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Southwest Gas Corporation

G-01551A-16-0107

Arizona Corporation Commission
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Part 2 of 3

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Southwest Gas Corporation

2016 General Rate Case Application

Volume II

Testimony

Docket No. G-01551A-16-0107

May 2, 2016

SOUTHWEST GAS CORPORATION

SOUTHWEST GAS CORPORATION

ARIZONA GENERAL RATE CASE

VOLUME II

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Tab A

Direct Testimony

of

Carla D. Ayala

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
CARLA D. AYALA

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 2, 2016

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of
Prepared Direct Testimony
of
CARLA D. AYALA

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Appendix A – Summary of Qualifications of Carla D. Ayala

Exhibit No.__(CDA-1)

Exhibit No.__(CDA-2)

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
CARLA D. AYALA

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Carla D. Ayala. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Systems Planning department. My title is Economist.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the California Public Utilities Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's adjustments to the recorded test year bills and volumes, to derive the test period billing determinants.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The adjustments made by Southwest Gas to the test year number of bills and volumes to derive test period billing determinants.
- Residential consumption per customer in Southwest Gas' Arizona rate jurisdiction.
- Recommendation to annually update the ten-year normal heating degree days used to calculate the Energy Efficiency Enabling Provision (EEP) weather adjustment.

II. METHODOLOGY USED TO DEVELOP BILLING DETERMINANTS

Q. 7 Please describe the methodology Southwest Gas utilized to develop the test period billing determinants.

A. 7 The development of the billing determinants commenced with the compilation of the monthly recorded number of bills and volumes by rate schedule for the test year – the 12 months ended November 30, 2015.

After compiling the recorded number of bills and volumes for the test year, Southwest Gas made the following adjustments to derive the adjusted test period billing determinants: (1) billing adjustments; (2) customer-specific volume annualizations; (3) customer reclassifications; (4) weather normalizations; and (5) customer annualizations. The details supporting these adjustments are set forth more fully below, and are shown in the Schedule H-2 Workpapers.

Q. 8 Why are adjustments made to the recorded test year number of bills and volumes?

A. 8 Adjustments are made to recorded bills and volumes to more accurately reflect the billing determinants that Southwest Gas would expect to experience during the rate effective period under normal weather conditions.

Q. 9 Has Southwest Gas made any changes to the general methodology for developing the billing determinants for the test period?

A. 9 No. In fact, Southwest Gas utilized the same general methodology to develop the billing determinants for its 2000 (Docket No. G-01551A-00-0309), 2004 (Docket No. G-01551A-04-0876), 2007 (Docket No. G-015551A-07-0504), and 2010 (Docket No. G-01551A-10-0458) general rate cases in Arizona, and this methodology was approved in Decision Nos. 64172, 68487, 70665 and 72723, respectively.

III. ADJUSTMENTS TO RECORDED NUMBER OF BILLS AND VOLUMES

Q. 10 Please explain Southwest Gas' proposed billing adjustments.

A. 10 After compiling recorded test year billing determinants, significant billing anomalies are investigated to ensure that the correct consumption level is reflected for each month in the test year. A majority of the corrections for the billing adjustments involve restating the monthly consumption levels for customer bills to reflect actual monthly usage. These adjustments are typically adjustments between months and do not impact the total test year sales. This adjustment is necessary to ensure that the monthly adjusted volumes accurately reflect actual test year consumption. Otherwise, distorted monthly values would reduce the reliability of the regression analysis associated with the weather normalization adjustments.

Q. 11 Please explain Southwest Gas' proposed volume annualization adjustments.

A. 11 After completing the corrections for billing adjustments, customer-specific volume annualization adjustments are performed to reflect a full year of consumption for each active customer (excluding residential and small commercial customers) billed during November 2015. The process involves

estimating additional consumption for months during the test year where a new customer was not on-line or was clearly in a start-up phase, as well as removing consumption attributable to specific customers who discontinued service during the test year.

Q. 12 Please explain Southwest Gas' proposed customer reclassification adjustments.

A. 12 Customer reclassification adjustments move customers and their associated consumption volumes between rate schedules. Reclassification adjustments are required when a customer changes rate schedules during the test year. For example, a general service customer whose consumption increases or decreases may qualify for a different rate schedule. These adjustments are performed to ensure that customer-specific consumption reflects a full 12-months of usage under the correct rate schedule at the end of the test year. Reclassification adjustments do not impact the overall number of bills or volumes for the test year.

Q. 13 Please explain Southwest Gas' proposed weather normalization adjustments.

A. 13 Weather normalization adjustments are made to address warmer or colder than normal weather during the test year and provide a more accurate depiction of test period volumes under normal (average) weather conditions. To the extent that weather for the test year deviates from normal weather conditions, heat-sensitive consumption per customer should be adjusted to represent monthly test year volumes under normal weather conditions.

For the test year in this case, actual billing cycle heating degree days were approximately 26 percent warmer than normal in Tucson and approximately 31 percent warmer than normal in Phoenix. As a result of these

deviations from normal weather, adjustments to test period volumes were computed to reflect anticipated volumes under normal weather conditions.

Weather normalization adjustments were completed for the following rate schedules: G-5 Single Family Residential; G-6 Multi-Family Residential; G-10 Single Family Low Income Residential; G-11 Multi-Family Low Income Residential; G-15 Special Residential; G-20 Master-Metered Mobile Home Park; G-25 Small, Medium, Large I and Large II Master-Metered Apartments; G-25 Small, Medium, Large I, and Large II Small Commercial; and G-25 Large I, Large II and Transportation Eligible (TE) Large Commercial; G-25 Small, Medium, Large I, Large II and Transportation Eligible (TE) Armed Forces.

Q. 14 What heating degree day normal did Southwest Gas use to weather normalize the heat-sensitive volumes for the test period?

A. 14 Southwest Gas used a ten-year average (120 months ended November 2015) of heating degree days, to represent normal weather conditions for the test period.

Q. 15 Is the use of ten-year average heating degree days to weather normalize the heat-sensitive volumes consistent with Southwest Gas' prior practices for general rate cases in Arizona?

A. 15 Yes. Southwest Gas has consistently utilized ten-year average heating degree days to weather normalize test period volumes in every general rate case filed in Arizona since 1986 (see Docket Nos. U-1551-86-300, U-1551-86-301, U-1551-89-102, U-1551-89-103, U-1551-90-322, U-1551-92-253, U-1551-93-272, U-1551-96-596, G-01551A-00-0309, G-01551A-04-0876, G-015551A-07-0504, G-01551A-10-0458 and Decision Nos. 60352, 64172, 68487, 70665 and 72723.)

Q. 16 Please explain Southwest Gas' procedure for calculating the weather normalization adjustments.

A. 16 Southwest Gas conducts a regression analysis to quantify the historical relationships between actual monthly consumption per customer and heating degree days for each heat-sensitive customer class. The monthly consumption per heating degree day factors (regression coefficients) quantified in the regression analysis are then applied to monthly heating degree day deviations from normal to quantify the corresponding adjustments to consumption per customer.

Q. 17 What was the impact of the weather normalization adjustments upon the test year volumes?

A. 17 The net result of the weather normalization adjustments was an increase in test year volumes of 60,419,523.

Q. 18 Please explain Southwest Gas' proposed customer annualization adjustments.

A. 18 Customer annualization adjustments were computed for the following rate schedules: G-5 Single Family Residential; G-6 Multi-Family Residential; G-10 Single Family Low Income Residential; G-11 Multi-Family Low Income Residential; and G-25 Small, Medium, Large I, and Large II Small Commercial.

Q. 19 What method was used to develop the customer annualization adjustments?

A. 19 Southwest Gas utilized the same methodology adopted by the Commission in Southwest Gas' last five general rate cases (see Docket Nos. U-1551-96-596, G-01551A-00-0309, G-01551A-04-0876, G-015551A-07-0504, G-01551A-10-0458 and Decision Nos. 60352, 64172, 68487, 70665 and

72723). This method captures the seasonal nature of test year customer growth by comparing the number of customers in the last month of the test year, November 2015, to the same month of the prior year, November 2014. The growth in customers is then prorated across the test year in declining intervals with 11/12ths of the adjustment in the first month of the test year (December 2014), 10/12ths in the second month (January 2015) and so forth. Adjustments to annualize volumes are made by multiplying the monthly customer additions by the respective monthly weather-adjusted average use per customer. Customer and volume adjustments are then added to the weather-normalized monthly bills and volumes to produce annualized test period monthly bills and volumes.

Q. 20 Why were the customer annualization adjustments only performed for the residential and small commercial customer classes?

A. 20 All rate schedules other than residential and small commercial were annualized by individual customers, based upon customer-specific information. These customer-specific annualization adjustments are covered under the volume annualization adjustments discussed in Q/A 11. Because of the sheer magnitude of the number of customers in the residential and small commercial customer classes, which includes thousands of billing records, tracking each customer's billing history to perform customer-specific billing or annualization adjustments is impractical. Accordingly, customer annualization adjustments are performed using the outlined methodology for the residential and small commercial customer classes.

Q. 21 Please summarize the impact of the adjustments performed for the preparation of the annualized number of bills and volumes for the test period.

A. 21 The impacts of each of the adjustments upon the number of bills and volumes included in the test year are indicated by rate schedule in Schedule H-2, sheets 5-8. All of the adjustments (billing adjustments, customer-specific volume annualizations, customer reclassifications, weather normalization and customer annualizations) were conducted to ensure the accuracy and propriety of the number of bills and volumes used to establish rates.

IV. RESIDENTIAL CONSUMPTION PER CUSTOMER

Q. 22 Please describe the historical trend in residential consumption per customer in Arizona.

A. 22 Over the last 30 years, Southwest Gas has experienced significant declines in residential consumption per customer. However, since its 2010 general rate case (Docket No. G-01551A-10-0458), Southwest Gas has experienced a slight increase in residential consumption per customer.

Q. 23 Were the declines in residential consumption per customer reflected in past general rate cases filed by Southwest Gas?

A. 23 Yes. In each general rate case filed in Arizona since 1986, weather-normalized residential consumption per customer was lower than the previous rate case.

Q. 24 What are the primary reasons for the long-term downward trend in residential consumption per customer?

A. 24 The long-term downward trend in residential consumption per customer occurred primarily because of continued improvements in the dwelling and appliance efficiencies of Southwest Gas' customer base. Improvements in

energy efficiencies are reflected in both new customer growth and the replacement, by existing customers, of older appliances with newer, more efficient appliances.

Q. 25 What are the primary reasons for the slight increase in residential use per customer since Southwest Gas' last rate case?

A. 25 Weather-normalized residential consumption per customer increased slightly from 297 therms in the Company's last rate case to 302 therms in this proceeding. Plausible factors for this subtle change from the long-term downward trend in residential consumption per customer includes fewer vacant homes on the market and Arizona's continued recovery from the economic impact of the recession. Another factor that should be considered when comparing these numbers is that the weather-normalized residential consumption from the last rate case included volumes from July 2009 to June 2010 – a time period in which Arizona was among the leaders in foreclosure rates. The long-term trends in annual residential consumption per customer utilized in each of Southwest Gas' general rate case proceedings since 1986 are graphically presented in Exhibit No.__(CDA-1).

V. NORMAL HEATING DEGREE DAY UPDATE TO THE MONTHLY WEATHER ADJUSTMENT CALCULATION

Q. 26 What is the effect of the Company's proposal to annually update the ten-year normal heating degree days used in calculating the monthly weather adjustment?

A. 26 The Company's proposal, as discussed in the prepared direct testimony of Company witness Edward Gieseking, will provide a more accurate and timely

representation of recent trends in heating degree days and actual weather experienced by customers.

Q. 27 What ten-year normal is currently being used in the monthly weather adjustment and what modifications will be made to the calculation?

A. 27 Southwest Gas has utilized a ten-year normal which was calculated in the 2010 Rate Case (Docket No. G-01551A-10-0458). As depicted in Exhibit No.__(CDA-2), there has been a significant decline in ten-year normals from one rate case to another. Moving forward, Southwest Gas will annually calculate a new ten-year normal at the end of each heating season and use the new normal for the upcoming heating season.

Q. 28 How will the change in monthly weather adjustment heating degree days benefit customers?

A. 28 Comparing weather sensitive consumption to a more recent ten-year average should result in a more precise monthly weather adjustment for our customers. To the extent that a customer's change in gas use is attributable to trending normal weather, updating the normal weather in the monthly adjustment will more closely align the monthly weather adjustment with changes in the customer's weather sensitive consumption.

Q. 29 Does this conclude your prepared direct testimony?

A. 29 Yes.

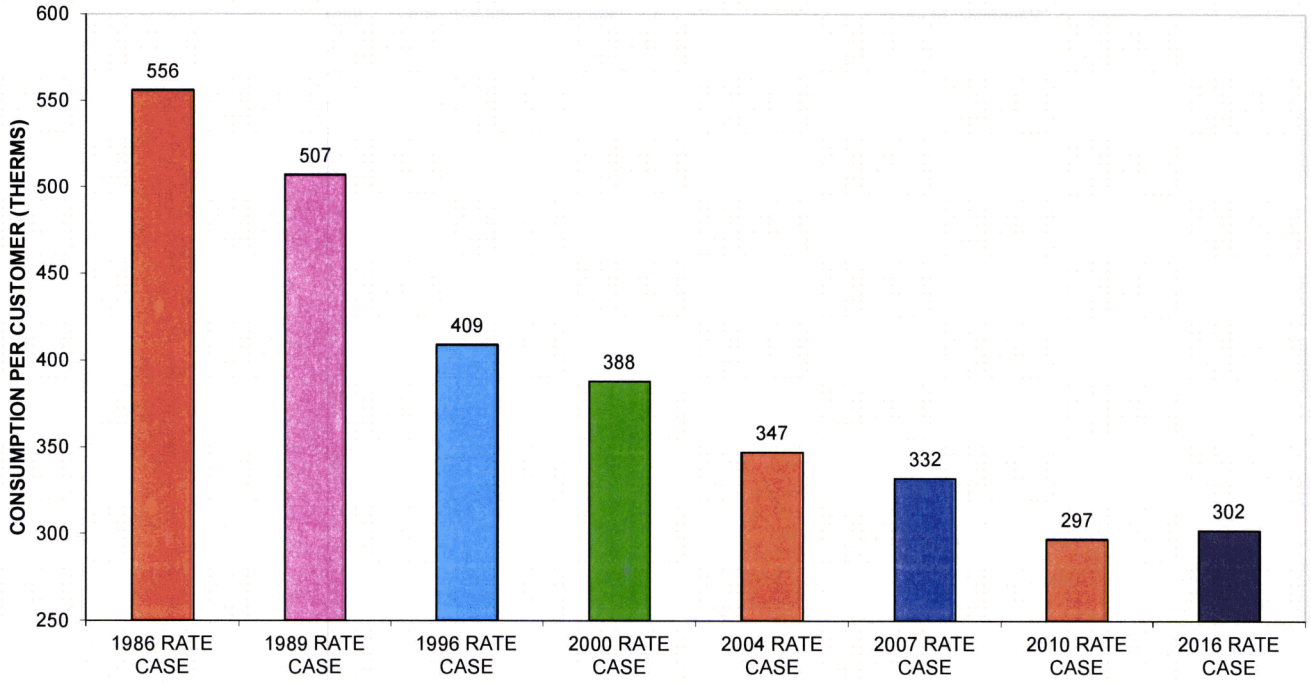
SUMMARY OF QUALIFICATIONS
CARLA D. AYALA

I graduated from New Mexico State University, Las Cruces, New Mexico, with a Bachelor of Arts degree in Economics in 2003. Thereafter in December 2004, I graduated from New Mexico State University, Las Cruces, New Mexico with a Master of Arts degree in Economics with a specialization in Public Utility Regulation.

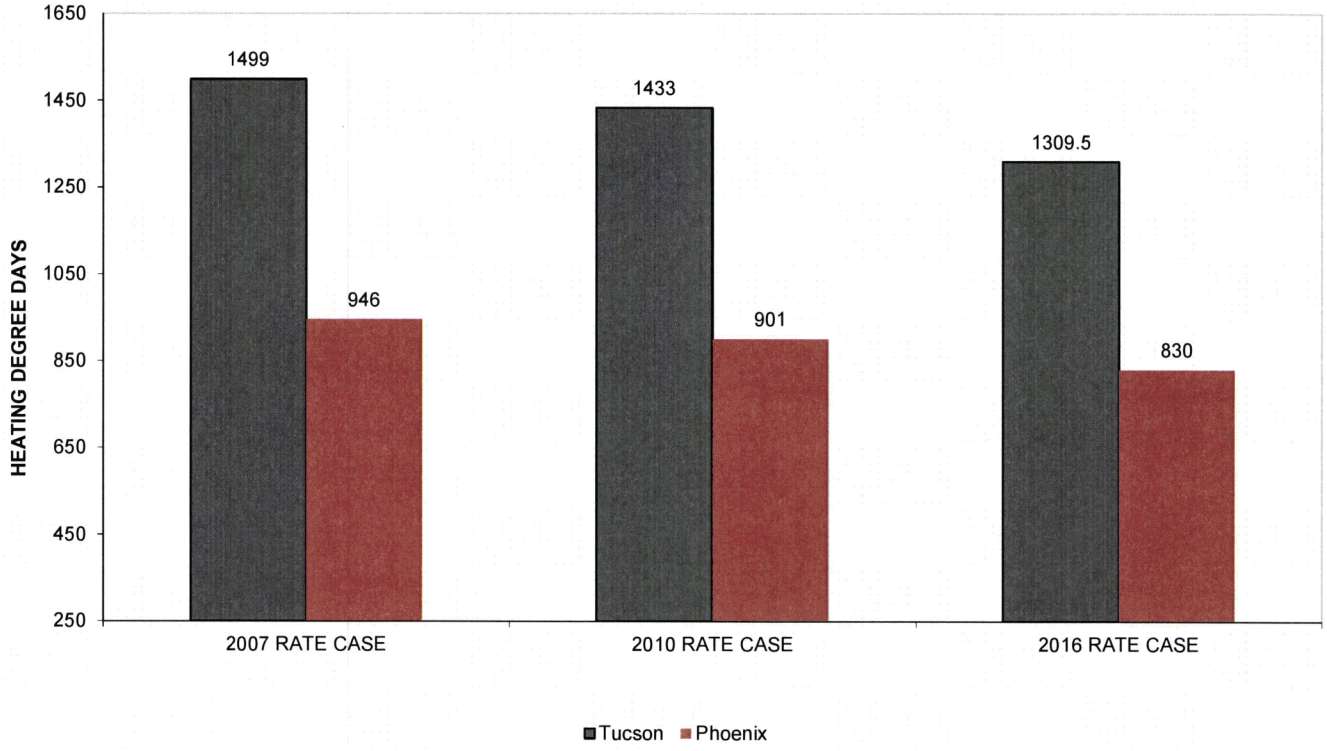
In 2005, I joined Southwest Gas as an Analyst in the Demand Planning Department. In December 2009, I was promoted to Analyst III/Demand Planning and in November 2013, I was promoted to Economist also within the Demand Planning Department. I am responsible for performing bill frequency analysis for general rate case filings. I am also responsible for the development of weather normalized billing determinants for rate cases, the development of short- and long-range demand forecasts for rate cases and systems planning, analysis and monitoring of the regional economy in each of Southwest Gas' rate jurisdictions and assorted load research activities.

Additionally, I am a member of the National Association of Business Economics.

ARIZONA
RESIDENTIAL GAS SERVICE (G-5 & G-6)
ANNUAL RATE CASE CONSUMPTION PER CUSTOMER
1986 - 2016



ARIZONA
10-YEAR CALENDAR MONTH HEATING DEGREE DAY NORMALS BY RATE CASE
2007 - 2016



Tab B

Direct Testimony

of

Byron C. Williams

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
BYRON C. WILLIAMS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
Prepared Direct Testimony
of
BYRON C. WILLIAMS

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Appendix A – Summary of Qualifications of Byron C. Williams

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
BYRON C. WILLIAMS

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Byron C. Williams. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Tax department. My title is Director/Tax.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Federal Energy Regulatory Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 My testimony supports the Company's request for a Property Tax True-up mechanism. It also addresses certain post-test year changes to federal and state income tax laws and explains how they impact the cost of service.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The Company's request for a Property Tax True-up mechanism;
- Relevant tax provisions included in the Protecting Americans from Tax Hikes (PATH) Act of 2015 or "tax extenders bill"; and
- The applicable Arizona corporate state income tax rate.

II. PROPERTY TAX TRUE-UP MECHANISM

Q. 7 Please describe the Property Tax True-up mechanism the Company is requesting.

A. 7 Southwest Gas is requesting authority to establish a Property Tax True-up mechanism to track 100 percent of the change in the Arizona property tax expense above or below the test year level. Please refer to the prepared direct testimony of Company witness Edward Gieseking for detail on the calculation of the surcharge associated with the Property Tax True-up mechanism.

Q. 8 What are some key factors related to property taxes in Arizona?

A. 8 Property taxes are a function of property values and governmental budgets within a particular tax jurisdiction. As property values decrease, local governments often increase rates to maintain tax revenues to cover their projected budgets. This has been the case in Maricopa, Pima and Pinal counties, where over 90 percent of the Company's Arizona plant is located as of November 30, 2015. The table below provides the total net assessed value of all taxpayers for these counties in 2010 (the year of the Company's last rate case), and 2015 (the most recent year for which data is available). It also shows the total percentage change from 2010 to 2015.

Tax Year	Maricopa County	Maricopa % Change	Pima County	Pima % Change	Pinal County	Pinal % Change
2010	$46,842,818,990		$8,939,647,260		$2,562,246,078	
2015	$34,623,670,323	-26.09%	$7,620,360,873	-14.76%	$2,057,547,528	-19.70%

As a result of declines in net assessed values, property tax rates have risen significantly in these jurisdictions during the same period. The table below shows the rise in the county-wide primary tax rate (per $100.00 of assessed value) and the percentage increase from 2010 to 2015.

Tax Year	Maricopa County	Maricopa % Change	Pima County	Pima % Change	Pinal County	Pinal % Change
2010	$2.1998		$4.6452		$5.8263	
2015	$3.1291	42.24%	$6.2620	34.81%	$6.8053	16.80%

Q. 9 How are property tax rates determined?

A. 9 Property tax rates are levied by governmental authorities based on projected budgeted revenue needs and estimated assessment values of the taxable property located in that jurisdiction. These local governments modify the property tax rates, in order to maintain tax revenues to cover their projected budgets. Property tax rates are often increased to account for decreasing property values or to generate revenue for additional government expenditures. These rates are established by the local governments for all property located within their jurisdiction and not just for property owned by Southwest Gas. As

such, the determination of the Company's property tax expense is really beyond the control of the Company.

Q. 10 Why has Southwest Gas' property tax rate changed significantly since its last Arizona rate case?

A. 10 A significant reason for the recent increase is the reduced property values, particularly for personal residences. As noted above, as property values decline, local governments increase the property tax rate to maintain or increase tax revenues. In general, many taxpayers may be indifferent to lower values and higher tax rates, as this may not significantly change the taxpayer's total tax liability. However, the assessed value for Southwest Gas is primarily based on the net book value of its fixed assets. Since the net book value of Southwest Gas property has increased (unlike residential values), when a local government also increases rates, the Company's total property tax liability is disproportionately affected. In addition, the majority of the Company's taxable property is located in major population centers (e.g., Maricopa, Pima and Pinal counties). The overall composite tax rates in these major population centers are generally higher than those of less populated Arizona counties. Therefore, the Company's composite rate is higher than the same type of business in more rural areas of the state.

Q. 11 Are there other reasons why Southwest Gas' property tax liability increased significantly since its last Arizona rate case?

A. 11 Yes. In addition to the increased property tax rates calculated by the local governments, the Company's Arizona property tax liability has increased since the last Arizona rate case because of additional capital expenditures, primarily for the replacement of natural gas infrastructure. These replacement

expenditures increased the Company's overall assessed value, with no significant change in the capacity or mileage of the distribution system, and without any increased revenues from customers.

Q. 12 Why is the Company proposing a Property Tax True-up mechanism?

A. 12 In recent years, the Company's total Arizona property tax liability has varied significantly from year to year without a direct correlation to the change in the total fair cash value of the Company's property. This volatility creates a significant difference between the property tax component in the authorized cost of service and the actual property tax expense paid by the Company. For example, the Company's proposed Annualized Property Tax Expense per Adjustment No. 15 in the instant proceeding is $41.6 million, compared to the previously authorized recovery of $27.2 million. This is an increase of approximately 53%, even though the full cash value of the Company's property increased by only 27% over the same period. This imbalance is a result of a number of factors, including significant increases in the property tax rates, which are set by local governments. Southwest Gas believes that this volatility will continue and that the test year level of property tax expense will be significantly different than the actual tax payments during the years that rates from this proceeding are effective.

Q. 13 What are the benefits of the Company's proposed Property Tax True-up mechanism?

A. 13 The proposed Property Tax True-up mechanism helps the Company address the volatility associated with the Arizona property tax liability between rate cases. As the determination of property tax rates are determined by local governments and beyond the control of the Company, it is appropriate for changes in property

taxes to be deferred and collected or refunded in a surcharge. The Property Tax True-up mechanism is a symmetrical mechanism, therefore, as the Arizona property tax expense increases, there will be a surcharge to customers and as the Arizona property tax expense decreases, there will be a credit to customers. The idea is to ensure customers never pay more than the actual property tax expense that is paid by the Company.

Q. 14 Have other Arizona utilities requested property tax adjustment mechanisms?

A. 14 Yes. Both Arizona Public Services Company (APS) in Docket No. E-01345A-11-0224 and UNS Electric, Inc. (UNSE) in Docket No. E-04204A-15-0142 requested property tax adjustment mechanisms.

Q. 15 Did the Arizona Corporation Commission (Commission) grant either of these requests?

A. 15 Yes. The Commission approved a property tax deferral for APS in Decision No. 73183 (May 24, 2012) as part of a settlement agreement. The UNSE request is currently pending before the Commission; however, Staff recommends accepting UNSE's proposed property tax recovery mechanism and states that it "allows recovery for items that are beyond the control of the Company and balances the interests of consumers and shareholders."[1]

III. PROTECTING AMERICANS FROM TAX HIKES ("PATH") ACT OF 2015 OR TAX EXTENDERS BILL

Q. 16 Have there been any significant federal income tax law changes that occurred after the close of test year in this proceeding?

[1] Direct Testimony of Donna H. Mullinax, Docket No. 15-0142, at p. 34, ll 2–4.

A. 16 Yes. In December 2015, Congress passed and President Obama signed the Protecting Americans from Tax Hikes (PATH) Act of 2015, sometimes referred to as the "tax extenders bill". This bill, among other things, extended 50 percent bonus depreciation through 2017, and applied the bonus deduction retroactively to depreciable property placed in service during all of 2015.

Q. 17 How did Southwest Gas treat the subsequent retroactive extension of 2015 bonus depreciation for purposes of the current rate case?

A. 17 Although the retroactive extension of bonus depreciation occurred after the close of the Company's test year, the Company has adjusted its Accumulated Deferred Income Tax (ADIT) balances to reflect 50 percent bonus depreciation for all depreciable property placed in service in 2015. Please see the discussion of Adjustment No. 20 in the prepared direct testimony of Company witness Randi L. Cunningham. This is consistent with what will be filed in the Company's 2015 consolidated federal income tax return.

Q. 18 Did Southwest Gas claim bonus depreciation on all eligible property placed in service since its last rate case?

A. 18 Yes, the Company has claimed bonus depreciation on all eligible assets since the last rate case and that bonus depreciation is reflected in the ADIT balances included in the instant filing.

IV. ARIZONA CORPORATE STATE INCOME TAX RATES

Q. 19 What Arizona corporate income tax rate is the Company utilizing in the cost of service calculation for the rate case?

A. 19 The Company is utilizing a 5.5 percent Arizona corporate income tax rate in the cost of service calculation for this proceeding (see Schedule C-3, Sheet 2). The 5.5 percent rate is the Arizona statutory rate for the 2016 calendar tax year (as

stated in Ariz. Rev. Stat. § 43-1111). This is a reduction from the 2015 calendar tax year rate of 6.0 percent. In the Company's prior rate cases, the Commission authorized post-test period adjustments when applicable events are known or reasonably certain to occur and are measurable prior to hearing. By using the 2016 state corporate income tax rate, the cost of service more accurately reflects the level of expenses and costs Southwest Gas will incur when rates approved in the current proceeding go into effect.

Q. 20 Does this conclude your prepared direct testimony?

A. 20 Yes.

SUMMARY OF QUALIFICATIONS
BYRON C. WILLIAMS

I am a graduate of Brigham Young University having received a Bachelor of Sciences in Accounting in 2001. In 2003, I earned a Master's in Business Taxation from the University of Southern California.

In 2002, I joined the tax department of PricewaterhouseCoopers LLP in Los Angeles, California. In 2010, I joined the Las Vegas office and was promoted to Director in 2011. In 2013, I joined Southwest Gas as Director/Tax. I am responsible for all phases of the Company's taxes, including preparation of all federal, state, and local tax returns and tax provisions, researching tax matters and preparation of tax-related testimony and exhibits for rate proceedings, including rate cases.

I have been licensed as a Certified Public Accountant by the state of California since 2007. In 2011, I was also licensed as a Certified Public Accountant by the state of Nevada. I am also a member of the American Institute of Certified Public Accountants, as well as the Nevada Society of CPAs.

Tab C

Direct Testimony

of

Kristien M. Tary

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY

OF

KRISTIEN M. TARY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
KRISTIEN M. TARY

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Appendix A – Summary of Qualifications of Kristien M. Tary

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
KRISTIEN M. TARY

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kristien M. Tary. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Rates and Regulatory Analysis department. My title is Analyst II.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 No.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's Class Cost of Service Study (CCOSS) reflected in Schedule G and the associated workpapers. I am also sponsoring certain portions of Schedules A, C and E as identified in the Table of Contents for Volume III of the Application.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The purpose of a CCOSS and summary of the schedules supporting the Company's CCOSS in this proceeding; and
- The process used to develop the Company's CCOSS.

II. PURPOSE OF A CLASS COST OF SERVICE STUDY (CCOSS)

Q. 7 What is the purpose of a CCOSS?

A. 7 The purpose of a CCOSS is to allocate the cost-of-service, or revenue requirement, to the appropriate customer rate classes, and determine the resulting rate of return for each customer class included in the study. In this case, the results of the CCOSS are used as a guide in establishing proposed class revenues and developing proposed rates for each customer class. These topics are discussed more fully in the prepared direct testimony of Company witness Christy M. Berger.

Q. 8 How is this accomplished?

A. 8 First, the Company's system and operations are analyzed to determine cost causation factors. Once the causation factors are determined, each customer class is examined to determine their proportionate responsibility to each causation factor. Based on the proportionate responsibility of each customer class, allocation factors are developed to use in the allocation of the Company's costs. After each cost is allocated across customer classes, the allocated amounts are summed, resulting in an allocation of revenue requirement to each customer class. The sum of the revenue requirement allocated to each customer class will equal the Company's total revenue requirement.

Q. 9 Please describe the CCOSS schedules you are supporting.

A. 9 I sponsor the CCOSS schedules summarized in Schedules G-1 and Schedule G-2, Sheets 1 and 2. The CCOSS summarized in Schedule G-1 was performed

using Southwest Gas' currently effective rates and rate schedules. Schedule G-2, Sheet 1 reflects, by customer class, the rate of return requested in the Company's Application. Schedule G-2, Sheet 2 reflects the rate of return at Southwest Gas' proposed rates for each customer class.

III. DEVELOPMENT OF THE CCOSS

Q. 10 Please describe the process for developing the CCOSS.

A. 10 The Company utilizes a three-step process to develop the CCOSS, where costs are: 1) functionalized; 2) classified; and 3) allocated to the customer classes included in Southwest Gas' proposed rate design.

Q. 11 What is meant by cost functionalization?

A. 11 Cost functionalization is the assignment of plant investment costs and expenses to the appropriate operating functions. Southwest Gas' functionalization follows the Federal Energy Regulatory Commission (FERC) uniform system of accounts. The major functions are production, storage, transmission, and distribution. Since Southwest Gas currently has no production, storage or transmission facilities in its Arizona service areas, all costs are appropriately functionalized as distribution.

Q. 12 What is meant by cost classification?

A. 12 Cost classification is the process of identifying whether Southwest Gas' plant investment costs and incurrence of expenses are related to: 1) providing capacity, i.e. sizing its facilities to serve customers' maximum demands; 2) the annual volume of gas actually delivered; or 3) providing customers with access, including related meter reading and billing expenses, to Southwest Gas' service irrespective of the amount of gas used. These are commonly referred to as demand, commodity and customer classifications, respectively.

Q. 13 What is meant by cost allocation?

A. 13 Cost allocation is the process of apportioning costs classified as demand, commodity or customer to each rate class based on distinct characteristics of class demand, class consumption and number of customers associated with each class. Demand-related allocations are based on relative customer class capacity demands. Commodity allocations are based on relative customer class annual natural gas consumption. Customer allocations are related to the number of customers in each class. A weighted customer class allocator is also developed to recognize cost variations in providing service, such as meter and service cost and billing expenses.

Q. 14 Is this the same process Southwest Gas has utilized in prior general rate cases?

A. 14 Yes. The Company has utilized, and the Commission has accepted, this methodology for performing the CCOSS in the Company's past several rate cases.

Q. 15 Does this conclude your prepared direct testimony?

A. 15 Yes.

SUMMARY OF QUALIFICATIONS
KRISTIEN M. TARY

I hold a Bachelor of Arts degree in Communication Studies from the University of Nevada, Las Vegas.

In 2000, I began my career at Southwest Gas Corporation (Southwest Gas or Company) as an Intern in the Corporate Communications Department. In 2001, I was hired by the Company as a Professional Staff Entry in the Corporate Communications Department. In 2004, I was promoted to Communications Representative. From 2001 to 2009, my primary responsibilities included representing the Company both internally and externally regarding communications, media relations, and consumer and community affairs; providing communications support for low income programs and regulatory/compliance items; providing expertise and resources to create and execute strategic communications plans.

In 2009, I was promoted to Analyst II in the State Regulatory Affairs Department. In this position, my primary responsibility was to monitor and manage regulatory proceedings in Arizona, California and Nevada, as well as ensure the Company met its regulatory compliance obligations. In this role, I also facilitated and managed the data request process, provided regulatory perspective when responding to customer inquiries, and acted as a liaison with the state regulatory agencies and consumer advocates, when appropriate. In addition, I collaborated with regulatory representatives from other utilities regarding statewide initiatives, and assisted with legislative activities.

In October 2014, I transitioned into my current position as Analyst II in the Rates and Regulatory Analysis Department. In this role, I am responsible for handling various rate and revenue requirement analysis for the Company's Arizona, California and Nevada ratemaking jurisdictions. I primarily support the Arizona jurisdiction by calculating and implementing customer rates, overseeing tariff administration, conducting economic feasibility analysis for customer bypass, as well as preparing forecasted results of operations and developing recommendations to management in support of corporate financial and regulatory goals. In addition, I maintain complex and technical analyses of multiple components for the Company's Arizona cost of service and rate design allocation model.

Tab D

Direct Testimony

of

Kevin M. Lang

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY

OF

KEVIN M. LANG

ON BEHALF OF

SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
Prepared Direct Testimony
of
KEVIN M. LANG

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Appendix A – Summary of Qualifications of Kevin M. Lang

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
KEVIN M. LANG

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kevin Lang. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Engineering Staff department. My title is Director/Engineering Staff.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the California Public Utilities Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor, from an operations perspective, the Company's proposal to expand its Customer Owned Yard Line (COYL) program, and the Company's proposal to accelerate the replacement of pre-1970 vintage steel pipe as part of its Gas Infrastructure Modernization (GIM) mechanism.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- An operational overview of Southwest Gas' current COYL program, and the proposed expansion of the COYL program; and
- An operational overview of the Company's proposed program to replace pre-1970 vintage steel pipeline and other aging infrastructure.

II. CUSTOMER OWNED YARD LINES (COYL) EXPANSION

Q. 7 Please provide a brief history of Southwest Gas' COYL program.

A. 7 As part of Decision No. 72723 in Southwest Gas' 2010 general rate case, the Commission approved the Company's COYL program consistent with the terms of a Settlement Agreement involving the Company, the Commission's Utilities Division Staff (Staff), and other parties to the docket. For the purpose of this program, the Company defines a COYL as the customer-owned exterior gas piping that connects at the meter and continues to where the gas piping enters the customer's premise. The Company originally proposed a COYL program after noticing an upward trend in odor calls related to COYLs. Prior to the COYL program, a customer's only option for remedying a leaking COYL was to pay Southwest Gas to replace the COYL with Southwest Gas facilities and relocate the gas meter, hire a licensed plumber to repair the leak or replace the COYL, or discontinue natural gas service to the customer. Through settlement negotiations, the settling parties were able to negotiate a settlement that included a COYL program designed to replace all COYLs within its service territory – subject to customer approval.

As initially designed, the COYL program authorized the Company to leak survey COYLs and provide those customers with leaking COYLs the opportunity to replace their COYLs with facilities owned and operated by Southwest Gas. As discussed in more detail below, the Commission authorized Southwest Gas

to expand its COYL program in January 2014 (Decision No. 74304). This expansion allows the Company to replace COYLs in conjunction with its other pipe replacement activities, and regardless of whether or not the COYLs are leaking.

Q. 8 Why was the COYL program modified in Decision No. 74304?

A. 8 The original COYL program, as approved in Decision No. 72723, allowed the Company to relocate the gas meter and replace the COYL only in those instances where the COYL is found to be leaking. The proposal to modify the program was driven by the Company's estimate that at the replacement rates experienced, it could take up to 50 years to completely remove all Arizona COYLs. The modification to the program in Decision No. 74304 included the proactive approach of offering to replace the COYL (with the customer's consent) in coordination with the Company's major pipe replacement projects regardless of whether or not they are leaking. The intent was to accelerate the replacement activity to ensure a more timely removal of all COYL from the Southwest Gas system.

Q. 9 What is the current status of the Southwest Gas COYL program?

A. 9 Southwest Gas provides annual COYL reports each February to the Commission. These reports document the continued success of the Company's COYL program. As of December 31, 2015, Southwest Gas replaced a total of 8,518 COYLs with facilities that are owned and operated by the Company.

Q. 10 What is the Company proposing in this rate case with respect to the COYL program?

A. 10 To build upon the success of the existing COYL program, the Company proposes to expand the program to include a proactive, systematic approach to

replacing COYLs, regardless of whether or not they are leaking. This would allow the Company to focus resources to replace COYLs, giving considerations to leak rates, COYL concentration, acceptance rates, customer demographics, etc., regardless of whether the COYL is leaking or not. The Company also proposes to slightly modify leak survey commitments to allow more flexible scheduling of leak surveys.

Q. 11 Why is the Company requesting expansion of the COYL program in this proceeding?

A. 11 Consistent with the goal of replacing all Arizona COYLs, the Company recognizes that there are still certain COYL customers that cannot take advantage of the replacement aspect of the program because their COYL is not leaking or they do not live in the vicinity of a planned replacement program by the Company. The Company estimates that approximately 86,205 total COYLs exist as of December 31, 2015. When combined with the other aspects of the current program, the proposed expansion would allow the Company to reach those additional customers and will lead to eliminating all remaining COYLs in Arizona in a more timely fashion.

Q. 12 Please describe the proposed change to the leak survey frequency?

A. 12 To effectuate the intent that each known COYLs in the Company's system be inspected once every three calendar years (i.e., that a COYL surveyed in year 1 of the program is surveyed again in year 4 of the program), Decision No. 72723 requires the Company to leak survey approximately one-third of its COYLs each year. In light of both the recent and proposed expansions of the COYL program, which allow for the replacement of COYLs regardless of whether they are leaking, modifying the "approximately one-third" requirement would provide

Southwest Gas greater flexibility to manage its COYL leak surveys. Accordingly, the Company proposes that the requirement to leak survey approximately one-third of its COYL inventory each year be restated as a requirement that the Company leak survey each known COYL once every three calendar years. This change will better accommodate the current state of the COYL program while continuing to satisfy the original intent of Decision No. 72723.

III. PRE-1970 VINTAGE STEEL PIPE REPLACEMENT AND OTHER AGING INFRASTRUCTURE

Q. 13 How has industry focus evolved on pipeline safety since the last general rate case?

A. 13 Since the test period in the Company's last general rate case (June 2010), there has been several large profile incidents that have heightened industry focus on replacing aging infrastructure to enhance pipeline safety efforts. Several of these efforts consist of modernizing pipeline systems to ensure natural gas operators meet modern requirements for record keeping and documentation regarding pipeline construction practices, material selection, material and pipeline testing, and other key elements of modern pipeline construction requirements. In addition, modernizing pipeline systems gain the benefit from the substantial enhancements to pipe quality and performance standards, steel pipe coating systems, and other construction and testing standards that have evolved over the past several decades.

Q. 14 What is the Company proposing with respect to modernizing its distribution system through the replacement of pre-1970's vintage steel pipe in Arizona?

A. 14 Southwest Gas is proposing to accelerate the replacement of pre-1970's vintage steel distribution and transmission pipe. Pre-1970's vintage steel pipe is defined

(for the purposes of this proposal) as all pipe with known installation dates prior to January 1, 1970. The Company seeks to include this accelerated replacement in its proposed GIM mechanism. The GIM mechanism is discussed in the prepared direct testimony of Company witness Edward Gieseking.

Q. 15 How much pre-1970's vintage steel distribution and transmission pipe does Southwest Gas have in its Arizona service territories?

