration all systematically overestimated the path of nominal interest rates just two years into the future (CBO 2015a).

Figure 5

10-Year Treasury Rates and Historical Economist Forecasts



Note: Forecasts are those reported by Blue Chip Economic Indicators released in March of the given calendar year, the median of over 50 private-sector economists. Source: Blue Chip Economic Indicators, Aspen Publishers.

A central question in forming a long-run forecast is whether interest rates are statistically stationary—i.e., whether they have a tendency to return to a definite long-run mean value or average. To the extent interest rates are mean-reverting, the historical average may contain the most useful information for projecting the long-run long-term interest rate. On the other hand, if changes in interest rates are permanent (or at least, highly persistent), recent data may contain more useful information about long-run interest rates than historical data. In general, econometric tests suggest that real and nominal interest rates revert to their mean very slowly, with close to unit root (non-stationary)[9] properties.[10] Tests for non-stationarity tend to be weak, however, in that distinguishing between a true unit root and mean reversion with very high persistence is difficult in a finite sample of data (Neely and Rapach 2008).

Economic theory strongly suggests that real interest rates are bounded, if not fully mean reverting (as discussed in more detail in section III).[11] A high return on investment should trigger a reallocation of resources from consumption toward capital accumulation, driving down the marginal product of capital and the real interest rate over time. Similarly, a low return on

[9] A time series is said to contain a unit root if its random changes contain a permanent component. In this case it is statistically non-stationary.

[10] Hamilton et. al. (2015) reject the hypothesis that the real interest rate converges to a fixed constant. The difficulty in predicting the long-run real interest rate leads them to be skeptical of models, like the Ramsey model considered below, that place a strong emphasis on the link between output growth and the real interest rate.

[11] Even when interest rates are mean-reverting, and therefore stationary in the statistical sense, they can be "trend-stationary," reverting to means that evolve deterministically over time rather than being constants. Thus, stationarity of interest rates does not rule out the possibility that they trend upward or downward over long periods as a result of somewhat predictable, secular economic forces.

EXHIBIT JAC-C

Sample Average Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), and
Comparable Earnings (CE) Results obtained for RUCO's Proxy Group of Companies
Compared to Average Results obtained for
FirstEnergy Corporation and PPL Corporation

Line No.	Mertic of Comparison	DCF Comparison [A] Average Growth	DCF Comparison [B] Expected Dividend Yield	DCF Comparison [C] DCF Rates	CAPM Comparison [D] Beta	CAPM Comparison [E] CAPM Rates	CE Comparison [F] 5-Yr Historical ROE	CE Comparison [G] 5-Yr Projected ROE	CE Comparison [H] 5-Yr Combined Hist. & Proj. ROE
1	RUCO Sample Average	4.20%	3.79%	7.99%	0.89	7.73%	9.3%	9.7%	9.5%
2	FirstEnergy Corporation	6.24%	4.81%	11.04%	0.85	7.45%	15.2%	16.3%	15.8%
3	PPL Corporation	3.68%	6.13%	9.81%	1.10	9.30%	15.6%	13.0%	14.3%
	Basis point excess:								
4	PPL over RUCO sample average		2.35%	1.82%	0.21	1.57%	6.30%	3.30%	4.80%
5	FE over RUCO sample average		1.02%	3.05%	N/A	N/A	5.88%	6.63%	6.26%

References for values on Line 1:

[A] Schedule JAC-3 (Page 4)
[B] Schedule JAC-3 (Page 4)
[C] Schedule JAC-3 (Page 4)
[D] Schedule JAC-4 (Page 1)
[E] Schedule JAC-4 (Page 1)
[F] Schedule JAC-5 (Page 1)
[G] Schedule JAC-5 (Page 1)
[H] Schedule JAC-5 (Page 1)

Computations for Lines 4-5:

Line 4: Line 3 - Line 1
Line 5: Line 2 - Line 1

Note: The computation of the values presented lines 2 and 3 for FE and PPL is identical to that of each company in RUCO's proxy group.

EXHIBIT JAC-D

Arizona Public Service Company
Test Year Ended June 30, 2019
Docket No. E-01345A-19-0236

Exhibit JAC- D

Change to *Value Line* Betas for RUCO's Proxy Companies
Since the Filing of Bulkley Direct Testimony

Line No.	RUCO Proxy Group Companies	Ticker	[A] VL Betas RUCO Sample Average	[B] VL Betas Bulkley Direct	[C] Increase to Beta	[D] Percentage Change to Beta
1	Allete, Inc.	ALE	0.85	0.65	0.20	30.77%
2	Ameren Corporation	AEE	0.80	0.60	0.20	33.33%
3	American Electric Power Company	AEP	0.75	0.55	0.20	36.36%
4	DTE Energy Company	DTE	0.90	0.55	0.35	63.64%
5	Duke Energy Corporation	DUK	0.85	0.50	0.35	70.00%
6	Exelon Corporation	EXC	0.95	0.70	0.25	35.71%
7	Evergy, Inc.	EVRG	1.00	N/A	N/A	N/A
8	OGE Energy Corporation	OGE	1.05	0.80	0.25	31.25%
9	Otter Tail Corporation	OTTR	0.85	0.70	0.15	21.43%
10	PNM Resources, Inc.	PNM	0.95	0.60	0.35	58.33%
11	Southern Company	SO	0.90	0.50	0.40	80.00%
12	Xcel Energy Inc.	XEL	0.80	0.50	0.30	60.00%
13	Average		**0.8875**	**0.6045**	**0.2830**	46.80%

Reference:
[A]: Schedule JAC-4 (Page 1 of 2)
[B]: Schedule AEB-4DR (Page 1 of 1)
[C]: [A] - [B]
[D]: [C] / [B]

EXHIBIT JAC-E

Comparison of Sample Average Current Stock Prices and Dividend Yields
Employed in RUCO's Constant Growth DCF Analyses
to those
Employed by Ms. Bulkley in her Constant Growth DCF Analyses

Line No.	RUCO Proxy Companies	Ticker	[A] RUCO Annualized Dividend	[B] RUCO 3-Month Average Stock Price	[C] Dividend Yield	[D] Bulkley Annualized Dividend	[E] Bulkley 30-Day Average Stock Price	[F] Dividend Yield
1	Allete, Inc.	ALE	$2.47	$ 58.25	4.24%	$2.35	$ 85.61	2.74%
2	Ameren Corporation	AEE	$1.98	$ 75.55	2.62%	$1.90	$ 76.31	2.49%
3	American Electric Power Company, Inc.	AEP	$2.80	$ 83.54	3.35%	$2.68	$ 89.89	2.98%
4	DTE Energy Company	DTE	$4.05	$ 111.83	3.62%	$3.78	$ 129.64	2.92%
5	Duke Energy Corporation	DUK	$3.86	$ 84.89	4.55%	$3.71	$ 88.63	4.19%
6	Exelon Corporation	EXC	$1.53	$ 38.23	4.00%	$1.45	$ 48.15	3.01%
7	Evergy, Inc.	EVRG	$2.02	$ 57.62	3.51%	$1.90	$ 60.93	3.12%
8	OGE Energy Corporation	OGE	$1.55	$ 32.07	4.83%	$1.46	$ 42.99	3.40%
9	Otter Tail Corporation	OTTR	$1.48	$ 40.62	3.64%	$1.40	$ 52.51	2.67%
10	PNM Resources, Inc.	PNM	$1.23	$ 41.32	2.98%	$1.16	$ 50.55	2.29%
11	Southern Company	SO	$2.56	$ 55.44	4.62%	$2.48	$ 55.84	4.44%
12	Xcel Energy Inc.	XEL	$1.72	$ 67.29	2.56%	$1.62	$ 60.65	2.67%
13	**RUCO Sample Average Dividend Yield**				**3.71%**			**3.08%**
14	**Percentage increase to RUCO sample average dividend yield**							**20.62%**
15	FirstEnergy	FE	$1.56	$ 33.48	4.66%	$1.52	$ 43.57	3.49%
16	PPL Corporation	PPL	$1.66	$ 27.57	6.02%	$1.65	$ 30.66	5.38%
17	**Bulkley Sample Average Dividend Yield**				**3.94%**			**3.27%**
18	**Percentage increase to Bulkley sample average dividend yield**							**20.58%**

References:
[A]: Schedule JAC-3 (Page 1), Column [A]
[B]: Schedule JAC-3 (Page 1), Column [D]
[C]: Schedule JAC-3 (Page 1), Column [E]
[D]: Bulkley Direct, Attachment AEB-2DR (Page 1), Column [1]
[E]: Bulkley Direct, Attachment AEB-2DR (Page 1), Column [2]
[F]: Bulkley Direct, Attachment AEB-2DR (Page 1), Column [3]

EXHIBIT JAC-F

Evidence of Overstatement to the Risk Premium Component in Ms. Bulkley's Bond Yield Plus Risk Premium Analysis Caused by Improper Use of the Yield on the 30-Year Treasury Bond in the Computation of the Risk Premium rather than Properly Employing the Yield on Moody's Aa', A', or Baa' Rated Utility Bonds (based on data for years 2007 - 2019)

Line No.	Calendar Quarter	U.S. Government 30-Year Treasury Yield's Employed by Ms. Bulkley in her Risk Premium Analysis													
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Q1 & Q2 2019	Average
1	Q1	4.80%	4.41%	3.44%	4.62%	4.56%	3.14%	3.13%	3.69%	2.55%	2.72%	3.04%	3.02%	3.01%	
2	Q2	4.99%	4.57%	4.17%	4.36%	4.34%	2.93%	3.14%	3.44%	2.88%	2.57%	2.90%	3.09%	2.78%	
3	Q3	4.95%	4.44%	4.32%	3.86%	3.69%	2.74%	3.71%	3.26%	2.96%	2.28%	2.82%	3.06%		
4	Q4	4.61%	3.65%	4.34%	4.17%	3.04%	2.86%	3.79%	2.96%	2.96%	2.83%	2.82%	3.27%		
5	Average Annual Yield – 30-Year Treasury Bond	4.84%	4.27%	4.07%	4.25%	3.91%	2.92%	3.44%	3.34%	2.84%	2.60%	2.90%	3.11%	2.90%	3.49%
6	Average Annual Yield – Moody's Baa' Rated Utility Bonds	6.33%	7.25%	7.06%	5.96%	5.57%	4.86%	4.98%	4.80%	5.03%	4.68%	4.38%	4.67%	4.61%	5.40%
7	**Annual Overstatement to Risk Premium**	1.49%	2.98%	2.99%	1.71%	1.66%	1.94%	1.54%	1.46%	2.19%	2.08%	1.48%	1.56%	1.71%	1.91%

References:

Lines 1-4:	Bulkley Direct, Attachment AEB-7DR (Pages 1 & 2 of 3), Column [2].
Line 5:	Average of Lines 1-4.
Line 6:	Schedule JAC-6 (Page 4 of 7), Moody's Baa' rated Utility Bonds.
Line 7:	Line 6 - Line 5

Note: Ms. Bulkley's Risk Premium analysis obtains estimates over the period, 1992 - 2019. RUCO had available Moody's Utility Bond rating data for the period 2007 - 2019, and it is for this reason that the above analysis does not include data for the period, 1992-2006.