A. 15 Southwest Gas has approximately 193 miles of transmission pipe and 5,741 miles of distribution pipe that are pre-1970's vintage steel in Arizona. This represents approximately 63% of the total transmission mileage and approximately 82% of the total distribution steel pipe mileage in Arizona respectively.[1]

Q. 16 What is the significance of pre-1970's vintage steel pipe?

A. 16 Prior to 1970, federal and state pipeline safety code requirements had not been formally established for pipeline construction practices, material selection, material and pipeline testing, cathodic protection requirement, recordkeeping requirements, and other key elements of modern pipeline construction requirements. Older pipelines do not have all of the safety features associated with modern pipelines such as improved coatings, enhancements to steel pipe quality and performance standards, more comprehensive welding procedures, and enhanced testing requirements. Prior to the promulgation of state and federal pipeline safety regulations, operators utilized industry consensus standards and other industry practices of the time to govern pipeline construction

[1] Percentages based upon comparison to 2015 Pipeline and Hazardous Materials Safety Administration (PHMSA) Annual Report data for Southwest Gas Corporation mileage within Arizona for total transmission and total distribution steel.

practices, material selection, and material and pipeline testing. These consensus standards were voluntary and not as comprehensive as the mandatory pipeline safety standards in place today.

Steel pipe is prone to corrosion which can lead to leaks in a piping system. Corrosion can be mitigated through the adequate application of cathodic protection on steel pipe. Cathodic protection is achieved through the combination of a protective coating system and the application of an electric current in order to modify the electric potential of the metal surface to prevent corrosion. Federal and state pipeline safety rules mandated the cathodic protection of all steel pipe after 1970. The possible lack of cathodic protection on pre-1970's vintage steel pipe therefore presents a potential corrosion risk to the pipe.

In addition, before the implementation of state and federal pipeline safety codes, pipeline installation records were not as complete as they are today, and were not always retained for the same length of time as they are today. The Pipeline and Hazardous Materials Safety Administration (PHMSA) recently issued a Notice of Proposed Rulemaking (NPRM) to address pipe testing, lack of adequate material records, and the establishment of Maximum Allowable Operating Pressure (MAOP) for steel transmission pipelines.[2] This NPRM proposes numerous provisions, including but not limited to requirements that operators identify and remediate vintage steel transmission lines that were not constructed or tested to current standards. This includes circumstances where

[2] On April 8, 2016, PHMSA released the Safety of Gas Transmission and Gathering Lines Proposed Rule in the Federal Register under PHMSA Docket No. PHMSA-2011-0023.

the MAOP was established based upon Historical Operating Pressure (HOP), pursuant to the grandfather clause[3] of the federal pipeline safety code.

The NPRM also proposes verification of pipeline materials where an operator's data may not be complete, requirements to verify MAOP through several proposed methods in the event MAOP was established utilizing the grandfather clause, and other key improvements and enhancements to the federal pipeline safety code – all of which will require operators to make significant investments in their systems to ensure compliance. Although a final rule has not yet been issued, the Company's proposal takes into account the potential replacement of pre-1970's vintage transmission steel pipe that would be necessitated by the promulgation of this proposed regulation.

The accelerated replacement of pre-1970's vintage steel pipe will address all of these factors by allowing the Company to bring all of its steel system up to modern construction and recordkeeping standards.

Q. 17 Is Southwest Gas proposing to accelerate the replacement of pre-1970's vintage steel distribution or transmission pipe because they are unsafe to operate?

A. 17 No. The pre-1970's vintage steel distribution or transmission pipe in Southwest Gas' system do not present an immediate safety concern and the Company maintains vigorous programs to ensure the distribution system is operated in a safe and reliable manner. To the contrary, the Company's proposal seeks to proactively replace this aging infrastructure before it becomes unsafe.

[3] PHMSA Advisory Bulletin ADB-2012-06 describes the grandfather clause as a "method, (which) allows pipelines that had safely operated prior to the pipeline safety MAOP regulations to continue to operate under similar conditions without retroactively applying recordkeeping requirements or requiring pressure tests". This provision was promulgated in the federal pipeline safety code in 49 CFR Part 192.619(c).

However, a portion of Southwest Gas' pre-1970's distribution system in Arizona was installed by other operators and later acquired by the Company. This further compounds the challenges of the completeness of pipeline records and the operations and maintenance history of these facilities.

Q. 18 What does Southwest Gas do to address the unsafe pipe in its system?

A. 18 Unsafe pipe, regardless of age or pipe type, is replaced immediately in accordance with the Company's Operations Manual. The Company's distribution and transmission integrity management programs work to identify those pipelines that may represent a safety concern and address those concerns through additional or accelerated actions and preventative and mitigative measures. Furthermore, Southwest Gas' integrity management programs and Operations Manual are designed to meet or exceed current federal and state pipeline safety requirements.

Q. 19 Please describe the Company's distribution integrity management program.

A. 19 The Company's distribution integrity management program involves a risk-based process to gather and evaluate information about the Company's distribution system and to prioritize and implement actions based upon that information to maintain the safety and integrity of those systems. Southwest Gas conducts an annual evaluation and assessment that assists in the determination of whether to schedule a particular pipe segment for replacement or whether to implement other risk control practices such as additional leak surveys.

Q. 20 Please describe the Company's transmission integrity management program.

A. 20 The Company's transmission integrity management program addresses transmission pipelines in locations where people gather, called high consequence areas. Pipelines in high consequence areas are inspected beyond

normal levels of operations and maintenance. These inspections, called assessments, are repeated on a regular interval, for an increased level of awareness and maintenance.

Q. 21 Does the proposed accelerated replacement of pre-1970's vintage steel pipe replace the processes established through the Company's integrity management programs?

A. 21 No, it complements them. The Company's integrity management programs will continue to identify and address potential safety concerns through normal operations. The accelerated replacement of pre-1970's vintage steel pipe will complement and build upon the success of the Company's integrity management plans by combining the risk based approach of integrity management with a comprehensive and proactive approach to modernize the Company's infrastructure.

Q. 22 Why is Southwest Gas proposing to accelerate the replacement of pre-1970's vintage steel pipe if no safety concern exists and the Company has a functional integrity management program that addresses potential safety concerns in its system?

A. 22 As mentioned previously, Southwest Gas has nearly 6,000 miles of pre-70's vintage steel pipe in Arizona. Given the large amount of pre-1970's vintage steel pipe in Arizona, Southwest Gas recommends a program be developed to start working towards modernizing these facilities in a systematic and methodical approach that does not unduly burdensome Southwest Gas or its customers. In addition, the proposed accelerated replacement of pre-1970's vintage steel pipe will accomplish a number of key operational objectives including: (1) the modernization of the Company's steel pipe facilities to current industry safety

standards; and (2) the elimination of vintage steel pipelines with MAOPs established based upon HOP. Further, this modernization program will also provide enhanced safety and reliability of the distribution and transmission systems through enhanced record keeping and documentation regarding pipeline construction practices, material selection, material and pipeline testing, as well as improved pipe quality and performance standards of newer facilities.

Q. 23 If Southwest Gas does not receive approval to recover the costs of accelerated replacement of pre-1970's vintage steel pipe through the GIM mechanism, will the Company proceed with its plans to replace this pipe on an accelerated basis?

A. 23 No. Without the ratemaking support provided by the GIM mechanism, the Company will not be able to accelerate the replacement of this aging infrastructure and will rely solely on the traditional approach of budgeting replacement work with the timing of rate case activity.

Q. 24 Does this conclude your prepared direct testimony?

A. 24 Yes.

SUMMARY OF QUALIFICATIONS
KEVIN M. LANG

Kevin M. Lang is the director/Engineering Staff for Southwest Gas Corporation (Southwest Gas). He directs and coordinates support to five operating divisions for pipeline safety code compliance; right-of-way support, material specifications and approval; environmental policies and procedures; proper energy measurement; pipeline cathodic protection; SCADA support; project design; and the training and qualification of technical services personnel. He previously oversaw the Company's distribution integrity management program and laboratory services under the same capacity.

Mr. Lang joined Southwest Gas in 2003 as an engineer in Victorville, CA. He was subsequently promoted to distribution engineer in 2005, supervisor/Engineering in 2006 and manager/Engineering in 2007. During this period, Mr. Lang oversaw the design of transmission and distribution facilities for new business, franchise and system reinforcements; PVC pipeline replacements; pipeline safety code compliance; MAOP studies and requalification programs; and preparation of short and long-term capital budgets.

He was promoted to director/Gas Operation Support Staff in 2011 where he directed the Company's technical skills training, Operator Qualification (OQ) training and testing, tool and equipment evaluations, operations-related procedures manuals, Incident Command System training and operation of the Emergency Response Training Facilities in Tempe and Las Vegas. Mr. Lang was subsequently promoted to director/Engineering Staff in November of 2012.

He holds a Bachelor of Science degree in Mining Engineering from Virginia Tech. He is a registered Professional Engineering in the state of Nevada with a proficiency in Civil

Engineering. Mr. Lang currently serves on the American Gas Association's Operations Safety Regulatory Action Committee.

Tab E

Direct Testimony

of

Brian T. Holmen

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
BRIAN T. HOLMEN

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 2, 2016

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of
Prepared Direct Testimony
of
Brian T. Holmen

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Appendix A – Summary of Qualifications of Brian T. Holmen

Confidential Exhibit No.__(BTH-1)

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
Brian Holmen

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Brian Holmen. My business address is 2 Park Plaza, Suite 250, Irvine, California 92614.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am an executive compensation consultant employed by Korn Ferry Hay Group (Hay Group) as the West Region Leader for Board Solutions. My title is Senior Principal.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 No.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 The purpose of my testimony is threefold. First, I provide an overview of the executive compensation programs and incentive plans offered by Southwest Gas Corporation (Southwest Gas or the Company) and describe the changes made to the incentive plans since the Company's last rate application to the Arizona Corporation Commission (Commission) in 2010. Second, Hay Group

performed an objective assessment of the competitive positioning of the Company's executive compensation pay levels and design relative to the market for nineteen senior executives who hold the title of Vice President (VP) or a more senior title (collectively, the Executives), the results of which I summarize in my testimony. Third, I provide my opinion on the portion of the Company's executive compensation costs and incentive program costs that I believe should be recovered through customer rates.

Q. 6 In reviewing the competitive positioning of the Executives' compensation programs, what aspects of compensation did Hay Group analyze?

A. 6 Hay Group analyzed the following elements of executive compensation in its market review:

- Base Salary
- Target Total Cash Compensation (TCC)
  - Each Executive's TCC is comprised of base salary plus the cash portion of the Executive's target annual incentive granted pursuant to the Company's Management Incentive Plan (MIP).
- Target Total Direct Compensation (TDC)
  - For survey data comparisons, TDC for each Executive is equal to TCC plus the target value of equity awards granted to the Executive pursuant to the MIP and the Company's Restricted Stock Unit Plan (RSUP).

- For proxy data comparisons, TDC for each Executive is equal to TCC plus grant date fair value of equity awards granted the Executive pursuant to the MIP and RSUP.[1]

- Supplemental Executive Retirement Program (SERP)
  - Hay Group reviewed the design and benefit levels among the Company's public-company peer group with respect to supplemental executive retirement programs for purposes of evaluating the SERP.
- Executive Deferral Plan (EDP)
  - Hay Group reviewed the EDP design and benefit levels compared to survey data in Hay Group's 2014 Executive Benefits Survey and Towers Watson's 2013 Executive Retirement Survey.

Q. 7 Did Hay Group prepare a written report of its assessment?

A. 7 Yes. A copy of Hay Group's report is attached as Confidential Exhibit___ (BTH-1) to my testimony.

Q. 8 Please summarize your prepared direct testimony.

A. 8 My prepared direct testimony sets forth my analysis to support the following conclusions:

- The Company's executive compensation programs and incentive programs are similar in design to those described in the Company's last rate application filed with the Commission in 2010, subject to updates to the designs of the Company's MIP and RSUP.

[1] The different methodologies for determining TDC are a function of how data is reported in surveys versus proxies. Proxy summaries disclose grant date fair value of long-term equity awards and Hay Group used this methodology for both the Company and the proxy peer companies to obtain a consistent comparison.

- Based on its review of the competitive market, Hay Group concludes as follows: the aggregate compensation paid to the Executives is generally within or below the range of competitive compensation levels relative to the comparator markets that we reviewed (proxy and survey data); the performance metrics used within the MIP and RSUP are in-line with common market practices among the Company's public-company peer group companies; the SERP is in line with programs provided by the Company's public-company peer group companies with respect to both design and level of benefits; and the EDP is in line with survey data on executive retirement practices as set forth in Hay Group and Towers Watson surveys.
- The following executive compensation costs should be recovered through customer rates as reasonable and necessary costs to attract and retain qualified Executives and employees who are delivering superior results for the Company's customers:
  - 100% of the Executives' base salaries
  - 100% of the Company's MIP award costs, except for the MIP costs associated with awards payable to the Company's President and CEO, its CFO and its SVP, Corporate Development, with respect to whom 90% of the Company's MIP award costs should be recovered
  - 100% of the Company's RSUP award costs, except for the RSUP costs associated with the awards payable to the Company's President and CEO, its CFO and its SVP, Corporate Development, with respect to whom 90% of the Company's RSUP award costs should be recovered
  - 100% of the Company's costs relating to the SERP
  - 100% of the Company's costs relating to the EDP

II. OVERVIEW OF THE COMPANY'S EXECUTIVE COMPENSATION PROGRAMS

Q. 9 Please describe the components of each Executive's TDC.

A. 9 TDC for each Executive is comprised of three components: (i) base salary, (ii) annual cash incentive opportunity granted pursuant to the MIP and (iii) annual equity award grants made pursuant to the MIP and RSUP.

Q. 10 Please describe the MIP.

A. 10 The MIP is an annual incentive program that provides Executives and other participating employees with an opportunity to receive variable, at-risk pay based upon the achievement of specific benchmarks that are critical to the short-term and long-term success of the Company and that reward superior performance for the Company's customers. For each participating Executive and employee (other than the Company's President and CEO, its CFO and its SVP, Corporate Development) the MIP includes the following five performance metrics: (i) Customer Satisfaction, (ii) Customer-to-Employee Ratio, (iii) Safety, (iv) Return on Equity and (v) Operating Cost Containment. Each performance metric is equally weighted at 20%, and actual performance may vary from 70% to 140% of the target incentive opportunity with respect to each metric based on performance relative to the target. No MIP awards are paid in any year unless dividends on the Company's common stock for that year equal or exceed the prior year's dividends. The five metrics are designed to reward participants for the following performance:

- Customer Satisfaction. Designed to reward success in achieving a predetermined customer satisfaction percentage.
- Customer-to-Employee Ratio. Designed to reward success in improving the customer-to-employee ratio.

- Safety. Designed to reward success in minimizing damages per 1,000 tickets and incident response time.
- Operating Cost Containment. Designed to reward success in achieving a predetermined percentage of cost containment or operating costs.
- Return on Equity (ROE). Designed to reward success in achieving the average authorized return on equity.

The MIP awards granted to the Company's President and CEO, its CFO and its SVP, Corporate Development include a sixth metric, Construction Services, which is tied to the Company's non-regulated construction services segment. For each of these three executives, the Construction Services metric represents 10% of the target MIP opportunity, ROE represents 10% of the target MIP opportunity, and the remaining four MIP metrics each represent 20% of the target MIP opportunity.

Sixty percent of the total award earned under the MIP is paid in cash following the financial close of the most recent calendar year. The remaining 40% of the total award earned under the MIP is issued as performance shares in the form of restricted stock units, with the number of units calculated based on the average price of the Company's common stock on the NYSE for the first five trading days of the month in which the award is granted. The performance shares vest with respect to 40 percent one year following the date of grant and with respect to 30 percent on each of the second and third anniversaries of the date of grant.

Q. 11 Has the MIP design changed since the Company's last rate application to the Commission in 2010?

A. 11 Yes. Prior to the 2015 plan year, the MIP included the following equally-weighted metrics for all plan participants: (i) Customer Satisfaction, (ii) Customer-to-Employee ratio, (iii) Return on Equity and (iv) Operating Cost Containment. Beginning with the 2015 plan year, the Company added a new metric to the MIP, Safety, which applies to all plan participants, and a second metric, Construction Services, which applies to three Executives (the Company's President and CEO, its CFO and its SVP, Corporate Development). The Company added the new Safety metric to underscore its emphasis on safety as this metric is directly linked to incidents in the Company's gas distribution system. The Company also added the new Construction Services metric as it is linked to the Company's non-regulated construction services segment and incentivizes the three Executives who will be actively involved in the oversight of this segment. Beginning with the 2015 plan year, the Company also altered the form of payment for earned MIP awards from 40% cash and 60% equity to 60% cash and 40% equity in the form of performance shares.

Q. 12 Please describe the RSUP.

A. 12 The RSUP is a long-term incentive (LTI) plan designed to reward sustained performance with respect to the metrics that the MIP measures on an annual basis. The determination of whether to grant an RSUP award and the value of RSUP grants is based upon the average MIP payout for the three years immediately preceding the RSUP award determination date. The target is set at an average MIP payout percentage of 100%, with a threshold award of 50% of target and maximum award of 150% of target, in each case depending on the average MIP payouts for the last three fiscal years relative to the target payouts under that plan. No RSUP award will be granted in a plan year unless the

average MIP payout for the prior three years is at or above 90%. Earned RSUP awards are granted in the form of restricted stock units based on the average price of the Company's common stock on the NYSE for the first five trading days of the month in which the award is granted. RSUP awards vest with respect to 40 percent one year following the date of grant and 30 percent on each of the second and third anniversaries of the date of grant.

Q. 13 Has the RSUP design changed since the Company's last rate application to the Commission in 2010?

A. 13 Yes. The Company's revised MIP metrics (including the addition of the Safety and Construction Services metrics), which are discussed in my testimony above, will impact RSUP awards granted beginning in 2016. The new metrics will apply to the 2015 MIP awards, which is one of the three years that will be averaged to determine the 2016 RSUP award (i.e., the 2013-2015 MIP award payouts). As noted above, the Construction Services metric applies to three senior Executives (the Company's President and CEO, CFO and VP, Corporate Development) and that metric applies solely to the RSUP awards granted to those Executives.

Q. 14 Please describe the components of the Company's executive retirement benefit programs.

A. 14 The Company maintains two retirement benefit programs that are made available solely to Executives, the EDP and the SERP.

Q. 15 Please describe the EDP.

A. 15 The Company maintains a tax-qualified defined contribution (401(k)) plan that is available to all of its employees, the Southwest Gas Corporation Employees' Investment Plan (EIP). The EIP permits participants to contribute between 2 and

60 percent of their base salaries to the plan and receive a corresponding Company matching contribution up to 3.5% of a participant's annual salary. Participant contributions to the EIP are subject to annual IRC limits that apply to the plan, which is $18,000 for 2016 plus an additional $6,000 in catch-up contributions for participants who are age 50 or older. Executives are not eligible to receive Company matching contributions under the EIP.

The EDP supplements salary deferral opportunities for Executives by permitting them to defer annually up to 100% of base salary and non-equity incentive compensation. The Company also provides matching contributions under the EDP that parallel the contributions it makes to other participants under the EIP, up to 3.5% of a participating Executive's base salary. Deferred contribution amounts and Company matching contributions bear interest at 150% of the Moody's Seasoned Corporate Bond Rate. The EDP is a non-qualified plan under which participating Executives are general unsecured creditors of the Company with respect to benefits payable under the plan. Additionally, base salary deferred under the EDP is not included in the formula used to calculate an Executive's pensionable benefit under the Company's tax-qualified defined benefit retirement plan (Retirement Plan), described in Q&A16.

Q. 16 Please describe the SERP.

A. 16 The Company maintains a tax-qualified defined benefit retirement plan (Retirement Plan), which is available to all Company employees under which benefits are based on an employee's years of service, up to a maximum of 30 years, and the 12-month average of the employee's highest five consecutive years' salaries, excluding bonuses, within the final 10 years of service. The Internal Revenue Code (IRC) places a limit on the annual compensation that

may be considered in determining benefits under this plan; for 2016, the annual limit is $265,000. The annual limit is adjusted over time to reflect cost-of-living increases established by the Internal Revenue Service. As noted above, base salary amounts deferred by executives under the EDP are not included for purposes of determining pensionable benefits under the Retirement Plan.

The SERP is designed to supplement the Retirement Plan for participating Executives by providing a normal retirement benefit at a level of 50% to 60% of base salary without regard to the IRC limits that apply to the Retirement Plan. To qualify for a normal retirement benefit under the SERP, which is based on the 12-month average of an Executive's highest consecutive 36 months' salary, an Executive must have reached age 55 with 20 years of service or age 65 with 10 years of service. There are currently seven Executives whose base salary exceeds the annual IRC limit and who would be eligible to receive a normal retirement benefit under the SERP.

The SERP also provides a limited retirement benefit for Executives who defer base salary under the EDP but who do not qualify for a normal retirement benefit under the plan. The limited benefit supplements the Retirement Plan by accounting for base salary amounts that are deferred under the EDP and that are not included in calculating pensionable benefits under the Retirement Plan. The SERP is a non-qualified plan under which participating Executives are general unsecured creditors of the Company with respect to benefits payable under the plan and benefits payable under the SERP are offset by benefits payable under the Retirement Plan to avoid double payment of benefits to Executives.

Q. 17 Please describe the purpose of the EDP and SERP.

A. 17 The Company maintains the EDP and SERP to attract and retain qualified executives in a competitive marketplace in which the majority of the Company's peer companies offer comparable executive retirement programs. The SERP and EDP also provide participating Executives with an opportunity to receive retirement benefits that are available to other Company employees under the Retirement Plan and EIP that are not otherwise available to the Executives due to applicable IRC limits. The SERP and EDP therefore help put Executives on par with other Company employees with respect to the level of benefits they receive at retirement. The SERP and EDP also align the Executives' interests with the long-term interests of the Company as general unsecured creditors of the Company with respect to their benefits under those plans.

III. HAY GROUP'S ASSESSMENT OF THE COMPANY'S EXECUTIVE COMPENSATION PROGRAMS

Q. 18 Please describe your understanding of the Company's compensation philosophy.

A. 18 The Compensation Committee (the Committee) of the Company's Board of Directors aims to implement executive compensation programs that elicit strong performance by the Company's senior Executives (those who hold a title of Senior Vice President (SVP) or a more senior title); that attract, retain and motivate superior talent; and that provide a direct link between pay and performance. In establishing levels of pay for senior Executives, the Committee benchmarks base salaries at approximately 50th percentile of the amounts paid by the public-company peer group (median), with overall compensation for each senior Executive generally targeted between 35th and 65th percentile of the peer

group (i.e., plus or minus 15 percent from the median, which represents a competitive range). The Company's compensation philosophy for the remaining Executives (those who hold the title of VP) is consistent with the philosophy of the Committee, with base salaries targeted at approximately the median of the market and overall compensation levels that are competitive within the market.

Q. 19 How does the Company determine the appropriate level of compensation?

A. 19 The Committee reviews the compensation payable to Executives who hold the title of SVP or a more senior title, which in 2015 included seven executives (President and CEO, Executive Vice President (EVP), and five SVPs) by evaluating multiple sources. A primary source of comparison is the compensation paid by companies within the Company's public-company peer group that is comprised of utilities deemed to be of comparable size and to have a similar basic structure and operational complexity as the Company. The Committee also reviews the design of the Company's incentive programs and executive retirement programs relative to the designs of the Company's public company peers. In addition to reviewing peer group data, the Committee reviews numerous compensation surveys, which typically include surveys prepared by the Towers Watson, American Gas Association, Mercer and/or Hay Group. The Committee works with an outside compensation consultant, currently Pay Governance, in performing its executive compensation review.

For Executives who hold the title of VP, which included twelve executives in 2015, the Company evaluates their compensation using Hay Group's job evaluation methodology, described in Q&A 20 below. The Company supplements Hay Group's analysis by reviewing the survey data that the Committee reviews for the Company's more senior executives.

Q. 20 Please explain the process employed by Hay Group to evaluate the Company's Executive compensation levels and design of the Company's compensation programs.

A. 20 Hay Group utilized several sources to evaluate the reasonableness of the Executives' compensation and the competitiveness of the Company's compensation programs. The first source was the Company's public-company peer group identified in its 2015 proxy with the exception of one company, UNS Energy, which was acquired by Fortis in August 2014.[2] Hay Group evaluated the level of pay for the peer companies' top five executive officers (the named executive officers or NEOs) as well as the design of those companies' incentive plans and SERPs for purposes of comparison to the programs maintained by the Company. In reviewing competitive pay levels for the Company's NEOs, Hay Group compared the applicable Executives to the market as follows:

- The Company's CEO[3] was compared to median compensation for peer group CEOs
- The Company's CFO was compared to median compensation for peer group CFOs
- The Company's President was compared to median compensation within the peer group for the highest-paid NEO other than the CEO and CFO

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[2] The Company's peer group is identified in Hay Group's report attached as Confidential Exhibit___(BTH-1) to this testimony.

[3] The Company's current President and CEO, John Hester, was promoted to President in August 2014 and CEO in March 2015. For purposes of evaluating CEO compensation for FY 2014, the most recent proxy data available as of the date of my testimony for most of the Company's peer-group companies, Hay Group reviewed the compensation paid to the Company's prior CEO, Jeffrey Shaw, in FY 2014. We compared the compensation paid to Mr. Hester in FY 2014 against the highest-compensated NEO among peer group companies excluding the CEO and CFO.

- The Company's EVP was compared to median compensation within the peer group for the second-highest paid NEO other than the CEO and CFO
- The Company's SVP, Corporate Development was compared to median compensation within the peer group for the third-highest paid NEO other than the CEO and CFO

Hay Group also evaluated the compensation for each Executive who holds a title of SVP or higher, excluding the Company's SVP, Corporate Development (i.e., six of the Company' seven senior Executives), utilizing Towers Watson's 2015 CDB Energy Services Executive Compensation Survey. The Committee utilizes Towers Watson data for these roles and Hay Group concluded that the compensation levels in the Towers Watson survey are representative of the market and are in line with the public company peer group data for the top five Executives (the NEOs). Hay Group matched the Executives' titles with comparable positions in the Towers Watson Survey except with respect to the SVP, Corporate Development, for whom no comparable position exists within the survey; to benchmark this position, Hay Group relied solely on proxy data comparisons. In matching the Company's senior Executives to Towers Watson data, Hay Group applied a premium or discount, as applicable, to reflect the size of the applicable Company position relative to the survey title match (i.e., in instances in which the benchmarked Company position entails additional responsibilities or lesser responsibilities to the matched role in the Towers Watson survey).

Hay Group also evaluated the compensation for each Executive who holds the title of VP (twelve Executives) by utilizing its job evaluation methodology to measure the internal value of each position's contribution to the organization to

link that value to external market data. The output of Hay Group's job evaluation is a measurement of job size in terms of points, with the following as the three most significant factors in determining a job's size: (i) required knowledge and skills (the required "inputs" for the job), (ii) the kind of thinking needed to solve problems (the required "throughput" for the job) and (iii) the job's impact and end results (the required "outputs" of the job). By assigning evaluation points to each position, Hay Group was able to compare the compensation payable for positions in the external marketplace that require similar experience, management scope and accountabilities as the surveyed position within the Company. Sizing the jobs permits Hay Group to review market data that is often a closer fit to the surveyed position than would be achieved by relying solely on title matching the relevant position to comparable titles in the market. Finally, Hay Group reviewed Hay Group and Towers Watson survey data on executive retirement practices to evaluate the terms and benefit levels provided under the EDP.

Q. 21 Please describe Hay Group's practice for evaluating a client's compensation levels relative to comparator markets.

A. 21 In interpreting a client's compensation levels relative to the market Hay Group typically considers base salary to be competitive if it falls within 10 percent of the market median. Hay Group typically considers TCC and TDC to be competitive if it falls within 15 percent of the market median. It is unusual for individuals' compensation levels to match the market median and reviewing compensation levels relative to a competitive market range is standard industry practice. In instances in which an individual's compensation level falls outside of the competitive market range individual factors applicable to that individual may

1 impact his or her compensation relative to the market, such as tenure and/or
2 performance levels. The relationship between pay and tenure is an important
3 factor for the Company as the average tenure of the Company's Executives is
4 24 years. The Company has a long-tenured and stable executive team who, as
5 discussed below, are delivering superior performance for the Company's
6 customers.
7 Q. 22 What were Hay Group's findings based on its assessment of the Company's
8 public company peer group?
9 A. 22 As a group, the Company's NEOs are below the competitive market range
10 relative to the median with respect to TDC. With respect to base salaries, the
11 NEOs' base salaries in the aggregate are slightly below the peer-group median
12 (6.1% below median) but within the competitive market range. Aggregate TCC
13 and TDC for the Company's NEOs are below the competitive market range of
14 +/-15% of the median (21.9% below median and 29.6% below median,
15 respectively).
16 With respect to MIP and RSUP design, the plans are consistent with peer
17 group incentive plans and include market-competitive terms. The MIP differs
18 from many of the Company's peer group companies in that it pays a portion of
19 the benefit in stock (a majority of peer group companies pay all annual incentive
20 amounts in cash). The mix of financial and non-financial performance metrics
21 in the MIP is a common design among peer group annual incentive plans.
22 However, the Company's RSUP is different in that a majority of peer-company
23 plans include primarily financial and shareholder metrics whereas the
24 Company's RSUP grants are based on a combination of financial and customer-
25 focused metrics.

The Company's SERP is in line with competitive practices in terms of benefit levels and design relative to its peer group companies. Ten of the Company's fifteen peer group companies (66%) offer some form of SERP to their executives; the SERP's benefit levels and accrual rates are consistent with market terms among the Company's peers.

Q. 23 What were Hay Group's findings based on its survey data review for the Executive positions?

A. 23 As a group, the Company's Executives are below the competitive market range relative to the survey data with respect to TDC (27.3% below median in the aggregate). With respect to base salaries the Executives are within competitive market range (9.2% below median in the aggregate) and with respect to TCC the Executives are slightly below the competitive market range in the aggregate (16% below median). With respect to the EDP, Hay Group and Towers Watson survey data indicates that a majority of participating companies in each survey provide an employer matching contribution in executive non-qualified deferred compensation plans and a majority of those plans permit deferrals of base salary plus annual incentives. These features are consistent with the EDP.

IV. COMPENSATION INCLUDIBLE IN CUSTOMER RATES UNDER APPLICABLE GUIDANCE

Q. 24 Should the costs associated with the Company's executive compensation programs be included in customer rates?

A. 24 Yes. As a threshold matter, I note that the Executives' TDC and the executive retirement plans (SERP and EDP) maintained by the Company constitute part of the Total Remuneration ("Total R") package that the Company provides to its Executives. When evaluating the reasonableness of a company's compensation

program, it is important to do so in the context of the Company's Total R package. For example, companies may offer lower incentive opportunities or base salaries in exchange for enhanced benefits such as a defined benefit plan and a SERP. When Hay Group evaluates Total R for its clients we view these programs holistically – how does Total R compare to the market within the context of the client's overall compensation philosophy? Under this approach, we look at individual components of Total R to determine reasonableness of each component but we also evaluate how that component fits within the context of the Total R package.[4] For companies that provide significant benefit programs – such as SERPs and deferred compensation plans – losing or reducing one component of Total R, such as reduced incentive benefits, impacts the analysis of whether the remaining components of Total R are "reasonable" and competitive within the market. For example, as noted above, the majority of the Company's public-company peers offer SERP benefits to their executives; if the Company opted to freeze its SERP and cease providing these benefits going forward, its competitive pay package to attract new talent (and retain existing talent) would lack a key retention program that is prevalent in the market and, in my experience, such a loss would typically be reflected through the enhancements of other Total R components such as higher pay.

It is critical to frame my testimony in the following Q&As regarding individual components of the Company's executive compensation and benefit programs in the broader context of the aggregate Total R package. Hay Group's

[4] See *Benchmark total remuneration, Improve the health of your reward benchmarking*, Hay Group, http://atrium.haygroup.com/downloads/marketingps/ww/HayGroup_Improve_the_health_of_your_reward_benchmarking.pdf. (December 2010).

study shows that the Company's Executive compensation programs and retirement programs are at or below competitive market levels in the aggregate and are reasonable and well-balanced relative to the market and reflect competitive market practices. As noted below, the existing Executive team is providing superior performance for its customers. Given these facts, the Company's recovery of 100% of its reasonable compensation and benefit costs through customer rates to incentivize and retain talent that is delivering superior results for the Company's customers is fair to customers and would not represent a burden to them. Therefore, it is my opinion that, with the exception of 10% of the Company's MIP costs and RSUP costs for awards payable to the Company's President and CEO, its CFO and its SVP, Corporate Development (which awards costs are associated with a non-regulated business segment that is unrelated to the Company's utility customers), 100% of the Company's costs associated with its Executive TDC costs, its MIP and RSUP costs and the costs for its Executive retirement programs (EDP and SERP) are recoverable through customer rates. This approach is consistent with the Commission's recent guidance in reviewing a request from EPCOR Water Arizona, Inc. (EPCOR) to recover compensation costs: "If overall compensation for employees is reasonable, it should be allowed assuming the allocation methods are reasonable. ..."[5]

Q. 25 Is there any data to confirm whether the Company is delivering high-quality customer service?

[5] Decision No. 75268, 2015 Ariz. PUC LEXIS 138 at *58-*59 (September 28, 2015). I address this guidance in more detail below.

A. 25 Yes. The existing Executive team has demonstrated superior customer performance as reflected in high engagement rates of the Company's customers relative to the market. The Company's superior performance for its customers was recently confirmed in an independent, third-party report prepared by Market Strategies International. The 2015 report, entitled *Utility Trusted Brand & Customer Engagement Study: Residential*, summarized the results of interviews with 50,000 utility customers nationwide regarding Brand Trust, Operational Satisfaction and Product Experience (the report focused on residential electric utilities, natural gas utilities and utilities that provided a combination of the two services). The report identified Southwest Gas as one of three "Customer Champion" natural gas utilities in the West and ranked the Company number 6 out of 38 gas utilities that it reviewed nationally for the survey.

Q. 26 Are there additional factors that support the inclusion of MIP costs in customer rates?

A. 26 Yes. The MIP costs, excluding those associated with the Construction Services metric, should be included in customer rates as the MIP incentives provide a direct link between Executive and employee compensation and customer service. The MIP incentivizes management to operate the Company in an efficient manner that minimizes customer rates while maximizing customer satisfaction and safety as follows:

- Customer Satisfaction. This metric is explicitly tied to customer satisfaction and benefits the Company's customers. If the Company's management chose to delay investment in infrastructure to improve its performance on the ROE or Operating Cost Containment metrics, management would risk diminished performance with respect to the Customer Satisfaction metric –

and Safety metric – and consequently the MIP payout with respect to those factors would decline. The Customer Satisfaction metric (as well as the Safety metric) therefore aligns with the MIP financial metrics to ensure that management focuses on financial performance that is enhanced through improved customer welfare. Put another way, if management chooses to emphasize the Company's financial performance to the detriment of its customers, the MIP is designed to penalize management through lower performance on other metrics and lower performance under the MIP over time will further impact performance under the RSUP.

- Customer-to-Employee Ratio. This metric provides a direct benefit to customers: as the Company improves its customer-to-employee ratio it controls costs, which helps it maintain lower rates.
- Safety. This metric provides a direct benefit to customers by focusing on the Company's response time and damages per 1,000 tickets in providing services. The Company added this metric subsequent to its last rate application to the Commission in 2010. The Safety metric enhances the MIP's focus on customers beyond the MIP design in place during the Company's last rate application with the Commission. The MIP's focus on the Company's gas distribution system benefits in senior Executives' incentive programs helps ensure that safety is a priority throughout the organization.
- Operating Cost Containment. Similar to the ROE metric discussed below, this provides a direct benefit to customers by focusing management on controlling costs, which helps the Company keep rates competitive.

- Return on Equity (ROE). Provides a direct benefit to customers because the return metric focuses the Company's management on the efficiency of the Company's operations. By controlling its costs (for example, aggressive pursuit of operational efficiencies, such as automated meter reading) the Company has kept its rates lower for customers while also creating cash for investment in its infrastructure. In short, the Company's efficiency in operations, as measured through ROE, benefits customers.

Q. 27 How does the Company's position with respect to recoverable MIP costs compare to that of the Commission's Utilities Division Staff (Staff) and Residential Utility Consumer Office (RUCO) in previous proceedings?

A. 27 In seeking recovery of 100% of its MIP costs, the Company's position varies from prior positions taken by Staff and RUCO, which each concluded that the Company should be limited to recovery of 50% of its MIP costs. Staff and RUCO proffered variations on two distinct arguments in the Company's past rate applications in proposing a 50 percent disallowance of the Company's MIP costs: (i) the MIP includes at-risk pay that may vary from the costs accrued during the test year (and any reduction in future MIP payments would still require customers to pay for that component of compensation in their rates to the benefit of shareholders) and (ii) the MIP includes financial metrics that primarily benefit shareholders.[6] On the second factor, Staff has argued that "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that

[6] See, e.g., Decision No. 70665, 2008 Ariz. PUC LEXIS 237 (December 24, 2008) at *27-*28 ("Staff witness Smith stated that shareholders and ratepayers stand to benefit from the performance goals, but added that there is no assurance that the award levels achieved during the test year will be repeated in future years" and "RUCO witness Rodney Moore testified that the MIP criteria include elements related to financial performance and cost containment goals, which are goals that primarily benefit shareholders.").

may not encourage the development of safe and reliable utility service at the lowest long-term cost . . . . For example, some maintenance can be temporarily deferred, thereby boosting earnings . . . . But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs."[7] The Commission has found these arguments to be persuasive.[8] In my opinion, the following three factors warrant reconsideration of the Commission's prior rulings on this issue with respect to the MIP.

- First, the MIP metrics cannot be viewed in isolation in determining whether they benefit customers. While the inclusion of financial metrics in the MIP clearly benefits shareholders, the mix of MIP metrics incentivizes management to achieve financial performance through corporate practices that benefit customers by controlling costs and maximizing efficiency while simultaneously maintaining high customer satisfaction and safety ratings. If management pursued a policy of delaying infrastructure improvements to minimize costs (which would potentially improve the MIP financial metrics in the short run) the Company risks deteriorating customer satisfaction and safety ratings, which would impact current and/or future MIP payments and crucially would also impact future RSUP payments, which are based on MIP performance over time. In short, focusing on financial performance metrics in isolation to support the argument that they potentially encourage corporate actions that are detrimental to customers does not account for the integrated design of the MIP's performance metrics, whereby customer-focused metrics

[7] See, e.g., Decision No. 69663, 2007 Ariz PUC LEXIS 126 at *74 (June 28, 2007) (Arizona Public Service Co. rate application).
[8] See Decision No. 70665, 2008 Ariz. PUC LEXIS 237 at *29, n.4 (citing Decision No. 69663 favorably).

provide a clear incentive to management to maximize financial performance in a manner that also maximizes customer welfare. The MIP's integrated performance metrics also benefit customers because the Executives' incentive to pursue operational efficiencies will be reflected in future rate cases through lower overall rate increases.

I further note that the Commission previously approved recovery of 100% of Arizona Public Service Company's (APS) requested annual incentive plan costs when the plan design clearly linked performance to customer benefit, which is consistent with the MIP's design of integrated performance metrics.[9] In a more recent decision addressing a rate application from EPCOR, the Commission approved recovery of 90% of EPCOR's annual incentive plan costs, concluding as follows:

> The real issue in evaluating incentive compensation is whether total compensation, including the incentive pay, is reasonable. If overall compensation for employees is reasonable, it should be allowed assuming the allocation methods are reasonable. ... The evidence in the record does not indicate that the overall compensation requested by EPCOR is excessive or unreasonable. Rather, Staff and RUCO argue that placing a label of "incentive" on a portion of total wages is sufficient to require the disallowance of some or all of that compensation...[10]

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[9] See Decision No. 69663, 2007 Ariz. PUC LEXIS 126 at *72-*75 (adopting Staff recommendation that "the costs of the cash-based incentive plan be included in rates because the [test year] level of those costs was tied to performance measures that benefit APS' customers" notwithstanding the fact that "corporate earnings serve as a threshold or precondition to the payout ....").

[10] Decision No. 75268, 2015 Ariz. PUC LEXIS 138 at *58-*59 (September 28, 2015). The Commission's analysis is consistent with the approach taken by the California Public Utilities Commission (CPUC), which reviews the Company's rate applications for costs associated with its California operations. For example, in a rate case decision that addressed incentive compensation cost recovery requested by Pacific Gas & Electric Company, the CPUC concluded that "... incentive pay is part and parcel of the overall compensation scheme" and further cited favorably to the conclusions reached in a workshop held by CPUC staff: "The consensus reached in the workshop was that the [CPUC] should not attempt to micromanage utility incentive compensation programs. Instead of adopting a 'cookie cutter' approach, workshop participants recommend that the [CPUC] review incentive compensation programs utility by utility, as a component of the total cash compensation requested in each utility's general rate case. They proposed, moreover, that the allocation of total cash compensation between salaries and incentives should be left to each utility's discretion." Decision No.92-12-057, 1992 Cal. PUC LEXIS 971 (December 16, 1992) at *126-*127.

As noted above, the Company is not seeking to recover its MIP and RSUP costs that are associated with a non-regulated business segment; I believe the remaining MIP costs are recoverable and the plan's design is consistent with the incentive plan at issue in the APS rate case because the performance measures are aligned to benefit customers.[11]

- The second factor that justifies a result different from the Commission's prior rulings is that the Company added a new Safety metric to the MIP that has a target weighting of 20% for all participants. This change further strengthens the link between performance and customer benefit, as discussed above. Therefore even if the Commission accepts the position that financial metrics primarily benefit shareholders to the potential detriment of customers (which I do not believe to be the case for the MIP for the reasons set forth above) the current MIP design places greater weighting on non-financial metrics than the MIP design reviewed by the Commission in the Company's last rate application in which the Commission approved recovery of 50% of the Company's MIP costs. The Commission's recent decisions approving recovery of all costs associated with non-financial metrics suggest that the Company should be entitled to recover more than 50% of its costs associated with the MIP (i.e., the percentage approved by the Commission in the Company's last rate application) in light of the design updates since its last rate application.
- A third factor that justifies a result different from the Commission's prior rulings is that historical performance indicates that, while MIP payouts vary

[11] See Decision No. 69663, 2007 Ariz. PUC LEXIS 126 at *75-*76.

from year-to-year, annual MIP payments over time typically equal or exceed target performance and there is no material risk of a windfall to shareholders by having customers pay for incentive payments in rates that may be materially lower in future years. For example, during the 10-year period covering plan years 2005-2014, the average MIP payout was approximately 110.9% of target. Historical performance suggests that recovery of the Company's MIP costs will not result in a windfall to shareholders over a multi-year period.