SCHEDULES

Arizona Public Service Company
Test Year Ended June 30, 2019
Docket No. E-01345A-19-0236

RUCO PROPOSED
CAPITAL STRUCTURE & WEIGHTED AVERAGE COST OF CAPITAL
($ thousands of dollars)

Line No	Description	[A] Company proposed Capital Structure	[B] RUCO Adjustments	[C] RUCO Adjusted Capital Structure	[D] Capital Ratio	[E] Cost Rate	[F] Weighted Cost
1	Long-Term Debt	$ 4,726,125	$ -	$ 4,726,125	45.33%	4.10%	1.86%
2							
3	Common Equity	5,700,968	$ -	$ 5,700,968	54.67%	8.74%	4.78%
4	TOTAL CAPITALIZATION	$ 10,427,093	$ -	$ 10,427,093	100.00%		**6.64%**

[A] : Company Schedule D-1
[B] : RUCO Adjustments
[C] : [A] + [B]
[D] : Capital ratio based on values shown in Column [C].
[E] : Company Schedule D-1, and RUCO Schedule JAC-2.
[F] : [D] * [E]

Arizona Public Service Company
Cost of Capital Calculation
Fair Value Rate Base (FVRB),
Fair Value Rate of Return (FVROR) and
Cost Rate to be Assigned to the Fair Value Increment
RUCO Recommended
($ in thousands)

Calculation of RUCO Fair Value Rate Base (FVRB)

Line No.	Rate Base Estimate	Amount	Weighting	Weighted Amount
1	[1] Original Cost Rate Base (OCRB) - RUCO Recommended	$ 8,261,698	50%	$ 4,130,849
2	[2] RUCO Reconstruction Cost New (RCND) Rate Base	$ 15,136,256	50%	7,568,128
3	**Fair Value Rate Base (FVRB)**			**$ 11,698,977**
4	Appreciation above OCRB			$ 3,437,279
5	FV/OCRB Multiple	1.42		

Calculation of RUCO Fair Value Rate of Return (FVROR)

	Capital	Amount	Percent	Cost Rate	Weighted Cost
6	Long-Term Debt	$ 3,744,650	32.01%	4.10%	1.31%
7	Common Equity	$ 4,517,048	38.61%	8.74%	3.37%
8	Capital Financing OCRB	$ 8,261,698			
9	Fair Value Increment	$ 3,437,279	29.38%	0.00%	0.00%
10	**Fair Value Rate of Return**	$ 11,698,977	100.00%		**4.69%**

Calculation of Cost Rate to be Assigned to the Fair Value Increment

	Cost Inputs	Cost Rate
11	[3] Nominal Risk-Free Rate - Forecasted	1.58%
12	[4] Less: CPI Inflation Component - Forecasted	1.30%
13	Real Risk-Free Rate	0.28%
14	**Cost Rate - Fair Value Increment**	0.28%
15	**RUCO RECOMMENDED COST RATE - Fair Value Increment**	**0.00%**

Sources:

[1] Frank Radigan Direct, Exhibit FWR-2 (RUCO Schedule A-1)

[2] Frank Radigan Direct, Exhibit FWR-2 (RUCO Schedule A-1)

[3] Nominal risk-free rate is the yield on the 30-year U.S. Treasury Bond, forecasted one year out to Q2 - 2021.
https://tradingeconomics.com/forecast/government-bond-10y

[4] Consumer Price Index (CPI) inflation, forecasted one year out to Q4 - 2021.
https://data.oecd.org/price/inflation-forecast.htm

Cost of Common Equity

Line No.			Common Equity Cost Rate		
			Indicated Cost of Common Equity	Weight Factor	Indicated Weighted Cost
1	Discounted Cash Flow Model ("DCF")	Schedule JAC - 3	8.75%	40.00%	3.50%
2	Capital Asset Pricing Model ("CAPM")	Schedule JAC - 4	7.68%	20.00%	1.54%
3	Comparable Earnings Model ("CE")	Schedule JAC - 5	9.75%	40.00%	3.90%
4	Sample Average Indicated Cost of Common Equity		8.73%		
5	**RUCO Indicated Weighted Cost of Common Equity**				**8.94%**
6	RUCO Proposed Downward Adjustment				0.20%
7	**RUCO Recommended Cost of Common Equity**				**8.74%**

[Lines 1 - 3]: From Schedules JAC-3, JAC-4 and JAC-5

[Lines 4 - 5]: See Testimony

[Line 6]: See Direct Testimony of Jordy Fuentes
[Line 7]: See Testimony

PROXY GROUP -- DIVIDEND YIELD

Line No	Proxy Group Companies	Ticker	(A) DPS	(B) June 2020 - August 2020 High	(C) June 2020 - August 2020 Low	(D) June 2020 - August 2020 Average	(E) Yield
1	Allete, Inc.	ALE	$2.47	$64.90	$51.60	$58.25	4.24%
2	Ameren Corporation	AEE	$1.98	$83.96	$67.14	$75.55	2.62%
3	American Electric Power Company, Inc.	AEP	$2.80	$89.93	$77.15	$83.54	3.35%
4	DTE Energy Company	DTE	$4.05	$121.47	$102.19	$111.83	3.62%
5	Duke Energy Corporation	DUK	$3.86	$92.20	$77.58	$84.89	4.55%
6	Exelon Corporation	EXC	$1.53	$41.96	$34.49	$38.23	4.00%
7	Evergy, Inc.	EVRG	$2.02	$65.43	$49.81	$57.62	3.51%
8	OGE Energy Corporation	OGE	$1.55	$34.91	$29.22	$32.07	4.83%
9	Otter Tail Corporation	OTTR	$1.48	$44.61	$36.63	$40.62	3.64%
10	PNM Resources, Inc.	PNM	$1.23	$45.70	$36.93	$41.32	2.98%
11	Southern Company	SO	$2.56	$60.47	$50.40	$55.44	4.62%
12	Xcel Energy Inc.	XEL	$1.72	$73.00	$61.58	$67.29	2.56%
13	Average						**3.71%**

References:

Column (A) - *Value Line Investment Survey*, Ratings & Reports (various issues - July 24, and August 14, and September 11, 2020).

DPS reflects annualization of most recent quarterly dividend.

Columns (B), (C), and (D) - Yahoo Finance

http://finance.yahoo.com

PROXY GROUP -- PER SHARE GROWTH RATES

Line No	Proxy Group Companies	Ticker	5-Year Compound Average Annual Historical Growth, 2015-2019				5-Year Compound Average Annual Projected Growth, 2020-2024			
			EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
1	Allete, Inc.	ALE	4.0%	3.5%	5.0%	4.2%	4.5%	4.5%	3.5%	4.2%
2	Ameren Corporation	AEE	6.5%	3.0%	2.5%	4.0%	6.0%	5.0%	6.0%	5.7%
3	American Electric Power Company	AEP	4.0%	5.5%	3.0%	4.2%	5.0%	5.5%	4.5%	5.0%
4	DTE Energy Company	DTE	7.5%	7.0%	5.0%	6.5%	6.0%	6.5%	5.5%	6.0%
5	Duke Energy Corporation	DUK	2.5%	3.0%	1.0%	2.2%	5.0%	2.5%	2.5%	3.3%
6	Exelon Corporation	EXC	NMF	NMF	NMF	NMF	NMF	NMF	NMF	NMF
7	Evergy, Inc.	EVRG	NMF	NMF	NMF	NMF	4.5%	5.5%	2.0%	4.0%
8	OGE Energy Corporation	OGE	2.0%	10.0%	5.5%	5.8%	3.0%	6.0%	0.5%	3.2%
9	Otter Tail Corporation	OTTR	9.0%	2.5%	4.5%	5.3%	3.5%	5.0%	4.0%	4.2%
10	PNM Resources, Inc.	PNM	7.0%	10.0%	NMF	8.5%	6.0%	5.5%	5.5%	5.7%
11	Southern Company	SO	3.0%	3.5%	3.0%	3.2%	3.0%	3.0%	3.5%	3.2%
12	Xcel Energy Inc.	XEL	5.0%	6.5%	4.5%	5.3%	6.0%	6.0%	5.5%	5.8%
13	Average					4.92%				4.56%

Reference:
Value Line Investment Survey, Ratings & Reports (various issues - July 24, August 14, and September 11, 2020)

PROXY GROUP -- GROWTH RATES
RETAINED TO COMMON EQUITY

Line No	Proxy Group Companies	Ticker	(A) 2015	(B) 2016	(C) 2017	(D) 2018	(E) 2019	Average	2020	2021	2023-'25	Average
1	Allete, Inc.	ALE	3.6%	2.8%	2.4%	2.7%	2.3%	2.8%	1.5%	2.0%	2.5%	2.0%
2	Ameren Corporation	AEE	2.5%	3.3%	3.4%	4.8%	4.4%	3.7%	4.0%	4.0%	4.5%	4.2%
3	American Electric Power Company	AEP	3.9%	5.5%	3.2%	3.5%	3.4%	3.9%	3.5%	3.5%	3.5%	3.5%
4	DTE Energy Company	DTE	3.4%	3.7%	4.6%	4.9%	4.1%	4.1%	4.0%	4.0%	4.5%	4.2%
5	Duke Energy Corporation	DUK	1.5%	0.6%	1.2%	1.0%	2.4%	1.3%	2.0%	2.0%	2.5%	2.2%
6	Exelon Corporation	EXC	4.5%	1.9%	4.7%	2.2%	4.7%	3.6%	3.5%	4.0%	4.0%	3.8%
7	Evergy, Inc.	EVRG				0.6%	2.4%	1.5%	2.0%	2.5%	2.5%	2.3%
8	OGE Energy Corporation	OGE	4.0%	3.3%	3.5%	3.8%	3.6%	3.6%	3.0%	3.0%	2.5%	2.8%
9	Otter Tail Corporation	OTTR	2.0%	2.1%	3.3%	4.0%	4.0%	3.1%	3.0%	3.0%	3.5%	3.2%
10	PNM Resources, Inc.	PNM	3.3%	2.8%	4.5%	2.9%	5.4%	3.8%	2.5%	4.0%	4.5%	3.7%
11	Southern Company	SO	3.1%	2.5%	3.9%	2.6%	2.8%	3.0%	2.5%	2.5%	3.0%	2.7%
12	Xcel Energy Inc.	XEL	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	3.5%	4.0%	4.0%	3.8%
13	Average							**3.22%**				**3.19%**

Source: *Value Line Investment Survey*, Ratings & Reports (various issues - July 24, August 14, and September 11, 2020)

PROXY GROUP -- DCF ANALYSIS

Line No	Proxy Group Companies	Ticker	(A) Current Dividend Yield (D_0 / P_{A1})	(B) Historic Retention Growth	(C) Projected Retention Growth	(D) Historical Per Share Growth Rates	(E) Projected Per Share Growth Rates	(F) Yahoo! Fin. Projected 5-Year EPS Growth	(G) Average Growth	(H) Expected Dividend Yield (D_1 / P_{A1})	(I) DCF Rates
1	Allete, Inc.	ALE	4.2%	2.8%	2.0%	4.2%	4.2%	7.00%	4.0%	4.3%	8.3%
2	Ameren Corporation	AEE	2.6%	3.7%	4.2%	4.0%	5.7%	5.85%	4.7%	2.7%	7.4%
3	American Electric Power Company	AEP	3.4%	3.9%	3.5%	4.2%	5.0%	5.63%	4.4%	3.4%	7.9%
4	DTE Energy Company	DTE	3.6%	4.1%	4.2%	6.5%	6.0%	5.95%	5.4%	3.7%	9.1%
5	Duke Energy Corporation	DUK	4.5%	1.3%	2.2%	2.2%	3.3%	2.80%	2.4%	4.6%	7.0%
6	Exelon Corporation	EXC	4.0%	3.6%	3.8%	NMF	NMF	NMF	3.7%	4.1%	7.8%
7	Evergy, Inc.	EVRG	3.5%	1.5%	2.3%	NMF	4.0%	6.80%	3.7%	3.6%	7.2%
8	OGE Energy Corporation	OGE	4.8%	3.6%	2.8%	5.8%	3.2%	2.40%	3.8%	4.9%	8.5%
9	Otter Tail Corporation	OTTR	3.6%	3.1%	3.2%	5.3%	4.2%	9.00%	4.9%	3.7%	8.7%
10	PNM Resources, Inc.	PNM	3.0%	3.8%	3.7%	8.5%	5.7%	4.95%	5.3%	3.1%	8.4%
11	Southern Company	SO	4.6%	3.0%	2.7%	3.2%	3.2%	4.55%	3.3%	4.7%	8.0%
12	Xcel Energy Inc.	XEL	2.6%	4.2%	3.8%	5.3%	5.8%	6.10%	5.1%	2.6%	7.7%
13	Mean		3.71%	3.22%	3.19%	4.92%	4.56%	5.55%	4.20%	3.79%	7.99%
14	Median		3.63%	3.62%	3.33%	4.75%	4.17%	5.85%	4.23%	3.73%	7.93%
15	Composite-Mean			7.00%	6.98%	8.70%	8.35%	9.33%	7.99%		
16	Composite-Median			7.35%	7.06%	8.48%	7.89%	9.58%	7.96%		

References:
Column [A] : Schedule JAC - 3 (Page 1)
Column [B] : Schedule JAC - 3, page 4 of 4
Column [C] : Schedule JAC - 3, page 4 of 4
Column [D] and Column [E] : Schedule JAC - 3, page 2 of 4
Column [F] : See Yahoo Finance, Growth Estimates - Next 5 Years - See Attachment 7 (Downloaded September 10, 2020)
Column [G] : Average Columns [B] through [F]
Column [H] : Column [A] * (1 + (Column [G]* (0.5)))
Column [I] : Column [G] + Column [H]
Note: Low and high values for each base (mean / composite mean, and median / composite median) are highlighted.
NMF: Not Meaningful Figure

CAPITAL ASSET PRICING MODEL -- PROXY COMPANY COST RATES

Line No	Proxy Group Companies	Ticker	[A] Risk Free Rate	[B] BETA	[C] Risk Premium	[D] [B] * [C]	[E] CAPM Rates
1	Allete, Inc.	ALE	1.16%	0.85	7.40%	6.29%	7.45%
2	Ameren Corporation	AEE	1.16%	0.80	7.40%	5.92%	7.08%
3	American Electric Power Company	AEP	1.16%	0.75	7.40%	5.55%	6.71%
4	DTE Energy Company	DTE	1.16%	0.90	7.40%	6.66%	7.82%
5	Duke Energy Corporation	DUK	1.16%	0.85	7.40%	6.29%	7.45%
6	Exelon Corporation	EXC	1.16%	0.95	7.40%	7.03%	8.19%
7	Evergy, Inc.	EVRG	1.16%	1.00	7.40%	7.40%	8.56%
8	OGE Energy Corporation	OGE	1.16%	1.05	7.40%	7.77%	8.93%
9	Otter Tail Corporation	OTTR	1.16%	0.85	7.40%	6.29%	7.45%
10	PNM Resources, Inc.	PNM	1.16%	0.95	7.40%	7.03%	8.19%
11	Southern Company	SO	1.16%	0.90	7.40%	6.66%	7.82%
12	Xcel Energy Inc.	XEL	1.16%	0.80	7.40%	5.92%	7.08%
13	Average			0.8875			7.73%
14	Median						7.64%
	20 year Treasury Bonds						
15	June 2020		1.27%				
16	July 2020		1.09%				
17	August 2020		1.14%				
18	Average		1.16%				
19	RUCO Risk-Free Rate			1.16%			

REFERENCES

Column [A]: United States Treasury Department - Attachment 2
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2019

Column [B]: *Value Line Investment Survey*, *Ratings & Reports* (July 24, August 14, and September 11, 2020) - See Attachment 1
Note: Updated beta coefficients for PNM and XEL obtained from *Value Line Investment Survey*, *Summary & Index* (Sept. 11, 2020).

Column [C]: JAC - 4, Page 2 of 2

Column [D]: [B] * [C]

Column [E]: [A] + [D]

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Line No.	Year	[A] EPS	[B] BVPS	[C] ROE	[D] 20-YEAR T-BOND	[E] RISK PREMIUM
1	1977		$79.07			
2	1978	$12.33	$85.35	15.00%	7.90%	7.10%
3	1979	$14.86	$94.27	16.55%	8.86%	7.69%
4	1980	$14.82	$102.48	15.06%	9.97%	5.09%
5	1981	$15.36	$109.43	14.50%	11.55%	2.95%
6	1982	$12.64	$112.46	11.39%	13.50%	-2.11%
7	1983	$14.03	$116.93	12.23%	10.38%	1.85%
8	1984	$16.64	$122.47	13.90%	11.74%	2.16%
9	1985	$14.61	$125.20	11.80%	11.25%	0.55%
10	1986	$14.48	$126.82	11.49%	8.98%	2.51%
11	1987	$17.50	$134.07	13.42%	7.92%	5.50%
12	1988	$23.75	$141.32	17.25%	8.97%	8.28%
13	1989	$22.87	$147.26	15.85%	8.81%	7.04%
14	1990	$21.73	$153.01	14.47%	8.19%	6.28%
15	1991	$16.29	$158.85	10.45%	8.22%	2.23%
16	1992	$18.86	$149.74	12.22%	7.26%	4.96%
17	1993	$21.89	$180.88	13.24%	7.17%	6.07%
18	1994	$30.60	$193.06	16.37%	6.59%	9.78%
19	1995	$33.96	$216.51	16.58%	7.60%	8.98%
20	1996	$38.73	$237.08	17.08%	6.18%	10.90%
21	1997	$39.72	$249.52	16.33%	6.64%	9.69%
22	1998	$37.71	$266.40	14.62%	5.83%	8.79%
23	1999	$48.17	$290.68	17.29%	5.57%	11.72%
24	2000	$50.00	$325.80	16.22%	6.50%	9.72%
25	2001	$24.70	$338.37	7.44%	5.53%	1.91%
26	2002	$27.59	$321.72	8.36%	5.59%	2.77%
27	2003	$48.73	$367.17	14.15%	4.80%	9.35%
28	2004	$58.55	$414.75	14.98%	5.02%	9.96%
29	2005	$69.93	$453.06	16.12%	4.69%	11.43%
30	2006	$81.51	$504.39	17.03%	4.68%	12.35%
31	2007	$66.18	$529.59	12.80%	4.86%	7.94%
32	2008	$14.88	$451.37	3.03%	4.45%	-1.42%
33	2009	$50.97	$513.58	10.56%	3.47%	7.09%
34	2010	$77.35	$579.14	14.16%	4.25%	9.91%
35	2011	$86.95	$613.14	14.59%	3.82%	10.77%
36	2012	$86.51	$666.97	13.52%	2.46%	11.06%
37	2013	$100.20	$715.84	14.49%	2.88%	11.61%
38	2014	$102.31	$726.96	14.18%	3.41%	10.77%
39	2015	$86.53	$740.29	11.79%	2.55%	9.24%
40	2016	$94.55	$768.98	12.53%	2.30%	10.23%
41	2017	$109.88	$807.04	13.94%	2.65%	11.29%
42	2018	$132.39	$841.26	16.06%	3.11%	12.95%
43	2019	$139.47	$892.65	16.09%	2.40%	13.69%
44	Average			**13.79%**	**6.39%**	**7.40%**

[A]: Diluted earnings per share on the S&P 500 Composite Index.
[B]: Book value per share on the S&P 500 Composite Index.
[C]: Average of current- and prior year [B] / current year [A].
[D]: Annual income returns on 20-year U.S. Treasury bonds.
[E]: [C] - [D]

Sources for [A] and [B]: Standard & Poor's 2015 Analysts' Handbook and
Standard & Poor's 500 Earnings and Book Value Per Share:
https://ycharts.com/indicators/reports/sp_500_earnings
https://ycharts.com/indicators/sandp_500_book_value_per_share
Source for [D]: Morningstar 2015 Classic Yearbook (Table A-7) and
U.S. Department of the Treasury
https://www.treasury.gov/Pages/default.aspx

COMPARABLE EARNINGS ANALYSIS

RETURN ON COMMON EQUITY FOR RUCO'S PROXY GROUP OF COMPANIES

		Historical ROEs										Projected ROEs			10-Year Historical Average	5-Year Historical Average	5-Year Projected Average	5-Yr Combined Historical & Projected Average
Company	Ticker	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2023 - 2025	2010-2019	2015-2019	2020-2024	
Allete, Inc.	ALE	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	6.5%	7.5%	8.0%	8.1%	8.1%	7.3%	7.7%
Ameren Corporation	AEE	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.5%	10.0%	10.0%	8.9%	9.6%	9.8%	9.7%
American Electric Power Company	AEP	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.5%	10.5%	10.5%	10.0%	10.4%	10.5%	10.5%
DTE Energy Company	DTE	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	10.5%	10.5%	11.0%	9.7%	10.1%	10.7%	10.4%
Duke Energy Corporation	DUK	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.3%	7.5%	8.0%	8.5%	7.1%	7.1%	8.0%	7.6%
Exelon Corporation	EXC	18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	8.0%	8.5%	9.0%	10.0%	7.9%	8.5%	8.2%
Evergy, Inc.	EVRG									5.3%	7.8%	7.0%	8.0%	8.5%	NMF	6.6%	7.8%	7.2%
OGE Energy Corporation	OGE	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	12.0%	12.0%	11.6%	10.3%	11.8%	11.1%
Otter Tail Corporation	OTTR	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	10.0%	11.0%	11.5%	8.3%	10.4%	10.8%	10.6%
PNM Resources, Inc.	PNM	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	10.9%	7.5%	9.0%	9.5%	7.3%	8.4%	8.7%	8.5%
Southern Company	SO	12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.0%	12.0%	12.5%	12.4%	12.3%	12.2%	12.2%
Xcel Energy Inc.	XEL	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.0%	10.0%	10.5%	10.0%	10.2%	10.2%	10.2%
Mean		9.3%	9.6%	8.9%	9.1%	9.4%	9.3%	9.0%	9.7%	9.2%	9.9%	9.2%	9.8%	10.1%	9.4%	9.3%	9.7%	9.50%
Median		8.9%	8.9%	8.8%	8.7%	9.7%	9.1%	9.3%	9.8%	10.2%	10.3%	9.8%	10.0%	10.3%	9.7%	9.8%	10.0%	10.00%

Source: *Value Line Investment Survey*, Ratings & Reports (several issues - July 24, August 14, and September 11, 2020).