In sum, it is my professional opinion that the MIP metrics cannot be viewed in isolation in determining the incentives that the metrics provide to Executives and employees and, reviewing the metrics as a whole, they provide a clear incentive to MIP participants to maximize financial performance in a manner that also benefits customers. The MIP has been enhanced since the Company's last rate application to further focus on customer welfare with the inclusion of a Safety metric. Finally, past performance under the MIP strongly suggests that permitting recovery of MIP costs does not present a material risk of a windfall to shareholders by having customers pay for incentive payments that may be materially lower in future years. Given these factors and the fact that the MIP constitutes part of a reasonable compensation package for Company Executives and is reasonable in design, I believe the costs associated with the MIP are recoverable through customer rates.[12]

[12] As noted above, the Company's MIP costs associated with the Construction Services performance metrics for three senior Executives (weighted at 10% of their target MIP award opportunity) should be excluded from recovery through customer rates.

Q. 28 Are there additional factors that support the inclusion of RSUP costs in customer rates?

A. 28 Yes. Before addressing the additional factors that I believe warrant recovery of the Company's RSUP costs, I note that Staff and RUCO have taken the position in the Company's past rate cases that 100% of the Company's RSUP costs should be disallowed, relying in part on past Commission rulings to the effect that "stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price."[13] The Commission has agreed with this position and disallowed recovery of RSUP costs in the Company's past rate applications.[14] For the reasons set forth below, it is my opinion that the RSUP design mitigates the concerns articulated by the Commission in its past rulings.

- The first factor that differentiates the RSUP design from the majority of stock-based LTI awards is that RSUP award amounts are determined based upon past performance under the MIP versus prospective performance measures that potentially implicate the concerns articulated by the Committee with

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[13] See Testimony of Ben Johnson, Ph.D., on Behalf of the Residential Utility Consumer Office, Docket No. G-01551A-10-0458 (June 10, 2011) at 42 (citing Commission Decision No. 64172 at 16, n.4); see also Public Direct Testimony of Ralph C. Smith on Behalf of the Utilities Division Staff, Arizona Corporation Commission, Docket No. G-01551A-10-0458 (June 10, 2011) at 31 (citing a prior Commission ruling that "[w]e agree with Staff that APS' stock-based compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate.") (citing Decision No. 69663 at 36).

[14] See, e.g., Decision No. 70665, 2008 Ariz. PUC LEXIS 237 at *29 n.4 ("On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP") [the Company's equity plan]. The costs related to similar incentive plans were recently rejected for APS and UNS Electric. ... As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price.").

respect to a performance-vested LTI award (e.g., financial and/or shareholder-focused performance metrics that potentially incentivize corporate behaviors that are detrimental to customers). The RSUP rewards Executives and employees for sustained performance with respect to MIP performance metrics and the Commission has consistently concluded the MIP metrics provide some benefit to the Company's customers.[15] The fact that the RSUP rewards Executives and employees for performance with respect to the same MIP incentive metrics that the Commission has determined benefit customers supports the conclusion that the Company's RSUP program also benefits the Company's customers and at least some portion of the costs associated with the program should be recoverable through customer rates.

The RSUP design is very unique in this respect, as demonstrated by a review of the LTI programs maintained by the Company's public-company peers. The performance equity awards of the peer-group companies focus almost entirely on prospective shareholder returns and financial metrics such as Earnings per Share (EPS) and EPS Growth.[16] The peer-companies' prospective LTI performance metrics, which are tied largely to the future stock performance, are much closer in design to the concerns expressed by the Commission regarding stock awards than Southwest Gas' RSUP performance metrics.

- A second, related, factor regarding the RSUP is that the Company's compensation costs for both the stock-based MIP awards and the RSUP awards

[15] See, e.g., Decision No. 70665, 2008 Ariz. PUC LEXIS 237 at *27-*29.
[16] See Confidential Exhibit___ (BTH-1).

is fixed on the date of grant under FASB Account Standards Codification Topic 718 (ASC 718). This is critical because the stock-related costs that the Company is seeking to recover from Customers with respect to the RSUP are unrelated to the Company's financial performance following the date of grant (as contrasted with the LTI awards granted by a significant majority of the Company's public-company peers with market-based vesting terms that will impact the compensation costs accrued for the awards).[17] In this respect the Company's stock-related costs with respect to the RSUP are determined in the same manner as its costs for the MIP. Given that the majority of MIP awards were payable through stock when the Commission previously reviewed the MIP costs and the Commission permitted the Company to recover 50% of its MIP costs,[18] the Commission has already permitted the Company to recover some of its stock-based compensation costs under an arrangement that is identical to the RSUP (that is, time-vested restricted stock units).

- Finally, it is my experience that restricted stock units provide strong retention incentives for participants who receive those awards. Because the awards are not tied to performance metrics, which may or may not be achieved, a participant knows that the award will deliver value in the future based on continued service. For this reason time-vested awards such as restricted stock units are often granted by companies as part of a portfolio of long-term

[17] For a discussion of the application of ASC 718 to equity awards, see *Accounting for Stock Compensation under FASB ASC Topic 718*, Frederic W. Cook & Co., Inc. (September 2, 2009), link at http://fwcook.com/alert_letters/09-02-09_ORIGINALLY-4-29-05_-Accounting-for-Stock-Compensation-Under-FASB-ASC-Topic-718.pdf. I note that, under ASC 718, the Company must reverse expenses for any RSUP awards that are forfeited due to failure to satisfy the service vesting condition following the date of grant. The Company's average Executive tenure of 24 years indicates that historical forfeitures of time-vested RSUP awards are minimal.

[18] For example, in Decision No. 70665, the Commission approved recovery of 50% of the Company's MIP costs and the majority of the Company's MIP costs (60%) were incurred with respect to the stock component of the MIP. See 2008 Ariz. LEXIS PUC 237 at *27-*29.

incentive vehicles that balance performance and retention considerations; this is a common approach taken by the Company's public peer group.[19] In light of these considerations, I believe the RSUP design benefits the Company's customers by providing significant retention incentives for the Company's high performing Executives and employees. While the Company could presumably revise its program to pay cash awards based on prior performance under the MIP (thereby avoiding the Commission's concerns regarding stock-based compensation under the RSUP) I believe such a design would hurt, rather than help, customers due to the loss of retention incentives.

- Based on the foregoing and the fact that the RSUP constitutes part of a reasonable total compensation package for the Executives, I believe that the Company's RSUP costs should be recoverable through customer rates as a reasonable and necessary component of the Company's overall compensation package. Hay Group's study concluded that these pay components are reasonable and in line with the market, as noted above. At a minimum, the RSUP costs should be recoverable to the same extent the Company is permitted to recover MIP costs.

Q. 29 Are there additional factors that support the inclusion of the Company's costs associated with the EDP and SERP in customer rates?

A. 29 Yes. As discussed above, the Company has long-tenured executives who have demonstrated high performance for the Company's customers. The EDP and

[19] As noted in Hay Group's study of the LTI designs among the Company's public-company peer group, the majority of peer group companies grant both performance-vested units and time-vested restricted stock units as part of a portfolio of equity vehicles.

SERP allow the Company to attract and retain these high performing individuals by providing supplemental retirement benefits as part of a competitive compensation package. For example, the average age and tenure of the Company's Executives (age 52 with 24 years of service, respectively) makes the SERP a strong retention tool for the Executive team to remain employed with the Company to vest in their SERP benefits. This continuity of service benefits the Company's customers and the EDP and SERP, which constitute part of the Company's reasonable compensation program for its Executives, should be recoverable through customer rates. Permitting the Company to recover at least some portion of its EDP and SERP costs would be consistent with recent guidance issued by the regulatory commissions in the Company's Nevada and California jurisdictions.[20]

Q. 30 Does this conclude your prepared direct testimony?

A. 30 Yes.

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[20] See Docket Nos. 12-02019 and 12-04005, 2012 Nev. PUC LEXIS 214 at *114-*117 (permitting the Company to recover the portion of its SERP costs that restore benefits that Executives lose under the Company's qualified retirement plans due to IRC limits and disallowing recovery of SERP benefits in excess of the IRC limits, under the rationale that "the SERP benefit which allows executive personnel to receive a retirement benefit, as a percentage of salary, equal to other employees, to be a fair cost for recovery in rates."); Decision No. 14-06-028, *ALTERNATE PROPOSED DECISION ADOPTING TEST YEAR 2014 GENERAL RATE INCREASES FOR SOUTHWEST GAS CORPORATION'S SOUTHERN CALIFORNIA, NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTIONS* (June 12, 2014) at 53-55 (concluding that 50% of the Company's SERP and EDP costs are recoverable through rates as beneficial to both ratepayers and shareholders and noting about the SERP that "[t]hese plans ... provide ratepayers with the benefit of having a continuity of executives and managers who are familiar with the corporate culture and the policies and objectives of the companies. For those reasons, it is reasonable and appropriate for ratepayers and shareholders to equally share in these costs".).

SUMMARY OF QUALIFICATIONS
BRIAN T. HOLMEN

Brian Holmen serves as the West Region Leader of Hay Group's Board Solutions group, which advises Boards of Directors and management on all facets of director and executive compensation and governance issues. In this role, Brian assists a variety of entities with benchmarking of executive compensation levels, determining appropriate pay structures, designing incentive compensation programs and advising with respect to governance and disclosure issues. Brian also advises clients with respect to tax, accounting and legal implications of compensation arrangements, including with respect to ERISA and state employment laws. Brian has over 13 years of experience advising clients regarding compensation arrangements.

Prior to joining Hay Group, Brian served as an executive compensation partner with the global law firm Jones Day. Brian also served as a compensation and benefits attorney with Morrison & Foerster LLP and clerked for a federal district court judge in Virginia. He is a veteran of the U.S. Navy.

Brian is a frequent speaker on executive compensation issues, including recent events hosted by NASDAQ/Equilar, Global Equity Organization (GEO), Financial Times Outside Director Exchange (FT-ODX), and the Advanced Employment Issues Symposium (AEIS). He is also a member of the Board of Directors of the Orange County chapter of the National Association of Stock Plan Professionals (NASPP) and is a member of the National Association of Corporate Directors (NACD).

Brian received a Bachelor's degree in Economics with Highest Honors from the University of California, Santa Cruz, and received his Juris Doctorate from the College of William & Mary. Brian served as the Editor-in-Chief of the *William & Mary Law Review* and graduated with Order of the Coif honors, which is reserved for the top ten percent of the

graduating class. Brian holds a Certified Executive Compensation Professional (CECP) certification through WorldatWork.

Exhibit BTH-1

CONFIDENTIAL

Filed Under Seal

Tab F

Direct Testimony

of

Dane A. Watson

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY

OF

DANE A. WATSON

ON BEHALF OF

SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
Prepared Direct Testimony
of
DANE A. WATSON

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Exhibit No.___(DAW-1)

Exhibit No.___(DAW-2)

Exhibit No.___(DAW-3)

Exhibit No.___(DAW-4)

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
DANE A. WATSON

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Dane A. Watson, and my business address is 1410 Avenue K, Suite 1105B, and Plano, Texas 75074. I am a Partner of Alliance Consulting Group. Alliance Consulting Group provides consulting and expert services to the utility industry.

Q. 2 What is your educational background?

A. 2 I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University.

Q. 3 Are you certified as a depreciation expert?

A. 3 Yes. The Society of Depreciation Professionals (the Society) has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I have met all requirements and have been recognized as a Certified Depreciation Professional (CDP).

Q. 4 Please outline your experience in the field of depreciation.

A. 4 Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation and certain accounting-related studies for

utilities in various industries. My duties relate to preparing depreciation studies and include (1) assembling and analyzing historical and simulated data, (2) conducting field reviews, (3) determining service life and net salvage estimates, (4) calculating annual depreciation, (5) presenting recommended depreciation rates to utility management for its consideration, and (6) supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities (TXU). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute (EEI) Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer (PE) in the State of Texas and, as previously noted, have meet the requirements for the Certified Depreciation Professional. I am a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE) and have held numerous offices on the Executive Board of the Dallas Section, Region and World-wide offices of IEEE. I have served as President of the Society of Depreciation Professionals twice, most recently in 2015.

Q. 5 Have you previously testified before any regulatory commissions?

A. 5 Yes. I have appeared before numerous state and federal agencies in my 31 year career in performing depreciation studies. I have conducted more than 150 depreciation studies, filed written testimony and/or testified before 30 regulatory

commissions. My Statement of Qualifications, along with a complete listing of my testimony appearances is found in Exhibit No.___(DAW-1).

II. PURPOSE OF DIRECT TESTIMONY

Q. 6 What is the purpose of your direct testimony in this proceeding?

A. 6 I sponsor and support the depreciation study performed for Southwest Gas Corporation (Southwest Gas or the Company).

Q. 7 Are you sponsoring any exhibits in this proceeding?

A. 7 Yes. I sponsor the following exhibits:

- DAW-1 – Dane A. Watson Statement of Qualifications and Testimony Appearances
- DAW-2 – Southwest Gas – Arizona Depreciation Rate Study at December 31, 2015
- DAW-3 – Southwest Gas System Allocable Depreciation Study
- DAW-4 – Existing Versus Approved System Allocable Depreciation Rates

Q. 8 Were these exhibits prepared by you or under your supervisions and control?

A. 8 Yes.

Q. 9 When did the last changes in the Company's depreciation rates occur?

A. 9 A depreciation study was filed for the Company's Southern Arizona and Central Arizona rate jurisdictions using data as of December 1988. These rates were effective January 1990. In Decision No. 60352, the Commission authorized the consolidation of the Southern and Central Arizona rate jurisdictions into the current Arizona rate jurisdiction. A weighted average of the existing depreciation rates by jurisdiction was used to develop the depreciation rates for the new combined Arizona rate jurisdiction. These rates were effective September 1997. No depreciation study has been filed since the 1988 study.

Q. 10 Do the depreciation studies you sponsor in this case reflect the most current data available for Southwest Gas' assets?

A. 10 Yes. The data used reflects the most recent experience and future expectations for life and net salvage characteristics for assets in Southwest Gas' Arizona rate jurisdiction as of December 31, 2015.

Q. 11 What definition of depreciation did you use for the purposes of conducting a depreciation study and preparing your testimony?

A. 11 The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. Upon retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. 12 Please describe your depreciation study approach.

A. 12 I conducted the depreciation studies in four phases as shown in my Exhibit No.___(DAW-2). The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the study, I collected historical data to be used in the analysis. After the data was assembled, I performed analyses to determine the life and net salvage percentage for the different property groups

being studied. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the study results, was then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans should be applied. Using all of these resources, I then calculated the depreciation rate for each function.

Q. 13 What depreciation methodology did you use in calculating the proposed rates for Arizona plant?

A. 13 The straight-line (method), Average Life Group (ALG) (procedure), and remaining-life (technique) depreciation system was employed to calculate annual and accrued depreciation in these studies.

Q. 14 How are the depreciation rates determined using the ALG procedure?

A. 14 In the ALG system, the annual depreciation expense for each account is computed by dividing the original cost of the asset, less allocated depreciation reserve, less estimated net salvage, by its respective remaining life. The resulting annual accrual amount of depreciable property within an account is divided by the original cost of the depreciable property in the account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. For each of the studies, the comparison of the current and recommended annual depreciation rates is shown in my Exhibit No.___(DAW-2), Appendix B. The

remaining life calculations are discussed below and are shown in Exhibit No.___(DAW-2), Appendix A.

Q. 15 What factors influence the depreciation rates for an account?

A. 15 The primary factors that influence the depreciation rate for an account are: (1) the remaining investment to be recovered in the account, (2) the depreciable life of the account, and (3) the net salvage for the account.

Q. 16 Please describe the Company's request in regards to the amortization of reserve deficit for general plant amortized assets.

A. 16 The Company seeks to implement "Vintage Group Amortization" in this depreciation study.

Q. 17 Please describe the Vintage Group methodology.

A. 17 For general plant in accounts 391-398, the Company is requesting to implement to use a vintage year accounting method approved by the FERC in Accounting Release Number 15 ("AR-15"), Vintage Year Accounting For General Plant Accounts, dated January 1, 1997. AR-15 allowed utilities to use a simplified method of accounting for general plant assets, excluding structures and improvements (referred to as "general plant"). The AR-15 release allowed high-volume, low cost assets to be amortized over the associated useful life, eliminated the need to track individual assets, and allows a retirement to be booked at the end of the depreciable life. This method is often referred to as "amortization of general plant."

Adopting the method of accounting allowed in AR-15 changes the level of detail maintained in the asset records and performs the depreciation calculation at a vintage level rather than at a total account level. The plant asset balances will be maintained by vintage installed with the retirement being recorded when

book depreciation has been completed. The empirical retirement data for actuarial or semi-actuarial analysis will no longer be reliable; however, the determination of useful life can be made appropriately with the use of market forces, manufacturer expected life, technological obsolescence, business planning, known causes of retirement, and changes in expected future utilization.

The depreciation calculation uses a useful life applied to a vintage versus the entire account. The depreciation recovery is complete when the vintage accumulated depreciation is equal to the vintage plant adjusted for estimated salvage and removal costs.

Q. 18 Please describe the methodology or technique employed in analyzing the life of Vintage Group property.

A. 18 I performed actuarial life analysis on each account. The results of the actuarial life analysis, together with my professional judgment, formed the basis of the proposed life for these accounts. The lives being proposed reflect more recent experience and Company information and set an appropriate recovery period for the assets going forward.

Q. 19 Please describe the results of the Vintage Group depreciation study.

A. 19 The Company's current depreciation rates were compared to the Depreciation Study recommendations in Appendix B of the depreciation studies. The rates proposed for Vintage Group Arizona property are an increase of $1.5 million based on plant balances as of December 31, 2015 when compared with the Company's current depreciation rates. The relevant computations are shown in Appendix A-1 of Exhibit No.___(DAW-2).

Q. 20 Please summarize your conclusions.

A. 20 The Southwest Gas depreciation studies and analysis that I have performed support establishing depreciation rates at the level recommended in my testimony. The Arizona depreciation rate study is attached to my testimony as Exhibit No.___(DAW–2). The Arizona study shows that a decrease in the annual depreciation expense for Southwest Gas' assets of approximately $42.0 million per year is needed to ensure that the appropriate amount of depreciation expense is collected by the Company. The increase in life and decrease in removal cost experienced by the Company in Account 376 Mains and the increase in life for Account 380 Services and decrease in its removal cost, along with the resulting change in the reserve position are the primary drivers for the decrease in expense.

These depreciation expense amounts in my Depreciation Study were determined by comparing the calculated depreciation expense using the current rates and the proposed rates as shown in Appendix B of Exhibit No.___ (DAW-2).

III. SOUTHWEST GAS – ARIZONA DEPRECIATION STUDY

Q. 21 What property is included in the depreciation study?

A. 21 There are two general classes, or functional groups, of depreciable property: Distribution Plant and General Plant property. The Distribution Plant functional group primarily consists of lines and associated facilities used to distribute gas within the areas served by Southwest Gas Arizona. General Plant property, both depreciated and amortized, is not location specific but is used to support the overall distribution of gas to its customers.

Q. 22 Do you have an initial observation about Southwest Gas' Arizona depreciation expense?

A. 22 Yes. The Arizona depreciation expense is decreasing from previously approved levels as shown on Exhibit No.___(DAW-2), Appendix B. Appendix B shows the approved and proposed annual depreciation rates and accruals for each account.

Q. 23 Why is Southwest Gas' Arizona depreciation expense decreasing?

A. 23 Minor adjustments in life and net salvage factors for various accounts influenced the depreciation expense change as discussed later and in Exhibit No.___(DAW-2). The most significant changes in the accrual amount were seen in Accounts 376 and 380. The increase in life and decrease in cost of removal for Distribution Account 376, Mains; and the increase in life for Distribution Account 380, Services along with the resulting reserve position, are the primary reasons for the decrease in depreciation expense.

Q. 24 What method did you use to analyze historical data to determine life characteristics?

A. 24 All accounts were analyzed using the retirement rate method (actuarial) analysis to estimate the life of property. This is the most appropriate method when aged retirement data is available. In much the same manner as human mortality is analyzed by actuaries, depreciation analysts use models of property mortality characteristics that have been validated in research and empirical applications. Further detail is found in the life analysis section of Exhibit No.___(DAW-2).

Q. 25 How did you determine the average service lives for each asset group?

A. 25 Specifically, the service life for each account within the Distribution and General functional groups was determined by using the actuarial method of life analysis.

Graphs and tables supporting the actuarial analysis and the chosen Iowa Curves used to determine the average service lives for each account are found in Exhibit No.___(DAW-2) and my depreciation study workpapers. A summary of the depreciable life for each account is shown in Exhibit No.___(DAW-2), Appendix C.

Q. 26 What is the significance of an asset's useful life in your depreciation study?

A. 26 An asset's useful life was used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread it ratably over future periods.

Q. 27 Please describe some of the changes in the average service lives for the various accounts?

A. 27 The detailed analysis of each account is described fully in Exhibit No.___ (DAW-2). Examples of some of the changes in average service lives are:

- The largest decrease was a change in life of 18 years for two accounts: Distribution Account 381 – Meters and Account 394 Tools, Shop and Garage Equipment.
- The largest increases were a change in life of 15 years in Accounts 374.20 – Rights of Way and 378–Measuring and Regulating Station Equipment.
- Overall, 8 accounts experienced some level of decrease in average service life while 8 accounts experienced a lengthening of average service life. The remaining accounts were unchanged.

Q. 28 What is net salvage?

A. 28 While discussed more fully in the study itself, net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost

(cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of the addition versus the retirement. For example, a Distribution asset in FERC Account 376 with a current installed cost of $500 (2015) would have had an installed cost of $41.23[1] in 1962. If one were to calculate removal cost as a percent of current cost, a removal cost of $50 for the asset would only have a -10 percent removal cost ($50/$500). This would be incorrect. A correct removal cost calculation would show a negative 121 percent removal cost for that asset ($50/$41.23). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

Q. 29 How did you determine the net salvage percentages for each asset group?

A. 29 The net salvage as a percent of retirements for various bands (i.e. groupings of years such as the three-year, five-year or 10-year average) for each account is shown in my Exhibit No.___(DAW-2), Appendix D. The historical experience, input from Company experts and judgment were used to select a net salvage percentage that represents the future expectations for each account.

Q. 30 Is this a reasonable method for determining net salvage rates?

A. 30 Yes. The method used to establish appropriate net salvage percentages for each account was determined by using the same methodology which is the basis

[1] Using the Handy-Whitman Bulletin No. 182, G-5, line 44, $41.23 = $500 x 63/764.

for the current approved rates used by Southwest Gas. It is also a methodology commonly employed throughout the industry and is a method recommended in authoritative texts.

Q. 31 Please describe some of the changes in the net salvage percentages for the various accounts.

A. 31 The detailed analysis of each account is described fully in Exhibit No.___ (DAW-2). Examples of some of the changes in net salvage are:

- The largest increases (i.e. less negative) in net salvage were in Distribution Accounts 380 – Services and 376 – Mains. Net salvage moved from a negative 96 percent to negative 45 percent for Account 380 and from a negative 60 percent to a negative 30 percent for Account 376.
- The largest decrease (i.e. more negative or less positive) is in Distribution Account 393 – Stores Equipment This change is due to a 20 percent net salvage as existing and to 0 percent net salvage.
- Overall, 8 accounts experienced some level of increase (less negative) in net salvage while 4 accounts experienced a decrease (more negative or less positive) in net salvage. The remaining accounts were unchanged.

IV. SOUTHWEST GAS – SYSTEM ALLOCABLE DEPRECIATION STUDY

Q. 32 Please describe the depreciation study the Company is using for its system allocable plant.

A. 32 The Company is utilizing the System Allocable depreciation study that was filed in the Company's most recent Nevada general rate case in Docket No. 12-04005. Utilizing the System Allocable depreciation study that is prepared pursuant to the Nevada requirement, that depreciation studies be filed at least once every six years, is consistent with prior Arizona rate cases.

Q. 33 Did you sponsor the system allocable depreciation study filed in Docket No. 12-04005?

A. 33 Yes, I did. A schedule showing the previous versus approved depreciation rates and the study related to those rates are attached as Exhibit No.___(DAW-3) and Exhibit No.___(DAW-4), respectively.

V. CONCLUSION

Q. 34 What account depreciation rates are you proposing, and how do they compare with the current rates?

A. 34 The current depreciation rates and the rates I am now proposing related to Arizona are found in my study, at Exhibit No.___(DAW-2). Detailed calculations of these rates are also included at Exhibit No.___(DAW-2).

Q. 35 Do you have any concluding remarks?

A. 35 Yes. The depreciation study and analysis performed under my supervision fully support setting depreciation rates at the level I have indicated in my testimony. The depreciation study for Southwest Gas' Arizona depreciable property as of December 31, 2015 describes the extensive analysis performed and the resulting rates that are now appropriate for Company property. Depreciation rates set at my recommended amounts will allow the Company the opportunity to recover its total investment in property over the estimated remaining life of the assets.

Q. 36 Does this conclude your prepared direct testimony?

A. 36 Yes.

Statement of Qualifications

Dane A. Watson

I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University.

The Society of Depreciation Professionals ("the Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I met all requirements and have become a Certified Depreciation Professional ("CDP").

I have been a member of the Society of Depreciation Professionals Training Faculty since 2005. I developed and teach the capstone class, "Preparing and Defending a Depreciation Study" and "Engineering Aspects of a Depreciation Study". I also teach depreciation to participants from the American Gas Association and Edison Electric Institute and for the Michigan State University Regulatory Conference. I have also provided training to state commissions at the request of various regulatory bodies.

Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation and certain accounting-related studies for utilities in various industries. My duties relate to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer ("PE") in the State of Texas and a Certified Depreciation Professional. I am a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE) and have held numerous offices on the Executive Board of the Dallas Section, Region and World-wide offices of IEEE. I currently serve as Treasurer of the Member and Geographic Unit Business Unit and serve on the IEEE Finance Committee. I have served as President of the Society of Depreciation Professionals twice, most recently in 2015.

Over the course of my career, I have testified in more than 125 proceedings before 30 regulatory bodies, both state commissions and FERC. A list of my testimony appearances before various regulatory bodies is provided below.

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	SPS NM	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	SPS NM	2015	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint-Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Xcel Energy	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power-Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	SPS	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Minnesota Northern States Power	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Texas	Texas Commission on Environmental Quality	Matter 37050-R	Southwest Water Company	2011	WasteWater Depreciation Study
Texas	Texas Commission on Environmental Quality	Matter 37049-R	Southwest Water Company	2011	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
California	California Public Utility Commission	A10071007	California American Water	2009-2010	Water and Waste Water Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Wyoming	Wyoming Public Service Commission	30022-148-GR10	Source Gas	2009-2010	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service of Colorado	2009	Electric Depreciation Study
Tennessee	Tennessee Regulatory Authority	11-00144	Piedmont Natural Gas	2009	Gas Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	35763	SPS	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	SPS	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service of Colorado	2006	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas, New Mexico	Public Utility Commission of Texas	32766	Xcel Energy	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciaiton Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

SOUTHWEST GAS CORPORATION

ARIZONA RATE JURISDICTION

DEPRECIATION RATE STUDY

AT DECEMBER 31, 2015

ALLIANCE
CONSULTING GROUP

http://www.utilityalliance.com

SOUTHWEST GAS CORPORATION
ARIZONA RATE JURISDICTION
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Southwest Gas Corporation ("Southwest Gas" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Arizona utility plant depreciable assets as of December 31, 2015.

This study was conducted under the traditional depreciation study approach. The net salvage analysis in this study paralleled the approach previously used by Southwest Gas in its existing depreciation rates, using broad group, average life remaining life depreciation.

Life and net salvage characteristics show change from the existing depreciation rates. Eight accounts show an increase in life, and eight accounts show a decrease in life, with the rest being unchanged. Eight accounts showed an increase in net salvage, and four accounts showed a decrease in net salvage. The Company's largest accounts in the distribution function show a less negative net salvage.

This study proposed to adopt FERC Accounting Release 15 ("AR-15") issued by the Federal Energy Regulatory Authority ("FERC") for many of the Company's general plant accounts. Appendix A-1 demonstrates those computations in depreciation expense.

This study recommends an overall decrease of $42.0 million in annual depreciation expense compared to the depreciation rates currently in effect. Appendix B demonstrates the change in depreciation expense for the various accounts.

SOUTHWEST GAS CORPORATION
ARIZONA RATE JURISDICTION
DEPRECIATION RATE STUDY
AT DECEMBER 31, 2015

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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on Southwest Gas' books at December 31, 2015 for its Arizona rate jurisdiction. The account based depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of Arizona property on a straight-line basis. Non-depreciable property and property which is amortized such as intangible software were excluded from this study.

The Arizona rate jurisdiction of Southwest Gas provides local gas distribution service to municipalities in Arizona. Southwest Gas owns distribution mains, and various other plant assets. Southwest Gas' assets consist of a complex system of intermediate and low pressure distribution networks located across the service area. There are a number of receipt points throughout the system where gas is delivered by the transmission system. Once gas is metered into individual cities, the pressure is reduced through regulators in order to meet system requirements as determined by pressure and volume needs. Then gas is delivered to customers for burner tip consumption.

Southwest Gas is the largest distributor in Arizona, selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas. The Arizona rate jurisdiction encompasses the central and southern regions of the state including the metropolitan areas of Phoenix and Tucson. The Arizona rate jurisdiction has approximately $2.8 billion in gross depreciable assets and includes more than one million services and 19,000 miles of mains. Distribution mains and services are more than $2.3 billion. There are approximately 5,500 miles of steel mains.

The gas plant investment history for Southwest Gas Arizona consists primarily of two acquisitions, plus additions since those acquisitions. In 1979, the Company acquired the gas properties of Tucson Gas and Electric

Company (TEPCO) and in 1984 it acquired the gas properties of Arizona Public Service (APS). In the more than 30 years since these two acquisitions, the Company has increased the gas plant investment significantly. In 1979, the TEPCO acquisition was combined with the existing Arizona properties to form the southern Arizona rate jurisdiction. In 1984, the APS acquisition formed the central Arizona rate jurisdiction. Subsequent additions to each jurisdiction were based on geographical boundaries. A depreciation study was filed for each jurisdiction using data as of December 1988. These rates were effective January 1990. In the mid-1990s, the two jurisdictions were combined into the current Arizona rate jurisdiction. A weighted average of the existing depreciation rates by jurisdiction was used to develop the depreciation rates for the new combined rate jurisdiction. These rates were effective September 1997. No depreciation study has been filed since that time.

STUDY RESULTS

Overall depreciation rates for all Southwest Gas - Arizona depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $81.5 million based on Southwest Gas' depreciable investment at December 31, 2015. The annual equivalent depreciation expense calculated by the same method using the approved rates was approximately $123.5 million. Appendix A demonstrates the development of the annual depreciation rates and accruals. Appendix B presents a comparison of approved rates versus proposed rates by account. Appendix C presents a summary of mortality and net salvage estimates by account.

Consistent with FERC Rule AR-15, this depreciation study develops depreciation expense for Vintage Group Amortization in Accounts 391-398. This process provides for the amortization of general plant over the same life as recommended in this study. At the end of the amortized life, property will be retired from the books. Implementation of this approach will not affect the annual expense accrued by Southwest Gas and provides for the timely retirement of assets and the simplification of accounting for general property. Vintage Group Amortization is widely used across the utility industry.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

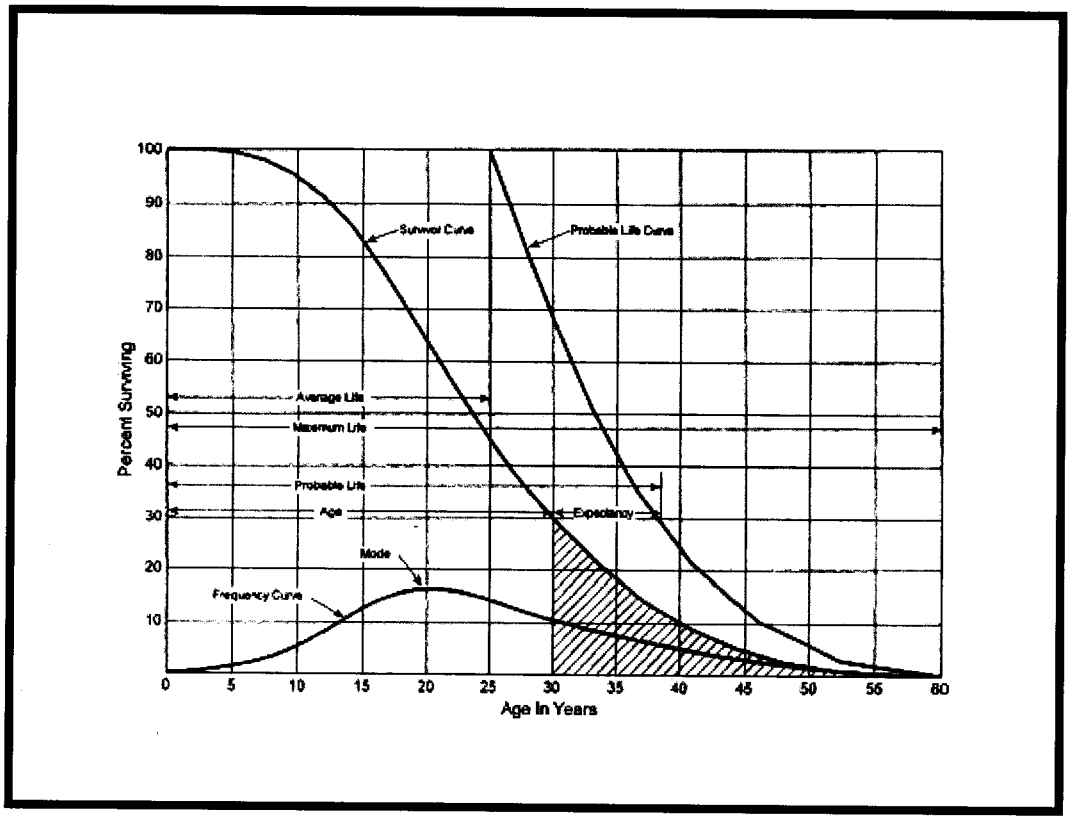
Basis of Depreciation Estimates

The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A and remaining life calculations are shown in Appendix B.

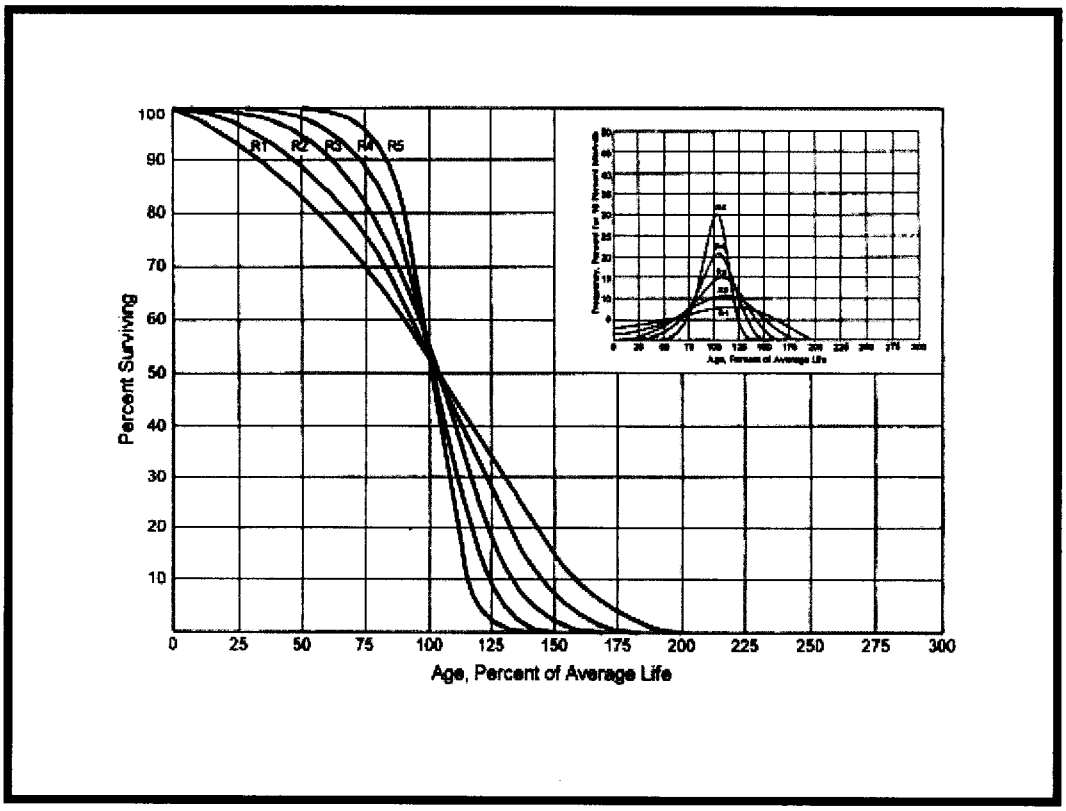
Actuarial analysis was used with each account within a function where sufficient data was available, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of "R" moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an

"L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the Distribution and General Plant accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

Southwest Gas was authorized to use the average life group ("ALG") in its existing depreciation rates. At the request of Southwest Gas, this study continues to use ALG depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG groups are defined by their respective account dispersion, life, and salvage estimates. A straight-line rate for each ALG group is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense and dividing the annual depreciation expense by the surviving investment. The resultant rate for each ALG group is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net book cost over the life of each account by averaging many components.

Theoretical Depreciation Reserve

The book depreciation reserve was allocated among accounts through use of the theoretical depreciation reserve model. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and the documenting the corresponding recommendations.

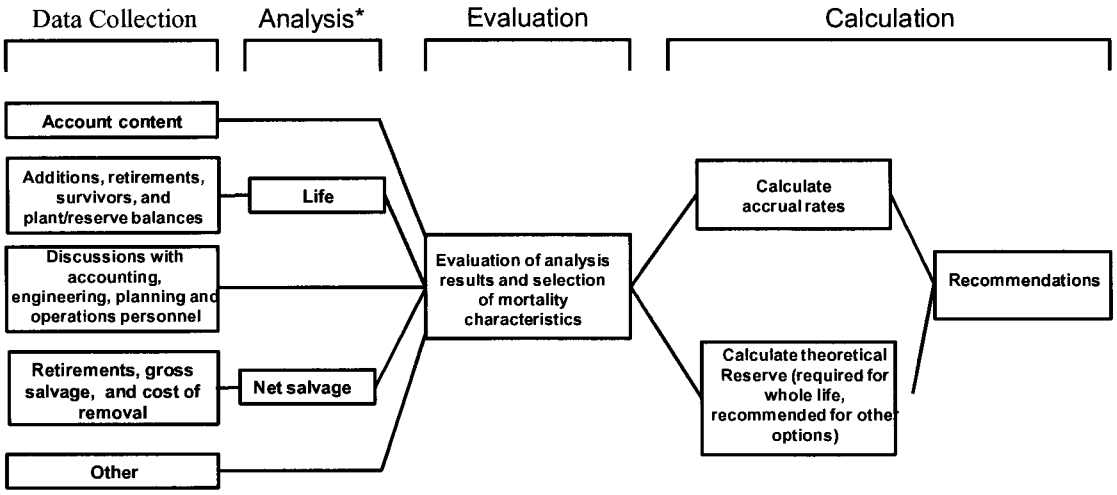
During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis and salvage analysis sections and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[1] documents the steps used in conducting this study. Depreciation Systems[2], page 289 documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, and document recommendations.

[1] Introduction to Depreciation for Public Utilities & Other Industries, AGA EEI 2013
[2] Depreciation Systems, by W. C. Fitch and F.K.Wolf, Iowa State Press, 1994, page 289.



Source: Introduction to Depreciation for Public Utilities and Other Industries, AGA EEI , 2013.

*Although not specifically noted, the mathematical analysis may need some level of input from other sources (for example, to determine analysis bands for life and adjustments to data used in all analysis).

Figure 1

ARIZONA RATE JURISDICTION DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable accounts of –the Arizona Rate Jurisdicion were calculated by the straight line, average life group, and remaining life procedure.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$AnnualAccrualRate = \frac{(100\% - NetSalvagePercent)}{AverageServiceLife}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, average life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$Composite\,\mathrm{Re}\,mainingLife = \frac{\sum OriginalCost - Theoretical\,\mathrm{Re}\,serve}{\sum WholeLifeAnnualAccrual}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation.

$$AnnualDepreciationExpense = \frac{OriginalCost - Book\,\mathrm{Re}\,serve - (OriginalCost) * (1 - NetSalvage\%)}{Composite\,\mathrm{Re}\,mainingLife}$$

where the *Net Salvage%* represents future net salvage.

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$AnnualDepreciationRate = \frac{\sum AnnualDepreciationExpense}{\sum OriginalCost}$$

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. Book depreciation reserves were reallocated from individual accounts based on the theoretical reserve computations. Theoretical reserve computations were also used to compute a composite remaining life for each account.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the Retirement Rate actuarial methods. After establishment of appropriate average service lives and retirement dispersion, remaining life was computed for each account. Theoretical depreciation reserve with zero net salvage was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the General Discussion section. The difference between plant balance and theoretical reserve was then spread over the ALG depreciation accruals. Remaining life computations are found for each account in Appendix B.

Life Analysis

The retirement rate actuarial analysis method was applied to all accounts for –the Arizona Rate Jurisdiction. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Survivor Curves to obtain the most appropriate match. A selected curve for each

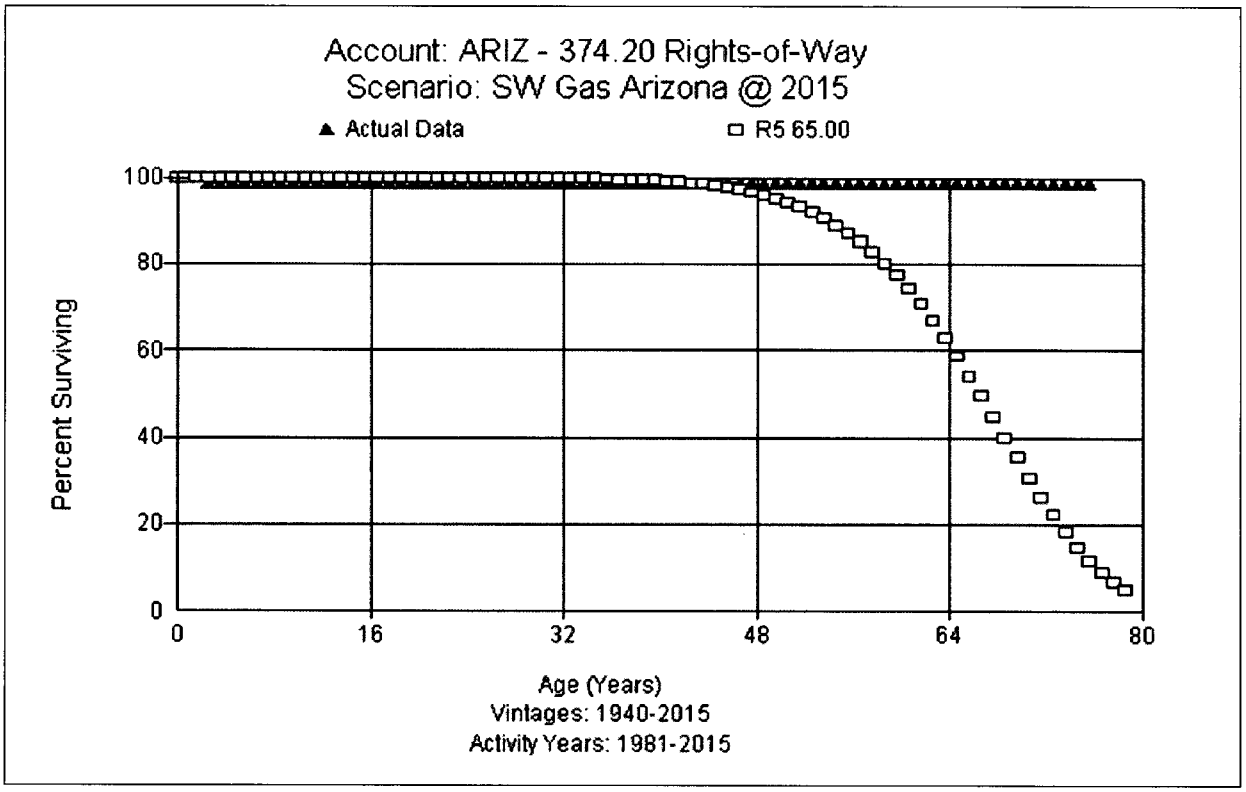
account is shown in the Life Analysis Section of this report. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

For each account on the overall band (i.e. placement from earliest vintage year which varied for each account through 2015), approved survivor curves were used as a starting point. Then using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e. L, S. or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed: in increments of approximately ten years, for instance 1986-2015, 1996-2015, 2006-2015, etc. Next placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

DISTRIBUTION PLANT

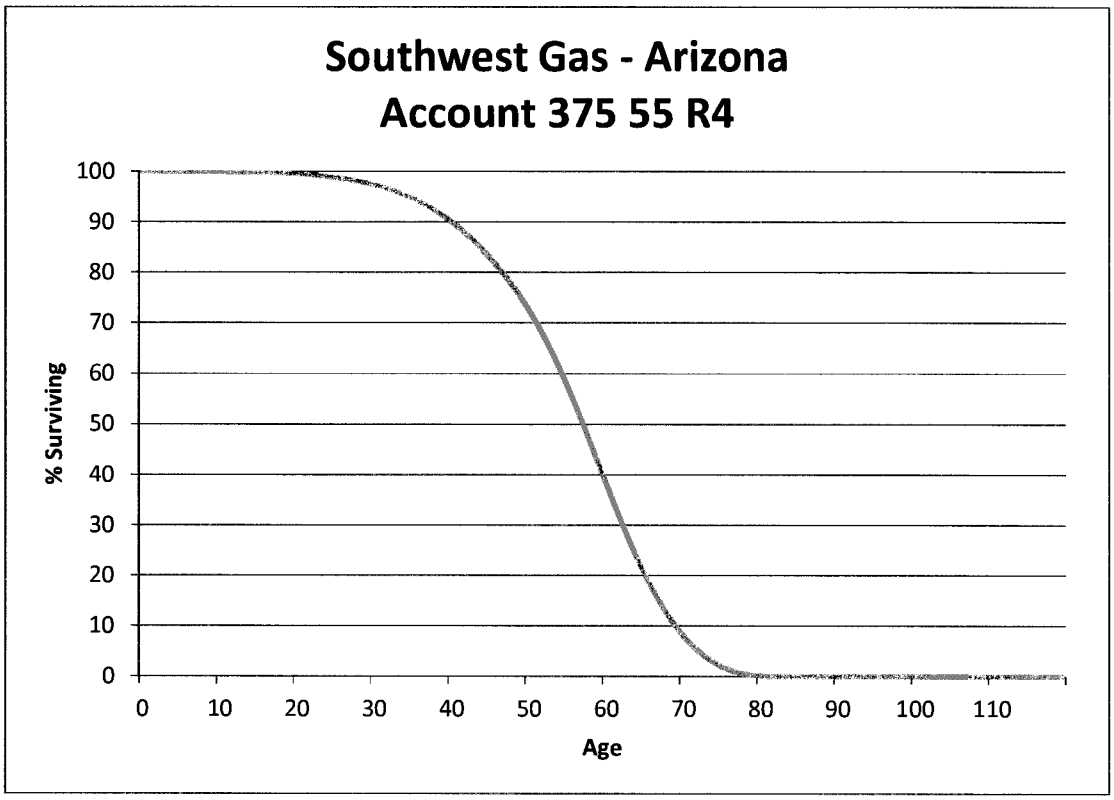
Account 374.20 Rights of Way (65 R5)

This account includes the cost of rights of way used in connection with distribution operations. There is approximately $2.7 million in this account. Currently, the approved life for this account is 50 years with an R5 dispersion. There have been few retirements in this account and actuarial analysis could not be used effectively. Since the lives of the assets in this account are tied to facilities in other accounts, this study recommends extending the lives similar to other accounts in this function. Based on judgment, this study recommends moving to a 65 year life and retaining the R5 dispersion.



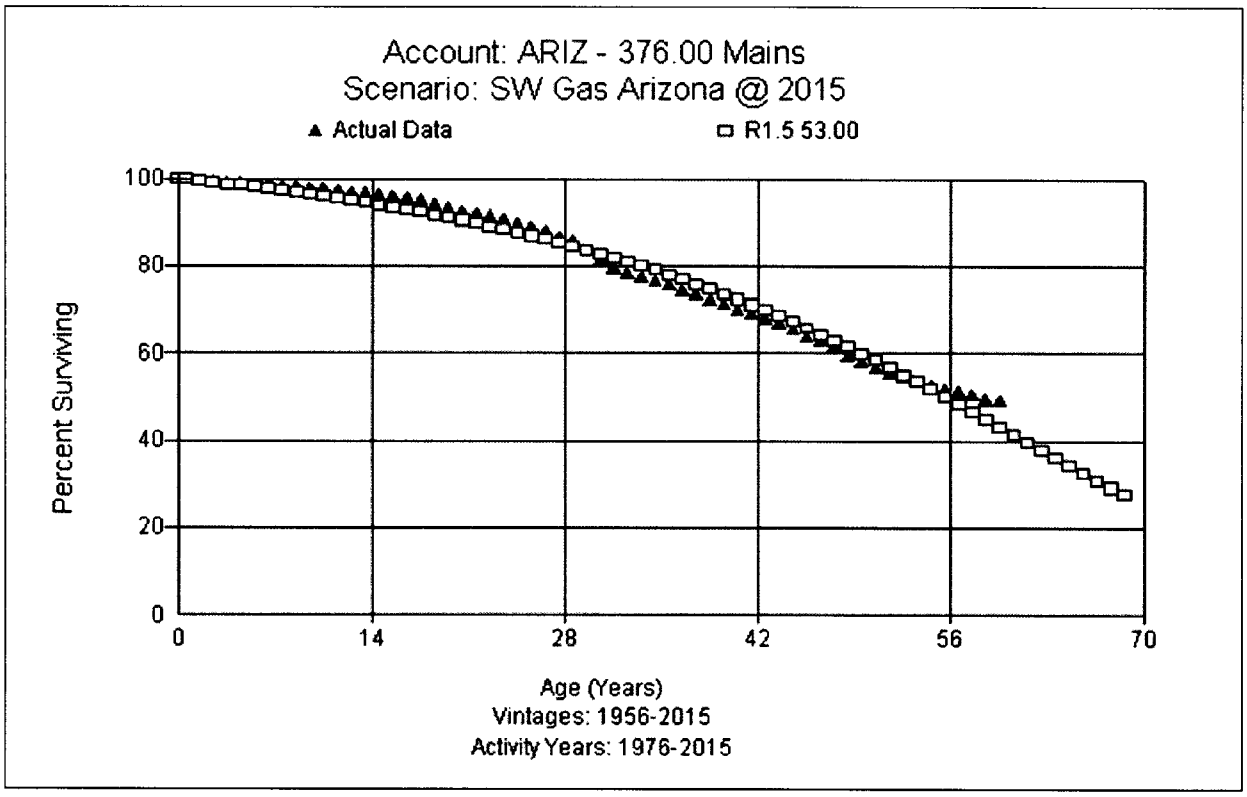
Account 375.00 Structures (55 R4)

This account includes the cost of structures used in connection with distribution operations. There is approximately $111 thousand in this account. Currently, the approved life for this account is 50 years with an R4 dispersion. There have been no retirements in this account during the period that retirement data is available. Based on judgment, this study recommends moving to a 55 year life and retaining the R4 dispersion.



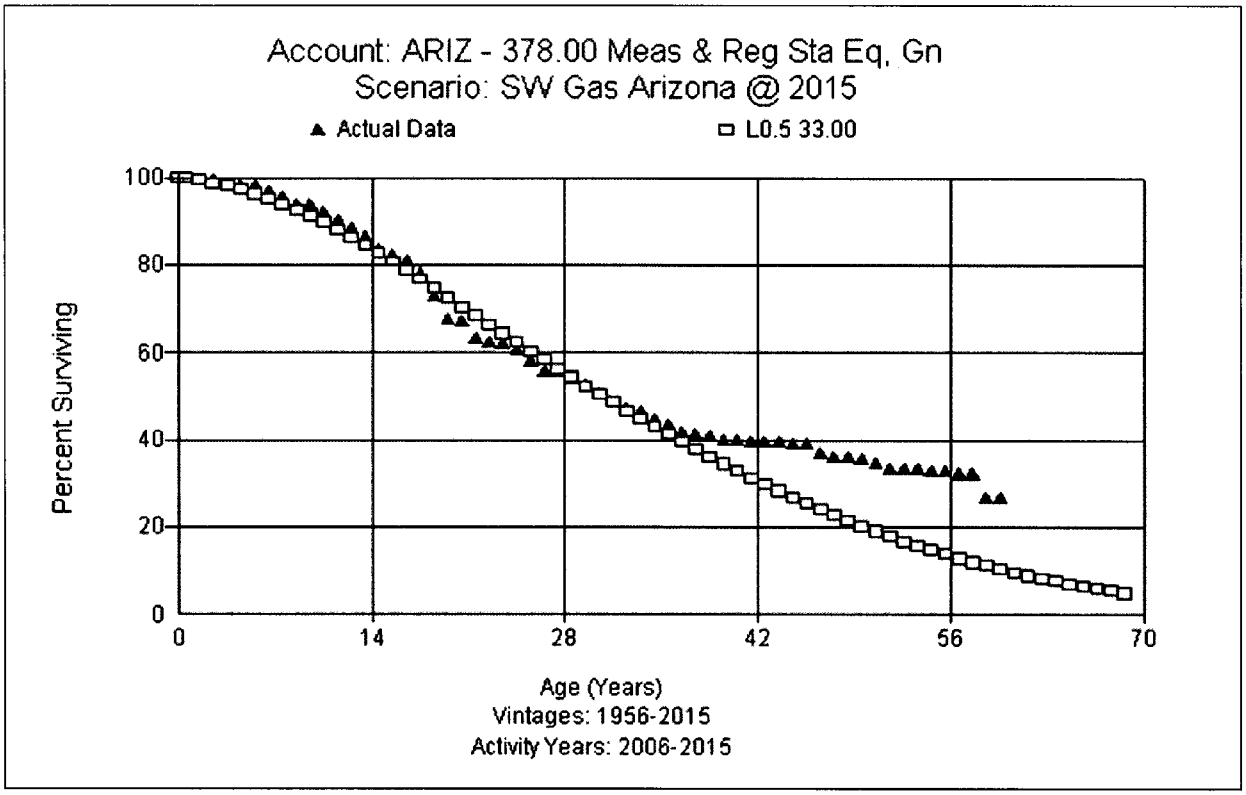
Account 376.00 Distribution Mains (53 R1.5)

This account includes the cost of all types and various sizes of mains, valves and other related equipment used in connection with distribution operations. The mains could be made of steel, plastic, or PVC. There is approximately $1.7 billion in this account. Currently, the approved life for this account is 45 years with an R4 dispersion. The Company initiated early vintage plastic replacement program which is a 20 year program and will end by 2026. About 440 miles of PVC is still on the system. The Company is starting PVC replacements and will complete by 2026. PVC was installed from 1965-1974 and now the PVC solvent is breaking down and fittings leaking. The Company is proposing to accelerate the replacement of pre-1970s vintage steel in the testimony of Company witness Kevin Lang. Many of the acquired facilities were not protected. The oldest operating steel is 1934 or 1935 vintage, but most of the steel is in vintages in the 1950s and 1960s. The distribution pipeline integrity program was a leak driven program. Some larger pipe (operated as transmission) is having seam issues and 15-20 miles has been replaced. Capacity needs can also cause replacement of assets. Based on the consistent curve and life indications across the bands analyzed and the excellent fits (see below) along with information from Company personnel, this study recommends moving slightly from the approved 45 year life to a 53 year life and from an R4 dispersion to an R1.5 dispersion. An observed life table is graphed for this account below.


Account: ARIZ - 376.00 Mains
Scenario: SW Gas Arizona @ 2015
Actual Data
R1.5 53.00
Percent Surviving
100
80
60
40
20
0
0
14
28
42
56
70
Age (Years)
Vintages: 1956-2015
Activity Years: 1976-2015

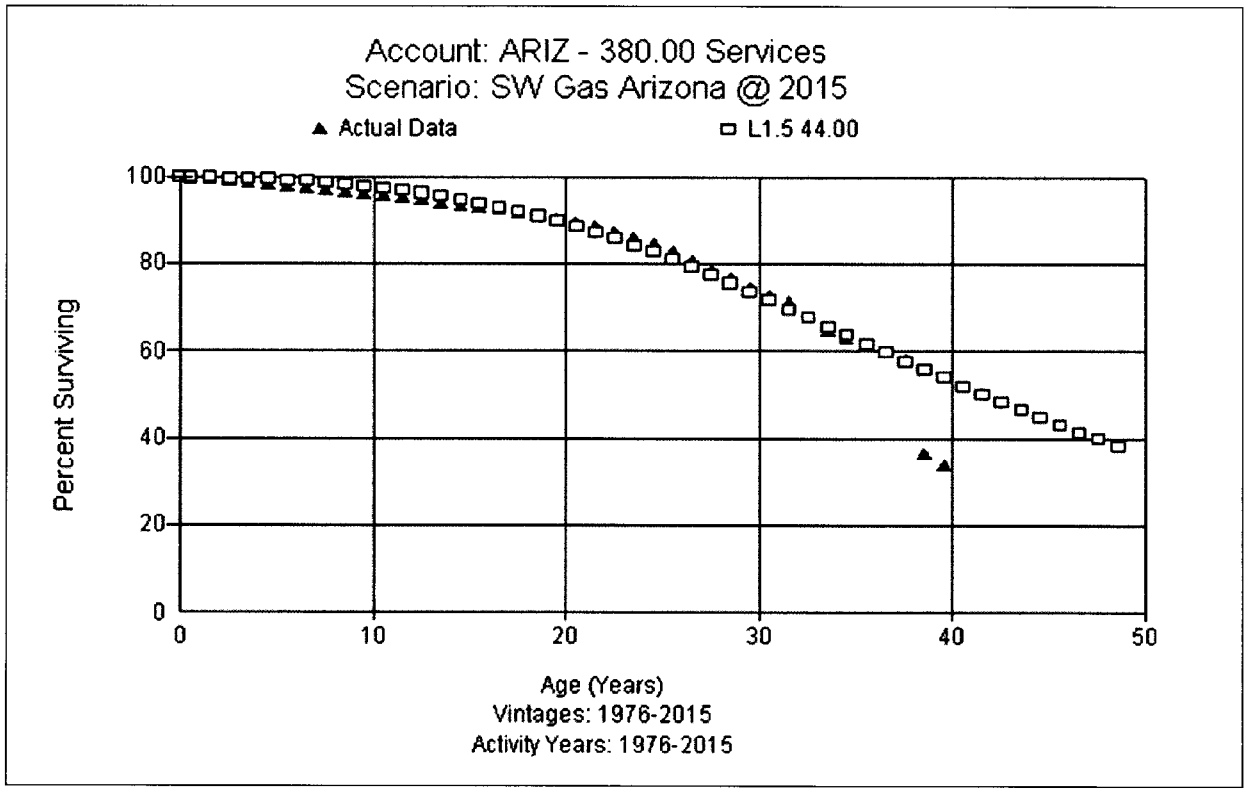
Account 378.00 Measuring and Regulating Station Equipment (33 L0.5)

This account consists of costs associated with tap assemblies, regulator stations, meters, ball valves, filter separator, vaults, and other equipment used in distribution measuring and regulating operations. There is approximately $75 million of investment in this account. The currently approved curve for this account is the 50 R4. Company personnel report that many measuring and regulating district regulator stations did not have adequate documentation and/or did not meet current standards. Most district regulator stations have been replaced in the last 15 years associated with other projects. Many stations were replaced during the HP steel replacement program. Company personnel also report that when district regulator stations were installed, generally they were placed close to roads and corners. Now some stations have had to be relocated earlier than physically necessary due to municipal improvements. Some upgrades to city gates have occurred but there have been but no replacements of the full gates. Based upon the analysis indications and discussions with Company personnel indicating Company is proactively replacing or moving stations where issues are present, this study recommends moving to a 33 year life and L0.5 dispersion for this account. An observed life table is graphed for this account below.


Account: ARIZ - 378.00 Meas & Reg Sta Eq, Gn
Scenario: SW Gas Arizona @ 2015
Actual Data
L0.5 33.00
Percent Surviving
100
80
60
40
20
0
0
14
28
42
56
70
Age (Years)
Vintages: 1956-2015
Activity Years: 2006-2015

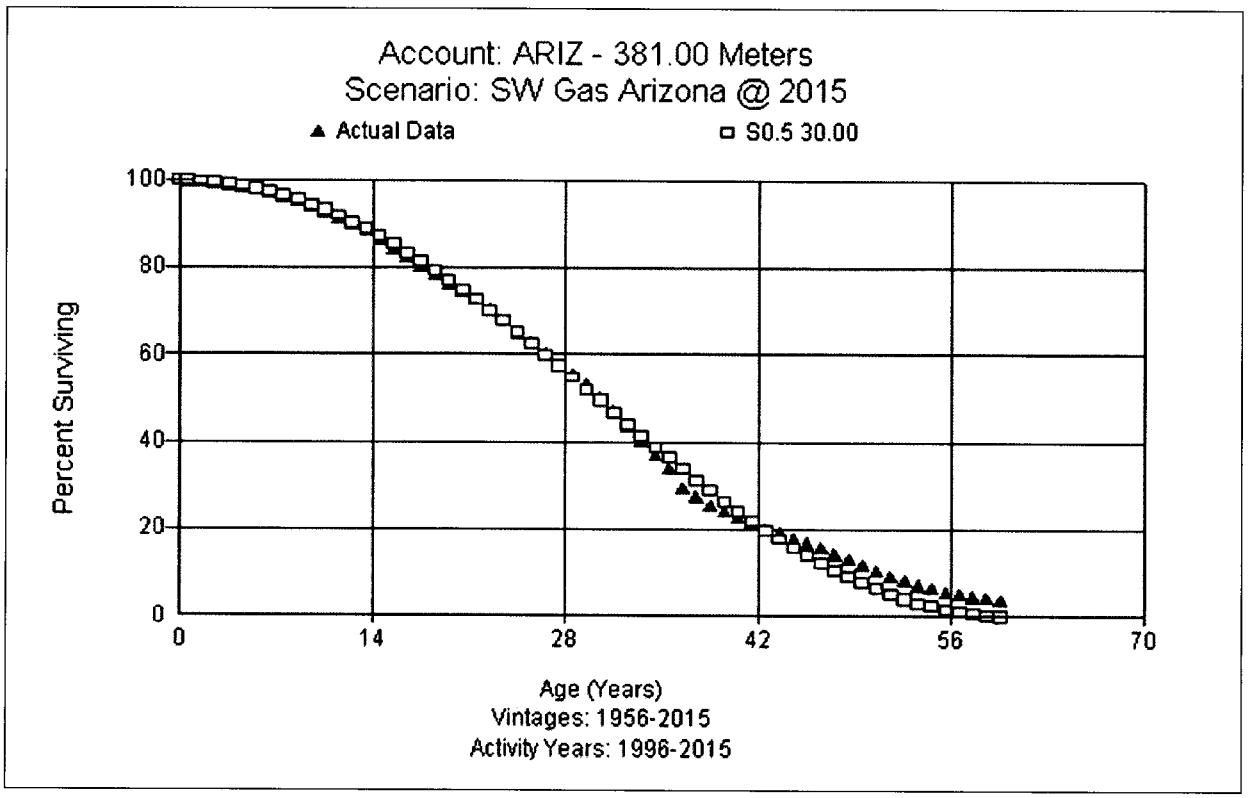
Account 380.00 Services (44 L1.5)

This account consists of services used in distribution operations. The material could be plastic, steel, or PVC. There is approximately $836 million of investment in this account. The currently approved curve for this account is the 42 L0. The Company is making replacement of isolated steel services a higher priority than other assets. The Company is also abandoning inactive facilities (services and stubs). Company personnel think the life of services will be shorter than Account 376, Mains. Based on actuarial analysis, judgment, and input from Company personnel, this study recommends a 44 year life while moving to a L1.5 dispersion for this account. An observed life table is graphed for this account below.



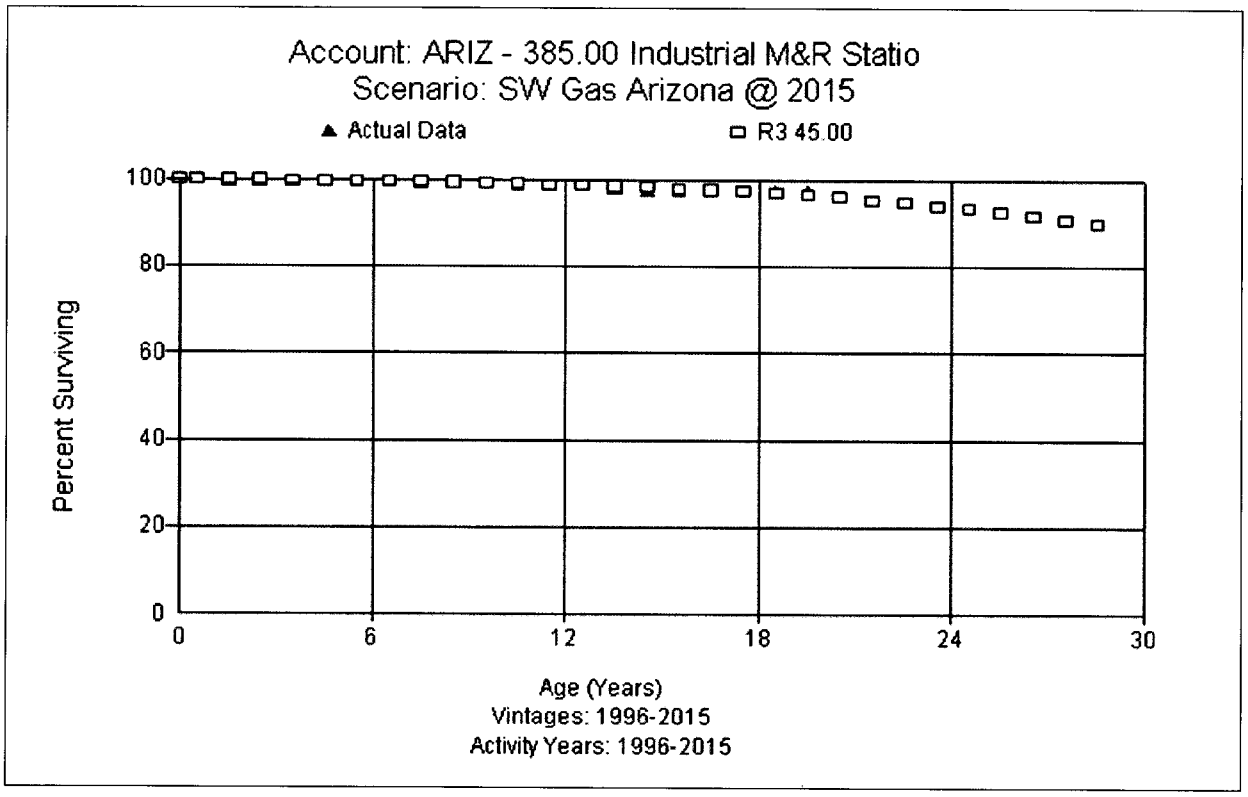
Account 381.00 Meters (30 S0.5)

This account includes the cost of meters used in measuring gas to customers. There is approximately $293 million in plant in this account. The currently approved life is 48 years with an R1.5 dispersion. The company is experiencing a shorter life for its meters than experienced in the past. Based on the majority of the bands analyzed, discussions with Company personnel, and the visual matching across many bands the 30 S0.5 curve is the best fit over all bands and is the study recommendation for this account. An observed life table is graphed for this account.



Account 385.00 Industrial Measuring/Regulating Station Equipment (45 R3)

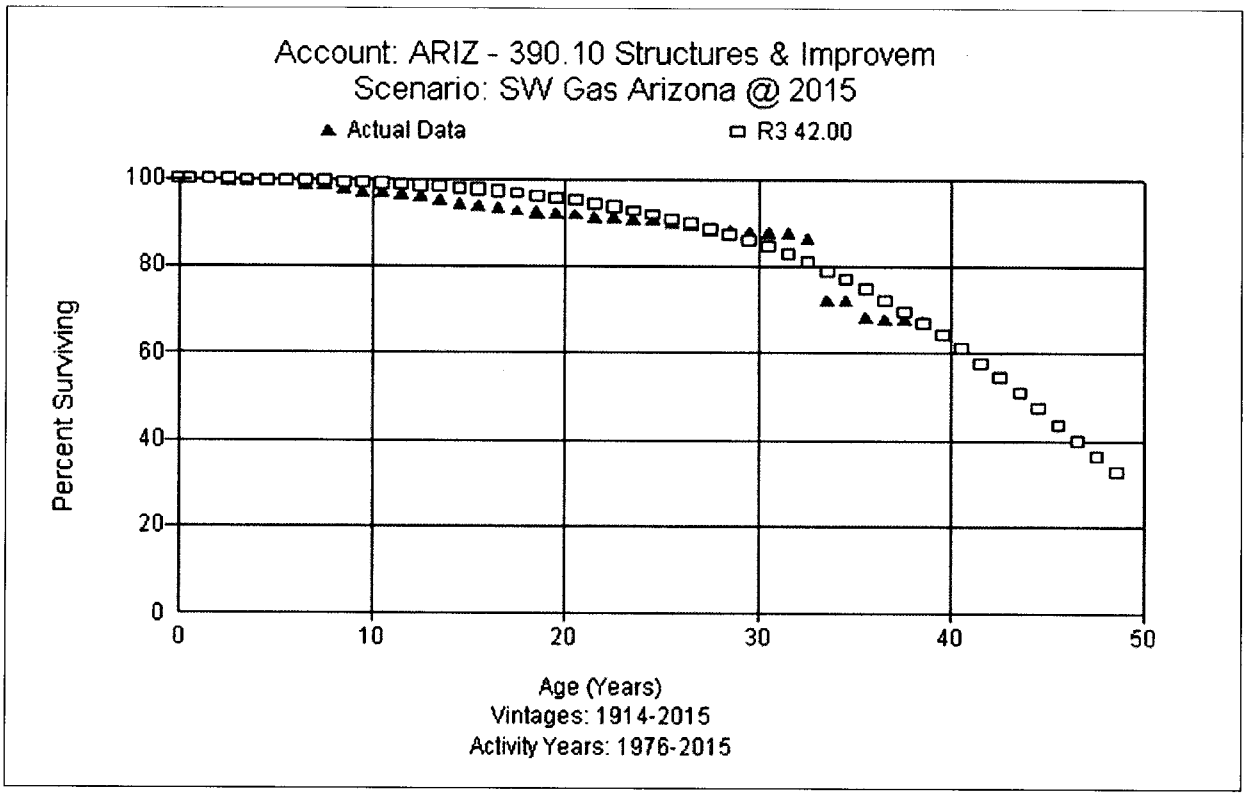
This account includes the cost of 2" and larger regulators, oil separators, electric meter correct devices, 4" valves and other industrial measuring and regulator station equipment. The currently approved life for this account is 30 R1. There is approximately $12 million in plant in this account. Company personnel state that there are few reasons to remove or replace these assets barring changes in customer load. Company personnel feel that 45 years is a reasonable life for this account. Therefore, this study recommends moving from the 30 R1 to the 45 R3 for this account. An observed life table (with limited data) is graphed for this account below.



GENERAL PLANT DEPRECIATED

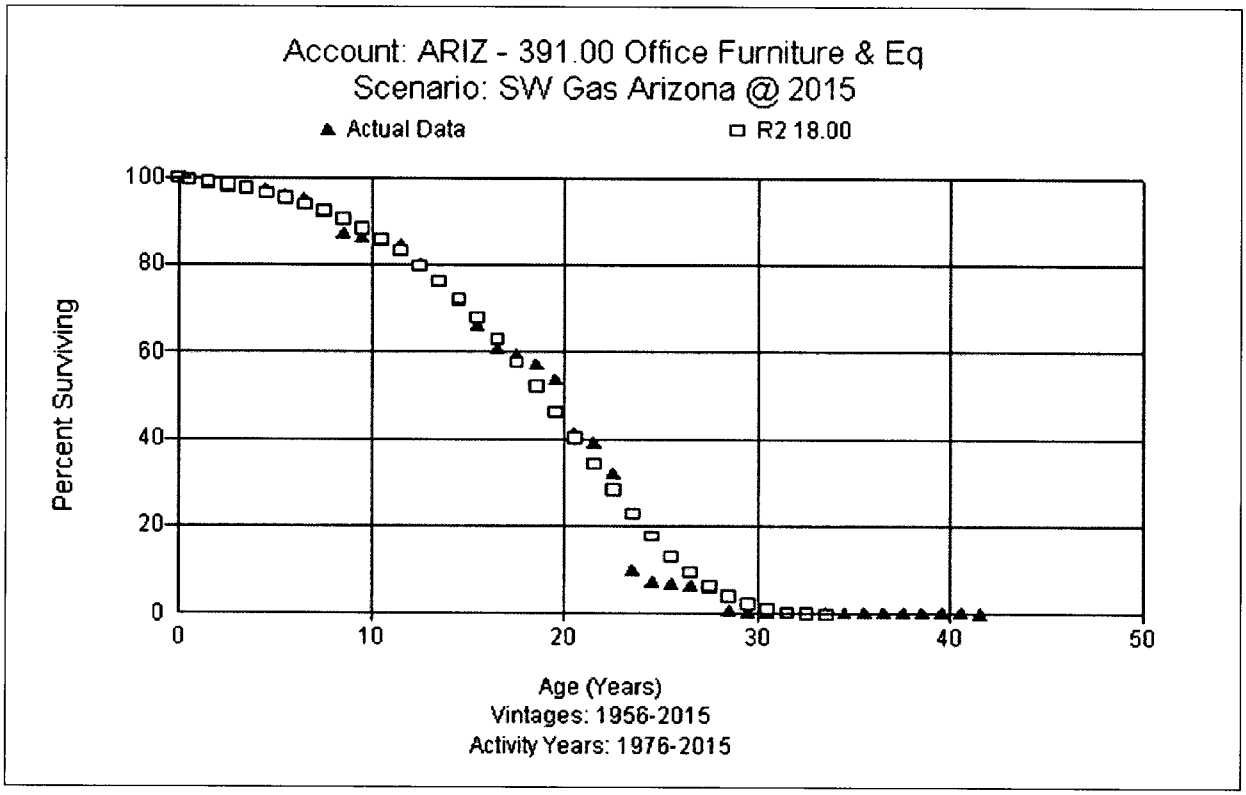
Account 390.10 Structures – Owned (42 R3)

This account includes the cost of office and warehouses, parking lots, HVAC, control systems, security systems and other general structures and improvements used to support utility service. There is approximately $50.1 million in this account. The current life for this account is a 45 R3. The building in Tempe and several other buildings were not in the data in the 1988 study. Several smaller buildings were retired since that point and a number of smaller replacements of components (e.g. replaced gas chillers – retired 2014, Tucson, HVAC replacement, lighting replacement) have occurred. Some roofing replacement starting in 2016. Company personnel feel that 42 years is a reasonable for this account. Based actuarial analysis, opinions of company personnel, and judgment, this study recommends moving to a 42 R3 at this time.



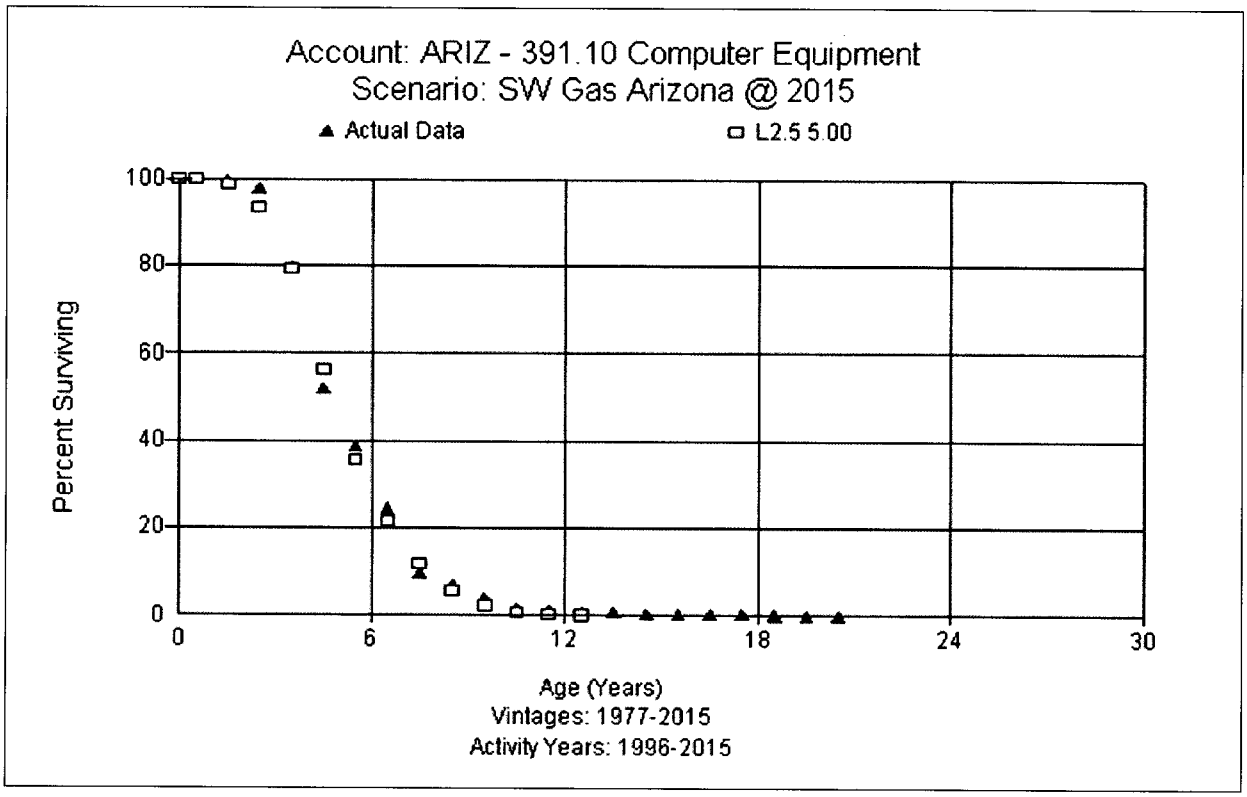
Account 391.00 Office Furniture & Eq. (18 R2)

This account consists of office furniture and equipment used for general utility service. There is approximately $5.1 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $5.0 million in this account. This account currently has an approved life of 31 years and an L1 dispersion. Most of the assets in this account are workstations. This study recommends moving to an 18 R2 for this account. A graph of the recommended curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



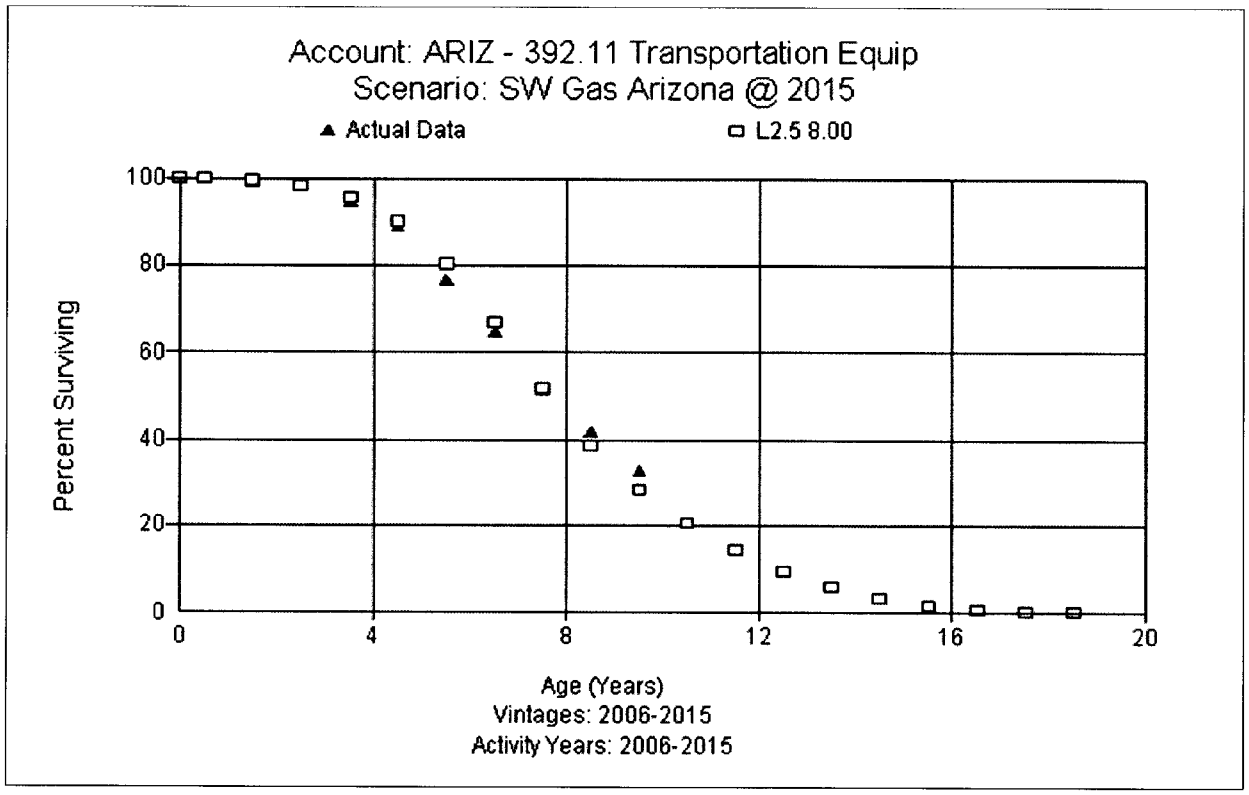
Account 391.10 Computer Equipment (5 L2.5)

This account consists of computer equipment used for general utility service. There is approximately $14.1 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $13.2 million in this account. This account currently has an approved life of 7 years and an R2 dispersion. Company personnel report the PCs have a refresh schedule of 3 years, printers 5-6 years, mainframe storage will have a life of 5-7 years. They recommend moving to a five year life for this account. This study recommends moving to a 5 L2.5 for this account. A graph of the recommended curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



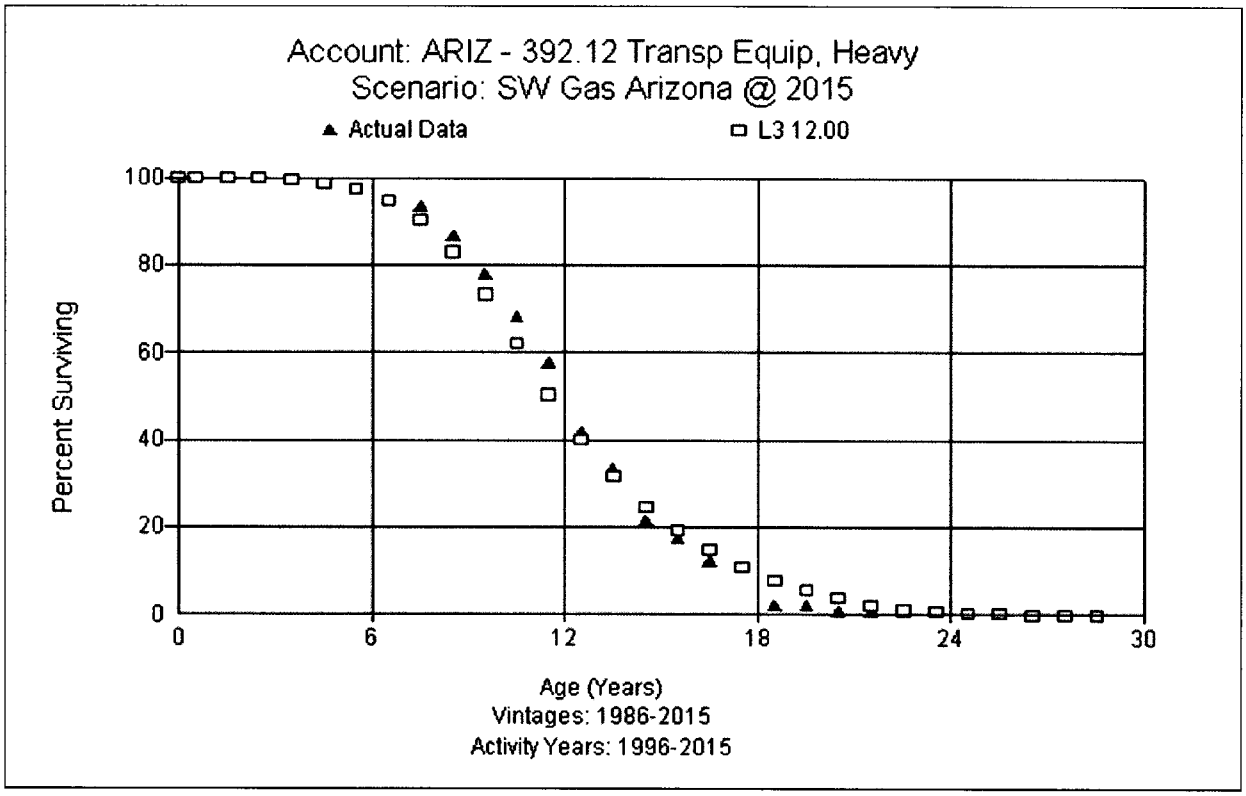
Account 392.11 Transportation Equipment – Light (8 L2.5)

This account consists of light transportation equipment used for general utility service. There is approximately $22 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $19.5 million in this account. This account currently has an approved life of 8 L2. Company personnel report that light vehicles are normally retired at 8 years or 80K miles. At times, they retire assets based on mileage which may work out to 5 or 6 years. The higher mileage vehicles are generally used in the customer service function. Based on life analysis and opinions of Company personnel, this study recommends moving to an 8 L2.5 for this account. A graph of the recommended curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



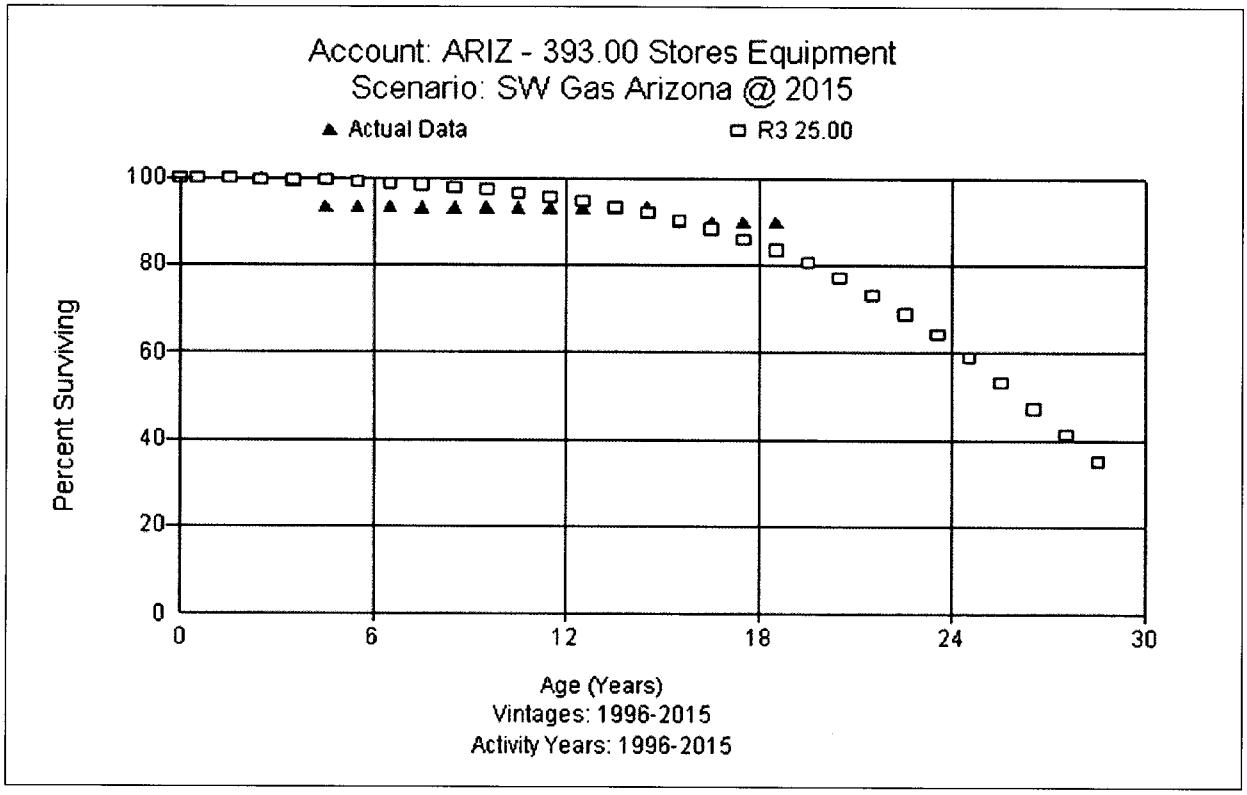
Account 392.12 Transportation Equipment – Heavy (12 L3)

This account consists of heavy transportation equipment used for general utility service. There is approximately $14.9 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $13.6 million in this account. This account currently has an approved life of 8 L2. Company personnel state that most of the heavy trucks are diesels which are generally operated for 12 years or 120K miles. Company personnel state that these assets usually retire around the 12 years or slightly shorter. Light vehicles are being sold at a shorter life and are well maintained. This study recommends moving to a 12 L3 for this account. A graph of the proposed curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.