ECONOMIC INDICATORS

Line No	Year	Real GDP Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle			
1	1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
2	1976	5.4%	10.8%	7.7%	4.8%	3.7%
3	1977	5.5%	5.9%	7.0%	6.8%	6.9%
4	1978	5.0%	5.7%	6.0%	9.0%	9.2%
5	1979	2.8%	4.4%	5.8%	13.3%	12.8%
6	1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
7	1981	1.8%	1.9%	7.5%	8.9%	7.1%
8	1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle			
9	1983	4.0%	3.7%	9.5%	3.8%	0.6%
10	1984	6.8%	9.3%	7.5%	3.9%	1.7%
11	1985	3.7%	1.7%	7.2%	3.8%	1.8%
12	1986	3.1%	0.9%	7.0%	1.1%	-2.3%
13	1987	2.9%	4.9%	6.2%	4.4%	2.2%
14	1988	3.8%	4.5%	5.5%	4.4%	4.0%
15	1989	3.5%	1.8%	5.3%	4.6%	4.9%
16	1990	1.8%	-0.2%	5.6%	6.1%	5.7%
17	1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle			
18	1992	3.0%	3.1%	7.5%	2.9%	1.6%
19	1993	2.7%	3.4%	6.9%	2.7%	0.2%
20	1994	4.0%	5.5%	6.1%	2.7%	1.7%
21	1995	3.7%	4.8%	5.6%	2.5%	2.3%
22	1996	4.5%	4.3%	5.4%	3.3%	2.8%
23	1997	4.5%	7.3%	4.9%	1.7%	-1.2%
24	1998	4.2%	5.8%	4.5%	1.6%	0.0%
25	1999	3.7%	4.5%	4.2%	2.7%	2.9%
26	2000	4.1%	4.0%	4.0%	3.4%	3.6%
27	2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
			2002 - 2009 Cycle			
28	2002	1.8%	0.2%	5.8%	2.4%	1.2%
29	2003	2.8%	1.2%	6.0%	1.9%	4.0%
30	2004	3.8%	2.3%	5.5%	3.3%	4.2%
31	2005	3.3%	3.2%	5.1%	3.4%	5.4%
32	2006	2.7%	2.2%	4.6%	2.5%	1.1%
33	2007	1.8%	2.5%	4.6%	4.1%	6.2%
34	2008	-0.1%	-3.5%	5.8%	0.1%	-0.9%
35	2009	-2.5%	-11.5%	9.3%	2.7%	4.3%
			Current Cycle			
36	2010	2.6%	5.5%	9.6%	1.5%	4.7%
37	2011	1.6%	3.1%	8.9%	3.0%	6.9%
38	2012	2.2%	3.0%	8.1%	1.7%	1.6%
39	2013	1.8%	2.0%	7.4%	1.5%	0.8%
40	2014	2.5%	3.1%	6.2%	0.8%	1.2%
41	2015	3.1%	-1.0%	5.3%	0.7%	-4.3%
42	2016	1.7%	-2.0%	4.9%	2.1%	-1.4%
43	2017	2.3%	2.3%	4.4%	2.1%	3.3%
44	2018	3.0%	3.9%	3.9%	1.9%	3.4%
45	2019	2.2%	0.8%	3.7%	2.3%	0.4%

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Line No	Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
1	2007					
2	1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
3	2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
4	3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
5	4th Qtr.	2.9%	1.7%	4.8%	0.6%	6.5%
6	2008					
7	1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
8	2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
9	3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
10	4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
11	2009					
12	1st Qtr.	-5.3%	-11.6%	8.1%	2.4%	-0.4%
13	2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%	9.2%
14	3rd Qtr.	1.4%	-9.3%	9.6%	2.0%	-0.8%
15	4th Qtr.	4.0%	-4.5%	10.0%	2.5%	8.8%
16	2010					
17	1st Qtr.	1.6%	2.7%	9.7%	0.9%	6.5%
18	2nd Qtr.	3.9%	6.5%	9.7%	-1.2%	-2.4%
19	3rd Qtr.	2.8%	6.9%	9.6%	2.8%	4.0%
20	4th Qtr.	2.8%	6.2%	9.6%	2.8%	9.2%
21	2011					
22	1st Qtr.	-1.5%	5.4%	9.0%	4.8%	9.6%
23	2nd Qtr.	2.9%	3.6%	9.0%	3.2%	3.6%
24	3rd Qtr.	0.8%	3.3%	9.1%	2.4%	6.4%
25	4th Qtr.	4.6%	4.0%	8.7%	0.4%	-1.2%
26	2012					
27	1st Qtr.	2.3%	4.5%	8.3%	3.2%	2.0%
28	2nd Qtr.	1.6%	4.7%	8.2%	0.0%	-2.8%
29	3rd Qtr.	2.5%	3.4%	8.1%	4.0%	9.6%
30	4th Qtr.	0.1%	2.8%	7.8%	0.0%	-3.6%
31	2013					
32	1st Qtr.	1.9%	2.5%	7.7%	2.0%	1.2%
33	2nd Qtr.	1.1%	2.0%	7.6%	1.2%	2.4%
34	3rd Qtr.	3.0%	2.6%	7.3%	1.6%	0.0%
35	4th Qtr.	3.8%	3.3%	7.0%	1.2%	0.3%
36	2014					
37	1st Qtr.	-1.2%	3.2%	6.6%	1.6%	0.3%
38	2nd Qtr.	4.0%	4.2%	6.2%	3.6%	0.2%
39	3rd Qtr.	5.0%	4.7%	6.1%	0.0%	0.0%
40	4th Qtr.	2.3%	4.5%	5.7%	-2.8%	-0.8%
41	2015					
42	1st Qtr.	3.2%	3.5%	5.6%	-0.2%	-2.3%
43	2nd Qtr.	2.7%	1.5%	5.4%	0.6%	1.2%
44	3rd Qtr.	1.6%	1.1%	5.2%	0.0%	-1.8%
45	4th Qtr.	0.6%	-0.8%	5.0%	0.2%	-0.9%
46	2016					
47	1st Qtr.	1.5%	-1.7%	4.9%	1.1%	-2.7%
48	2nd Qtr.	2.3%	-1.3%	4.9%	1.0%	-2.2%
49	3rd Qtr.	1.9%	-1.2%	4.9%	1.1%	-1.5%
50	4th Qtr.	1.8%	-0.1%	4.7%	1.8%	0.9%
51	2017					
52	1st Qtr.	1.8%	0.6%	4.7%	2.5%	3.7%
53	2nd Qtr.	3.0%	2.2%	4.3%	1.9%	3.1%
54	3rd Qtr.	2.8%	1.6%	4.3%	1.9%	2.9%
55	4th Qtr.	2.3%	3.5%	4.1%	2.1%	3.6%
56	2018					
57	1st Qtr.	3.8%	3.5%	4.1%	1.7%	3.2%
58	2nd Qtr.	2.7%	3.3%	3.9%	2.3%	3.9%
59	3rd Qtr.	2.1%	4.9%	3.8%	1.3%	3.9%
60	4th Qtr.	1.3%	3.9%	3.8%	1.0%	2.5%
61	2019					
62	1st Qtr.	2.9%	2.9%	3.9%	0.2%	0.8%
63	2nd Qtr.	1.5%	1.1%	3.6%	0.2%	0.8%
64	3rd Qtr.	2.6%	0.2%	3.6%	0.2%	-0.1%
65	4th Qtr.	2.4%	-0.7%	3.5%	0.2%	0.2%
66	2020					
67	1st Qtr.	-5.0%	-2.0%	3.8%	-0.1%	0.4%
68	2nd Qtr.	-31.7%		13.0%		
69	3rd Qtr.					
70	4th Qtr.					

*GDP=Gross Domestic Product
Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Line No	Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
2	1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
3	1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
4	1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
5	1979	12.67%	10.04%	9.43%	9.86%	10.22%	10.49%	10.96%
6	1980	15.27%	11.51%	11.43%	12.30%	13.00%	13.34%	13.95%
7	1981	18.89%	14.03%	13.92%	14.64%	15.30%	15.95%	16.60%
8	1982	14.86%	10.69%	13.01%	14.22%	14.79%	15.86%	16.45%
9	1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
10	1984	12.04%	9.58%	12.46%	12.72%	13.66%	14.03%	14.53%
11	1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
12	1986	8.33%	5.98%	7.67%	8.92%	9.30%	9.58%	10.00%
13	1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
14	1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
15	1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
16	1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
17	1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
18	1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
19	1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
20	1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
21	1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
22	1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
23	1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
24	1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
25	1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
26	2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
27	2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
28	2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
29	2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
30	2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
31	2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
32	2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
33	2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
34	2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
35	2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
36	2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
37	2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
38	2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
39	2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
40	2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
41	2015	3.27%	0.06%	2.14%		4.00%	4.12%	5.03%
42	2016	3.51%	0.33%	1.84%		3.73%	3.93%	4.68%
43	2017	4.13%	0.94%	2.33%		3.82%	4.00%	4.38%
44	2018	4.96%	1.94%	2.91%		4.09%	4.25%	4.67%
45	2019	5.25%	2.09%	2.14%		3.61%	3.77%	4.19%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Mergent Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Moody's Rated Utility Bonds Aa	Moody's Rated Utility Bonds A	Moody's Rated Utility Bonds Baa
1	2009						
2	Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
3	Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
4	Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
5	Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
6	May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
7	June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
8	July	3.25%	0.19%	3.56%	5.63%	5.97%	6.87%
9	Aug	3.25%	0.18%	3.59%	5.33%	5.71%	6.36%
10	Sept	3.25%	0.13%	3.40%	5.15%	5.53%	6.12%
11	Oct	3.25%	0.08%	3.39%	5.23%	5.65%	6.14%
12	Nov	3.25%	0.05%	3.40%	5.33%	5.64%	6.18%
13	Dec	3.25%	0.07%	3.59%	5.52%	5.79%	6.26%
14	2010						
15	Jan	3.25%	0.08%	3.73%	5.55%	5.77%	6.18%
16	Feb	3.25%	0.10%	3.69%	5.69%	5.87%	6.25%
17	Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
18	Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
19	May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
20	June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
21	July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
22	Aug	3.25%	0.15%	2.70%	4.75%	5.01%	5.55%
23	Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
24	Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
25	Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
26	Dec	3.25%	0.15%	3.26%	5.32%	5.56%	6.04%
27	2011						
28	Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
29	Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
30	Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
31	Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.96%
32	May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
33	June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
34	July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
35	Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
36	Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
37	Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
38	Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
39	Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
40	2012						
41	Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
42	Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
43	Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
44	Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
45	May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
46	June	3.25%	0.09%	1.62%	3.79%	4.06%	4.91%
47	July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
48	Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
49	Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
50	Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
51	Nov	3.25%	0.11%	1.65%	3.50%	3.84%	4.42%
52	Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Moody's Rated Utility Bonds Aa	Moody's Rated Utility Bonds A	Moody's Rated Utility Bonds Baa
1	2013						
2	Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
3	Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
4	Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
5	Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
6	May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
7	June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
8	July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
9	Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
10	Sept	3.25%	0.02%	2.81%	4.56%	4.80%	5.31%
11	Oct	3.25%	0.05%	2.62%	4.48%	4.70%	5.17%
12	Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
13	Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
14	2014						
15	Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.08%
16	Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
17	Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
18	Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
19	May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
20	June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
21	July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
22	Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
23	Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
24	Oct	3.25%	0.02%	2.30%	3.98%	4.05%	4.67%
25	Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
26	Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%
27	2015						
28	Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
29	Feb	3.25%	0.02%	1.98%	3.62%	3.67%	4.44%
30	Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
31	Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%
32	May	3.25%	0.02%	2.20%	4.06%	4.17%	4.91%
33	June	3.25%	0.02%	2.36%	4.29%	4.39%	5.13%
34	July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
35	Aug	3.25%	0.07%	2.17%	4.13%	4.25%	5.23%
36	Sept	3.25%	0.02%	2.17%	4.25%	4.39%	5.42%
37	Oct	3.25%	0.02%	2.07%	4.13%	4.29%	5.47%
38	Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
39	Dec	3.50%	0.23%	2.24%	4.18%	4.35%	5.55%
40	2016						
41	Jan	3.50%	0.26%	2.09%	4.08%	4.27%	5.49%
42	Feb	3.50%	0.31%	1.78%	3.94%	4.11%	5.28%
43	Mar	3.50%	0.30%	1.89%	3.93%	4.16%	5.12%
44	Apr	3.50%	0.23%	1.81%	3.74%	4.00%	4.75%
45	May	3.50%	0.27%	1.81%	3.65%	3.93%	4.80%
46	Jun	3.50%	0.27%	1.64%	3.56%	3.78%	4.47%
47	Jul	3.50%	0.30%	1.50%	3.36%	3.57%	4.16%
48	Aug	3.50%	0.30%	1.56%	3.39%	3.59%	4.20%
49	Sep	3.50%	0.29%	1.63%	3.47%	3.66%	4.27%
50	Oct	3.50%	0.33%	1.76%	3.59%	3.77%	4.34%
51	Nov	3.50%	0.46%	2.14%	3.91%	4.08%	4.64%
52	Dec	3.75%	0.51%	2.49%	4.11%	4.27%	4.79%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Moody's Rated Utility Bonds Aa	Moody's Rated Utility Bonds A	Moody's Rated Utility Bonds Baa
1	2017						
2	Jan	3.75%	0.52%	2.43%	3.96%	4.14%	4.62%
3	Feb	3.75%	0.53%	2.42%	3.99%	4.18%	4.58%
4	Mar	4.00%	0.72%	2.48%	4.04%	4.23%	4.62%
5	Apr	4.00%	0.81%	2.30%	3.93%	4.12%	4.51%
6	May	4.00%	0.89%	2.30%	3.94%	4.12%	4.50%
7	Jun	4.25%	0.99%	2.19%	3.77%	3.94%	4.32%
8	Jul	4.25%	1.08%	2.32%	3.82%	3.99%	4.36%
9	Aug	4.25%	1.03%	2.21%	3.67%	3.86%	4.23%
10	Sep	4.25%	1.04%	2.20%	3.70%	3.87%	4.24%
11	Oct	4.25%	1.08%	2.36%	3.74%	3.91%	4.26%
12	Nov	4.25%	1.25%	2.35%	3.65%	3.83%	4.16%
13	Dec	4.50%	1.34%	2.40%	3.62%	3.79%	4.14%
14	2018						
15	Jan	4.50%	1.43%	2.58%	3.69%	3.86%	4.18%
16	Feb	4.50%	1.59%	2.86%	3.94%	4.09%	4.42%
17	Mar	4.75%	1.73%	2.84%	3.97%	4.13%	4.52%
18	Apr	4.75%	1.75%	2.87%	3.99%	4.17%	4.58%
19	May	4.75%	1.90%	2.98%	4.10%	4.26%	4.71%
20	Jun	5.00%	1.94%	2.91%	4.11%	4.27%	4.71%
21	Jul	5.00%	1.96%	2.80%	4.10%	4.27%	4.67%
22	Aug	5.00%	2.07%	2.89%	4.08%	4.26%	4.64%
23	Sep	5.25%	2.17%	3.00%	4.18%	4.32%	4.74%
24	Oct	5.25%	2.29%	3.15%	4.31%	4.45%	4.91%
25	Nov	5.25%	2.37%	3.12%	4.40%	4.52%	5.03%
26	Dec	5.50%	2.41%	2.83%	4.24%	4.37%	4.92%
27	2019						
28	Jan	5.50%	2.42%	2.71%	4.16%	4.35%	4.91%
29	Feb	5.50%	2.44%	2.68%	4.05%	4.25%	4.76%
30	Mar	5.50%	2.45%	2.57%	3.98%	4.16%	4.65%
31	Apr	5.50%	2.43%	2.53%	3.91%	4.08%	4.55%
32	May	5.50%	2.40%	2.40%	3.84%	3.98%	4.47%
33	Jun	5.50%	2.22%	2.07%	3.65%	3.82%	4.31%
34	Jul	5.50%	2.15%	2.06%	3.53%	3.69%	4.13%
35	Aug	5.25%	1.99%	1.63%	3.17%	3.29%	3.63%
36	Sep	5.00%	1.93%	1.70%	3.24%	3.37%	3.71%
37	Oct	4.75%	1.65%	1.71%	3.24%	3.36%	3.72%
38	Nov	4.75%	1.54%	1.81%	3.25%	3.43%	3.76%
39	Dec	4.75%	1.57%	1.86%	3.22%	3.40%	3.73%
40	2020						
41	Jan	4.75%	1.55%	1.76%	3.12%	3.29%	3.60%
42	Feb	4.75%	1.54%	1.50%	2.96%	3.11%	3.42%
43	Mar	3.25%	0.90%	0.87%	3.30%	3.50%	3.96%
44	Apr	3.25%	0.14%	0.66%	2.93%	3.19%	3.82%
45	May	3.25%	0.13%	0.67%	2.89%	3.14%	3.63%
46	Jun	3.25%	0.16%	0.73%	2.80%	3.07%	3.44%
47	Jul	3.25%	0.13%	0.62%	2.46%	2.74%	3.09%
48	Aug	3.25%	0.10%	0.65%	2.49%	2.73%	3.06%
49	Sep						
50	Oct						
51	Nov						
52	Dec						

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Mergent Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Line No	Year	S&P Composite	NASDAQ Composite	DJIA	S&P Dividend/Price Ratio	S&P Earnings/Price Ratio
1	1975			802.49	4.31%	9.15%
2	1976			974.92	3.77%	8.90%
3	1977			894.63	4.62%	10.79%
4	1978			820.23	5.28%	12.03%
5	1979			844.40	5.47%	13.46%
6	1980			891.41	5.26%	12.66%
7	1981			932.92	5.20%	11.96%
8	1982			884.36	5.81%	11.60%
9	1983			1,190.34	4.40%	8.03%
10	1984			1,178.48	4.64%	10.02%
11	1985			1,328.23	4.25%	8.12%
12	1986			1,792.76	3.49%	6.09%
13	1987			2,275.99	3.08%	5.48%
14	1988			2,060.82	3.64%	8.01%
15	1989	322.84		2,508.91	3.45%	7.41%
16	1990	334.59		2,678.94	3.61%	6.47%
17	1991	376.18	491.69	2,929.33	3.24%	4.79%
18	1992	415.74	599.26	3,284.29	2.99%	4.22%
19	1993	451.21	715.16	3,522.06	2.78%	4.46%
20	1994	460.42	751.65	3,793.77	2.82%	5.83%
21	1995	541.72	925.19	4,493.76	2.56%	6.09%
22	1996	670.50	1,164.96	5,742.89	2.19%	5.24%
23	1997	873.43	1,469.49	7,441.15	1.77%	4.57%
24	1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
25	1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
26	2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
27	2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
28	2002	993.94	1,539.73	9,226.43	1.61%	2.92%
29	2003	965.23	1,647.17	8,993.59	1.77%	3.84%
30	2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
31	2005	1,207.06	2,099.03	10,547.67	1.83%	5.36%
32	2006	1,310.67	2,265.17	11,408.67	1.87%	5.78%
33	2007	1,476.66	2,577.12	13,169.98	1.86%	5.29%
34	2008	1,220.89	2,162.46	11,252.61	2.37%	3.54%
35	2009	946.73	1,841.03	8,876.15	2.40%	1.86%
36	2010	1,139.31	2,347.70	10,662.80	1.97%	6.04%
37	2011	1,268.89	2,680.42	11,966.36	1.99%	6.77%
38	2012	1,379.56	2,965.77	12,967.08	2.24%	6.20%
39	2013	1,642.51	3,537.69	14,999.67	2.14%	5.57%
40	2014	1,930.67	4,374.31	16,773.99	1.94%	5.25%
41	2015	2,061.20	4,943.49	17,590.61	2.05%	4.59%
42	2016	2,092.39	4,982.49	17,908.08	2.18%	4.17%
43	2017	2,448.22	6,231.28	21,741.91	1.97%	4.22%
44	2018	2,744.68	7,419.27	25,045.75	1.90%	4.67%
45	2019	2,912.50	7,936.85	26,378.41	1.93%	4.53%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI

STOCK PRICE INDICATORS

Line No		S&P Composite	NASDAQ Composite	DJIA	S&P Dividends/Price Ratio	S&P Earnings/Price Ratio
1	**2006**					
2	1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
3	2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
4	3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
5	4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
6	**2007**					
7	1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
8	2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
9	3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
10	4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
11	**2008**					
12	1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
13	2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
14	3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
15	4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
16	**2009**					
17	1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
18	2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
19	3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
20	4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
21	**2010**					
22	1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
23	2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
24	3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
25	4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
26	**2011**					
27	1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
28	2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
29	3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
30	4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
31	**2012**					
32	1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
33	2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
34	3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
35	4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
36	**2013**					
37	1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
38	2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
39	3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.65%
40	4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
41	**2014**					
42	1st Qtr.	1,834.30	4,210.05	16,170.26	2.04%	5.39%
43	2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
44	3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.38%
45	4th Qtr.	2012.04	4607.88	17368.36	2.03%	4.97%
46	**2015**					
47	1st Qtr.	2063.46	4821.99	17806.47	2.02%	4.80%
48	2nd Qtr.	2102.03	5017.47	18007.48	2.05%	4.60%
49	3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
50	4th Qtr.	2,053.17	5,000.70	17,482.97	2.16%	4.23%
51	**2016**					
52	1st Qtr.	1,948.32	4,609.47	16,635.76	2.31%	4.20%
53	2nd Qtr.	2,074.99	4,845.55	17,763.85	2.19%	4.14%
54	3rd Qtr.	2,161.36	5,165.06	18,367.92	2.13%	4.11%
55	4th Qtr.	2,184.88	5,309.89	18,864.77	2.13%	4.22%
56	**2017**					
57	1st Qtr.	2,323.95	5,730.36	20,385.12	2.05%	4.24%
58	2nd Qtr.	2,396.22	6,087.11	20,979.77	2.02%	4.29%
59	3rd Qtr.	2,467.72	6,344.72	21,889.58		4.25%
60	4th Qtr.	2,604.98	6,762.93	23,713.18		4.11%
61	**2018**					
62	1st Qtr.	2,732.58	7,250.93	25,122.58	1.88%	4.37%
63	2nd Qtr.	2,703.16	7,356.20	24,555.62	1.92%	4.51%
64	3rd Qtr.	2,850.99	7,877.47	25,613.63	1.83%	4.47%
65	4th Qtr.	2,692.00	7,192.48	24,891.19	1.98%	5.28%
66	**2019**					
67	1st Qtr.	2,722.08	7,346.37	25,161.98	2.00%	4.74%
68	2nd Qtr.	2,882.89	7,874.48	26,102.16	1.93%	4.60%
69	3rd Qtr.	2,958.59	8,068.08	26,682.54	1.92%	4.46%
70	4th Qtr.	3,086.44	8,458.48	27,566.95	1.88%	4.32%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI
https://ycharts.com/indicators/sp_500_dividend_yield

PROXY GROUP COMMON EQUITY RATIOS

	Company	Ticker	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	5-Year Average 2015-2019	2020	2021	2022-'25	5-Year Average 2020-2024	Combined 5-Yr Historical & Projected Avg.
								Historical						Projected				
1	Allete, Inc.	ALE	55.8%	55.7%	56.3%	55.4%	55.6%	53.7%	58.0%	59.0%	60.1%	61.4%	58.4%	59.0%	60.0%	59.0%	59.3%	58.9%
2	Ameren Corporation	AEE	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	49.3%	45.5%	47.0%	49.0%	47.2%	48.3%
3	American Electric Power Company	AEP	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	47.9%	44.0%	46.0%	48.0%	46.0%	46.9%
4	DTE Energy Company	DTE	48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	45.2%	40.0%	40.0%	41.5%	40.5%	42.9%
5	Duke Energy Corporation	DUK	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	47.0%	45.5%	45.5%	45.0%	45.3%	46.2%
6	Exelon Corporation	EXC	52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	48.2%	48.0%	49.5%	50.0%	49.2%	48.7%
7	Evergy, Inc.	EVRG									60.0%	49.4%	54.7%	48.5%	47.5%	46.5%	47.5%	51.1%
8	OGE Energy Corporation	OGE	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	57.5%	51.0%	52.0%	51.0%	51.3%	54.4%
9	Otter Tail Corporation	OTTR	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	56.3%	58.0%	55.0%	53.0%	55.3%	55.8%
10	PNM Resources, Inc.	PNM	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.3%	51.0%	46.0%	49.0%	48.7%	45.5%
11	Southern Company	SO	45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.4%	38.5%	38.0%	39.5%	38.7%	38.5%
12	Excel Energy Inc.	XEL	46.3%	48.9%	48.7%	48.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	44.1%	43.0%	43.0%	42.5%	42.8%	43.5%
13	Average		50.9%	51.2%	50.8%	52.2%	51.6%	50.4%	48.6%	48.6%	49.0%	47.6%	49.1%	47.7%	47.5%	47.8%	47.7%	48.4%

Source: *Value Line Investment Survey*, Ratings & Reports (several issues - July 24, August 14, and September 11, 2020).

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-19-0236

DIRECT TESTIMONY

OF

JORDY FUENTES

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

OCTOBER 2, 2020

EXECUTIVE SUMMARY

Over the last several years, there have been many documented inadequate, unacceptable and negligent customer service related issues, by Arizona Public Service ("Company"). During the last rate case, the Company was authorized to transition customers away from the Company's then existing rate plans to a series of new rate plans, many of which included demand charges. The Company, without any meaningful Stakeholder input, nor it would appear, any substantive research regarding best practices, developed a deficient Customer Education and Outreach Plan ("CEOP") for the significant transition. Chief among the negative consequences of the deficiently implemented components of this plan were customers' confusion regarding the available rate plans, customers' inability to understand the charges on their bill, accuracy of the Rate Comparison Tool, difficulty in navigating the Company's website, and inappropriate levels of available customer service representatives coupled with a lack of proper training of these representatives.

The Arizona Corporation Commission ("Commission"), has held multiple public meetings to address these failings, and seek assurances from the Company regarding plans to correct these failings. The past and current Chief Executive Officers have personally addressed these customer service related issues in proceedings before the Commission, which demonstrates the perceived importance of these issues. It also demonstrates that the Commission's concerns and actions act as a powerful motivation for focusing the Company's attention to these issues.

The effectiveness of a Customer Education and Outreach Plan was a "significant issue" in the settlement of the prior Company's rate Case[1]. There have been several reports and analyses, and filings regarding these topics[2]. As the evidence and findings of this Commission demonstrates, the Company has utterly failed to provide adequate customer service in these areas. This is especially problematic because the Company is a utility with a defined service territory and customers have no other choice for electric service.

The Residential Utility Consumer Office ("RUCO") recommends the Commission require the Company to adopt the recommendations contained herein, sending a strong message to the Company that their failure to prioritize customer service is not acceptable. Additionally, RUCO recommends the Commission <u>reduce</u> the Company's authorized Return on Equity ("ROE"), in this case, by 20 basis points, from 8.94% to 8.74%, or a $12.1 million dollar annual decrease. The revenue requirement schedules in Mr. Frank Radigan's Direct Testimony will reflect both the proposed 8.94% ROE and the effects of a reduced 8.74% ROE. Assuming the Company is on a three year rate case cycle, the reduced ROE totals over $36 million dollars over three years. RUCO's recommended reduction to the ROE is within the range of reasonableness, based on the outputs of ROE models. There are no issues related to Fair Value, because the Commission would only be modifying the Company's Rate of Return, not the Company's Rate Base. Moreover, the Commission will be considering this and all the other rate case elements as part of the rate case. Mr. John Cassidy's testimony will provide the analysis

[1] Settlement agreement section 1.5 Decision No 76374 September 19, 2017
[2] Overland, Brattle, Barbara Alexander, EnergyTools, Joint Stakeholders,

of the range of reasonableness based on the outputs of his ROE models. Mr. Frank Radigan will provide the calculations for rate impacts in his testimony.

The Company should be required to make regular filings quantifying the improvement in customer service. Such filings should include independent evaluations of customer service satisfaction metrics. RUCO proposes specific customer service metrics the Commission should require the Company report on, including specific call center reporting statistics, the Company's J.D. Power ranking, and an effective new customer education and outreach plan. The Company should be required to make quarterly filings regarding customer service satisfaction. These reports should be evaluated in the next rate case.

INTRODUCTION

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

A. My name is Jordy Fuentes. I am Director of the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 W. Washington Street, Suite 220, Phoenix, AZ 85007.

Q. Briefly describe your responsibilities and capacity as Director.

A. I manage all aspects of the office and ensure that my staff is focused on the mission of professionally representing residential utility ratepayers in regulatory proceedings before the Arizona Corporation Commission, advocating for fair and reasonable utility rates and quality utility services. I discuss with RUCO staff which rate cases RUCO should participate in. I review all RUCO proposed filings, including testimony, briefs and other legal memoranda. I confer regularly with RUCO staff regarding substantive positions in all rate cases and facilitate policy discussions with RUCO staff.

I participate in Stakeholder meetings with the Utilities and other rate case parties and Stakeholders. I appear before the Commission at Open Meetings, and help develop correspondence relating to Commission Rulemaking and other proceedings. I also participate and present in National organizations' meetings addressing regulatory issues involving utilities.

Q. Please state your educational background and qualifications in the utility regulatory field.

A. I received a Bachelor of Science Degree in Software Engineering from the University of Advancing Technology and a Juris Doctorate from Arizona State

University Sandra Day O'Connor School of Law. I also received the Law and Sustainability Certificate from Sandra Day O'Connor School of Law.

I have been employed by RUCO in many capacities since 2015, starting as a Special Projects Advisor, followed by Deputy Director, and finally as Director. I have served as Director since April 2019. Prior to joining RUCO, I was employed as an IT Director of both the Laveen Elementary School District and the Snowflake Unified School District from 2007 through 2014. In that role, I managed all IT and Telecommunication Services.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your Testimony in this proceeding?

A. The purpose of my testimony is to present RUCO's recommendations regarding a new CEOP, quarterly reporting, and a Return on Equity ("ROE") reduction for the Company, in the current rate case. RUCO's recommendations are based on the Company's failed, inadequate and unacceptable customer service efforts. The ROE reduction is based upon significant public policy concerns, particularly the lack of prudency on the part of the Company, related to the level of customer service being provided by the Company.

Q. What is the scope of your testimony in this case?

A. I am presenting testimony on the Company's customer service failures, including proposed remedies. Mr. Frank Radigan will be providing testimony and schedules, related to the operating revenues, expenses and rate design. RUCO witness John Cassidy is presenting RUCO's cost of capital recommendations.

Q. What is the basis of your testimony in this case?

A. The basis for my testimony was a review of reports undertaken by the Commission in various dockets, and by private consultants prepared for the Commission and for the Company, orders and findings of the Commission, my participation in Open Meetings where customer service related issues were being discussed, a review of other States' methodologies and practices, my interactions with other Stakeholders and the Company, and a review of independent reports relating to customer service failures by the Company and the continuous decline in customer service.

I have also reviewed consumer comments filed in this and other dockets, related to the Company, and those expressed in local and other media sources. I have discussed these issues with numerous ratepayers. At this point, I believe I have a well informed understanding of the community and ratepayer's perspective on these issues. It is clear to me that the quality of the Company's customer service has suffered which must be addressed in <u>this</u> rate case. Customer and Commissioner frustration with "kicking the can down the road" should end now.