Account: ARIZ - 392.12 Transp Equip, Heavy
Scenario: SW Gas Arizona @ 2015
Actual Data
L3 12.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1986-2015
Activity Years: 1996-2015

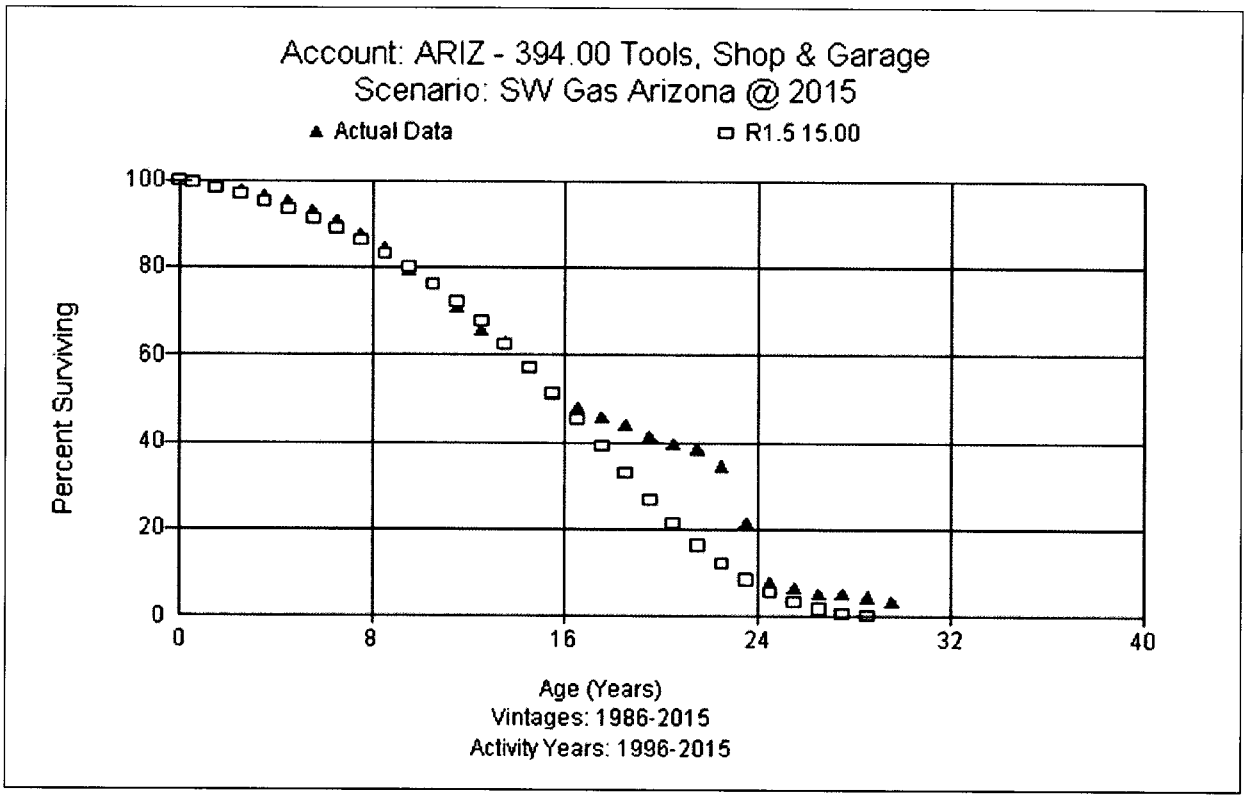
Account 393.00 Stores Equipment (25 R3)

This account consists of stores equipment used for general utility service. There is approximately $799 thousand in this account. After retirement of assets whose age is greater than the proposed average service life, there is $636 thousand in this account. This account currently has an approved life of 25 years and an R3 dispersion. Company personnel recommend retaining the 25 R3 for this account. A graph of the recommended curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



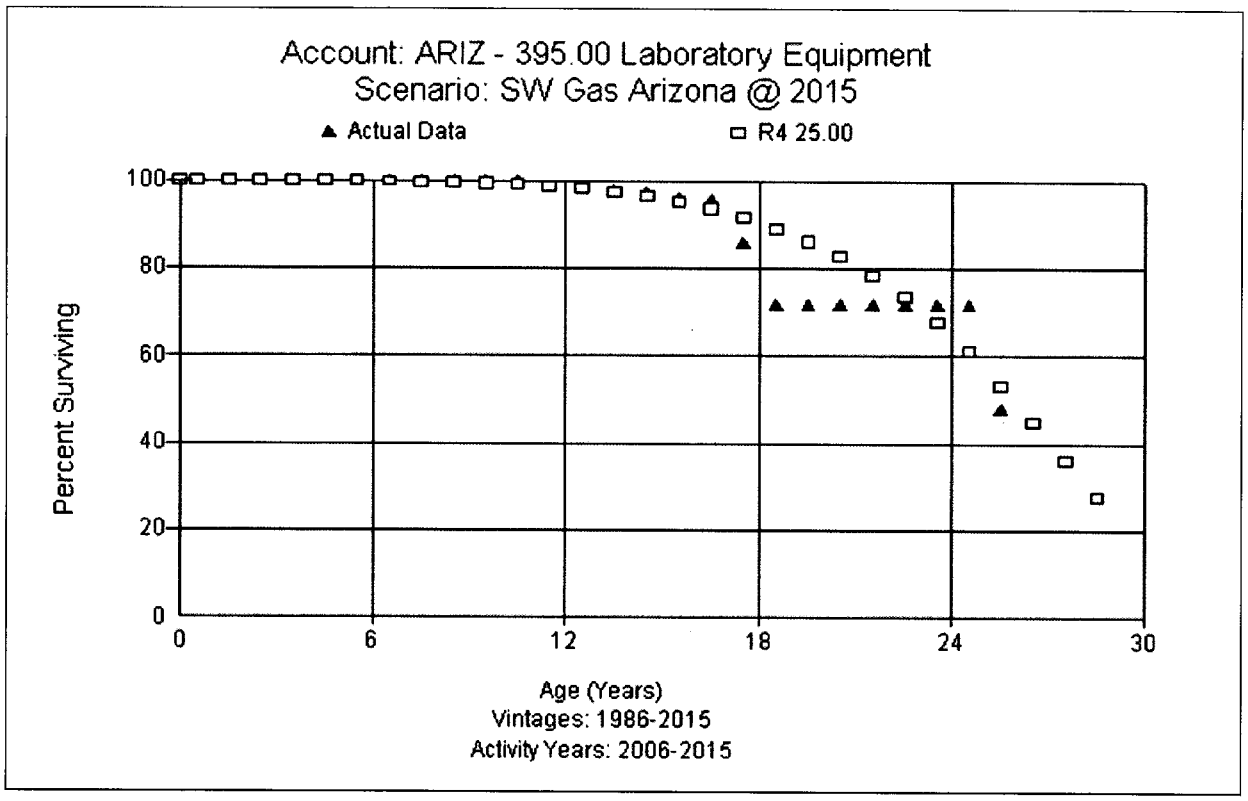
Account 394.00 Tools, Shop & Garage (15 R1.5)

This account consists of tools, shop and garage equipment used for general utility service. There is approximately $9.6 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $8.3 million in this account. This account currently has an approved life of 33 years and an R3 dispersion. Company personnel state that the tools in this account have an array of different lives: tools like gas detection equipment, fusion equipment etc. will have a fairly short life of around 10-15 years; electrofusion 10 years; butt fusion 15-20 years, gas detection equipment 5-10 years; and pipe locators 10-15 years. Other equipment like boring equipment will have a long life, portable air compressors are estimated at 5 years, and welding equipment is estimated at 10-15 years. Company personnel recommend moving to a 15 year life. This study recommends moving to a 15 R1.5 for this account. A graph of the recommended curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



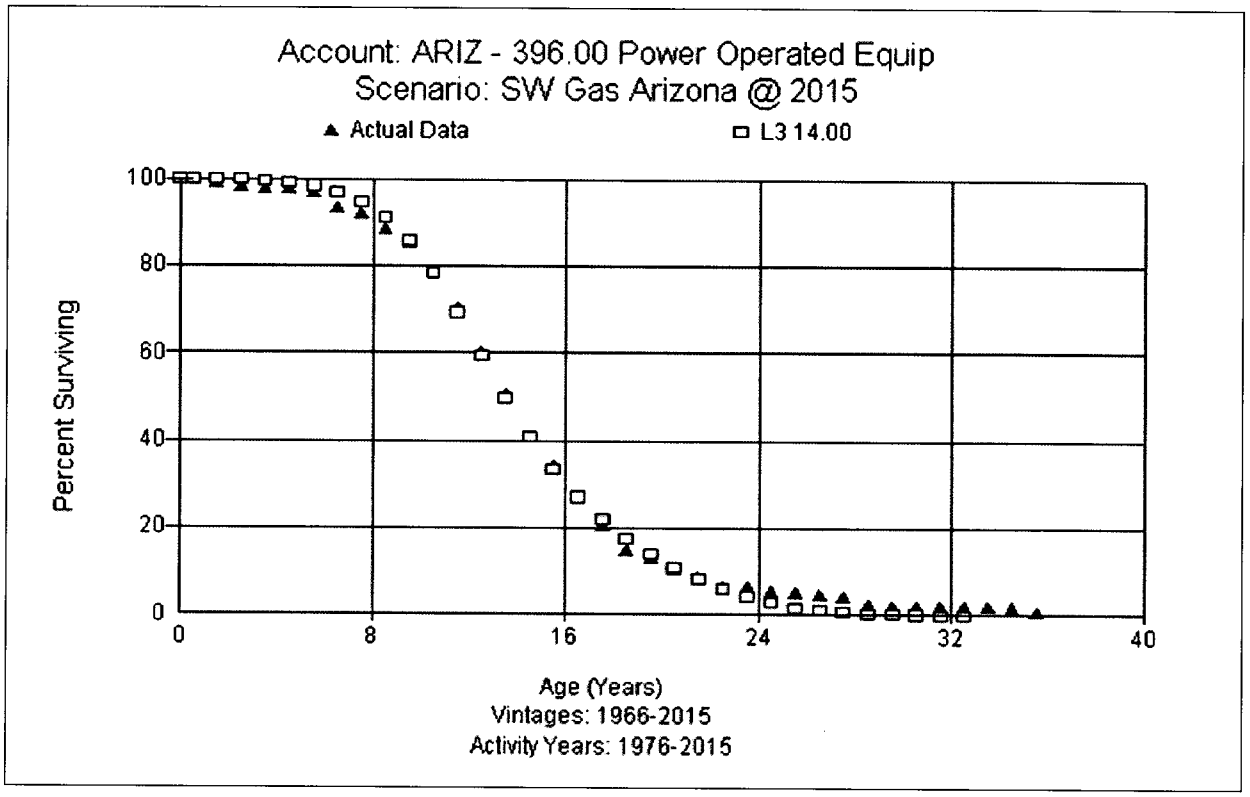
Account 395.00 Laboratory Equipment (25 R4)

This account consists of laboratory equipment used for general utility service. There is approximately $499 thousand in this account. After retirement of assets whose age is greater than the proposed average service life, there is $498 thousand in this account. This account currently has an approved life of 25 years and an R4 dispersion. Company personnel recommend a life for this account of 25 years, even though some of the actuarial analysis might suggest a slightly longer life. A 25 year life is consistent with the lifecycle of the various assets within this account. This study recommends retention of the 25 R4 for this account. A graph of the recommended curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.


Account: ARIZ - 395.00 Laboratory Equipment
Scenario: SW Gas Arizona @ 2015
Actual Data
R4 25.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1986-2015
Activity Years: 2006-2015

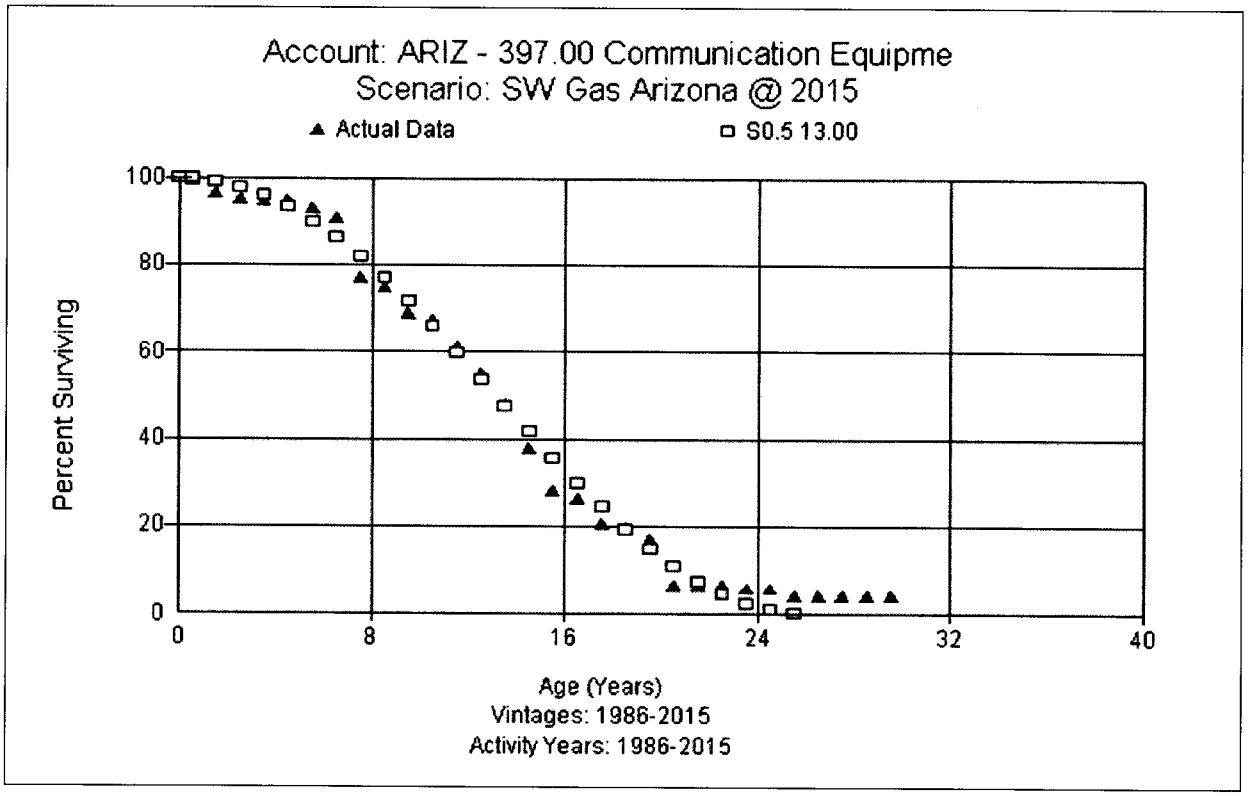
Account 396.00 Power Operated Equipment (14 L3)

This account consists of backhoes, bulldozers, forklifts, trenchers, and other power operated equipment that cannot be licensed on roadways. There is approximately $7.9 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $7.5 million in this account. This account currently has an approved life of 12 years with an S0.5 dispersion. Life analysis shows a longer life than exhibited in currently approved. Company personnel recommend a life of 13 to 14 years for this account. This study recommends moving to a 14 L3 for this account. A graph of the proposed curve is shown below. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



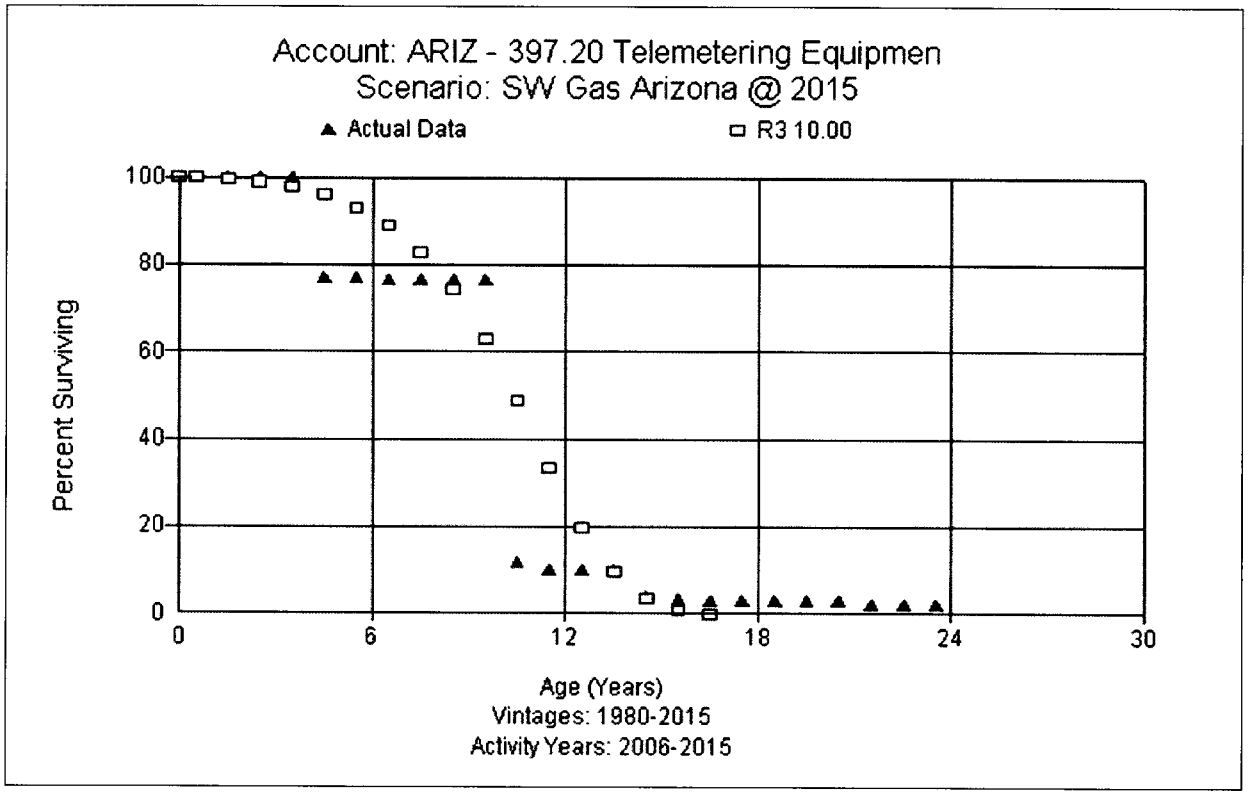
Account 397.00 Communication Equipment (13 S0.5)

This account consists of miscellaneous communication equipment used in general utility service. There is approximately $2.1 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $1.7 million in this account. This account currently has an approved life of 12 S0. Company personnel report that much of the account is mobile radios, and a life of 13 to 14 years is consistent with their experience. This study recommends moving to a 13 year life and S0.5 dispersion for this account. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



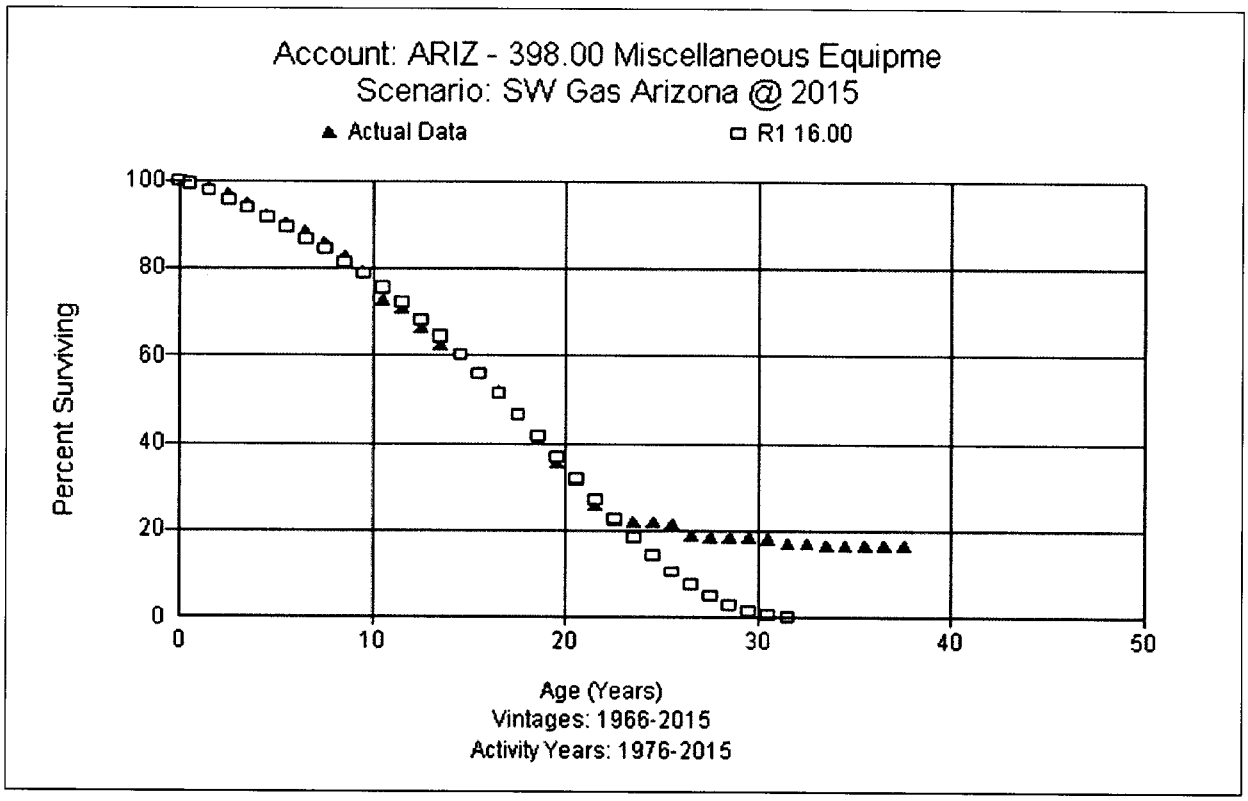
Account 397.20 Telemetry Equipment (10 R3)

This account consists of telemetry equipment used in general utility service. There is approximately $213 thousand in this account. This account currently has an approved life of 15 R2. With the change in technology, Company personnel opine that the maximum life of this account would be 10 years. Based on input from Company personnel, actuarial life analysis, and judgment, this study recommends moving to a 10 R3 for this account. After the implementation of general plant amortization, the survivor curve will become a SQ curve.



Account 398.00 Miscellaneous Equipment (16 R1)

This account consists of miscellaneous equipment used in general utility service. There is approximately $1.1 million in this account. After retirement of assets whose age is greater than the proposed average service life, there is $1.1 million in this account. This account currently has an approved life of 20 L2. Company personnel report that the Company recently upgraded the Emergency Operations Center (EOC) in 2015. Based on the types of assets (predominantly electronic), Company personnel believe the life of the account is approximately 15 years. Based on input from Company personnel, actuarial life analysis, and judgment, this study recommends moving to a 16 R1 dispersion for this account. After the implementation of general plant amortization, the survivor curve will become a SQ curve.


Account: ARIZ - 398.00 Miscellaneous Equipme
Scenario: SW Gas Arizona @ 2015
Actual Data
R1 16.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1966-2015
Activity Years: 1976-2015

Salvage Analysis

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the timing of the original addition versus the retirement. For example, a Distribution asset in FERC Account 376 with a current installed cost of $500 (2015) would have had an installed cost of $41.23[3] in 1962. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a -10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 121 percent removal cost for that asset ($50/$41.23). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

The net salvage analysis uses the history of the individual accounts to estimate the future net salvage that Southwest Gas can expect in its operations. As a result, the analysis not only looks at the historical experience of Southwest Gas, but also takes into account recent and expected changes in operations that could reasonably lead to different future expectations for net salvage than were experienced in the past. Recent experience is more heavily weighted in making net salvage recommendations than experience several years in the past.

Salvage Characteristics

For each plant account, data for retirements, gross salvage, and cost of

[3] Using the Handy-Whitman Bulletin No. 182, G-5, line 44, $41.23 = $500 x 63/764,

removal for each plant account group adjusted as discussed above was derived from 1993-2015. Moving averages, which remove timing differences between retirement and salvage and removal cost, were analyzed over periods varying from one to 10 years.

DISTRIBUTION PLANT

Account 374.20 Rights of Way (0 %)

This account includes any salvage and removal cost related to land rights used in connection with distribution operations. Generally, little or no removal cost is incurred and no salvage is received at the retirement of land rights. The existing net salvage is 0 percent, is supported by the historical data for this account. Therefore, this study recommends retaining the approved 0 percent net salvage for this account.

Account 375.00 Structures & Improvements (0%)

This account consists of any salvage and removal cost related to small structures and associated assets on the distribution system. The approved net salvage is a 0 percent net salvage rate for this account. There has been no retirement activity in this account from 1993-2015. Based on judgment, this study recommends retaining the approved 0 percent net salvage for this account.

Account 376.00 Mains (negative 35%)

This account consists of any salvage and removal cost related to Mains of all material types. The authorized net salvage rate for this account is negative 60 percent. The moving averages from 5 to 10 years range from negative 55 percent to negative 38 percent, suggesting cost of removal has decreased from the levels experienced when the approved rates were established. The overall moving average from 1993 to 2015 is negative 32 percent. This study recommends changing the negative 60 percent net salvage rate to negative 35 percent rate at this time.

Account 378.00 Measuring & Regulating Station Equipment (negative 25%)

This account includes any salvage and removal cost related to installed equipment used in regulating gas at entry points to the distribution system. The

currently authorized net salvage is negative 48 percent. The moving averages from 5 to 10 years range from negative 27 percent to negative 24 percent, suggesting cost of removal has decreased from the levels experienced when the approved rates were established. The overall moving average from 1993 to 2015 is negative 35 percent. Based on these indications, this study recommends moving to negative 25 percent net salvage for this account.

Account 380.00 Services (negative 55%)

This account includes any salvage and removal cost related to services related to distribution operations. Service lines are the pipes and accessories leading from the main to the customers' premises. The authorized net salvage rate for this account is negative 96 percent. Generally, pipe is abandoned in place. However, removal cost is still incurred even when abandoning the pipe in place. For pipe that is abandoned in place, activities such as isolating the old pipe, cutting the old pipe, purging or foaming the old pipe and capping the old pipe are charged as removal costs. When the pipe is not being abandoned in place, in addition to the above activities, dispatching a crew, uncovering the pipe, recovering the hole and repairing the surface are additional activities charged to removal cost. The net salvage ratio in transaction year 2015 is negative 266 percent. Since that is much higher than any other year, the focus was on moving averages from transaction year 2014 and prior. In 2014, the moving averages ranged from negative 69 percent to negative 43 percent. The overall moving average from 1993 to 2015 is negative 69 percent. To consider the recent trends, this study recommends moving to retention of the existing negative 55 percent net salvage for this account.

Account 381.00 Meters (0%)

This account includes any salvage and removal cost related to meters used in measuring gas to residential customers. The currently authorized net salvage rate is negative 7 percent. The moving averages from 5 to 10 years

range from positive 1 percent to negative 0 percent, suggesting cost of removal has changed from the levels experienced when the approved rates were established. The overall moving average from 1993 to 2015 is negative 1 percent. No salvage or cost of removal is expected on a consistent basis so this study recommends 0 percent net salvage for this account.

Account 385.00 Industrial Measuring & Regulating Station Equipment (negative 15%)

This account includes any salvage and removal cost related to industrial measuring and regulating station equipment used in measuring gas to residential customers. The currently authorized net salvage rate is negative 30 percent. The overall moving average from 1993 to 2015 is negative 17 percent. Based on historic activity and judgment, this study recommends moving from the approved negative 30 percent net salvage to a negative 15 percent net salvage for this account.

GENERAL PLANT

Account 390.10 Structures & Improvements (0%)

This account includes any salvage and removal cost related to structures and improvements used for general utility operations. The currently authorized net salvage rate for this account is 15 percent. The moving averages from 5 to 10 years range are negative 1 percent. The overall moving average from 1993 to 2015 is negative 1 percent. Based on the overall analysis, expectations, and judgment, this study recommends a 0 percent net salvage for this account.

Account 391.00 Office Furniture & Eq. (0%)

This account includes any salvage and removal cost related to office furniture and equipment used for general utility operations. The currently authorized net salvage rate for this account is 6 percent. The moving averages from 5 to 10 years range are 0 percent. The overall moving average from 1993

to 2015 is 0 percent. Based on the overall analysis, expectations and judgment, this study recommends a 0 percent net salvage for this account.

Account 391.10 Computer Equipment (0%)

This account includes any salvage and removal cost related to computer equipment used for general utility operations. The currently authorized net salvage rate for this account is 0 percent. Generally computer equipment has little net salvage. Based on the overall analysis, expectations and judgment, this study recommends retention of the 0 percent net salvage for this account.

Account 392.11 Transportation Equipment – Light (25%)

This account includes any salvage and removal cost related to light transportation equipment used in general operations. The currently authorized net salvage rate for this account is 14 percent. The moving averages from 5 to 10 years range from positive 25 to positive 18 percent. The overall moving average from 1993 to 2015 is positive 19 percent. Based on the overall analysis, expectations and judgment, moving to 25 percent net salvage is recommended for this account.

Account 392.12 Transportation Equipment – Heavy (18%)

This account includes any salvage and removal cost related to heavy transportation equipment used in general operations. The currently authorized net salvage rate for this account is 14 percent. Data in 2015 shows a much smaller gross salvage than prior years. For that reason, more focus was given to moving averages ending in 2014. For 2014, moving averages from 5 to 10 years range from positive 18 to positive 15 percent. Based on the overall analysis, expectations and judgment, moving to an 18 percent net salvage is recommended for this account.

Account 393.00 Stores Equipment (0%)

This account includes any salvage and removal cost related to stores equipment. The currently authorized net salvage rate for this account is 20 percent. Very small amounts of gross salvage have been received over the period 1993-2015. Based on the overall analysis, expectations, and judgment, moving to 0 percent net salvage is recommended for this account.

Account 394.00 Tools, Shop, and Garage Equipment (0%)

This account includes any salvage and removal cost related to various items or tools used in shop and garages such as air compressors, grinders, mixers, hoists, and cranes. The currently authorized net salvage rate for this account is 0 percent. The moving averages from 5 to 10 years range from 0 percent to positive 1 percent. The overall moving average from 1993 to 2015 is negative 0 percent. Based on the overall analysis, expectations and judgment, retention of 0 percent net salvage is recommended for this account.

Account 395.00 Laboratory Equipment (0%)

This account includes any salvage and removal cost related to laboratory equipment. The currently authorized net salvage rate for this account is 0 percent. Over the period from 1993 to 2015, no gross salvage or removal cost has been experienced in this account. The overall moving average from 1993 to 2015 is 0 percent. Based on the overall analysis, expectations and judgment, retention of 0 percent net salvage is recommended for this account.

Account 396.00 Power Operated Equipment (30%)

This account includes any salvage and removal cost related to bulldozers, forklifts, trenchers, and other power operated equipment that cannot be licensed on roadways. The currently authorized net salvage rate for this account is 18 percent. The moving averages from 5 to 10 years range from positive 32 to positive 30 percent. The overall moving average from 1993 to 2015 is positive 30 percent. Based on the overall analysis, expectations and judgment, an

increase to 30 percent is recommended for this account.

Account 397.00 Communication Equipment (0%)

This account includes any salvage and removal cost related to miscellaneous communication equipment. The currently authorized net salvage rate for this account is 0 percent. Over the period from 1993 to 2015, no gross salvage or removal cost has been experienced in this account. The overall moving average from 1993 to 2015 is 0 percent. This study recommends retaining the approved net salvage of 0 percent for this account.

Account 397.20 Telemetry Equipment (0%)

This account includes any salvage and removal cost related to telemetry equipment. The currently authorized net salvage rate for this account is 0 percent. Over the period from 1993 to 2015, no gross salvage or removal cost has been experienced in this account. The overall moving average from 1993 to 2015 is 0 percent. This study recommends retaining the approved net salvage of 0 percent for this account.

Account 398.00 Miscellaneous Equipment (0%)

This account includes any salvage and removal cost related to miscellaneous equipment. The currently authorized net salvage rate for this account is 2 percent. Little salvage or removal cost is expected for these assets. The moving averages from 5 to 10 years range from positive 4 to positive 2 percent. The overall moving average from 1993 to 2015 is positive 1 percent. Based on the overall analysis, expectations and judgment, a 0 percent net salvage is recommended for this account.

APPENDIX A

Computation of Depreciation Accrual Rate

Southwest Gas Corporation
Arizona Rate Jurisdiction

Computation of Proposed Depreciation Accrual Rates
Using ALG Broad Group Remaining Life Depreciation
At December 31, 2015

Acct	Plant at 12/31/2015	Allocated Book Reserve at 12/31/15	Net Salvage %	Net Salvage Amount	Unaccrued Balance	Average Remaining Life	Annual Accrual Amount	Proposed Annual Accrual Rate
(a)	(b)	(c)	(d)	(e)= (b) * (d)	(f) = (b)-(c)- (e)	(g)	(h) =(f) /(g)	(i) =(h)/(b)
Distribution Plant								
374.20 Rights-of-Way	2,694,946	726,299	0.00%	0	1,968,647	52.98	37,159	1.38%
375.00 Structures & Improvement	110,557	107,248	0.00%	0	3,309	9.91	334	0.30%
376.00 Mains	1,661,082,834	589,095,901	-35.00%	(581,378,992)	1,653,365,925	43.45	38,049,876	2.29%
378.00 Meas & Reg Sta Eq.	74,903,202	22,784,415	-25.00%	(18,725,800)	70,844,588	27.51	2,575,407	3.44%
380.00 Services	835,721,110	486,779,937	-55.00%	(459,646,611)	808,587,784	32.69	24,734,185	2.96%
381.00 Meters	293,267,849	124,165,616	0.00%	0	169,102,233	21.20	7,974,744	2.72%
385.00 Industrial M&R Station	11,809,530	5,937,592	-15.00%	(1,771,430)	7,643,368	31.44	243,148	2.06%
Total Distribution	2,879,590,027	1,229,597,007		(1,061,522,832)	2,711,515,853		73,614,853	
General Plant								
390.10 Structures & Improvement	50,104,315	19,739,602	0.00%	0	30,364,713	30.58	992,927	1.98%
Total General Depreciated	50,104,315	19,739,602		0	30,364,713		992,927	
Total	2,929,694,342	1,249,336,609		(1,061,522,832)	2,741,880,566		74,607,780	

Southwest Gas Corporation
Arizona Rate Jurisdiction

Computation of Proposed Amortization Rates
Using ALG Broad Group Remaining Life Depreciation
At December 31, 2015

Acct	Plant Balance 12/31/2015	Allocated Reserve 12/31/2015	Theoretical Reserve 12/31/2015	Reserve Difference	Remaining Life	Assets to Ret > ASL
(a)	(b)	(c)	(d)	(e)= (c) - (d)	(f)	(g)
General Plant Amortized						
391.00 Office Furniture & Eq	5,098,148	2,239,651	2,239,651	0	10.25	76,489
391.10 Computer Equipment	14,138,270	7,965,571	7,965,571	0	2.34	949,785
392.11 Transportation Equip - Light	21,953,490	8,103,704	8,103,704	0	4.58	2,464,889
392.12 Transportation Equip - Heavy	14,850,037	5,817,658	5,817,658	0	6.85	1,255,644
393.00 Stores Equipment	799,109	397,144	397,144	0	15.79	162,725
394.00 Tools, Shop & Garage	9,594,419	4,322,961	4,322,961	0	9.55	1,316,592
395.00 Laboratory Equipment	499,163	194,415	194,415	0	15.31	1,480
396.00 Power Operated Equipment	7,990,811	2,845,778	2,845,778	0	7.32	486,683
397.00 Communication Equipment	2,134,699	567,328	567,328	0	9.47	395,131
397.20 Telemetering Equipment	211,611	137,806	137,806	0	3.93	23,624
398.00 Miscellaneous Equipment	1,133,346	587,193	587,193	0	8.15	60,965

After Retirement of Fully Accrued Assets

Account	Plant Balance	Allocated Reserve	Proposed Life	Proposed Net Salvage %	Annual Amortization	Accrual For Reserve Deficiency	Proposed Amortization Rate
391.00 Office Furniture & Eq	5,021,658	2,163,161	18	0%	278,981	0	5.56%
391.10 Computer Equipment	13,188,485	7,015,786	5	0%	2,637,697	0	20.00%
392.11 Transportation Equip - Light	19,488,601	3,612,890	8	25%	1,827,056	0	9.38%
392.12 Transportation Equip - Heavy	13,594,393	3,514,835	12	18%	928,950	0	6.83%
393.00 Stores Equipment	636,385	234,420	25	0%	25,455	0	4.00%
394.00 Tools, Shop & Garage	8,277,827	3,006,369	15	0%	551,855	0	6.67%
395.00 Laboratory Equipment	497,683	192,935	25	0%	19,907	0	4.00%
396.00 Power Operated Equipment	7,504,128	1,505,362	14	30%	375,206	0	5.00%
397.00 Communication Equipment	1,739,568	172,197	13	0%	133,813	0	7.69%
397.20 Telemetering Equipment	187,987	114,182	10	0%	18,799	0	10.00%
398.00 Miscellaneous Equipment	1,072,381	526,228	16	0%	67,024	0	6.25%

APPENDIX B

Comparison of Depreciation Accrual Rates

Southwest Gas Corporation
Arizona Rate Jurisdiction
Comparison of Existing and Proposed Depreciation Rates
Using ALG Broad Group Remaining Life Depreciatoin
At December 31, 2015

Acct	Plant at 12/31/2015	Current Rate	Annual Expense	Proposed Rate	Proposed Expense	Expense Change
(a)	(b)	(c)	(d) = (b) *(c)	(e)	(f) =(b) *(e)	(g) =(f) -(d)
Distribution Plant						
374.20 Rights-of-Way	2,694,946	2.15%	57,941	1.38%	37,159	(20,782)
375.00 Structures & Improvement	110,557	1.15%	1,271	0.30%	334	(938)
376.00 Mains	1,661,082,834	3.82%	63,453,364	2.29%	38,049,876	(25,403,488)
378.00 Meas & Reg Sta Eq,	74,903,202	4.12%	3,086,012	3.44%	2,575,407	(510,605)
380.00 Services	835,721,110	5.30%	44,293,219	2.96%	24,734,185	(19,559,034)
381.00 Meters	293,267,849	1.98%	5,806,703	2.72%	7,974,744	2,168,041
385.00 Industrial M&R Station	11,809,530	4.31%	508,991	2.06%	243,148	(265,842)
	2,879,590,027		117,207,502		73,614,853	(43,592,648)
General Plant	50,104,315	1.84%	921,919	1.98%	992,927	71,007
390.10 Structures & Improvement	5,021,658	2.73%	137,091	5.56%	278,981	141,890
391.00 Office Furniture & Eq	13,188,485	14.87%	1,961,128	20.00%	2,637,697	676,569
391.10 Computer Equipment	19,488,601	7.65%	1,490,878	9.38%	1,827,056	336,178
392.11 Transportation Equip - Light	13,594,393	7.65%	1,039,971	6.83%	928,950	(111,021)
392.12 Transportation Equip - Heavy	636,385	2.08%	13,237	4.00%	25,455	12,219
393.00 Stores Equipment	8,277,827	2.17%	179,629	6.67%	551,855	372,226
394.00 Tools, Shop & Garage	497,683	3.93%	19,559	4.00%	19,907	348
395.00 Laboratory Equipment	7,504,128	3.88%	291,160	5.00%	375,206	84,046
396.00 Power Operated Equipment	1,739,568	8.88%	154,474	7.69%	133,813	(20,661)
397.00 Communication Equipment	187,987	6.19%	11,636	10.00%	18,799	7,162
397.20 Telemetering Equipment	1,072,381	4.53%	48,579	6.25%	67,024	18,445
398.00 Miscellaneous Equipment	121,313,411		6,269,261		7,857,671	1,588,410
	3,000,903,439		123,476,763		81,472,525	(42,004,238)

* After retirement of fully accrued assets for Accounts 391.00-398.00 will use an SQ curve after implementing Vintage Group Depreciation

APPENDIX C

Current Commission Approved Rates

Southwest Gas Corporation
Arizona Rate Jurisdiction
Rates at December 31, 2015
Life and Net Salvage Parameters

	Existing			Proposed			Difference	
Account Description	**ASL**	**Curve**	**Net Salvage %**	**ASL**	**Curve**	**Net Salvage %**	**ASL**	**Net Salvage %**
Distribution Plant								
374.20 Rights-of-Way	50	R5	0%	65	R5	0%	15	0%
375.00 Structures & Improvement	50	R4	0%	55	R4	0%	5	0%
376.00 Mains	45	R4	-60%	53	R1.5	-35%	8	25%
378.00 Meas & Reg Sta Eq,	50	R4	-48%	33	L0.5	-25%	-17	23%
380.00 Services	42	L0	-96%	44	L1.5	-55%	2	41%
381.00 Meters	48	R1.5	-7%	30	S0.5	0%	-18	7%
385.00 Industrial M&R Station	30	R1	-30%	45	R3	-15%	15	15%
							0	0%
General Plant							0	0%
390.10 Structures & Improvement	45	R3	15%	42	R3	0%	-3	-15%
391.00 Office Furniture & Eq	31	L1	6%	18	R2	0%	-13	-6%
391.10 Computer Equipment	7	R2	0%	5	L2.5	0%	-2	0%
392.11 Transportation Equip - Light	8	L2	14%	8	L2.5	25%	0	11%
392.12 Transportation Equip - Heavy	8	L2	14%	12	L3	18%	4	4%
393.00 Stores Equipment	25	R3	20%	25	R3	0%	0	-20%
394.00 Tools, Shop & Garage	33	R3	0%	15	R1.5	0%	-18	0%
395.00 Laboratory Equipment	25	R4	0%	25	R4	0%	0	0%
396.00 Power Operated Equipment	12	S0.5	18%	14	L3	30%	2	12%
397.00 Communication Equipment	12	S0	0%	13	S0.5	0%	1	0%
397.20 Telemetering Equipment	15	R2	0%	10	R3	0%	-5	0%
398.00 Miscellaneous Equipment	20	L2	2%	16	R1	0%	-4	-2%

* Accounts 391.00- 398.00 will use an SQ curve after implementing Vintage Depreciation Depreciation.

Appendix D
Net Salvage

ARIZONA RATE JURISDICTION
NET SALVAGE HISTORY
AS ADJUSTED

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %	11-yr Net Salv. %	12-yr Net Salv. %	13-yr Net Salv. %	14-yr Net Salv. %	15-yr Net Salv. %	20-yr Net Salv. %	24-yr Net Salv. %
ARIZ - 374.20 Rights-of-Way	1993	-	-	-	-	NA																
ARIZ - 374.20 Rights-of-Way	1994	-	-	-	-	NA	NA															
ARIZ - 374.20 Rights-of-Way	1995	-	-	-	-	NA	NA	NA														
ARIZ - 374.20 Rights-of-Way	1996	-	-	-	-	NA	NA	NA	NA													
ARIZ - 374.20 Rights-of-Way	1997	-	-	-	-	NA	NA	NA	NA	NA												
ARIZ - 374.20 Rights-of-Way	1998	-	-	-	-	NA	NA	NA	NA	NA	NA											
ARIZ - 374.20 Rights-of-Way	1999	-	-	-	-	NA	NA	NA	NA	NA	NA	NA										
ARIZ - 374.20 Rights-of-Way	2000	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA									
ARIZ - 374.20 Rights-of-Way	2001	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	NA								
ARIZ - 374.20 Rights-of-Way	2002	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA							
ARIZ - 374.20 Rights-of-Way	2003	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
ARIZ - 374.20 Rights-of-Way	2004	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA					
ARIZ - 374.20 Rights-of-Way	2005	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA				
ARIZ - 374.20 Rights-of-Way	2006	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA			
ARIZ - 374.20 Rights-of-Way	2007	22,759.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 374.20 Rights-of-Way	2008	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 374.20 Rights-of-Way	2009	-	-	-	-	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 374.20 Rights-of-Way	2010	-	-	-	-	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 374.20 Rights-of-Way	2011	-	-	-	-	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 374.20 Rights-of-Way	2012	-	-	-	-	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 374.20 Rights-of-Way	2013	-	-	-	-	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 374.20 Rights-of-Way	2014	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 374.20 Rights-of-Way	2015	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ARIZ - 376.00 Mains	1993	2,582,622.00	-	568,551.00	(568,551.00)	-22.01%																
ARIZ - 376.00 Mains	1994	1,329,806.00	-	624,863.00	(624,863.00)	-46.99%	-30.50%															
ARIZ - 376.00 Mains	1995	3,091,952.00	-	1,195,698.00	(1,195,698.00)	-38.67%	-41.17%	-34.11%														
ARIZ - 376.00 Mains	1996	2,086,576.00	468.00	730,666.00	(730,198.00)	-35.00%	-37.19%	-39.19%	-34.31%													
ARIZ - 376.00 Mains	1997	1,927,071.00	-	629,916.00	(629,916.00)	-32.69%	-33.89%	-35.97%	-37.71%	-34.03%												
ARIZ - 376.00 Mains	1998	2,264,393.00	-	563,678.00	(563,678.00)	-24.89%	-28.48%	-30.64%	-33.29%	-34.99%	-32.47%											
ARIZ - 376.00 Mains	1999	2,840,061.00	-	675,575.00	(675,575.00)	-23.79%	-24.26%	-26.58%	-28.51%	-31.08%	-32.64%	-30.94%										
ARIZ - 376.00 Mains	2000	2,864,349.00	-	388,771.00	(388,771.00)	-13.62%	-18.69%	-20.46%	-22.84%	-24.96%	-27.77%	-29.33%	-28.34%									
ARIZ - 376.00 Mains	2001	2,373,860.00	-	634,416.00	(634,416.00)	-26.73%	-19.57%	-21.05%	-21.90%	-23.59%	-26.26%	-27.63%	-29.00%	-28.16%								
ARIZ - 376.00 Mains	2002	3,049,515.00	-	784,192.00	(784,192.00)	-25.72%	-26.16%	-21.83%	-22.33%	-22.77%	-24.02%	-25.33%	-27.36%	-28.54%	-27.85%							
ARIZ - 376.00 Mains	2003	3,138,162.00	-	841,107.00	(841,107.00)	-26.80%	-26.27%	-26.39%	-23.20%	-23.32%	-23.63%	-24.49%	-25.56%	-27.27%	-28.32%	-27.73%						
ARIZ - 376.00 Mains	2004	3,379,469.00	-	580,446.00	(580,446.00)	-17.18%	-21.81%	-23.06%	-23.78%	-21.82%	-22.14%	-22.45%	-23.36%	-24.37%	-26.01%	-26.99%	-26.58%					
ARIZ - 376.00 Mains	2005	2,511,320.00	-	498,904.00	(498,904.00)	-19.87%	-18.32%	-21.27%	-22.39%	-23.10%	-21.64%	-21.86%	-22.16%	-23.00%	-23.94%	-25.49%	-26.41%	-26.07%				
ARIZ - 376.00 Mains	2006	2,378,319.33	-	512,089.00	(512,089.00)	-21.53%	-20.68%	-19.25%	-21.32%	-22.25%	-22.88%	-21.54%	-21.82%	-22.10%	-22.87%	-23.74%	-25.19%	-26.06%	-25.77%			
ARIZ - 376.00 Mains	2007	3,464,438.40	-	778,505.00	(778,505.00)	-22.47%	-22.09%	-21.42%	-20.20%	-21.59%	-22.29%	-22.81%	-21.68%	-21.91%	-22.15%	-22.82%	-23.61%	-24.93%	-25.73%	-25.48%		
ARIZ - 376.00 Mains	2008	4,705,621.72	-	889,561.00	(889,561.00)	-18.90%	-20.42%	-20.67%	-20.51%	-19.83%	-20.95%	-21.59%	-22.08%	-21.21%	-21.45%	-21.68%	-22.29%	-23.01%	-24.22%	-24.96%		
ARIZ - 376.00 Mains	2009	7,425,367.55	-	1,297,824.06	(1,297,824.06)	-17.48%	-18.03%	-19.02%	-19.36%	-19.41%	-19.10%	-19.99%	-20.57%	-21.02%	-20.42%	-20.67%	-20.91%	-21.45%	-22.08%	-23.16%		
ARIZ - 376.00 Mains	2010	7,057,129.44	24,439.00	1,522,991.89	(1,498,552.89)	-21.23%	-19.31%	-19.21%	-19.71%	-19.88%	-19.88%	-19.58%	-20.25%	-20.70%	-21.06%	-20.56%	-20.76%	-20.96%	-21.42%	-21.97%		
ARIZ - 376.00 Mains	2011	5,667,832.69	-	1,220,613.08	(1,220,613.08)	-21.54%	-21.37%	-19.94%	-19.74%	-20.07%	-20.19%	-20.16%	-19.89%	-20.43%	-20.81%	-21.12%	-20.67%	-20.85%	-21.02%	-21.43%		
ARIZ - 376.00 Mains	2012	5,255,555.61	-	1,743,685.85	(1,743,685.85)	-33.18%	-27.14%	-24.82%	-22.67%	-22.09%	-22.13%	-22.09%	-21.94%	-21.56%	-21.82%	-22.16%	-22.38%	-21.91%	-22.00%	-22.12%	-24.01%	
ARIZ - 376.00 Mains	2013	5,284,475.08	-	2,742,019.54	(2,742,019.54)	-51.89%	-42.56%	-36.21%	-30.97%	-27.70%	-26.53%	-26.17%	-25.90%	-25.56%	-24.96%	-25.07%	-25.11%	-25.18%	-24.61%	-24.58%	-26.12%	
ARIZ - 376.00 Mains	2014	5,471,831.19	-	1,858,029.65	(1,858,029.65)	-33.96%	-42.77%	-39.62%	-34.89%	-31.54%	-28.65%	-27.53%	-27.13%	-26.85%	-26.49%	-25.89%	-25.94%	-25.93%	-25.96%	-25.41%	-26.32%	
ARIZ - 376.00 Mains	2015	1,385,718.14	-	5,230,681.09	(5,230,681.09)	-377.47%	-103.37%	-80.96%	-56.53%	-55.47%	-47.45%	-41.52%	-39.00%	-37.75%	-35.95%	-35.10%	-34.92%	-34.47%	-34.03%	-33.75%	-32.34%	-32.49%
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1993	576,354.00	-	160,240.00	(160,240.00)	-27.85%																
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1994	495,530.00	19,492.00	232,486.00	(212,994.00)	-42.98%	-34.85%															
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1995	652,870.00	-	225,295.00	(225,295.00)	-34.51%	-38.17%	-34.72%														
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1996	508,071.00	-	387,341.00	(387,341.00)	-76.24%	-52.77%	-49.84%	-44.17%													
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1997	306,702.00	-	126,274.00	(126,274.00)	-41.17%	-63.04%	-50.35%	-48.49%	-43.81%												
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1998	441,616.00	-	147,695.00	(147,695.00)	-33.44%	-36.61%	-52.64%	-46.44%	-45.73%	-42.27%											
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	1999	885,643.00	-	929,904.00	(929,904.00)	-105.00%	-81.19%	-73.68%	-74.29%	-64.99%	-61.68%	-56.64%										
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2000	246,272.00	-	119,944.00	(119,944.00)	-48.70%	-92.75%	-76.11%	-70.41%	-71.65%	-63.67%	-60.78%	-56.17%									
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2001	211,916.00	-	63,413.00	(63,413.00)	-29.92%	-40.02%	-82.84%	-70.62%	-66.31%	-68.25%	-61.48%	-59.03%	-54.88%								
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2002	298,041.00	-	144,061.00	(144,061.00)	-48.34%	-40.68%	-43.30%	-76.68%	-67.44%	-64.07%	-66.20%	-60.37%	-58.24%	-54.46%							
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2003	296,196.00	-	52,909.00	(52,909.00)	-17.86%	-33.16%	-32.30%	-38.14%	-67.61%	-61.27%	-58.97%	-61.72%	-57.10%	-55.49%	-52.26%						
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2004	420,339.00	-	88,171.00	(88,171.00)	-20.98%	-19.69%	-28.10%	-28.42%	-31.81%	-59.29%	-55.22%	-53.83%	-56.98%	-53.54%	-52.44%	-49.79%					
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2005	632,288.00	-	151,133.00	(151,133.00)	-23.90%	-22.73%	-21.66%	-26.49%	-26.88%	-29.44%	-51.81%	-49.45%	-48.77%	-52.06%	-49.72%	-49.10%	-47.06%				
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2006	245,660.00	-	34,155.00	(34,155.00)	-13.90%	-21.10%	-21.06%	-20.47%	-24.86%	-25.37%	-27.81%	-48.93%	-47.07%	-46.62%	-48.97%	-48.01%	-47.57%	-45.74%			
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2007	407,266.55	-	106,412.00	(106,412.00)	-26.13%	-21.53%	-22.70%	-22.27%	-21.62%	-25.08%	-25.49%	-27.56%	-46.39%	-44.99%	-44.72%	-47.99%	-46.40%	-46.12%	-44.54%		
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2008	444,441.96	-	66,020.00	(66,020.00)	-14.85%	-20.25%	-18.83%	-20.68%	-20.74%	-20.39%	-23.43%	-23.89%	-25.80%	-42.96%	-42.03%	-41.98%	-45.23%	-44.07%	-43.98%		
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2009	939,366.63	-	99,810.77	(99,810.77)	-10.63%	-11.98%	-15.20%	-15.04%	-17.14%	-17.66%	-17.68%	-20.16%	-20.69%	-22.36%	-36.92%	-36.64%	-36.88%	-40.06%	-39.54%		
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2010	910,288.30	-	285,382.23	(285,382.23)	-31.35%	-20.83%	-19.87%	-20.64%	-20.08%	-20.76%	-20.78%	-20.58%	-22.38%	-22.71%	-23.98%	-36.06%	-35.88%	-36.12%	-38.96%		
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2011	817,213.57	-	49,986.82	(49,986.82)	-6.12%	-19.41%	-16.32%	-16.11%	-17.27%	-17.05%	-18.03%	-18.29%	-18.27%	-19.92%	-20.30%	-21.49%	-32.44%	-32.60%	-32.86%		
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2012	581,130.91	-	153,419.29	(153,419.29)	-26.40%	-14.56%	-21.17%	-18.12%	-17.73%	-18.56%	-18.30%	-19.01%	-19.16%	-19.10%	-20.55%	-20.87%	-21.93%	-31.96%	-32.05%	-34.94%	
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2013	749,956.92	-	162,024.23	(162,024.23)	-21.60%	-23.70%	-17.01%	-21.26%	-18.78%	-18.38%	-19.03%	-18.78%	-19.35%	-19.46%	-19.39%	-20.67%	-20.95%	-21.90%	-31.00%	-34.38%	
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2014	752,493.39	-	61,660.46	(61,660.46)	-8.19%	-14.89%	-18.10%	-14.72%	-18.69%	-17.10%	-16.91%	-17.58%	-17.42%	-18.06%	-18.23%	-18.22%	-19.42%	-19.70%	-20.60%	-32.15%	
ARIZ - 378.00 Meas & Reg Sta Eq, Gn	2015	236,272.00	-	424,344.51	(424,344.51)	-179.60%	-49.15%	-37.27%	-34.55%	-27.14%	-28.09%	-24.80%	-23.98%	-24.13%	-23.72%	-23.74%	-23.58%	-23.35%	-24.31%	-24.46%	-35.37%	-35.28%
ARIZ - 380.00 Services	1993	2,777,130.00	-	1,278,574.00	(1,278,574.00)	-46.04%																
ARIZ - 380.00 Services	1994	3,145,240.00	-	1,533,492.00	(1,533,492.00)	-48.76%	-47.48%															
ARIZ - 380.00 Services	1995	3,293,854.00	-	1,327,426.00	(1,327,426.00)	-40.30%	-44.43%	-44.92%														
ARIZ - 380.00 Services	1996	2,971,479.00	-	1,025,319.00	(1,025,319.00)	-34.51%	-37.56%	-41.30%	-42.38%													
ARIZ - 380.00 Services	1997	2,500,487.00	-	954,532.00	(954,532.00)	-38.17%	-36.18%	-37.73%	-40.64%	-41.66%												
ARIZ - 380.00 Services	1998	2,297,332.00	-	716,807.00	(716,807.00)	-31.20%	-34.84%	-34.71%	-36.37%	-39.11%	-40.25%											
ARIZ - 380.00 Services	1999	2,728,684.00	-	999,176.00	(999,176.00)	-36.62%	-34.14%	-35.48%	-35.21%	-36.42%	-38.71%	-39.74%										
ARIZ - 380.00 Services	2000	2,408,335.00	-	930,470.00	(930,470.00)	-38.64%	-37.56%	-35.60%	-36.25%	-35.85%	-36.75%	-38.70%	-39.62%									
ARIZ - 380.00 Services	2001	2,361,754.00	-	926,473.00	(926,473.00)	-39.23%	-38.93%	-38.09%	-36.47%	-36.82%	-36.37%	-37.07%	-38.76%	-39.59%								
ARIZ - 380.00 Services	2002	2,692,993.00	-	1,234,335.00	(1,234,335.00)	-45.84%	-42.75%	-41.42%	-40.13%	-38.49%	-38.44%	-37.79%	-38.18%	-39.54%	-40.20%							
ARIZ - 380.00 Services	2003	2,917,978.00	-	1,116,387.00	(1,116,387.00)	-38.26%	-41.90%	-41.11%	-40.53%	-39.72%	-38.45%	-38.41%	-37.85%	-38.19%	-39.40%	-40.02%						
ARIZ - 380.00 Services	2004	3,430,712.00	-	1,438,734.00	(1,438,734.00)	-41.94%	-40.25%	-41.91%	-41.36%	-40.88%	-40.18%	-39.08%	-38.98%	-38.43%	-38.65%	-39.69%	-40.21%					
ARIZ - 380.00 Services	2005	2,696,543.00	-	1,467,729.00	(1,467,729.00)	-54.43%	-47.43%	-44.47%	-44.79%	-43.86%	-43.09%	-42.18%	-41.00%	-40.71%	-40.03%	-40.06%	-40.88%	-41.27%				
ARIZ - 380.00 Services	2006	4,041,947.00	-	1,383,267.00	(1,383,267.00)	-34.22%	-42.31%	-42.18%	-41.31%	-42.08%	-41.71%	-41.35%	-40.79%	-39.93%	-39.78%	-39.27%	-39.37%	-40.16%	-40.56%			
ARIZ - 380.00 Services	2007	3,990,321.00	-	1,780,272.00	(1,780,272.00)	-44.61%	-39.39%	-43.17%	-42.87%	-42.08%	-42.59%	-42.23%	-41.88%	-41.35%	-40.56%	-40.38%	-39.88%	-39.92%	-40.59%	-40.93%		
ARIZ - 380.00 Services	2008	3,035,470.30	-	1,834,578.00	(1,834,578.00)	-60.44%	-51.46%	-45.16%	-46.98%	-45.97%	-44.85%	-44.97%	-44.43%	-43.92%	-43.27%	-42.42%	-42.11%	-41.52%	-41.42%	-41.94%		
ARIZ - 380.00 Services	2009	4,733,764.06	-	1,729,354.87	(1,729,354.87)	-36.53%	-45.87%	-45.46%	-42.57%	-44.30%	-43.93%	-43.27%	-43.52%	-43.18%	-42.84%	-42.36%	-41.67%	-41.46%	-40.97%	-40.92%		
ARIZ - 380.00 Services	2010	4,074,379.94	-	1,639,128.03	(1,639,128.03)	-40.23%	-38.24%	-43.93%	-44.10%	-42.09%	-43.57%	-43.35%	-42.84%	-43.09%	-42.83%	-42.55%	-42.13%	-41.53%	-41.34%	-40.90%		
ARIZ - 380.00 Services	2011	6,173,739.01	-	1,540,263.89	(1,540,263.89)	-24.95%	-31.02%	-32.76%	-37.43%	-38.73%	-38.03%	-39.57%	-39.82%	-39.69%	-40.13%	-40.08%	-39.99%	-39.79%	-39.36%	-39.32%		
ARIZ - 380.00 Services	2012	5,063,476.93	-	1,653,716.40	(1,653,716.40)	-32.53%	-28.37%	-31.52%	-32.71%	-36.35%	-37.57%	-37.13%	-38.51%	-38.83%	-38.79%	-39.23%	-39.23%	-39.20%	-39.06%	-38.72%	-39.36%	
ARIZ - 380.00 Services	2013	3,398,449.09	-	2,269,607.31	(2,269,607.31)	-66.78%	-46.26%	-37.28%	-37.92%	-37.64%	-40.25%	-40.82%	-40.05%	-41.09%	-41.16%	-40.97%	-41.26%	-41.15%	-41.04%	-40.81%	-40.46%	
ARIZ - 380.00 Services	2014	4,340,903.99	-	2,987,830.68	(2,987,830.68)	-68.83%	-67.93%	-53.90%	-44.49%	-43.74%	-42.51%	-44.27%	-44.31%	-43.26%	-43.99%	-43.83%	-43.49%	-43.62%	-43.42%	-43.21%	-41.86%	

ARIZONA RATE JURISDICTION
NET SALVAGE HISTORY
AS ADJUSTED

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %	11-yr Net Salv. %	12-yr Net Salv. %	13-yr Net Salv. %	14-yr Net Salv. %	15-yr Net Salv. %	20-yr Net Salv. %	24-yr Net Salv. %
ARIZ - 380.00 Services	2015	10,178,923.50	-	##########	(27,095,366.43)	-266.19%	-207.19%	-180.56%	-147.84%	-121.84%	-111.84%	-102.46%	-99.34%	-94.49%	-89.53%	-87.70%	-84.85%	-82.51%	-80.89%	-79.33%	-71.95%	-69.03%
ARIZ - 381.00 Meters	1993	126,940.00	-	57,544.00	(57,544.00)	-45.33%																
ARIZ - 381.00 Meters	1994	641,015.00	-	46,261.00	(46,261.00)	-7.22%	-13.52%															
ARIZ - 381.00 Meters	1995	591,425.00	-	51,100.00	(51,100.00)	-8.64%	-7.90%	-11.40%														
ARIZ - 381.00 Meters	1996	650,079.00	-	55,896.00	(55,896.00)	-8.60%	-8.62%	-8.14%	-10.49%													
ARIZ - 381.00 Meters	1997	1,140,302.00	-	57,169.00	(57,169.00)	-5.01%	-6.32%	-6.89%	-6.96%	-8.51%												
ARIZ - 381.00 Meters	1998	613,075.00	-	44,923.00	(44,923.00)	-7.33%	-5.82%	-6.57%	-6.98%	-7.02%	-8.32%											
ARIZ - 381.00 Meters	1999	1,164,893.00	-	25,313.00	(25,313.00)	-2.17%	-3.96%	-4.37%	-5.14%	-6.63%	-5.85%	-6.86%										
ARIZ - 381.00 Meters	2000	1,059,301.00	-	25,978.00	(25,978.00)	-2.46%	-2.31%	-3.39%	-3.86%	-4.52%	-4.99%	-5.23%	-6.08%									
ARIZ - 381.00 Meters	2001	3,230,499.00	-	60,958.00	(60,958.00)	-1.89%	-2.03%	-2.06%	-2.59%	-2.97%	-3.44%	-3.80%	-4.04%	-4.61%								
ARIZ - 381.00 Meters	2002	2,268,210.00	-	82,557.00	(82,557.00)	-3.64%	-2.61%	-2.58%	-2.52%	-2.88%	-3.13%	-3.48%	-3.77%	-3.96%	-4.42%							
ARIZ - 381.00 Meters	2003	2,631,338.00	-	66,457.00	(66,457.00)	-2.53%	-3.04%	-2.58%	-2.57%	-2.52%	-2.79%	-3.00%	-3.29%	-3.52%	-3.69%	-4.07%						
ARIZ - 381.00 Meters	2004	2,366,324.00	-	19,773.00	(19,773.00)	-0.84%	-1.73%	-2.32%	-2.19%	-2.21%	-2.21%	-2.44%	-2.66%	-2.90%	-3.12%	-3.28%	-3.60%					
ARIZ - 381.00 Meters	2005	2,633,575.00	-	14,686.00	(14,686.00)	-0.56%	-0.69%	-1.32%	-1.85%	-1.86%	-1.91%	-1.93%	-2.13%	-2.33%	-2.56%	-2.75%	-2.90%	-3.18%				
ARIZ - 381.00 Meters	2006	4,447,312.00	-	22,553.00	(22,553.00)	-0.51%	-0.53%	-0.60%	-1.02%	-1.44%	-1.52%	-1.57%	-1.61%	-1.78%	-1.95%	-2.14%	-2.31%	-2.45%	-2.68%			
ARIZ - 381.00 Meters	2007	4,523,637.00	-	16,414.00	(16,414.00)	-0.36%	-0.43%	-0.46%	-0.53%	-0.84%	-1.18%	-1.28%	-1.34%	-1.38%	-1.52%	-1.67%	-1.84%	-1.99%	-2.11%	-2.31%		
ARIZ - 381.00 Meters	2008	4,362,845.05	-	35,592.00	(35,592.00)	-0.82%	-0.59%	-0.56%	-0.56%	-0.59%	-0.84%	-1.11%	-1.21%	-1.25%	-1.29%	-1.42%	-1.56%	-1.70%	-1.83%	-1.94%		
ARIZ - 381.00 Meters	2009	4,938,610.16	-	33,028.48	(33,028.48)	-0.67%	-0.74%	-0.62%	-0.59%	-0.58%	-0.61%	-0.80%	-1.03%	-1.12%	-1.16%	-1.20%	-1.31%	-1.43%	-1.56%	-1.67%		
ARIZ - 381.00 Meters	2010	2,564,112.48	-	19,660.04	(19,660.04)	-0.77%	-0.70%	-0.74%	-0.64%	-0.61%	-0.60%	-0.63%	-0.80%	-1.01%	-1.09%	-1.14%	-1.17%	-1.27%	-1.38%	-1.51%		
ARIZ - 381.00 Meters	2011	3,241,209.12	40,974.96	14,173.39	26,801.57	0.83%	0.12%	-0.24%	-0.41%	-0.40%	-0.42%	-0.43%	-0.46%	-0.64%	-0.84%	-0.93%	-0.97%	-1.00%	-1.10%	-1.21%		
ARIZ - 381.00 Meters	2012	5,411,519.21	-	(31,058.44)	31,058.44	0.67%	0.67%	0.34%	0.03%	-0.15%	-0.19%	-0.24%	-0.26%	-0.30%	-0.46%	-0.64%	-0.74%	-0.78%	-0.81%	-0.90%	-1.39%	
ARIZ - 381.00 Meters	2013	8,241,237.68	-	(286,880.58)	286,880.58	3.48%	2.33%	2.04%	1.67%	1.20%	0.89%	0.72%	0.58%	0.50%	0.43%	0.26%	0.07%	-0.05%	-0.10%	-0.15%	-0.59%	
ARIZ - 381.00 Meters	2014	2,688,155.12	-	40,486.82	(40,486.82)	-1.51%	2.25%	1.70%	1.55%	1.29%	0.93%	0.69%	0.56%	0.44%	0.38%	0.31%	0.16%	-0.01%	-0.13%	-0.17%	-0.56%	
ARIZ - 381.00 Meters	2015	4,747,182.58	-	110,637.28	-110637.28	-2.33%	-2.03%	0.87%	0.79%	0.80%	0.65%	0.44%	0.29%	0.22%	0.15%	0.11%	0.06%	-0.07%	-0.21%	-0.31%	-0.62%	-0.84%
ARIZ - 385.00 Industrial M&R Statio	1993	34,265.00	-	1,488.00	(1,488.00)	-4.34%																
ARIZ - 385.00 Industrial M&R Statio	1994	19,120.00	-	2,676.00	(2,676.00)	-14.00%	-7.80%															
ARIZ - 385.00 Industrial M&R Statio	1995	11,682.00	-	1,704.00	(1,704.00)	-14.59%	-14.22%	-9.02%														
ARIZ - 385.00 Industrial M&R Statio	1996	77,036.00	6,220.00	9,946.00	(3,726.00)	-4.84%	-6.12%	-7.52%	-6.75%													
ARIZ - 385.00 Industrial M&R Statio	1997	23,564.00	-	31,688.00	(31,688.00)	-134.48%	-35.20%	-33.06%	-30.28%	-24.92%												
ARIZ - 385.00 Industrial M&R Statio	1998	29,255.00	-	4,529.00	(4,529.00)	-15.48%	-68.57%	-30.76%	-29.42%	-27.59%	-23.50%											
ARIZ - 385.00 Industrial M&R Statio	1999	7,246.00	-	8,448.00	(8,448.00)	-116.59%	-35.55%	-74.36%	-35.30%	-33.67%	-31.43%	-26.84%										
ARIZ - 385.00 Industrial M&R Statio	2000	4,120.00	-	4.00	(4.00)	-0.10%	-74.36%	-31.96%	-69.59%	-34.27%	-32.77%	-30.68%	-26.30%									
ARIZ - 385.00 Industrial M&R Statio	2001	1,019.00	-	-	-	0.00%	-0.08%	-68.24%	-31.17%	-68.51%	-34.02%	-32.55%	-30.60%	-26.18%								
ARIZ - 385.00 Industrial M&R Statio	2002	11,093.00	-	4,162.00	(4,162.00)	-37.52%	-34.35%	-25.67%	-53.73%	-32.51%	-64.00%	-34.28%	-32.88%	-30.92%	-26.75%							
ARIZ - 385.00 Industrial M&R Statio	2003	6,456.00	-	6,860.00	(6,860.00)	-106.26%	-62.81%	-59.36%	-48.60%	-65.06%	-40.55%	-67.30%	-37.18%	-35.65%	-33.47%	-29.03%						
ARIZ - 385.00 Industrial M&R Statio	2004	23,849.00	-	9,740.00	(9,740.00)	-40.84%	-54.78%	-50.15%	-48.95%	-44.62%	-54.32%	-40.64%	-51.38%	-37.66%	-36.28%	-34.29%	-30.17%					
ARIZ - 385.00 Industrial M&R Statio	2005	29,887.00	-	-	-	0.00%	-18.13%	-27.58%	-29.13%	-28.71%	-27.17%	-34.92%	-29.88%	-47.94%	-32.39%	-31.46%	-30.10%	-26.93%				
ARIZ - 385.00 Industrial M&R Statio	2006	19,760.00	-	2,530.00	(2,530.00)	-12.80%	-5.10%	-16.69%	-23.93%	-25.58%	-25.30%	-24.22%	-30.69%	-27.34%	-43.50%	-30.73%	-29.96%	-28.80%	-25.99%			
ARIZ - 385.00 Industrial M&R Statio	2007	1,030.00	-	1,126.00	(1,126.00)	-109.32%	-17.59%	-7.21%	-17.97%	-25.01%	-26.52%	-26.23%	-25.12%	-31.47%	-27.97%	-43.93%	-31.07%	-30.29%	-29.12%	-26.28%		
ARIZ - 385.00 Industrial M&R Statio	2008	6,256.00	-	2,701.00	(2,701.00)	-43.17%	-52.53%	-23.50%	-11.17%	-19.93%	-26.32%	-27.58%	-27.30%	-26.21%	-32.13%	-28.65%	-43.90%	-31.39%	-30.61%	-29.44%		
ARIZ - 385.00 Industrial M&R Statio	2009	(5,288.82)	-	873.09	(873.09)	16.51%	-369.54%	-235.34%	-33.23%	-14.00%	-22.48%	-29.08%	-30.09%	-29.76%	-28.51%	-34.57%	-30.42%	-45.92%	-32.47%	-31.62%		
ARIZ - 385.00 Industrial M&R Statio	2010	96,066.74	-	-	-	0.00%	-0.96%	-3.58%	-4.79%	-6.14%	-4.89%	-9.89%	-13.39%	-14.80%	-14.72%	-14.41%	-18.09%	-17.76%	-28.57%	-23.05%		
ARIZ - 385.00 Industrial M&R Statio	2011	35,625.87	-	337.76	(337.76)	-0.95%	-0.26%	-0.96%	-2.95%	-3.77%	-4.93%	-4.13%	-8.35%	-11.31%	-12.61%	-12.55%	-12.33%	-15.51%	-15.51%	-25.18%		
ARIZ - 385.00 Industrial M&R Statio	2012	49,627.94	-	551.13	(551.13)	-1.11%	-1.04%	-0.49%	-1.00%	-2.45%	-3.05%	-4.00%	-3.49%	-6.95%	-9.39%	-10.53%	-10.49%	-10.33%	-13.02%	-13.25%	-17.26%	
ARIZ - 385.00 Industrial M&R Statio	2013	10,358.54	-	-	-	0.00%	-0.92%	-0.93%	-0.46%	-0.95%	-2.32%	-2.89%	3.80%	-3.34%	-6.68%	-9.03%	-10.14%	-10.11%	-9.97%	-12.57%	-17.84%	
ARIZ - 385.00 Industrial M&R Statio	2014	437.95	-	-	-	0.00%	0.00%	-0.91%	-0.93%	-0.46%	-0.94%	-2.31%	-2.88%	-3.80%	-3.33%	-6.67%	-9.02%	-10.13%	-10.09%	-9.95%	-17.99%	
ARIZ - 385.00 Industrial M&R Statio	2015	9,318.49	-	417.65	(417.65)	-4.48%	-4.28%	-2.08%	-1.39%	-1.24%	-0.65%	-1.11%	-2.41%	-2.95%	-3.82%	-3.37%	-6.60%	-8.87%	-9.96%	-9.92%	-17.79%	-16.65%
ARIZ - 390.10 Structures & Improvem	1993	128,616.16	93,215.00	(360.00)	93,575.00	72.76%																
ARIZ - 390.10 Structures & Improvem	1994	9,075.00	-	1,868.00	(1,868.00)	-20.58%	66.60%															
ARIZ - 390.10 Structures & Improvem	1995	33,943.00	2,430.00	-	2,430.00	7.16%	1.31%	54.85%														
ARIZ - 390.10 Structures & Improvem	1996	7,189.57	-	-	-	0.00%	5.91%	1.12%	52.64%													
ARIZ - 390.10 Structures & Improvem	1997	235,700.00	-	36,531.00	(36,531.00)	-15.50%	-15.04%	-12.32%	-12.58%	13.90%												
ARIZ - 390.10 Structures & Improvem	1998	151,146.00	-	100,202.00	(100,202.00)	-66.29%	-35.36%	-34.70%	-31.38%	-31.16%	-7.63%											
ARIZ - 390.10 Structures & Improvem	1999	101,313.00	-	-	-	0.00%	-39.59%	-28.01%	-27.60%	-25.37%	-25.29%	-6.39%										
ARIZ - 390.10 Structures & Improvem	2000	67,068.00	-	-	-	0.00%	0.00%	-31.36%	-24.63%	-24.31%	-22.52%	-22.49%	-5.80%									
ARIZ - 390.10 Structures & Improvem	2001	456,998.00	-	-	-	0.00%	0.00%	0.00%	-12.90%	-13.51%	-13.41%	-12.75%	-12.82%	-3.58%								
ARIZ - 390.10 Structures & Improvem	2002	98,430.00	-	-	-	0.00%	0.00%	0.00%	0.00%	-11.46%	-12.31%	-12.23%	-11.66%	-11.73%	-3.30%							
ARIZ - 390.10 Structures & Improvem	2003	2,432.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	-11.42%	-12.28%	-12.21%	-11.64%	-11.71%	-3.30%						
ARIZ - 390.10 Structures & Improvem	2004	17,204.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-11.20%	-12.10%	-12.02%	-11.46%	-11.53%	-3.25%					
ARIZ - 390.10 Structures & Improvem	2005	621,916.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-6.61%	-7.80%	-7.77%	-7.49%	-7.55%	-2.21%				
ARIZ - 390.10 Structures & Improvem	2006	99,342.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-6.20%	-7.38%	-7.36%	-7.10%	-7.16%	-2.10%			
ARIZ - 390.10 Structures & Improvem	2007	127,647.60	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-5.75%	-6.91%	-6.88%	-6.65%	-6.71%	-1.97%		
ARIZ - 390.10 Structures & Improvem	2008	235,408.72	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-5.06%	-6.17%	-6.15%	-5.95%	-6.01%		
ARIZ - 390.10 Structures & Improvem	2009	334,831.33	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-4.33%	-5.36%	-5.35%	-5.18%		
ARIZ - 390.10 Structures & Improvem	2010	161,157.37	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-4.05%	-5.04%	-5.03%		
ARIZ - 390.10 Structures & Improvem	2011	561,054.68	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-3.30%	-4.18%		
ARIZ - 390.10 Structures & Improvem	2012	33,300.79	71.25	-	71.25	0.21%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-3.26%	-1.22%	
ARIZ - 390.10 Structures & Improvem	2013	1,660,408.01	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-2.61%	
ARIZ - 390.10 Structures & Improvem	2014	42,046.29	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-2.56%	
ARIZ - 390.10 Structures & Improvem	2015	1,764,480.99	-	50,154.09	(50,154.09)	-2.84%	-2.78%	-1.37%	-1.35%	-1.18%	-1.13%	-1.05%	-1.00%	-0.98%	-0.96%	-0.86%	-0.85%	-0.85%	-0.84%	-0.78%	-2.68%	-1.30%
ARIZ - 391.00 Office Furniture & Eq	1993	443,836.00	-	-	-	0.00%																
ARIZ - 391.00 Office Furniture & Eq	1994	29,590.00	4,204.00	-	4,204.00	14.21%	0.89%															
ARIZ - 391.00 Office Furniture & Eq	1995	15,187.00	50.00	-	50.00	0.33%	9.50%	0.87%														
ARIZ - 391.00 Office Furniture & Eq	1996	4,059.00	-	-	-	0.00%	0.26%	8.71%	0.86%													
ARIZ - 391.00 Office Furniture & Eq	1997	4,729.00	-	-	-	0.00%	0.00%	0.21%	7.94%	0.86%												
ARIZ - 391.00 Office Furniture & Eq	1998	39,110.00	-	-	-	0.00%	0.00%	0.00%	0.08%	4.59%	0.79%											
ARIZ - 391.00 Office Furniture & Eq	1999	129,476.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.03%	1.91%	0.64%										
ARIZ - 391.00 Office Furniture & Eq	2000	1,231,426.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.29%	0.22%									
ARIZ - 391.00 Office Furniture & Eq	2001	538,968.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.21%	0.17%								
ARIZ - 391.00 Office Furniture & Eq	2002	30,278.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.21%	0.17%							
ARIZ - 391.00 Office Furniture & Eq	2003	83,214.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.17%						
ARIZ - 391.00 Office Furniture & Eq	2004	34,665.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.16%					
ARIZ - 391.00 Office Furniture & Eq	2005	3,819.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20%	0.16%				
ARIZ - 391.00 Office Furniture & Eq	2006	50,205.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.19%	0.16%			
ARIZ - 391.00 Office Furniture & Eq	2007	1,019,344.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.13%	0.12%		
ARIZ - 391.00 Office Furniture & Eq	2008	2,181,455.15	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%		
ARIZ - 391.00 Office Furniture & Eq	2009	27,686.60	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 391.00 Office Furniture & Eq	2010	8,845.32	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		