Q. What did you find when you reviewed the materials described above?

A. The findings and recommendations from the sources listed above were comprehensive and detailed. Following are some of the key factors identified as inadequate, and unacceptable customer service:

1. The Company failed to establish adequate measurements to determine if the CEOP plan they implemented was effective in educating customers regarding how to select a Rate plan best suited to the customers' needs.
2. The Company had inadequate and confusing customer contacts.[3]

[3] "APS's CEOP should have included more personal customer contact or outreach efforts regarding the new modernized rate plans and which plan would be of most benefit to the customer." ...
"APS did not explain the adjustor mechanisms in its CEOP, nor did APS clarify the fact that there would be annual updates to the adjustor mechanism billing rates occurring outside of the rate case and that such

3. The Company's Rate Comparison Tool was defective.
4. The Company summarily rejected customer advocates' proposals and suggestions.
5. The nomenclature of the various rate plans was confusing to customers.
6. Actual customer bills were not easily understandable.[4]

Commissioner Marquez-Peterson best summed up the Company's customer service efforts when she said in the December Open Meeting, "For APS, these miscues seem to be the status quo and compounded by more bad news the next day."[5]

Q. What have you learned about the level of customer service from ratepayers and the community?

A. I have continuously reviewed the customer comments submitted to this and other dockets related to the Company, and am very aware of the level of dissatisfaction with the Company's customer service. The number and scope of complaints are too vast and detailed to list here. In general, the complaints range in scope from

---

rate changes may result in an increase in customer bills. These additional bill adjustments may have been confusing to some customers, especially without notice of the adjustor mechanism changes."...
"The information provided by APS in its rate increase notices and personalized letters failed to convey certain important information, including:
The "average customer" rate increase percentage and bill impact (4.5% increase, $6 per month) disclosed in customer notices and press releases failed to adequately convey that the impact of the modernized rate design on individual customers could vary widely, and over time, depending on customer-specific circumstances and changes in other customer bill components such as adjustors and taxes and fees, and were not included in the notice regarding the average percentage or bill increase. The rate plan transition letters mailed in the first few months of 2018 failed to adequately convey to customers that the additional increases in their bills, beyond those that occurred with the 2017 transition rates. The information conveyed did not include that these additional increase in bills were dependent on customer-specific circumstances, including the specific rate plans customers were on before and after the transition, and behavioral changes in energy usage patterns under the new rate plans which could minimize bill increases, such as shifting usage to accommodate the new on-peak hours and demand charges." (emphasis added)
See also Overland Report P.5-7 filed June 4, 2019 http://docket.images.azcc.gov/0000198445.pdf
See also Alexander Report, page 25, http://docket.images.azcc.gov/E000006583.pdf.

[4] For a detailed description of APS customer bill's complexity, See: Customer comment articulating the challenges in understanding an APS bill written by Steve Neil and filed by Commissioner Olsen on December 19, 2019 in Docket No 19-00003 at https://docket.images.azcc.gov/E000004007.pdf

[5] Arizona Corporation Commission December, 10-11 Open Meeting.

confusing and hard to understand rate plan selection to inaccurate and untruthful statements regarding those plans and which plan is best for an individual customer.

The dissatisfaction goes far beyond the substance of the rate plans and it is obvious that there is a general feeling of mistrust of the Company by the public. It is clear that ratepayers feel that they are being overcharged. From what I can discern, at least part of that has to do with confusion caused by the Company in explaining the basis for the customer's bill. A more customer friendly bill would go a long way to eliminate customer mistrust. Additionally, using an average customer's bill to explain rate impacts to all customers is not helpful and sets unrealistic expectations, which further heightens frustrations. RUCO recommends discontinuation of any reference to "average" customer bills on its website, on customer bills and any materials included in a new CEOP. These issues and other concerns expressed by the ratepayers lend support to RUCO's recommendations regarding steps the Company should take to address their customer service problems.

Q. What reports have you reviewed which demonstrate a continuous decline in customer service provided by the Company?

A. I reviewed a report prepared by the *Energy Policy Institute, Pollution Pay Day: Analysis of Executive Compensation and Incentives of the Largest U.S. Investor-owned Utilities September 23, 2020 ("Report")* and the sources cited therein.[6]

[6] https://www.energyandpolicy.org/wp-content/uploads/2020/09/Pollution-Payday-Analysis-of-executive-compensation-and-incentives-of-the-largest-U.S.-investor-owned-utilities.pdf

Q. Please provide a brief summary of this report.

A. The Report studied executive compensation for 19 large electric utilities. One segment of the report provides detailed information regarding executive compensation at Arizona Public Service, citing SEC filings, Proxy Statements and other publicly available information.

Q. What were the most significant factors in the Report regarding executive compensation and customer service declines by the Company?

A. The Company had previously used J.D. Power and Associates customer satisfaction ratings as one metric of executive compensation, as recently as 2016, as stated in the Report:

> "After several years of ranking relatively well, APS dropped to second-to-last among large electric utilities in the West in the J.D. Power rankings published in July 2017. In its next proxy filing, published in March 2018, APS said it would not use J.D. Power customer satisfaction rankings as a metric for its 2017 executive compensation, and claimed that the change was due to an upgrade to its customer service platform at that time.
>
> Although APS' characterization of that decision suggested it would be temporary, "during this enterprise-wide project," APS has not returned to using J.D. Power customer satisfaction rankings as a factor in determining its executives' compensation. APS continues to rank poorly in J.D. Power's customer satisfaction surveys; among major electric utilities in the West, it ranked second to last in 2018, and tied for last in 2019."[7]

Q. Did you do your own analysis of the J.D. Power Residential Customer Satisfaction Index Ranking?

A. Yes I did.

[7] Id. at Page 55.

Q. What did you find in your analysis of the Company's J.D. Power Residential Customer Satisfaction Index Ranking?

A. I found that in the Company's J.D. Power Residential Customer Satisfaction Index West Region: Large Segment Ranking, the Company's ranking has fallen significantly. As can be seen in the chart below, in years 2015 and 2016, the Company was ranked higher than the class average. In the following years, the Company's rankings fell consistently, as compared to the class average, with a 2019 ranking in the West Region: Large Class tied for last place among the thirteen west region utilities.[8]

Rankings taken from J.D. Power.com for years 2015-2019.

Q. What conclusions do you draw from the Report and supporting citations?

A. The facts reflected in the Report and supporting citations indicate that the Company was aware of, and did nothing about the precipitous decline in its customer service quality, from prior J.D. Power customer satisfaction surveys. Rather than focus efforts on improving customer satisfaction rankings, the Company eliminated customer service quality evaluations by J.D. Power as a metric for executive

[8] https://www.jdpower.com/business/press-releases/2019-electric-utility-residential-customer-satisfaction-study

compensation, in order to avoid the negative effects on executive compensation that a poor quality ranking would have[9].

Q. Why are you addressing customer service issues in this rate case?

A. In Commission Decision No. 77270 (June 27. 2019), the Commission required the Company to file a rate case, as a consequence of the numerous issues outlined above. Additionally, Commissioners have pointed to the rate case as the place to address the Company's customer service shortcomings. Commissioner Dunn filed a letter in Docket # E-01345A-19-0003, dated November 20, 2019, after more issues arose related to the Company's customer service efforts. In this letter Commissioner Dunn stated, "[r]atepayers should not shoulder the cost for a company's management failures. Companies will be held accountable for their poor business decisions. In this case, the Commission should also discuss whether sanctions are appropriate and what remedies are available to us to make ratepayers whole."[10]

Q. Why is a rate case the best forum for addressing these issues?

A. Under the existing regulatory framework, a utility's rate case is the principal mechanism to ensure financial accountability for the utility customers and shareholders. This is accomplished in part, by a review of costs and prudency of the utility's investments and actions.

Many parties and utilities erroneously believe that a prudency determination made by the Commission is confined to the *capital cost* component of ratemaking. This

[9] RUCO will also address the customer service decline in its executive compensation testimony.
[10] Letter from Commissioner Dunn, Accessed at:
https://images.edocket.azcc.gov/docketpdf/E000003744.pdf

is not correct. The prudent investment test or prudency determination is a necessary and flexible regulatory tool in ratemaking, and can be used for identifying prudent operating *expenses* and for placing the risk of utility mismanagement on utility owners.[11]

Q. What does RUCO propose in order to remedy the Company's inadequate and unacceptable behavior in implementing new rates and educating its customers regarding these rates?

A. First, the Commission should require the Company adopt many of the recommendations in the Staff/Barbara Alexander report, filed on May 19, 2020[12], including but not limited to:

> "... the Commission should order APS to create and propose a Customer Education Plan concerning not only rate design options but integrate its rate design education with its limited income programs, demand side management programs, and consumer protection rights and remedies to ensure the retention of essential electricity service. Such a comprehensive plan would allow APS to develop customer educational materials and outreach strategies in a coordinated manner for its residential customers. Most importantly, such a plan should address all the many deficiencies of the Customer Education Plan implemented in 2017-2018 as identified in this Report, particularly including the need for ongoing customer research and feedback mechanisms. As a key requirement, the Commission should require the Plan to include performance standards and reporting mechanisms that will allow a meaningful and regular review of APS's progress in implementing the plan and

[11] See Robert E. Burns, T*he Prudent Investment Test in the 1980s at vii* (Despite these uncertainties, the extensive contemporary use of the judicially developed prudent investment concept by state commissions demonstrates the vitality and usefulness of the concept. It is not confined to the capital cost component of ratemaking, but has been used to assess the reasonableness of decisions involving operating expenses as well. Under the existing regulatory framework, a utility's rate case is the only occasion for providing accountability to the consuming public and the investing public. Within this framework, the prudent investment test is emerging as a necessary and flexible regulatory tool for identifying types of risk and for placing the risk of utility mismanagement on utility owners.
https://ipu.msu.edu/wp-content/uploads/2016/12/Burns-Prudent-Investment-Test-84-16-85-1.pdf

[12] http://docket.images.azcc.gov/E000006583.pdf

> achieving its goals and objectives. Performance standards should include, at a minimum, measuring and reporting quarterly on:
>
> - Customer initiated changes to their rate plans,
> - APS initiated changes to customer rate plans,
> - Number of customers not on the "best" or "most economical rate" by rate class,
> - frequency and type of complaints;
> - Call center performance,
> - Results of customer research on messaging and bill presentment,
> - Enrollment for limited income programs,
> - Achievement of participation objectives for demand side management programs;
> - Analysis of the impact of rate design on system benefits, such as peak load reduction and lower generation supply costs, and
> - Key indicia of credit and collection activities, such as disconnection notices, disconnections, and payment arrangements....
>
> "A future Customer Education Plan should be developed with frequent and substantive interaction with consumer stakeholders and reflect an obligation for ongoing customer research and feedback mechanisms that will encourage an organic and updated Plan. After opportunity for stakeholder input and response to that input by APS, the Plan should be the subject of a more formal review process with opportunity for hearings if substantive disagreements cannot be resolved in a collaborative manner."

RUCO proposes the Commission require the Company to pay for this new CEOP, since ratepayers paid $5 million for the last inadequate and ineffective CEOP.

RUCO proposes the Commission require the Company to undergo a significant redesign of its customer bills. The Company's current bill format is not customer friendly. The bills are dense with data which is unintelligible or not meaningful for many customers. The number of line items on the bill were modified in the last rate case and there is a lack of consistency among the charges contained in those line items. To ensure clarity and understanding, the Company should focus on

simplicity of communications while still providing all aspects of a customer's bill, especially those charges contained in the Company's tariffs. Importantly, the Company should solicit feedback from a large sample of both Spanish and English speaking customers.

The Commission should also require the Company to communicate clearly the range of potential bill impacts, in this rate case, using a bell curve type chart to show the wide range of impacts a customer may experience. The use of an average customer to explain the rate impacts associated with this rate case, has and would only create unrealistic expectations with customers.

Q. Does RUCO have other recommendations?

A. Yes. RUCO also recommends the Commission send a strong message to the Company, and to all other utilities that good customer service is the minimum standard necessary to provide service and maintain a CC&N. In view of the Company's continuing failure to meet the standard, RUCO believes the Commission has numerous options to ensure compliance with this minimum standard. RUCO believes that ratepayers should be made whole for poor and inadequate service.