ARIZONA RATE JURISDICTION
NET SALVAGE HISTORY
AS ADJUSTED

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %	11-yr Net Salv. %	12-yr Net Salv. %	13-yr Net Salv. %	14-yr Net Salv. %	15-yr Net Salv. %	20-yr Net Salv. %	24-yr Net Salv. %
ARIZ - 391.00 Office Furniture & Eq	2011	173,600.64	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 391.00 Office Furniture & Eq	2012	19,239.63	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.07%	
ARIZ - 391.00 Office Furniture & Eq	2013	2,870.11	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%	
ARIZ - 391.00 Office Furniture & Eq	2014	170,122.16	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 391.00 Office Furniture & Eq	2015	7,262.04	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.07%
ARIZ - 391.10 Computer Equipment	1993	63,815.00	-	-	-	0.00%																
ARIZ - 391.10 Computer Equipment	1994	56,480.00	20.00	-	20.00	0.04%	0.02%															
ARIZ - 391.10 Computer Equipment	1995	148,693.00	-	-	-	0.00%	0.01%	0.01%														
ARIZ - 391.10 Computer Equipment	1996	9,212.00	-	-	-	0.00%	0.00%	0.01%	0.01%													
ARIZ - 391.10 Computer Equipment	1997	1,975,342.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%												
ARIZ - 391.10 Computer Equipment	1998	126,729.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%											
ARIZ - 391.10 Computer Equipment	1999	5,368,286.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%										
ARIZ - 391.10 Computer Equipment	2000	28,371.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%									
ARIZ - 391.10 Computer Equipment	2001	1,093,926.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
ARIZ - 391.10 Computer Equipment	2002	478,862.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
ARIZ - 391.10 Computer Equipment	2003	444,530.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						
ARIZ - 391.10 Computer Equipment	2004	468,478.00	23,573.00	-	23,673.00	5.03%	2.58%	1.69%	0.95%	0.94%	0.30%	0.29%	0.24%	0.24%	0.23%	0.23%	0.23%					
ARIZ - 391.10 Computer Equipment	2005	3,994,249.00	675.00	-	675.00	0.02%	0.54%	0.49%	0.45%	0.37%	0.37%	0.20%	0.20%	0.17%	0.17%	0.17%	0.17%	0.17%				
ARIZ - 391.10 Computer Equipment	2006	1,386,399.00	81,838.00	-	81,838.00	5.90%	1.63%	1.81%	1.69%	1.57%	1.35%	1.34%	0.80%	0.79%	0.69%	0.69%	0.68%	0.68%	0.68%			
ARIZ - 391.10 Computer Equipment	2007	409,318.00	401,363.00	-	401,363.00	98.06%	26.91%	8.36%	8.11%	7.67%	7.07%	6.13%	6.11%	3.71%	3.68%	3.22%	3.22%	3.19%	3.17%	3.16%		
ARIZ - 391.10 Computer Equipment	2008	172,812.53	70,647.00	-	70,647.00	40.88%	81.08%	28.14%	9.30%	8.99%	8.41%	7.86%	6.84%	6.82%	4.18%	4.14%	3.63%	3.62%	3.59%	3.58%		
ARIZ - 391.10 Computer Equipment	2009	4,415,870.96	54,936.71	501.92	54,434.79	1.23%	2.73%	10.53%	9.53%	5.87%	5.83%	5.60%	5.37%	4.92%	4.91%	3.46%	3.44%	3.11%	3.10%	3.08%		
ARIZ - 391.10 Computer Equipment	2010	573,047.98	-	-	-	0.00%	1.09%	2.42%	9.45%	8.74%	5.56%	5.54%	5.33%	5.12%	4.71%	4.70%	3.36%	3.34%	3.02%	3.02%		
ARIZ - 391.10 Computer Equipment	2011	3,029,248.25	32,407.56	-	32,407.56	1.07%	0.90%	1.08%	1.92%	6.50%	6.42%	4.59%	4.60%	4.46%	4.33%	4.04%	4.03%	3.04%	3.02%	2.77%		
ARIZ - 391.10 Computer Equipment	2012	148,092.89	25,851.21	1,619.00	24,232.21	16.36%	1.78%	1.51%	1.36%	2.18%	6.67%	6.56%	4.71%	4.72%	4.58%	4.44%	4.15%	4.14%	3.13%	3.11%	2.83%	
ARIZ - 391.10 Computer Equipment	2013	226,077.23	-	-	-	0.00%	6.48%	1.66%	1.42%	1.32%	2.12%	6.50%	6.42%	4.64%	4.65%	4.51%	4.38%	4.09%	4.09%	3.10%	2.81%	
ARIZ - 391.10 Computer Equipment	2014	4,225,684.25	-	-	-	0.00%	0.00%	0.53%	0.74%	0.69%	0.88%	1.42%	4.42%	4.56%	3.58%	3.52%	3.54%	3.45%	3.27%	3.27%	2.40%	
ARIZ - 391.10 Computer Equipment	2015	3,369,269.74	64,520.87	-	64,520.87	1.91%	0.85%	0.82%	1.11%	1.10%	1.05%	1.10%	1.52%	3.91%	4.06%	3.33%	3.36%	3.30%	3.23%	3.08%	2.36%	2.34%
ARIZ - 392.11 Transportation Equip	1993	2,368,785.00	142,434.00	31.00	142,403.00	6.01%																
ARIZ - 392.11 Transportation Equip	1994	1,270,309.00	358,159.00	-	358,159.00	28.19%	13.76%															
ARIZ - 392.11 Transportation Equip	1995	1,906,950.00	811,165.00	-	811,165.00	42.54%	36.80%	23.65%														
ARIZ - 392.11 Transportation Equip	1996	322,212.00	75,999.00	-	75,999.00	23.59%	39.80%	35.59%	23.65%													
ARIZ - 392.11 Transportation Equip	1997	1,499,856.00	240,672.00	-	240,672.00	16.05%	17.38%	30.24%	29.72%	22.10%												
ARIZ - 392.11 Transportation Equip	1998	1,774,178.00	320,628.00	-	320,628.00	18.07%	17.14%	17.72%	26.32%	26.67%	21.32%											
ARIZ - 392.11 Transportation Equip	1999	1,511,772.00	241,048.00	-	241,048.00	15.94%	17.09%	16.77%	17.20%	24.08%	24.71%	20.56%										
ARIZ - 392.11 Transportation Equip	2000	1,918,841.00	470,403.00	-	470,403.00	24.51%	20.74%	19.83%	18.98%	19.19%	24.18%	24.68%	21.16%									
ARIZ - 392.11 Transportation Equip	2001	2,993,342.00	618,307.00	-	618,307.00	20.66%	22.16%	20.70%	20.13%	19.60%	19.63%	23.29%	23.77%	21.06%								
ARIZ - 392.11 Transportation Equip	2002	881,194.00	175,639.00	-	175,639.00	19.93%	20.49%	21.82%	20.61%	20.11%	19.54%	19.66%	23.06%	23.53%	21.00%							
ARIZ - 392.11 Transportation Equip	2003	1,965,316.00	302,428.00	-	302,428.00	15.39%	16.79%	18.77%	20.19%	19.50%	19.27%	18.89%	19.00%	22.04%	22.53%	20.40%						
ARIZ - 392.11 Transportation Equip	2004	277,696.00	34,978.00	-	34,978.00	12.60%	15.04%	16.42%	18.49%	19.93%	19.30%	19.11%	18.75%	18.87%	21.87%	22.36%	20.29%					
ARIZ - 392.11 Transportation Equip	2005	2,726,725.00	474,846.00	-	474,846.00	17.41%	16.97%	16.34%	16.88%	18.16%	19.29%	18.88%	18.78%	18.52%	18.62%	21.18%	21.65%	19.92%				
ARIZ - 392.11 Transportation Equip	2006	4,246,987.00	420,059.00	-	420,059.00	9.89%	12.83%	12.82%	13.37%	13.94%	15.48%	16.63%	16.57%	16.72%	16.67%	16.78%	19.01%	19.51%	18.26%			
ARIZ - 392.11 Transportation Equip	2007	5,991,844.00	798,408.00	-	798,408.00	13.32%	11.90%	13.06%	13.06%	13.35%	13.71%	14.80%	15.69%	15.71%	15.88%	15.89%	15.98%	17.79%	18.24%	17.33%		
ARIZ - 392.11 Transportation Equip	2008	4,151,830.49	757,377.00	-	757,377.00	18.24%	15.34%	13.73%	14.32%	14.29%	14.40%	14.64%	15.42%	16.11%	16.10%	16.22%	16.22%	16.29%	17.85%	18.24%		
ARIZ - 392.11 Transportation Equip	2009	3,377,492.03	455,025.83	-	455,025.83	13.47%	16.10%	14.87%	13.68%	14.18%	14.16%	14.26%	14.47%	15.17%	15.80%	15.81%	15.93%	15.94%	16.01%	17.43%		
ARIZ - 392.11 Transportation Equip	2010	2,860,720.51	495,924.17	-	495,924.17	17.34%	15.24%	16.44%	15.30%	14.19%	14.56%	14.54%	14.61%	14.78%	15.38%	15.84%	15.94%	16.05%	16.05%	16.11%		
ARIZ - 392.11 Transportation Equip	2011	2,264,258.69	703,631.72	-	703,631.72	31.08%	23.41%	19.46%	19.06%	17.22%	15.86%	16.02%	15.99%	15.94%	16.07%	16.50%	16.86%	16.81%	16.97%	16.93%		
ARIZ - 392.11 Transportation Equip	2012	3,700,022.36	814,271.85	-	814,271.85	22.01%	25.46%	22.82%	20.23%	19.73%	18.01%	16.71%	16.78%	16.74%	16.66%	16.74%	17.07%	17.46%	17.40%	17.43%	18.14%	
ARIZ - 392.11 Transportation Equip	2013	1,952,141.72	444,544.27	-	444,544.27	22.77%	22.27%	24.79%	22.81%	20.58%	20.05%	18.39%	17.13%	17.15%	17.11%	17.01%	17.09%	17.37%	17.72%	17.66%	18.94%	
ARIZ - 392.11 Transportation Equip	2014	3,774,490.07	824,711.79	-	824,711.79	21.85%	22.16%	22.10%	23.84%	22.56%	20.85%	20.36%	18.86%	17.68%	17.66%	17.62%	17.50%	17.56%	17.78%	18.08%	18.92%	
ARIZ - 392.11 Transportation Equip	2015	1,717,551.51	511,740.35	-	511,740.35	29.79%	24.33%	23.92%	23.29%	24.60%	23.33%	21.63%	21.04%	19.49%	18.29%	18.23%	18.18%	18.04%	18.08%	18.26%	18.39%	18.92%
ARIZ - 392.12 Transp Equip, Heavy	1993	-	-	-	-	NA																
ARIZ - 392.12 Transp Equip, Heavy	1994	159,509.00	-	-	-	0.00%	0.00%															
ARIZ - 392.12 Transp Equip, Heavy	1995	869,191.00	-	-	-	0.00%	0.00%	0.00%														
ARIZ - 392.12 Transp Equip, Heavy	1996	218,761.00	-	-	-	0.00%	0.00%	0.00%	0.00%													
ARIZ - 392.12 Transp Equip, Heavy	1997	133,469.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%												
ARIZ - 392.12 Transp Equip, Heavy	1998	443,056.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%											
ARIZ - 392.12 Transp Equip, Heavy	1999	232,442.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%										
ARIZ - 392.12 Transp Equip, Heavy	2000	569,502.00	94,567.00	-	94,567.00	16.61%	11.79%	7.60%	5.86%	5.92%	3.85%	3.62%	3.62%									
ARIZ - 392.12 Transp Equip, Heavy	2001	1,129,878.00	93,108.00	-	93,108.00	8.24%	11.04%	9.71%	7.90%	7.48%	6.88%	5.23%	5.01%	5.01%								
ARIZ - 392.12 Transp Equip, Heavy	2002	125,174.00	16,863.00	-	16,863.00	13.47%	8.76%	11.21%	9.94%	8.18%	7.77%	7.17%	5.51%	5.28%	5.28%							
ARIZ - 392.12 Transp Equip, Heavy	2003	721,783.00	63,572.00	-	63,572.00	8.81%	9.50%	8.78%	10.53%	9.65%	8.32%	7.99%	7.50%	6.05%	5.84%	5.84%						
ARIZ - 392.12 Transp Equip, Heavy	2004	98,586.00	25,199.00	-	25,199.00	25.57%	10.82%	11.17%	9.58%	11.09%	10.19%	8.83%	8.49%	7.99%	6.47%	6.25%	6.25%					
ARIZ - 392.12 Transp Equip, Heavy	2005	478,260.00	34,082.00	-	34,082.00	7.13%	10.28%	9.48%	9.81%	9.12%	10.48%	9.76%	8.62%	8.33%	7.89%	6.53%	6.33%	6.33%				
ARIZ - 392.12 Transp Equip, Heavy	2006	130,330.00	25,218.00	-	25,218.00	19.35%	9.74%	11.95%	10.36%	10.61%	9.61%	10.84%	10.12%	8.97%	8.68%	8.24%	6.86%	6.66%	6.66%			
ARIZ - 392.12 Transp Equip, Heavy	2007	637,328.00	66,108.00	-	66,108.00	10.37%	11.90%	10.07%	11.20%	10.37%	10.54%	9.76%	10.76%	10.15%	9.17%	8.91%	8.51%	7.26%	7.05%	7.05%		
ARIZ - 392.12 Transp Equip, Heavy	2008	538,928.51	57,267.00	-	57,267.00	10.63%	10.49%	11.37%	10.23%	11.04%	10.42%	10.56%	9.88%	10.75%	10.21%	9.32%	9.09%	8.72%	7.64%	7.35%		
ARIZ - 392.12 Transp Equip, Heavy	2009	1,154,527.08	98,613.35	-	98,613.35	8.54%	9.20%	9.52%	10.04%	9.57%	10.09%	9.84%	9.96%	9.57%	10.29%	9.88%	9.18%	8.99%	8.69%	7.69%		
ARIZ - 392.12 Transp Equip, Heavy	2010	227,709.87	68,241.13	-	68,241.13	29.97%	12.07%	11.67%	11.34%	11.73%	11.04%	11.47%	10.99%	11.07%	10.46%	11.06%	10.64%	9.91%	9.71%	9.40%		
ARIZ - 392.12 Transp Equip, Heavy	2011	1,063,449.91	127,764.81	-	127,764.81	12.01%	15.18%	12.05%	11.79%	11.54%	11.81%	11.28%	11.61%	11.21%	11.26%	10.72%	11.21%	10.84%	10.21%	10.03%		
ARIZ - 392.12 Transp Equip, Heavy	2012	964,683.47	152,351.13	-	152,351.13	15.79%	13.81%	15.44%	13.11%	12.77%	12.43%	12.63%	12.12%	12.37%	11.94%	11.97%	11.39%	11.77%	11.43%	10.84%	9.34%	
ARIZ - 392.12 Transp Equip, Heavy	2013	664,795.13	187,392.37	-	187,392.37	28.19%	20.86%	17.36%	18.34%	15.57%	14.99%	14.43%	14.55%	13.94%	14.13%	13.56%	13.56%	12.80%	13.06%	12.71%	10.52%	
ARIZ - 392.12 Transp Equip, Heavy	2014	1,017,375.96	183,991.60	-	183,991.60	18.08%	22.06%	19.79%	17.56%	18.28%	16.07%	15.55%	15.02%	15.11%	14.56%	14.71%	14.16%	14.15%	13.40%	13.59%	11.34%	
ARIZ - 392.12 Transp Equip, Heavy	2015	502,726.69	9,560.00	-	9,560.00	1.90%	12.73%	17.44%	16.93%	15.69%	16.42%	14.80%	14.43%	14.05%	14.15%	13.69%	13.85%	13.41%	13.41%	12.79%	11.80%	10.80%
ARIZ - 393.00 Stores Equipment	1993	6,600.00	-	-	-	0.00%																
ARIZ - 393.00 Stores Equipment	1994	-	-	-	-	NA	0.00%															
ARIZ - 393.00 Stores Equipment	1995	-	-	-	-	NA	NA	0.00%														
ARIZ - 393.00 Stores Equipment	1996	-	-	-	-	NA	NA	NA	0.00%													
ARIZ - 393.00 Stores Equipment	1997	12,638.00	2,000.00	-	2,000.00	15.83%	15.83%	15.83%	15.83%	10.40%												
ARIZ - 393.00 Stores Equipment	1998	13,232.00	-	-	-	0.00%	7.73%	7.73%	7.73%	7.73%	6.16%											
ARIZ - 393.00 Stores Equipment	1999	-	-	-	-	NA	0.00%	7.73%	7.73%	7.73%	7.73%	6.16%										
ARIZ - 393.00 Stores Equipment	2000	95,490.00	-	-	-	0.00%	0.00%	0.00%	1.65%	1.65%	1.65%	1.65%	1.56%									
ARIZ - 393.00 Stores Equipment	2001	158,330.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.72%	0.72%	0.72%	0.72%	0.70%								
ARIZ - 393.00 Stores Equipment	2002	3,533.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.71%	0.71%	0.71%	0.71%	0.69%							
ARIZ - 393.00 Stores Equipment	2003	30,457.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.64%	0.64%	0.64%	0.64%	0.62%						
ARIZ - 393.00 Stores Equipment	2004	15,970.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%	0.61%	0.61%	0.59%					
ARIZ - 393.00 Stores Equipment	2005	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%	0.61%	0.61%	0.59%				
ARIZ - 393.00 Stores Equipment	2006	-	-	-	-	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%	0.61%	0.61%	0.59%			

ARIZONA RATE JURISDICTION
NET SALVAGE HISTORY
AS ADJUSTED

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %	11-yr Net Salv. %	12-yr Net Salv. %	13-yr Net Salv. %	14-yr Net Salv. %	15-yr Net Salv. %	20-yr Net Salv. %	24-yr Net Salv. %
ARIZ - 393.00 Stores Equipment	2007	-	-	-	-	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%	0.61%	0.61%	0.59%		
ARIZ - 393.00 Stores Equipment	2008	-	-	-	-	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%	0.61%	0.61%		
ARIZ - 393.00 Stores Equipment	2009	-	-	-	-	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%	0.61%		
ARIZ - 393.00 Stores Equipment	2010	-	-	-	-	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%	0.61%		
ARIZ - 393.00 Stores Equipment	2011	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.61%		
ARIZ - 393.00 Stores Equipment	2012	-	-	-	-	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.59%	
ARIZ - 393.00 Stores Equipment	2013	13,864.00	4,206.40	-	4,206.40	30.30%	30.30%	30.30%	30.30%	30.30%	30.30%	30.30%	30.30%	30.30%	14.09%	6.97%	5.59%	1.84%	1.32%	1.32%	1.81%	
ARIZ - 393.00 Stores Equipment	2014	52,514.41	-	-	-	0.00%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	5.11%	3.73%	3.52%	1.53%	1.14%	1.57%	
ARIZ - 393.00 Stores Equipment	2015	46,861.91	-	-	-	0.00%	0.00%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.25%	2.54%	2.58%	1.31%	1.40%	1.38%
ARIZ - 394.00 Tools, Shop & Garage	1993	1,943,190.00	9,279.00	-	9,279.00	0.48%																
ARIZ - 394.00 Tools, Shop & Garage	1994	171,992.00	1,387.00	-	1,387.00	0.81%	0.50%															
ARIZ - 394.00 Tools, Shop & Garage	1995	62,248.00	-	-	-	0.00%	0.59%	0.49%														
ARIZ - 394.00 Tools, Shop & Garage	1996	262,832.00	1,602.00	3,370.00	(1,768.00)	-0.67%	-0.54%	-0.06%	0.36%													
ARIZ - 394.00 Tools, Shop & Garage	1997	15,814.00	3,610.00	-	3,610.00	22.83%	0.66%	0.64%	0.63%	0.61%												
ARIZ - 394.00 Tools, Shop & Garage	1998	82,868.00	2,886.00	-	2,886.00	3.48%	6.58%	1.31%	1.12%	1.03%	0.61%											
ARIZ - 394.00 Tools, Shop & Garage	1999	140,832.00	-	-	-	0.00%	1.29%	2.71%	0.94%	0.84%	0.83%	0.57%										
ARIZ - 394.00 Tools, Shop & Garage	2000	1,849,907.00	905.00	-	905.00	0.05%	0.05%	0.18%	0.35%	0.24%	0.23%	0.27%	0.36%									
ARIZ - 394.00 Tools, Shop & Garage	2001	1,173,954.00	-	-	-	0.00%	0.03%	0.03%	0.12%	0.23%	0.16%	0.16%	0.19%	0.29%								
ARIZ - 394.00 Tools, Shop & Garage	2002	259,274.00	-	-	-	0.00%	0.00%	0.03%	0.03%	0.11%	0.21%	0.15%	0.15%	0.17%	0.27%							
ARIZ - 394.00 Tools, Shop & Garage	2003	259,975.00	-	-	-	0.00%	0.00%	0.00%	0.03%	0.02%	0.10%	0.19%	0.14%	0.14%	0.16%	0.29%						
ARIZ - 394.00 Tools, Shop & Garage	2004	229,090.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.09%	0.18%	0.13%	0.13%	0.19%	0.25%					
ARIZ - 394.00 Tools, Shop & Garage	2005	696,367.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.08%	0.16%	0.11%	0.11%	0.13%	0.23%				
ARIZ - 394.00 Tools, Shop & Garage	2006	242,090.00	1,171.00	-	1,171.00	0.48%	0.12%	0.10%	0.08%	0.07%	0.04%	0.04%	0.04%	0.10%	0.17%	0.13%	0.13%	0.15%	0.24%			
ARIZ - 394.00 Tools, Shop & Garage	2007	427,056.00	16,200.00	-	16,200.00	3.79%	2.50%	1.27%	1.09%	0.94%	0.81%	0.52%	0.35%	0.34%	0.39%	0.48%	0.41%	0.40%	0.41%	0.43%		
ARIZ - 394.00 Tools, Shop & Garage	2008	204,947.14	-	-	-	0.00%	2.58%	1.98%	1.11%	0.97%	0.84%	0.74%	0.49%	0.34%	0.33%	0.38%	0.44%	0.39%	0.39%	0.40%		
ARIZ - 394.00 Tools, Shop & Garage	2009	381,737.61	-	-	-	0.00%	0.00%	1.80%	1.38%	0.89%	0.80%	0.71%	0.64%	0.44%	0.32%	0.31%	0.35%	0.41%	0.37%	0.35%		
ARIZ - 394.00 Tools, Shop & Garage	2010	205,919.29	-	-	-	0.00%	0.00%	0.00%	1.33%	1.19%	0.80%	0.73%	0.68%	0.59%	0.42%	0.31%	0.30%	0.34%	0.40%	0.35%		
ARIZ - 394.00 Tools, Shop & Garage	2011	244,846.77	-	-	-	0.00%	0.00%	0.00%	0.00%	1.11%	1.02%	0.72%	0.68%	0.60%	0.55%	0.40%	0.29%	0.29%	0.33%	0.35%		
ARIZ - 394.00 Tools, Shop & Garage	2012	236,218.47	2,309.74	-	2,309.74	0.97%	0.48%	0.34%	0.22%	0.18%	1.09%	1.01%	0.75%	0.69%	0.53%	0.59%	0.43%	0.32%	0.31%	0.35%	0.30%	
ARIZ - 394.00 Tools, Shop & Garage	2013	353,028.74	-	-	-	0.00%	0.39%	0.28%	0.22%	0.16%	0.14%	0.90%	0.85%	0.69%	0.61%	0.57%	0.52%	0.40%	0.30%	0.30%	0.35%	
ARIZ - 394.00 Tools, Shop & Garage	2014	252,168.79	-	-	-	0.00%	0.00%	0.27%	0.21%	0.16%	0.14%	0.12%	0.80%	0.77%	0.61%	0.57%	0.53%	0.40%	0.38%	0.29%	0.33%	
ARIZ - 394.00 Tools, Shop & Garage	2015	231,104.21	-	-	-	0.00%	0.00%	0.00%	0.21%	0.16%	0.15%	0.12%	0.11%	0.73%	0.71%	0.67%	0.53%	0.50%	0.46%	0.38%	0.33%	0.36%
ARIZ - 395.00 Laboratory Equipment	1993	732.00	-	-	-	0.00%																
ARIZ - 395.00 Laboratory Equipment	1994	1,071.00	-	-	-	0.00%	0.00%															
ARIZ - 395.00 Laboratory Equipment	1995	-	-	-	-	NA	0.00%	0.00%														
ARIZ - 395.00 Laboratory Equipment	1996	-	-	-	-	NA	NA	0.00%	0.00%													
ARIZ - 395.00 Laboratory Equipment	1997	928.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%												
ARIZ - 395.00 Laboratory Equipment	1998	35,721.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%											
ARIZ - 395.00 Laboratory Equipment	1999	19,463.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%										
ARIZ - 395.00 Laboratory Equipment	2000	60,151.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%									
ARIZ - 395.00 Laboratory Equipment	2001	156,237.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
ARIZ - 395.00 Laboratory Equipment	2002	98,301.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
ARIZ - 395.00 Laboratory Equipment	2003	2,677.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						
ARIZ - 395.00 Laboratory Equipment	2004	153,558.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					
ARIZ - 395.00 Laboratory Equipment	2005	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
ARIZ - 395.00 Laboratory Equipment	2006	-	-	-	-	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
ARIZ - 395.00 Laboratory Equipment	2007	3,517.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 395.00 Laboratory Equipment	2008	1,708.95	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 395.00 Laboratory Equipment	2009	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 395.00 Laboratory Equipment	2010	1,203.24	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 395.00 Laboratory Equipment	2011	17,821.66	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 395.00 Laboratory Equipment	2012	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 395.00 Laboratory Equipment	2013	11,523.36	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 395.00 Laboratory Equipment	2014	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 395.00 Laboratory Equipment	2015	3,900.89	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ARIZ - 396.00 Power Operated Equip	1993	366,566.00	16,290.00	-	16,290.00	4.58%																
ARIZ - 396.00 Power Operated Equip	1994	899,203.00	354,059.00	-	354,059.00	39.38%	29.52%															
ARIZ - 396.00 Power Operated Equip	1995	262,114.00	162,639.00	1,175.00	161,464.00	61.60%	44.39%	36.05%														
ARIZ - 396.00 Power Operated Equip	1996	146,483.00	66,804.00	-	66,804.00	45.61%	56.86%	44.53%	35.99%													
ARIZ - 396.00 Power Operated Equip	1997	5,971.00	1,900.00	-	1,900.00	31.82%	46.07%	56.52%	44.47%	36.97%												
ARIZ - 396.00 Power Operated Equip	1998	82,624.00	12,540.00	1,495.00	11,045.00	13.37%	14.61%	33.92%	48.61%	42.63%	34.91%											
ARIZ - 396.00 Power Operated Equip	1999	158,903.00	15,736.00	-	15,736.00	9.90%	11.09%	11.59%	24.24%	39.16%	36.29%	32.83%										
ARIZ - 396.00 Power Operated Equip	2000	415,729.00	61,747.00	-	61,747.00	14.85%	13.46%	13.46%	13.81%	19.39%	29.71%	34.11%	29.50%									
ARIZ - 396.00 Power Operated Equip	2001	291,061.00	82,331.00	-	82,331.00	28.29%	20.36%	18.44%	18.00%	18.08%	21.74%	29.40%	33.37%	29.46%								
ARIZ - 396.00 Power Operated Equip	2002	89,008.00	2,656.00	-	2,656.00	2.98%	22.36%	18.41%	17.00%	16.71%	16.80%	20.34%	27.78%	32.22%	28.58%							
ARIZ - 396.00 Power Operated Equip	2003	129,822.00	41,136.00	-	41,136.00	31.68%	20.01%	24.73%	20.27%	18.76%	18.37%	18.44%	21.48%	28.10%	32.19%	28.73%						
ARIZ - 396.00 Power Operated Equip	2004	560.00	1,486.00	-	1,486.00	225.00%	32.69%	20.62%	24.96%	20.42%	18.86%	18.49%	18.56%	21.58%	28.19%	32.24%	28.77%					
ARIZ - 396.00 Power Operated Equip	2005	430,558.00	157,126.00	-	157,126.00	36.48%	36.77%	36.60%	31.13%	30.25%	25.81%	23.88%	23.34%	23.37%	25.23%	29.96%	32.87%	29.79%				
ARIZ - 396.00 Power Operated Equip	2006	354,092.00	126,106.00	-	126,106.00	35.61%	36.09%	36.25%	35.60%	32.71%	31.72%	27.50%	26.10%	25.66%	25.58%	26.97%	30.81%	33.16%	30.38%			
ARIZ - 396.00 Power Operated Equip	2007	636,187.00	167,866.00	-	167,866.00	26.39%	29.63%	31.79%	31.78%	31.78%	30.22%	29.93%	27.25%	26.16%	25.74%	25.76%	28.82%	29.86%	32.04%	29.79%		
ARIZ - 396.00 Power Operated Equip	2008	514,017.42	112,161.00	-	112,161.00	21.82%	24.30%	26.96%	29.08%	29.15%	29.31%	28.22%	28.23%	26.28%	25.62%	26.00%	25.11%	28.03%	28.98%	30.89%		
ARIZ - 396.00 Power Operated Equip	2009	274,636.70	62,416.50	-	62,416.50	22.73%	22.14%	24.00%	26.31%	28.29%	28.35%	26.53%	27.60%	27.67%	25.97%	26.19%	24.90%	24.91%	25.77%	28.26%		
ARIZ - 396.00 Power Operated Equip	2010	198,944.55	113,090.75	-	113,090.75	56.86%	37.06%	26.13%	28.02%	29.38%	30.65%	30.70%	30.75%	29.81%	29.66%	27.91%	26.99%	26.68%	26.09%	27.43%		
ARIZ - 396.00 Power Operated Equip	2011	347,679.02	99,465.40	-	99,465.40	28.61%	38.86%	33.48%	28.98%	28.12%	29.29%	30.39%	30.44%	30.46%	29.67%	29.56%	27.88%	27.14%	26.36%	28.89%		
ARIZ - 396.00 Power Operated Equip	2012	156,360.98	51,805.00	-	51,805.00	33.13%	30.01%	37.61%	33.43%	29.43%	28.49%	29.51%	30.54%	30.58%	30.63%	29.84%	29.71%	28.10%	27.37%	27.09%	29.67%	
ARIZ - 396.00 Power Operated Equip	2013	51,157.01	22,002.15	-	22,002.15	43.01%	35.51%	31.21%	37.97%	33.90%	28.88%	28.83%	29.78%	30.75%	30.80%	30.83%	30.05%	29.91%	28.29%	27.67%	31.43%	
ARIZ - 396.00 Power Operated Equip	2014	127,432.67	25,369.71	-	25,369.71	19.93%	28.54%	29.62%	29.10%	35.39%	32.38%	29.12%	28.34%	29.31%	30.31%	30.36%	30.40%	29.67%	29.56%	28.03%	29.58%	
ARIZ - 396.00 Power Operated Equip	2015	1,535.94	17,494.80	-	17,494.80	1139.03%	33.28%	36.03%	34.68%	31.66%	37.28%	33.83%	30.14%	29.08%	29.95%	30.86%	30.80%	30.93%	30.15%	30.03%	28.07%	29.86%
ARIZ - 397.00 Communication Equipme	1993	42,518.00	-	-	-	0.00%																
ARIZ - 397.00 Communication Equipme	1994	8,997.00	-	-	-	0.00%	0.00%															
ARIZ - 397.00 Communication Equipme	1995	327,014.00	-	-	-	0.00%	0.00%	0.00%														
ARIZ - 397.00 Communication Equipme	1996	256,681.00	-	-	-	0.00%	0.00%	0.00%	0.00%													
ARIZ - 397.00 Communication Equipme	1997	16,810.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%												
ARIZ - 397.00 Communication Equipme	1998	117,222.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%											
ARIZ - 397.00 Communication Equipme	1999	114,548.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%										
ARIZ - 397.00 Communication Equipme	2000	539,563.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%									
ARIZ - 397.00 Communication Equipme	2001	1,054,709.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
ARIZ - 397.00 Communication Equipme	2002	379,425.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							

ARIZONA RATE JURISDICTION
NET SALVAGE HISTORY
AS ADJUSTED

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %	11-yr Net Salv. %	12-yr Net Salv. %	13-yr Net Salv. %	14-yr Net Salv. %	15-yr Net Salv. %	20-yr Net Salv. %	24-yr Net Salv. %
ARIZ - 367.00 Communication Equipme	2003	1,865,286.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						
ARIZ - 367.00 Communication Equipme	2004	45,730.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					
ARIZ - 367.00 Communication Equipme	2005	106,800.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
ARIZ - 367.00 Communication Equipme	2006	19,448.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
ARIZ - 367.00 Communication Equipme	2007	146,694.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.00 Communication Equipme	2008	320,421.88	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.00 Communication Equipme	2009	49,961.11	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.00 Communication Equipme	2010	37,468.05	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.00 Communication Equipme	2011	377,836.29	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.00 Communication Equipme	2012	232,583.08	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 367.00 Communication Equipme	2013	161,120.30	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 367.00 Communication Equipme	2014	881,750.07	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 367.00 Communication Equipme	2015	74,761.27	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ARIZ - 367.20 Telemetering Equipmen	1993	-	-	-	-	NA																
ARIZ - 367.20 Telemetering Equipmen	1994	1.00	-	-	-	0.00%	0.00%															
ARIZ - 367.20 Telemetering Equipmen	1995	7,312.00	-	-	-	0.00%	0.00%	0.00%														
ARIZ - 367.20 Telemetering Equipmen	1996	-	-	-	-	NA	0.00%	0.00%	0.00%													
ARIZ - 367.20 Telemetering Equipmen	1997	996.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%												
ARIZ - 367.20 Telemetering Equipmen	1998	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%											
ARIZ - 367.20 Telemetering Equipmen	1999	-	-	-	-	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%										
ARIZ - 367.20 Telemetering Equipmen	2000	26,266.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%									
ARIZ - 367.20 Telemetering Equipmen	2001	476,016.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
ARIZ - 367.20 Telemetering Equipmen	2002	37,564.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
ARIZ - 367.20 Telemetering Equipmen	2003	57,063.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						
ARIZ - 367.20 Telemetering Equipmen	2004	305,513.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					
ARIZ - 367.20 Telemetering Equipmen	2005	2,323.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
ARIZ - 367.20 Telemetering Equipmen	2006	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
ARIZ - 367.20 Telemetering Equipmen	2007	-	-	-	-	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.20 Telemetering Equipmen	2008	-	-	-	-	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.20 Telemetering Equipmen	2009	350,656.34	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.20 Telemetering Equipmen	2010	-	-	-	-	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.20 Telemetering Equipmen	2011	61,769.61	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 367.20 Telemetering Equipmen	2012	19,264.58	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 367.20 Telemetering Equipmen	2013	5,275.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 367.20 Telemetering Equipmen	2014	13,961.73	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
ARIZ - 367.20 Telemetering Equipmen	2015	358,290.68	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ARIZ - 368.00 Miscellaneous Equipme	1993	31,778.00	-	-	-	0.00%																
ARIZ - 368.00 Miscellaneous Equipme	1994	7,023.00	904.00	-	904.00	12.87%	2.33%															
ARIZ - 368.00 Miscellaneous Equipme	1995	7,259.00	-	-	-	0.00%	5.33%	1.96%														
ARIZ - 368.00 Miscellaneous Equipme	1996	-	-	-	-	NA	0.00%	6.33%	1.96%													
ARIZ - 368.00 Miscellaneous Equipme	1997	63,222.00	-	-	-	0.00%	0.00%	0.00%	1.17%	0.83%												
ARIZ - 368.00 Miscellaneous Equipme	1998	2,152.00	-	-	-	0.00%	0.00%	0.00%	0.00%	1.13%	0.81%											
ARIZ - 368.00 Miscellaneous Equipme	1999	45,417.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.72%	0.58%										
ARIZ - 368.00 Miscellaneous Equipme	2000	279,740.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.22%	0.21%									
ARIZ - 368.00 Miscellaneous Equipme	2001	186,620.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.16%	0.14%								
ARIZ - 368.00 Miscellaneous Equipme	2002	19,830.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.15%	0.14%							
ARIZ - 368.00 Miscellaneous Equipme	2003	20,375.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.14%	0.14%						
ARIZ - 368.00 Miscellaneous Equipme	2004	80,868.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.13%	0.12%					
ARIZ - 368.00 Miscellaneous Equipme	2005	30,134.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.12%				
ARIZ - 368.00 Miscellaneous Equipme	2006	11,050.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.11%			
ARIZ - 368.00 Miscellaneous Equipme	2007	95,447.00	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%	0.10%		
ARIZ - 368.00 Miscellaneous Equipme	2008	31,668.88	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%		
ARIZ - 368.00 Miscellaneous Equipme	2009	76,134.96	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 368.00 Miscellaneous Equipme	2010	23,963.15	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 368.00 Miscellaneous Equipme	2011	78,599.96	-	-	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
ARIZ - 368.00 Miscellaneous Equipme	2012	56,768.70	8,027.34	-	8,027.34	14.14%	5.93%	5.07%	3.42%	3.01%	2.22%	2.15%	1.99%	1.69%	1.59%	1.53%	1.12%	0.81%	0.77%	0.77%	0.78%	
ARIZ - 368.00 Miscellaneous Equipme	2013	23,437.65	-	-	-	0.00%	10.01%	6.06%	4.42%	3.11%	2.77%	2.06%	2.03%	1.88%	1.58%	1.52%	1.47%	1.09%	0.79%	0.76%	0.78%	
ARIZ - 368.00 Miscellaneous Equipme	2014	5,120.88	-	-	-	0.00%	0.00%	9.41%	4.90%	4.29%	3.05%	2.72%	2.06%	2.00%	1.88%	1.57%	1.51%	1.45%	1.08%	0.79%	0.76%	
ARIZ - 368.00 Miscellaneous Equipme	2015	24,768.30	-	-	-	0.00%	0.00%	0.00%	7.29%	4.25%	3.79%	2.78%	2.51%	1.93%	1.88%	1.76%	1.48%	1.44%	1.30%	1.05%	0.69%	0.74%

SOUTHWEST GAS CORPORATION

SYSTEM ALLOCABLE

DEPRECIATION RATE STUDY

AT DECEMBER 31, 2011

3-28-12

ALLIANCE
CONSULTING GROUP

http://www.utilityalliance.com

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Southwest Gas Corporation ("Southwest Gas" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's System Allocable utility plant depreciable assets as of December 31, 2011.

This study was conducted under the traditional depreciation study approach. The net salvage analysis in this study is paralleled the approach previously used by Southwest Gas Company in Docket 07-09030.

For General accounts, the lives of the accounts mainly remain the same. Two accounts, 390.1 and 392.11 show a shorter life than previously approved. With general property, only the 392 and 396 exhibit any net salvage.

Most of the accounts in the System Allocable property are amortized using FERC Accounting Release 15 ("AR-15") issued by the Federal Energy Regulatory Authority ("FERC"). When the theoretical reserve and actual book reserves for those accounts are compared, substantial differences between book and theoretical reserves by account exist. This study proposes to amortize the surplus or deficiency between book and theoretical reserve over the remaining life of the assets. Appendix A demonstrates those computations in depreciation expense.

This study recommends an overall increase of $540 thousand in annual depreciation expense compared to the depreciation rates currently in effect. Appendix B demonstrates the change in depreciation expense for the various accounts.

Index for Statements A, B & C

Statement A (1)(a) see Appendix A on page 27 and Appendix C on page 31.

Statement A (1)(b) see Appendix C on page 31.

Statement A (1)(c) see Appendix C on page 31.

Statement A (1)(d) see Appendix B on page 29.

Statement B see pages 3 through 9.

Statement C see pages 15 through 27.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DEPRECIATION RATE STUDY
AT DECEMBER 31, 2011

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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on Southwest Gas' books at December 31, 2011 for the System Allocable Division. The account based depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of System Allocable Division's property on a straight-line basis. Non-depreciable property and property which is amortized such as intangible software were excluded from this study.

System Allocable contains general property that supports the operations of Northern Nevada and Southern Nevada Divisions of Southwest Gas.

STUDY RESULTS

Overall depreciation rates for all Southwest Gas System Allocable depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $4.8 million based on Southwest Gas' depreciable investment at December 31, 2011. The annual equivalent depreciation expense calculated by the same method using the approved rates was $4.3 million. Appendix A demonstrates the development of the annual depreciation rates and accruals. Appendix B presents a comparison of approved rates versus proposed rates by account. Appendix C presents a summary of mortality and net salvage estimates by account.