While nothing can make up for the already received poor service quality, a reduction in the Company's approved Return on Equity ("ROE") is one option. As a consequence of the Company's demonstrated poor customer service, RUCO recommends the Commission adopt a 20 basis point reduction to the Company's ROE, from the recommended 8.94% in John Cassidy's Direct Testimony to 8.74%. This equates to a $12.1 million dollar annual reduction. Over an assumed three

year rate case cycle, this would amount to more than $36 million dollars for ratepayers.

Q. What does RUCO believe will be accomplished through its proposals?

A. RUCO presumes that the Company, like most shareholder owned utilities, is highly motivated by financial/profit metrics. Certainly, it will take its obligation to provide good customer service seriously if it knows there will be financial consequences for failing to maintain the minimum customer service standard.

Q. Are there other tools at the Commission disposal to incentivize a utility to comply with the minimum customer service standard?

A. Yes. The Commission could consider Performance Based Rates ("PBR") to incentivize a utility to comply with the minimum customer service standard.

Q. Is RUCO requesting the Commission adopt Performance Based Rates ("PBR") for the Company to accomplish this?

A. No. RUCO is not requesting the Commission adopt PBR in this rate case. RUCO is discussing PBR to provide background information about other methods of motivating better customer service and to be responsive to Commissioners' prior requests for such information.

Q. What are Performance Based Rates ("PBR")?

A. PBR is a departure from traditional cost of service regulation ("COSR"), where utility revenues are set based on the revenue requirement that must be collected from ratepayers for the utility to recover its costs and earn a reasonable rate of return on its investments. The Regulatory Assistance Project describes PBR as "a regulatory

framework to connect goals, targets, and measures to utility performance or executive compensation."[13]

Q. Has there been discussion of PBR in other parts of the country? If so, please provide an overview of the different variations of PBR being discussed or implemented.

A. There has been discussion by public utility commissions in other parts of the country about PBR. The most common form of PBR discussed is a multiyear rate plan ("MRP") with a PBR adjustment mechanism, which replaces traditional COSR and provides utilities with a pre-determined annual increase in incremental revenues to cover costs over the term of a PBR plan, usually a 5-year time frame. A Performance Incentive Mechanism ("PIM") traditionally accompanies the MRP, but it is not required.

Another form of PBR is a standalone Award Penalty Mechanism ("APM"). PIMs and APMs usually are mechanisms that associate performance metrics with targets and incentives that encourage utility management to focus time and resources to perform in areas traditionally outside of the utility's traditional core business operations, like increased renewable integration, energy efficiency, and system peak reduction. However, instead of replacing traditional COSR, leading PBR efforts are using regulatory proceedings to layer components of PBR for a more incremental, but nevertheless substantial, shift in objectives.

[13] Regulatory Assistance Project (RAP) and the National Renewable Energy Laboratory Report (September 2017) Next-Generation Performance Based Regulation Emphasizing Utility Performance to Unleash Power Sector Innovation, Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf, p. ix.

Q. Is RUCO recommending the Commission evaluate or adopt a MRP or APM for the Company?

A. No, not in the current rate case. A MRP is an extreme deviation from traditional COSR and RUCO believes that in the current utility environment, such a deviation is not warranted and would be detrimental for ratepayers. RUCO is also not proposing an APM. RUCO is most concerned with improvements to customer service, a basic core business practice, rather than incentivizing Company behavior outside of the utility's traditional core business operations.

Q. What is RUCO's position on the Company's formula rate concept alternative?

A. RUCO does not support it.

Q. Is RUCO recommending the commission evaluate or adopt PIMs for the Company?

A. No, not in the current rate case. In future rate cases, RUCO may recommend the Commission adopt PIMs, a component of some PBR initiatives. If RUCO were to recommend the use of PIMs, it would not be in the traditional way they have been implemented in other jurisdictions.

Q. How have PIMs traditionally been implemented?

A. A PIM is a method of prioritizing, focusing, or aligning a utility's operational behavior with a specific goal or desired outcome via the regulatory framework. They have been traditionally used to incent desired outcomes outside of the utility's traditional core business operations, like increased renewable integration, energy efficiency, and system peak reduction.

Q. How could a PIM incent the Company to address its customer service issues?

A. Profit is a strong motivator for regulated utilities. By strategically setting predefined PIMs and attaching a monetary value to each, there is a strong incentive for the Company to meet the specified outcomes encouraged by the PIMs.

Q. Have incentive measures such as those described by RUCO been used in other states to encourage public utilities' improvements in customer service? If so, please describe how they have been used?

A. Yes. The Maine Public Utilities Commission ("MPUC") issued an order earlier this year in the matter of STATE OF MAINE PUBLIC UTILITIES COMMISSION in re: PUBLIC UTILITIES COMMISSION Investigation into Rates and Revenue Requirement s of Central Maine Power Company on February 19, 2020 in docket No. 2018-00194 requiring an 18 month ROE adjustment until the utility met customer service metrics.[14]

Q. Provide a brief summary of the underlying facts of the Maine order.

A. Central Maine Power Company ("CMP") is a distribution utility company. The MPUC opened an investigation into the utility's rates, and added the issue of customer service to the rate case, after a review of a consultant's audit report regarding metering, billing and customer communication issues. As in the current rate case, there was detailed evidence regarding the failure of the CMP to provide adequate customer service. In its resolution of the rate case, the MPUC authorized a distribution revenue of $270.586 million per year, and imposed a substantial reduction to the Company's ROE of 100 basis points for a rolling period of 18

[14] https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=105431&CaseNumber=2018-00194

months, which would be a reduction of distribution revenue of $9.9 million over the 18 months. The MPUC stated:

> "This reduction is supported by substantial evidence of failures by CMP's management to provide reasonable and adequate customer service over recent years and especially following the transition to its new billing system, which leads us to find that this service has been imprudent. This ROE reduction is directly tied to CMP service quality; the adjustment will remain in place until CMP improves its performance in several specified areas of customer service over a rolling period of 18 consecutive months (measured beginning March 1, 2020)."[15]

Q. Have PIMs, PBR, or APM been discussed by the Arizona Corporation Commission?

A. Commissioner Marquez-Peterson has opened Docket# E-00000A-20-0019 with the description of "In the matter of the investigation of the Arizona Corporation Commission into the Role of Performance Incentive Mechanisms in regulated investor owned electric utility rate cases in Arizona". Commissioner Dunn, in a letter dated June 17, 2019, filed in Docket# E-01345A-19-0003, stated that "I wanted to raise the idea of a performance based rate design (PBR) for consideration by the Commission in the pending rate case. I believe this approach would be an effective way to address Arizona Public Service Company's (APS or the Company) continuing disregard for customer outreach, education, and satisfaction."[16] Commissioner Dunn also stated "[b]ecause APS is currently in the middle of a rate case, I believe the most effective legal approach is to use its rate-setting authority to align the interests of customers with the interests of the Company's bottom line."[17]

---

[15] Order February 19, 2020 Docket No. 2018-00194 page 1. See also Alexander Report, page 25, http://docket.images.azcc.gov/E000006583.pdf.
[16] Letter from Commissioner Dunn, Accessed at: https://docket.images.azcc.gov/E000007099.pdf
[17] Id.

Q. Have PIMs, PBR or APM ever been adopted by the Arizona Corporation Commission?

A. No. However, the Commission has adopted the Lost Fixed Cost Recovery ("LFCR") mechanism, which acts somewhat like an APM. The LFCR is a source of revenue for a utility to help recover the fixed costs of providing a utility service that are not recovered from customers, due to a utility incurring costs to facilitate Commission mandated energy efficiency and renewable resource requirements.

Q. Is RUCO recommending a proposal like that adopted in Maine?

A. Not exactly. RUCO is only recommending an ROE reduction. RUCO is not proposing the reduction be coupled with a mechanism for the Company to start earning back part or all of its reduced ROE. RUCO is proposing that the ROE reduction stay in place until new rates are put in place in the Company's next rate case.

Q. How did RUCO determine the amount of the ROE reduction?

A. RUCO acknowledges that making ratepayers whole, based on the facts as presented is a difficult task. The Maine Commission agreed when they said:

> "The Commission has recognized that while it is often difficult to determine the effect of imprudent conduct, that fact does not excuse the conduct.[35] The Commission has reasoned:
>
> It is true that a precise measurement of the rates that would have resulted had the Company followed a prudent and reasonable course of action is difficult to estimate at this time. This is typically a problem when measuring the harm of a course of conduct not taken. Still, the regulatory response must never be to ignore unreasonable and imprudent utility action because measuring precisely the costs of the reasonable and prudent course of action are difficult or even impossible. In fact, . . . our statutory duty to set just and reasonable

> rates would be violated if we set rates that reflect costs that are clearly unreasonable."[18]

RUCO's recommendation takes into account the fact that determining a precise number is challenging. As such, RUCO estimated the reduction to the Company's ROE to be commensurate to the annual harm ratepayers have received.

Q. Is RUCO's proposed reduction to ROE for poor customer service structured in such a way that it is consistent with the Commission's Fair Value requirement?

A. Yes. RUCO believes there are no issues related to Fair Value, if the Commission were to adopt a reduction to the Company's ROE for poor customer service. RUCO is asking that the Commission make a downward adjustment to the Company's ROE, an adjustment that is well within the range of a reasonable ROE and supported by the Cost of Capital models. RUCO is not proposing any modification to the Company's rate base. RUCO is also making this recommendation in the context of a rate case, not outside the rate case.

Q. Does RUCO provide any recommendations regarding filings by the Company regarding customer service measurements?

A. Yes, the Company should make quarterly filings regarding its ranking in the J.D. Power Residential Customer Satisfaction Index Ranking and specifically their ranking within the West Region: Large Segment. Additionally, the Commission should require the Company to file its call center metrics, related to call answer times and abandonment rates. Industry standards for utility call centers, as found

[18] Docket No. 2019-00015, Order dated 2/26/20, page 52, accessed at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=105506&CaseNumber=2019-00015

in the Staff/Barbara Alexander Report, require 80% of phone calls to be answered within 30 seconds or less.[19] Call abandonment rates should also be less than 5%.[20] This information will be able to be used in the Company's next rate case in evaluating whether the Company has significantly improved its customer service.

Q. What does RUCO propose regarding the development of a new Customer Education and Outreach Plan, as described in the Staff/Barbara Alexander Report?

A. The Commission should require the Company to file a new Customer Education and Outreach Plan ("CEOP") at the expense of shareholders. The plan should include performance standards and reporting mechanisms that will allow a meaningful and regular review of the Company's progress, in implementing the plan and achieving its goals and objectives. The recommendations contained in the Barbara Alexander Report should be used as the basis for the new CEOP. As soon as possible after a Commission decision in the rate case, the Company should submit for approval by the Commission, the proposed CEOP. Stakeholders should be included in the development of the CEOP.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[19] http://docket.images.azcc.gov/E000006583.pdf, page 25.
[20] Id.