Consistent with FERC Rule AR-15, this depreciation study develops depreciation expense for Vintage Group Amortization in Accounts 391, 393-395, and 397-398.00. This process provides for the amortization of general plant over the same life as recommended in this study (with a separate amortization to allocate deficit or excess reserve). At the end of the amortized life, property will be retired from the books. Implementation of this approach did not affect the annual expense accrued by Southwest Gas and provides for the timely retirement of assets and the simplification of accounting for general property. The Public Utilities Commission of Nevada ("PUCN") approved this approach in the Company's last case.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

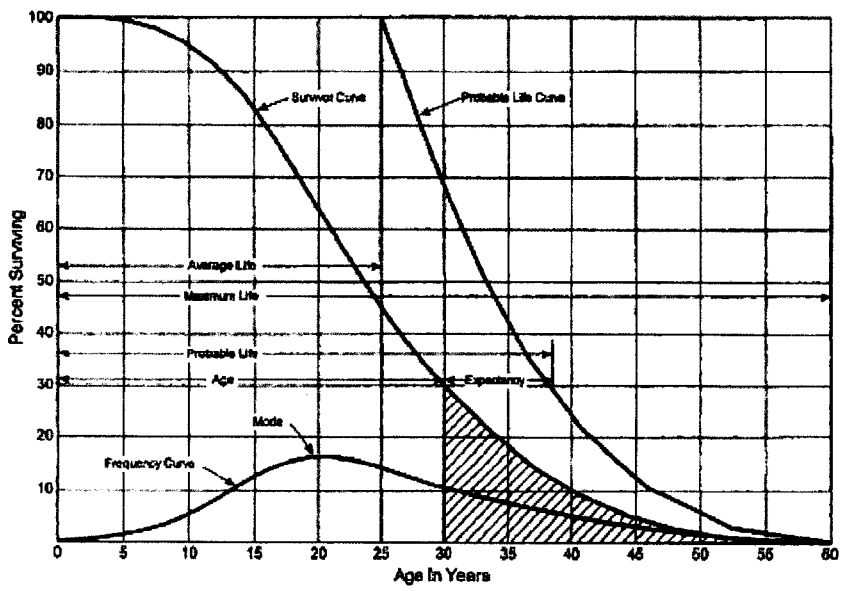
Basis of Depreciation Estimates

The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A and remaining life calculations are shown in Appendix B.

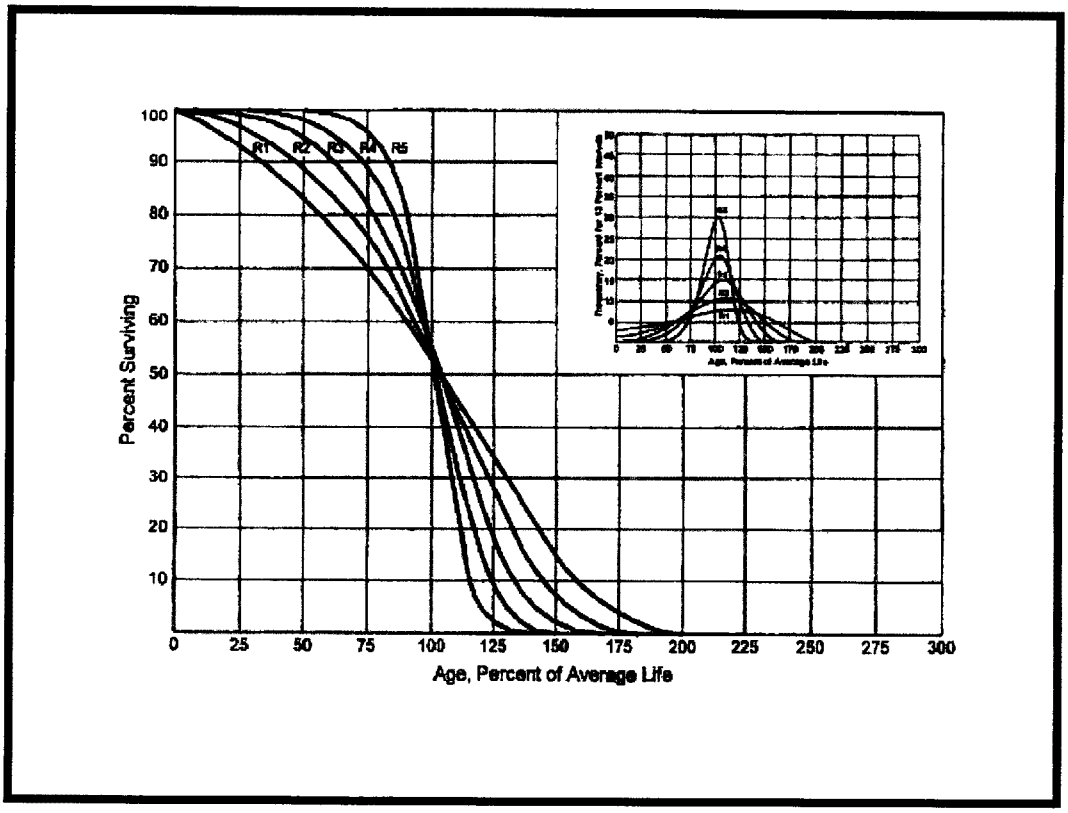
Actuarial analysis was used with each account within a function where sufficient data was available, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of "R" moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a

moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data, permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the General Plant accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

Southwest Gas was authorized to use the average life group ("ALG") depreciation procedure in Nevada Docket 7-09030. At the request of Southwest Gas, this study continues to use the ALG depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG groups are defined by their respective account dispersion, life, and salvage estimates. A straight-line rate for each ALG group is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense and dividing the annual depreciation expense by the surviving investment. The resultant rate for each ALG group is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net book cost over the life of each account by averaging many components.

Theoretical Depreciation Reserve

The book depreciation reserve was allocated among accounts within a function through use of the theoretical depreciation reserve model. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and the documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis and salvage analysis sections and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[1] documents the steps used in conducting this study. Depreciation Systems, page 289 documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, write logic supporting forecasts and estimation, and write final report.

[1] Public Utility Finance & Accounting, A Reader

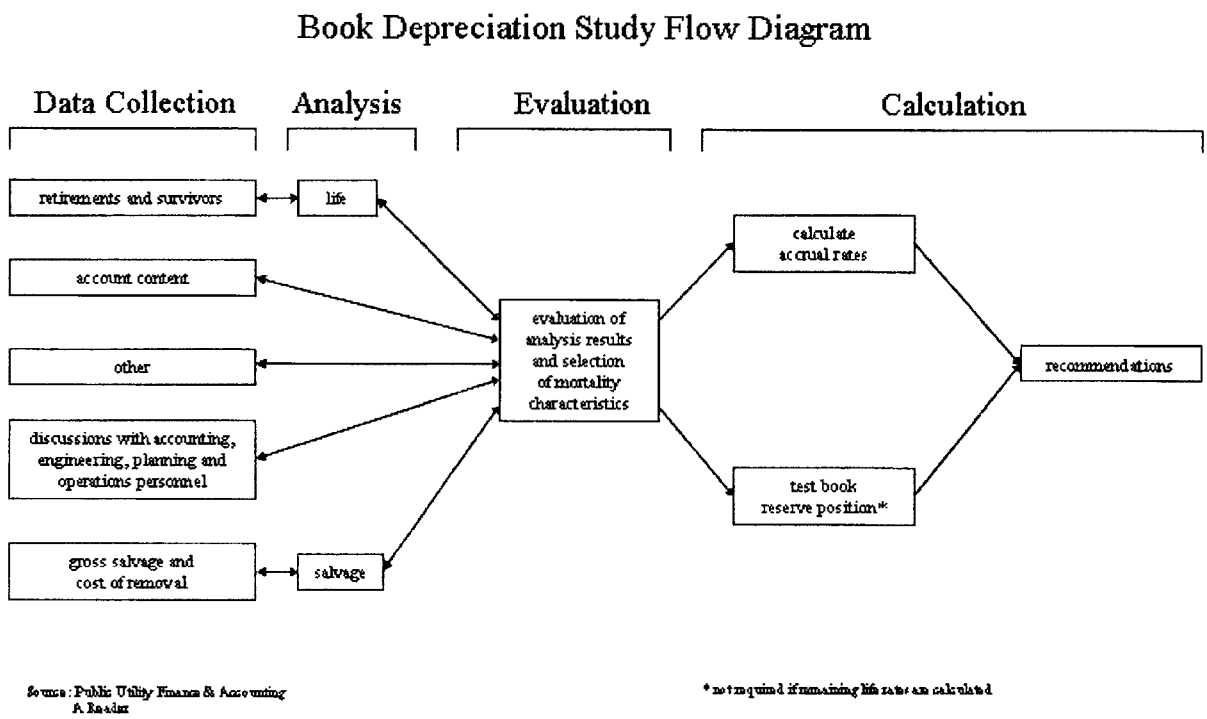


Figure 1

SOUTHWEST GAS DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable accounts of Southwest Gas were calculated by the straight line, average life group, remaining life procedure.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$AnnualAccrualRate = \frac{(100\% - NetSalvagePercent)}{AverageServiceLife}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, average life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$Composite\,\mathrm{Re}\,mainingLife = \frac{\sum OriginalCost - Theoretical\,\mathrm{Re}\,serve}{\sum WholeLifeAnnualAccrual}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation.

$$AnnualDepreciationExpense = \frac{OriginalCost - Book\,\mathrm{Re}\,serve - (OriginalCost) * (1 - NetSalvage\%)}{Composite\,\mathrm{Re}\,mainingLife}$$

where the *Net Salvage%* represents future net salvage.

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$AnnualDepreciationRate = \frac{\sum AnnualDepreciationExpense}{\sum OriginalCost}$$

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. Book depreciation reserves were reallocated from an account level based on the theoretical reserve and the theoretical reserve computation was used to compute a composite remaining life for each account.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the Retirement Rate actuarial methods. After establishment of appropriate average service lives and retirement dispersion, remaining life was computed for each account. Theoretical depreciation reserve with zero net salvage was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the General Discussion section. The difference between plant balance and theoretical reserve was then spread over the ALG depreciation accruals. Remaining life computations are found for each account in Appendix B.

Life Analysis

The retirement rate actuarial analysis method was applied to all accounts for Southwest Gas. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Survivor Curves to obtain the most appropriate match. A selected curve for each account is shown in the Life Analysis Section of this report. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

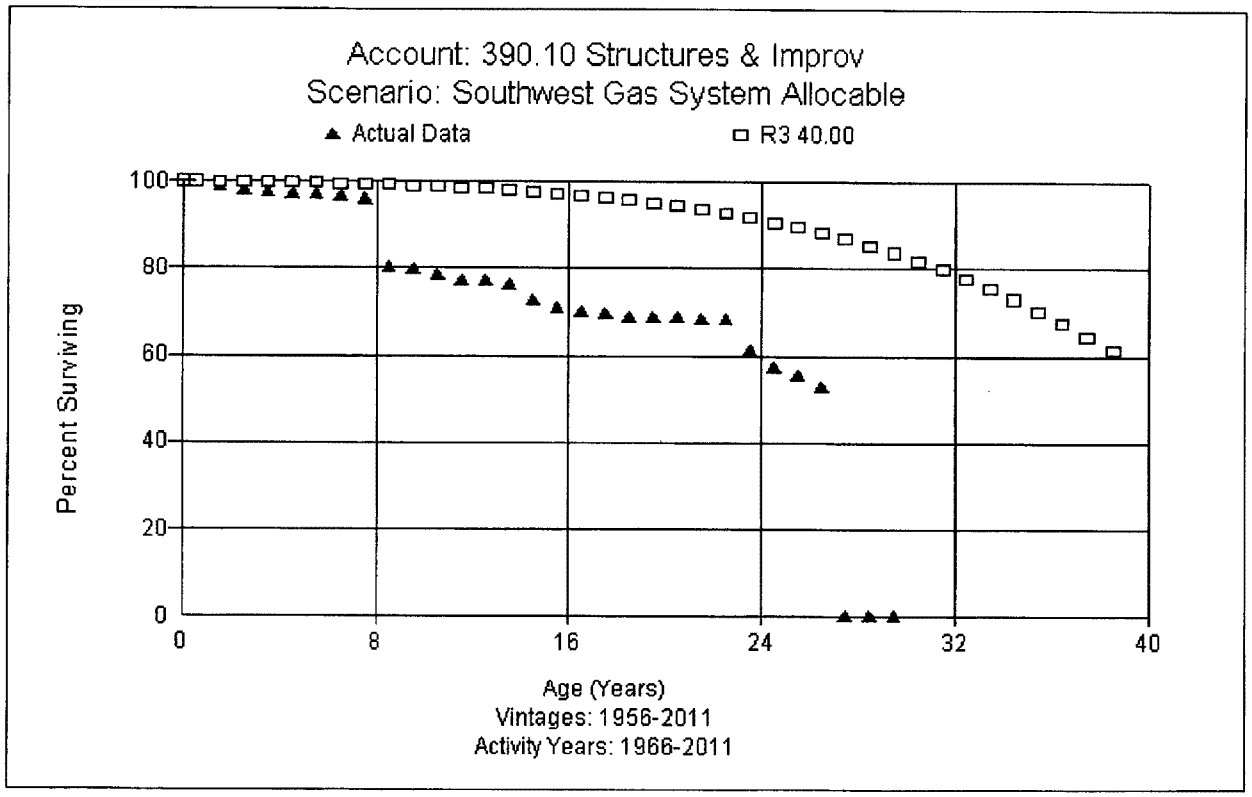
For each account on the overall band (i.e. placement from earliest vintage year which varied for each account through 2011), approved survivor curves from Nevada Docket No. 7-09030 were used as a starting point. Then using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e. L, S. or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed: in increments of approximately ten years, for instance 1982-2011, 1992-2011, 2002-2011, etc. Next placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion

family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

GENERAL PLANT DEPRECIATED

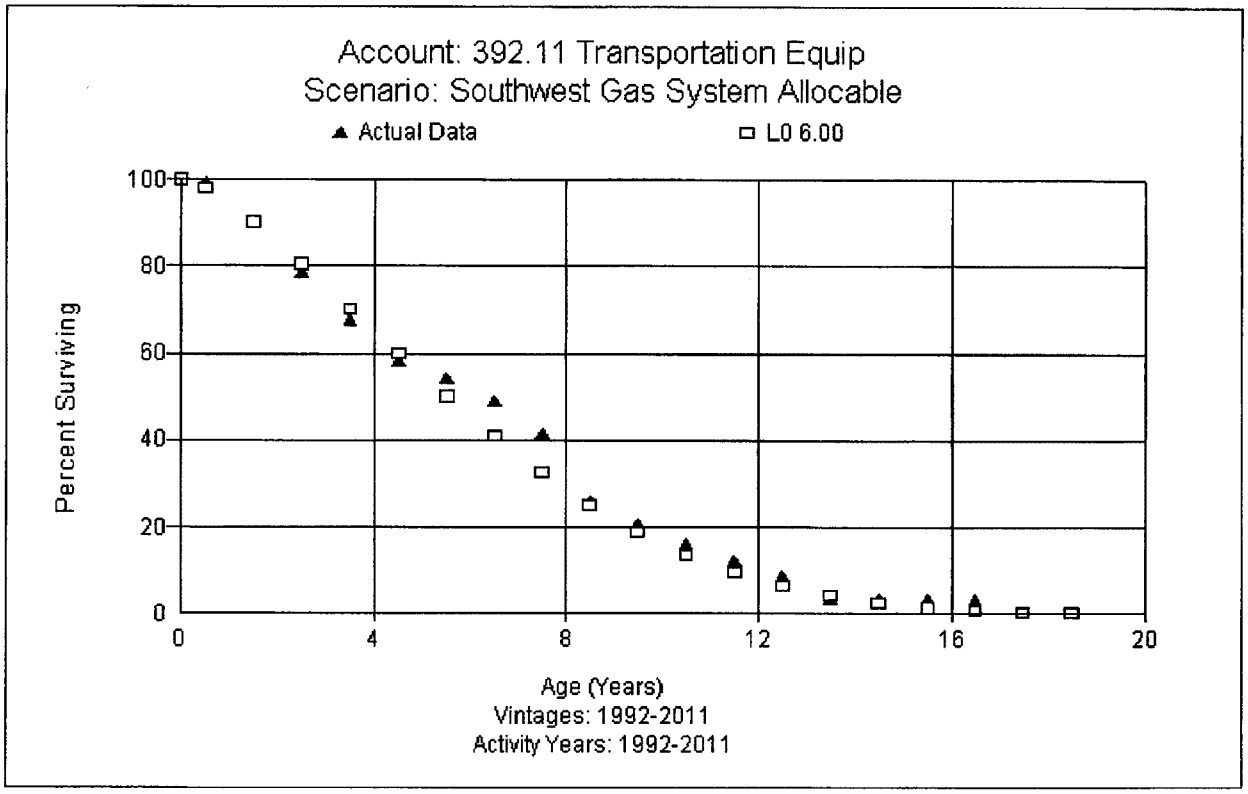
Account 390.10 Structures and Improvements

This account includes the cost of office buildings, hangar, A/C, roof, carpet, and other structures and improvements used for utility service. There is approximately $15 million in this account. The current average age of the surviving balance is 17.54 years and the average age of the retirements is 10.95 years. The current life for this account is a 40 R3. Several bands were analyzed with similar results across the bands indicating a shorter life than what would be expected for the largest investment in the account. Based on this fact this study recommends retention of the existing 40 R3.



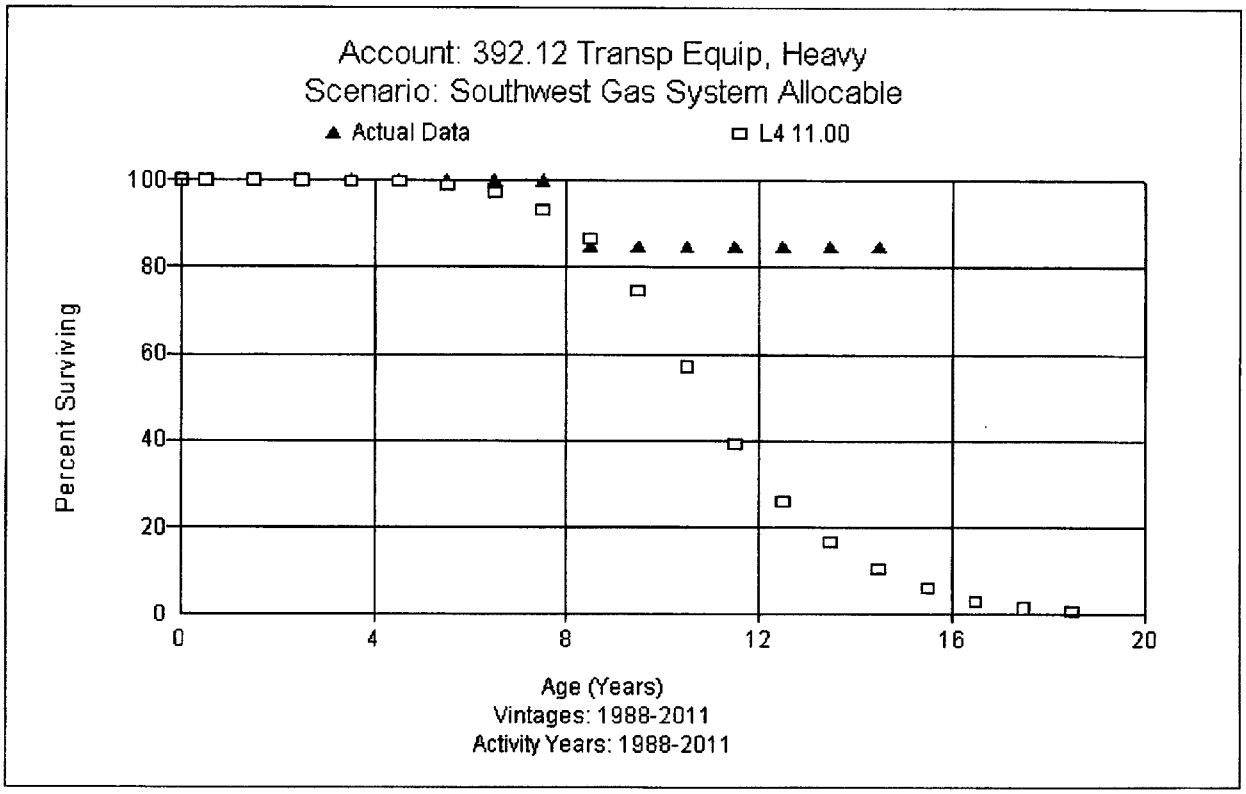
Account 392.11 Transportation Equipment - Light

This account consists of cars, light trucks, and van transportation equipment used for general utility service. There is approximately $3.4 million in this account. This account currently has a fixed life for amortization of 8 years. Based on life analysis results, a shorter life than the approved eight years is indicated for this account. This study recommends moving back to group depreciation with a 6 L0 life for this account. A graph of the proposed curve and the observed life table for this account is shown below.



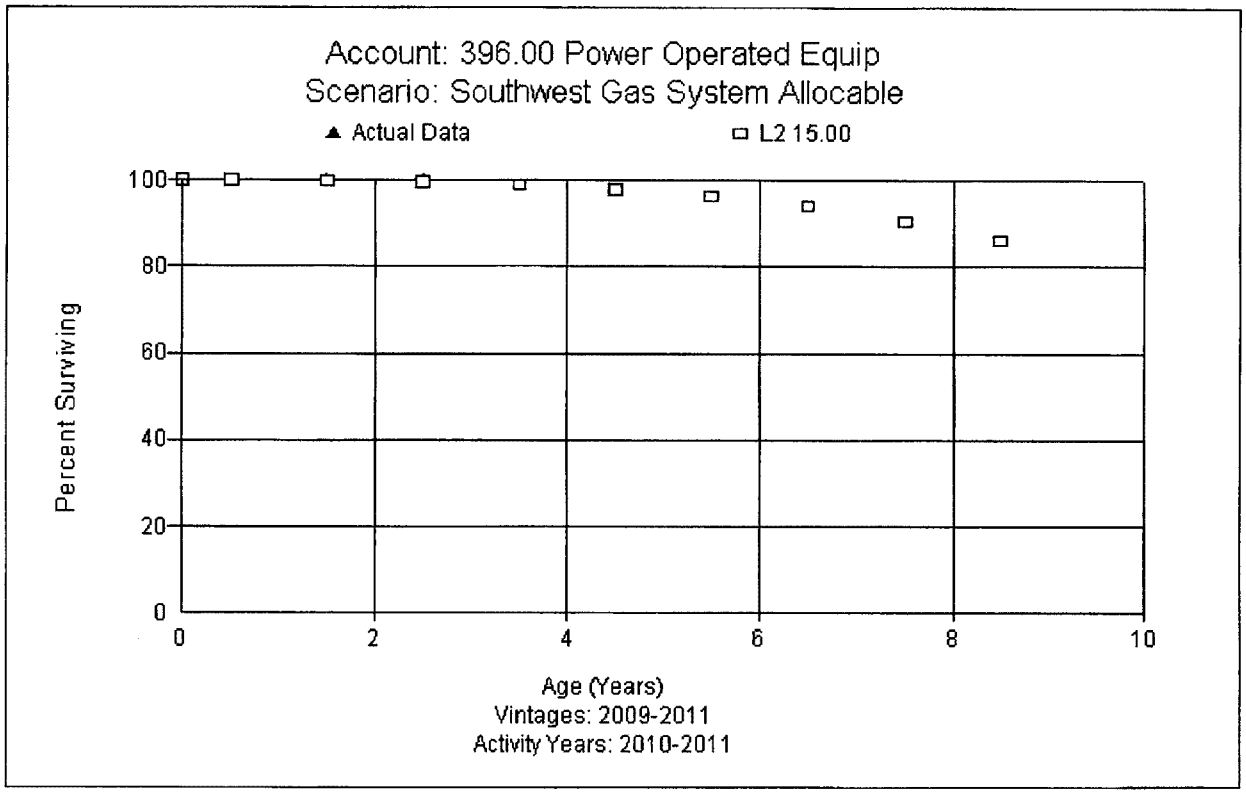
Account 392.12 Transportation Equipment - Heavy

This account consists of heavy transportation equipment used for general utility service. There is approximately $86 thousand in this account. This account currently has a fixed life for amortization of 8 years. The life analysis results indicate a different life than the approved eight years. This study recommends moving back to group depreciation with an 11 L4 life for this account. A graph of the proposed curve and the observed life table for this account is shown below.



Account 396.00 Power Operated Equipment

This account consists of bulldozers, forklifts, trenchers, and other power operated equipment that cannot be licensed on roadways. There is approximately $12 thousand in this account. This account currently has a fixed life for amortization of 20 years. Based on the type of equipment and experience with the Northern Nevada Division, this study recommends moving back to group depreciation with a 15 L2 life for this account.



GENERAL PLANT AMORTIZED

Account 391.00 Office Furniture and Equipment

This account consists of miscellaneous office furniture such as desks, chairs, filing cabinets, and tables used for general utility service. There is approximately $7.6 million in this account. This account currently has a fixed life for amortization of 15 years. This study recommends retaining the 15 year amortization life for this account.

Account 391.10 Computer Equipment

This account consists of computer equipment used for general utility service. There is approximately $12.6 million in this account. This account currently has a fixed life for amortization of 5 years. This study recommends retaining the 5 year amortization life for this account.

Account 392.21 Aircraft Equipment

This account consists of aircraft used for general utility service. There is approximately $8.2 million in this account. This account currently has a fixed life for amortization of 10 years. There is no retirement history for this account, and this study recommends retaining the 10 year amortization life for this account.

Account 393.00 Stores Equipment

This account consists of stores equipment used for general utility service. There is approximately $35 thousand in this account. This account currently has a fixed life for amortization of 15 years. This study recommends retaining the 15 year amortization life for this account.

Account 394.00 Tools, Shop, and Garage Equipment

This account consists of various items or tools used in shop and garages such as air compressors, grinders, mixers, hoists, and cranes. There is approximately $402 thousand in this account. This account currently has a fixed life

for amortization of 15 years. This study recommends retaining the 15 year amortization life for this account.

Account 395.00 Laboratory Equipment

This account consists of laboratory equipment used in general utility service. There is approximately $410 thousand in this account. This account currently has a fixed life for amortization of 20 years. This study recommends retaining the 20 year amortization life for this account.

Account 397.00 Communication Equipment

This account consists of miscellaneous communication equipment used in general utility service. There is approximately $5.3 million in this account. This account currently has a fixed life for amortization of 15 years. This study recommends retaining the 15 year amortization life for this account.

Account 397.20 Telemetry Equipment

This account consists of telemetry equipment used in general utility service. There is approximately $345 thousand in this account. This account currently has a fixed life for amortization of 6 years. This study recommends retaining the 6 year amortization life for this account.

Account 398.00 Miscellaneous Equipment

This account consists of miscellaneous equipment used in general utility service. There is approximately $792 thousand in this account. This account currently has a fixed life for amortization of 15 years. This study recommends retaining the 15 year amortization life for this account.

Salvage Analysis

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a

terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset.

The net salvage analysis uses the history of the individual accounts to estimate the future net salvage that Southwest Gas can expect in its operations. As a result, the analysis not only looks at the historical experience of Southwest Gas, but also takes into account recent and expected changes in operations that could reasonably lead to different future expectations for net salvage than were experienced in the past. Recent experience is generally more heavily weighted in making net salvage recommendations than experience several years in the past.

Salvage Characteristics

For each account, data for retirements, gross salvage, and cost of removal for each plant account adjusted as discussed above was derived from 1987-2011. Moving averages, which remove timing differences between retirement and salvage and removal cost, were analyzed over periods varying from one to 10 years.

GENERAL PLANT

The accounts within the general plant have been split into two categories, depreciated and amortized. For accounts that are depreciated (390.10) account analysis discussions are presented first. For amortized accounts (391.00 – 398.00) they all have a 0 percent net salvage factor, except for 391.10. Individual net salvage analysis for each account is found in Appendix D.

Depreciated Accounts

Account 390.10 Structures-Owned

This account includes any salvage and removal cost related to structures

used for general utility operations. The currently authorized net salvage rate for this account is 0 percent. This study recommends retaining the existing 0 percent net salvage rate for this account.

Account 392.11 Transportation Equipment - Light

This account includes any salvage and removal cost related to light transportation equipment used in general operations. The currently authorized net salvage rate for this account is 20 percent. Based on the overall analysis, expectations ad judgment, a 17 percent net salvage is recommended for this account.

Account 392.12 Transportation Equipment - Heavy

This account includes any salvage and removal cost related to heavy transportation equipment used in general operations. The currently authorized net salvage rate for this account is 20 percent. Based on the overall analysis, expectations and judgment, a 10 percent net salvage is recommended for this account.

Account 396.00 Power Operated Equipment

This account includes any salvage and removal cost related to bulldozers, forklifts, trenchers, and other power operated equipment. The currently authorized net salvage rate for this account is 0 percent. Based on the experience in other divisions of Southwest Gas, this study recommends 15 percent net salvage for this account.

<u>Amortized Accounts</u>

Account 391.00 Office Furniture and Equipment

This account includes any salvage and removal cost related to miscellaneous office furniture such as desks, chairs, filing cabinets, and tables. The currently authorized net salvage rate for this account is 0 percent. Based on the overall

analysis, expectations and judgment, a 0 percent net salvage is recommended for this account.

Account 391.10 Computer Equipment

This account includes any salvage and removal cost related to computer equipment used in general operations. The currently authorized net salvage rate for this account is 0 percent. The overall analysis would indicate a 0 percent net salvage or barely 1 percent. Based on discussions and analysis that some salvage can be received and for consistency with the South and North recommendations, this study recommends moving to 1 percent net salvage at this time.

Account 392.21 Aircraft Equipment

This account consists of aircraft used for general utility service. Based on information from aircraft manufacturers, this study recommends a 60 percent positive net salvage for this account.

Account 393.00 Stores Equipment

This account includes any salvage and removal cost related to stores equipment. The currently authorized net salvage rate for this account is 0 percent. Based on the overall analysis, expectations and judgment, a 0 percent net salvage is recommended for this account.

Account 394.00 Tools, Shop, and Garage Equipment

This account includes any salvage and removal cost related to various items or tools used in shop and garages such as air compressors, grinders, mixers, hoists, and cranes. The currently authorized net salvage rate for this account is 0 percent. Based on the overall analysis, expectations and judgment, a 0 percent net salvage is recommended for this account.

Account 395.00 Laboratory Equipment

This account includes any salvage and removal cost related to laboratory equipment. The currently authorized net salvage rate for this account is 0 percent. Based on the overall analysis, expectations and judgment, a 0 percent net salvage is recommended for this account.

Account 397.00 Communication Equipment

This account includes any salvage and removal cost related to miscellaneous communication equipment. The currently authorized net salvage rate for this account is 0 percent. This study recommends retention of the 0 percent net salvage for this account.

Account 397.20 Telemetry Equipment

This account includes any salvage and removal cost related to telemetry equipment. The currently authorized net salvage rate for this account is 0 percent. This study recommends retaining the approved 15 percent net salvage for this account.

Account 398.00 Miscellaneous Equipment

This account includes any salvage and removal cost related to miscellaneous equipment. The currently authorized net salvage rate for this account is 0 percent. Little salvage or removal cost is expected for these assets. Based on the overall analysis, expectations and judgment, a 0 percent net salvage is recommended for this account.

APPENDIX A

Computation of Depreciation Accrual Rates

Southwest Gas Corporation
Computation of Depreciation Accrual Rates
System Allocable
At December 31, 2011

Account	Description	Original Cost at 12/31/11	Allocated Book Reserve at 12/31/11	Net Salvage %	Net Salvage Amount	Unrecovered Investment	Remaining Life	Annual Accrual Amount	Annual Accrual %
390.10	Structures-Owned	15,008,238	5,746,898	0%	0	9,261,340	23.92	387,252	2.58%
392.11	Transportation Equipment-Light	3,431,454	853,814	17%	583,347	1,994,293	4.11	485,096	14.14%
392.12	Transportation Equipment-Heavy	86,303	59,042	10%	8,630	18,631	2.22	8,395	9.73%
392.21	Transportation Equipment-Aircraft	8,221,361	156,578	60%	4,932,817	3,131,966	9.50	329,681	4.01%
396.00	Power Operated Equipment	11,760	1,546	15%	1,764	8,450	12.56	673	5.72%

General Plant - Amortized		Plant Balance at 12/31/11	Allocated Book Reserve at 12/31/11	Theoretical Reserve at 12/31/11	Reserve Deficiency	Remaining Life	Amortize Reserve Deficiency
391.00	Office Furniture & Equipment	7,666,347	2,983,020	3,132,560	(149,540)	8.87	16,857
391.10	Computer Equipment	12,589,033	4,907,080	5,144,864	(237,784)	2.98	79,926
393.00	Stores Equipment	35,615	9,437	9,910	(473)	10.83	44
394.00	Tools, Shop, & Garage Equipment	402,435	101,807	106,911	(5,104)	11.02	463
395.00	Laboratory Equipment	409,749	88,041	92,454	(4,414)	15.49	285
397.00	Communication Equipment	5,288,425	1,898,108	1,993,261	(95,153)	9.35	10,181
397.20	Telemetry Equipment	344,882	140,654	147,706	(7,051)	3.43	2,056
398.00	Miscellaneous Equipment	792,171	303,568	355,970	(52,402)	8.26	6,344
		27,528,656	10,431,715	10,983,635	(551,920)		116,156

General Plant - Amortized		Plant Balance at 12/31/11	Allocated Book Reserve at 12/31/11	Annual Amortization	Accrual For Reserve Deficiency	Total Amortization	Annual Amortization %
391.00	Office Furniture & Equipment	7,666,347	2,983,020	511,090	16,857	527,947	6.89%
391.10	Computer Equipment	12,423,619	4,741,667	2,459,877	79,926	2,539,803	20.44%
393.00	Stores Equipment	35,615	9,437	2,374	44	2,418	6.79%
394.00	Tools, Shop, & Garage Equipment	402,435	101,807	26,829	463	27,292	6.78%
395.00	Laboratory Equipment	409,749	88,041	20,487	285	20,772	5.07%
397.00	Communication Equipment	5,288,425	1,898,108	352,562	10,181	362,742	6.86%
397.20	Telemetry Equipment	344,882	140,654	57,480	2,056	59,536	17.26%
398.00	Miscellaneous Equipment	792,171	303,568	52,811	6,344	59,156	7.47%
		27,363,243	10,266,302	3,483,511	116,156	3,599,667	

APPENDIX B

Comparison of Depreciation Accrual Rates

Appendix B

Southwest Gas Corporation
Comparison of Depreciation Accrual rates
System Allocable
At December 31, 2011

Account	Description	Original Cost at 12/31/11	Approved Accrual Rate	Approved Accrual Amount	Proposed Accrual Rate	Proposed Accrual Amount	Difference
General Plant Depreciated							
390.10	Structures-Owned	15,008,238	2.79%	418,730	2.58%	387,252	(31,478)
392.11	Transportation Equipment-Light	3,431,454	10.00%	343,145	14.14%	485,096	141,950
392.12	Transportation Equipment-Heavy	86,303	0.00%	0	9.73%	8,395	8,395
396.00	Power Operated Equipment	11,760	0.00%	0	5.72%	673	673
	Total General Plant Depreciated	18,537,755		761,875		881,415	119,540
General Plant Amortized							
391.00	Office Furniture & Equipment	7,666,347	6.67%	511,345	6.89%	527,947	16,602
391.10	Computer Equipment	12,423,619	20.00%	2,484,724	20.44%	2,539,803	55,079
392.21	Transportation Equipment-Aircraft	8,221,361	0.00%	0	4.01%	329,681	329,681
393.00	Stores Equipment	35,615	6.67%	2,376	6.79%	2,418	43
394.00	Tools, Shop, & Garage Equipment	402,435	6.67%	26,842	6.78%	27,292	450
395.00	Laboratory Equipment	409,749	5.00%	20,487	5.07%	20,772	285
397.00	Communication Equipment	5,288,425	6.67%	352,738	6.86%	362,742	10,004
397.20	Telemetry Equipment	344,882	16.66%	57,457	17.26%	59,536	2,078
398.00	Miscellaneous Equipment	792,171	6.67%	52,838	7.47%	59,156	6,318
	Total General Plant Amortized	35,584,604		3,508,808		3,929,347	420,540
	Total System Allocable	54,122,359		4,270,683		4,810,763	540,080

APPENDIX C

Current Commission Approved Rates

Southwest Gas Corporation
Current Commission Approved Rates
System Allocable
From Docket No. 07-09030

Account	Description	Approved Rate	Approved Service Life	Approved Iowa Curve	Approved Net Salvage	Proposed Service Life	Proposed Iowa Curve	Proposed Net Salvage
General Plant - Depreciated								
390.10	Structures-Owned	2.79%	40	R3	0%	40	R3	0%
392.11	Transportation Equipment-Light	10.00%	8	SQ	20%	6	L0	17%
392.12	Transportation Equipment-Heavy					11	L4	10%
392.21	Transportation Equipment-Aircraft					10	SQ	60%
396.00	Power Operated Equipment					15	L2	15%
General Plant - Amortized								
391.00	Office Furniture & Equipment	6.67%	15	SQ	0%	15	SQ	0%
391.10	Computer Equipment	20.00%	5	SQ	0%	5	SQ	1%
393.00	Stores Equipment	6.67%	15	SQ	0%	15	SQ	0%
394.00	Tools, Shop, & Garage Equipment	6.67%	15	SQ	0%	15	SQ	0%
395.00	Laboratory Equipment	5.00%	20	SQ	0%	20	SQ	0%
397.00	Communication Equipment	6.67%	15	SQ	0%	15	SQ	0%
397.20	Telemetry Equipment	16.66%	6	SQ	0%	6	SQ	0%
398.00	Miscellaneous Equipment	6.67%	15	SQ	0%	15	SQ	0%

Appendix D

Net Salvage

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE - NET SALVAGE ANALYSIS

FERC	Activity Year	Reserve Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
	Structures & Improvements														
390.1	1988	1,389	0	0	0	0.00%									
390.1	1989	0	0	0	0	NA	0.00%								
390.1	1990	0	0	0	0	NA	NA	0.00%							
390.1	1991	0	0	0	0	NA	NA	NA	0.00%						
390.1	1992	0	0	0	0	NA	NA	NA	NA	0.00%					
390.1	1993	529,082	212,800	176,742	36,058	6.82%	6.82%	6.82%	6.82%	6.82%	6.80%				
390.1	1994	7,406	0	0	0	0.00%	6.72%	6.72%	6.72%	6.72%	6.72%	6.70%			
390.1	1995	0	0	0	0	NA	0.00%	6.72%	6.72%	6.72%	6.72%	6.72%	6.70%		
390.1	1996	0	0	0	0	NA	NA	0.00%	6.72%	6.72%	6.72%	6.72%	6.72%	6.70%	
390.1	1997	0	0	0	0	NA	NA	NA	0.00%	6.72%	6.72%	6.72%	6.72%	6.72%	6.70%
390.1	1998	9,199	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	6.61%	6.61%	6.61%	6.61%	6.61%
390.1	1999	13,329	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.45%	6.45%	6.45%	6.45%
390.1	2000	212,304	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.67%	4.67%	4.67%
390.1	2001	21,000	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.55%	4.55%
390.1	2002	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.55%
390.1	2003	3,978	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390.1	2004	255,263	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390.1	2005	357,336	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390.1	2006	78,000	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390.1	2007	85,000	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
390.1	2008	2,600	0	18,000	(18,000)	-692.31%	-20.55%	-10.87%	-3.44%	-2.31%	-2.30%	-2.30%	-2.24%	-1.77%	-1.75%
390.1	2009	58,590	0	0	0	0.00%	-29.42%	-12.31%	-8.03%	-3.10%	-2.15%	-2.14%	-2.14%	-2.09%	-1.68%
390.1	2010	0	0	0	0	NA	0.00%	-29.42%	-12.31%	-8.03%	-3.10%	-2.15%	-2.14%	-2.14%	-2.09%
390.1	2011	9,000	0	0	0	0.00%	0.00%	0.00%	-25.64%	-11.60%	-7.72%	-3.05%	-2.13%	-2.12%	-2.12%
391	Office Furniture & Equipment														
391	1987	24,871	0	0	0	0.00%									
391	1988	19,454	500	0	500	2.57%	1.13%								
391	1989	3,220	20	0	20	0.62%	2.29%	1.09%							
391	1990	57,291	600	0	600	1.05%	1.02%	1.40%	1.07%						
391	1991	12,124	0	0	0	0.00%	0.86%	0.85%	1.22%	0.96%					
391	1992	17,130	0	0	0	0.00%	0.00%	0.69%	0.69%	1.03%	0.84%				
391	1993	566,774	8,000	0	8,000	1.41%	1.37%	1.34%	1.32%	1.31%	1.35%	1.30%			
391	1994	58,107	4,200	0	4,200	7.23%	1.95%	1.90%	1.87%	1.80%	1.79%	1.81%	1.76%		
391	1995	59,684	0	0	0	0.00%	3.57%	1.78%	1.74%	1.71%	1.66%	1.66%	1.68%	1.63%	
391	1996	538,103	1,000	0	1,000	0.19%	0.17%	0.79%	1.08%	1.06%	1.05%	1.05%	1.05%	1.08%	1.06%
391	1997	193,787	0	0	0	0.00%	0.14%	0.13%	0.61%	0.93%	0.92%	0.91%	0.92%	0.92%	0.94%
391	1998	230,179	0	0	0	0.00%	0.00%	0.10%	0.10%	0.48%	0.80%	0.79%	0.79%	0.80%	0.80%
391	1999	147,455	0	0	0	0.00%	0.00%	0.00%	0.09%	0.09%	0.42%	0.74%	0.73%	0.72%	0.73%
391	2000	1,399,741	0	0	0	0.00%	0.00%	0.00%	0.00%	0.04%	0.04%	0.20%	0.41%	0.41%	0.41%
391	2001	2,098,383	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.11%	0.25%	0.25%
391	2002	688,596	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.10%	0.22%

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE - NET SALVAGE ANALYSIS

FERC	Activity Year	Reserve Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
391	2003	619,597	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	0.09%
391	2004	82,715	3,440	0	3,440	4.16%	0.49%	0.25%	0.10%	0.07%	0.07%	0.07%	0.06%	0.07%	0.07%
391	2005	108,384	0	0	0	0.00%	1.80%	0.42%	0.23%	0.10%	0.07%	0.07%	0.06%	0.06%	0.07%
391	2006	108,269	20,000	0	20,000	18.47%	9.23%	7.83%	2.55%	1.46%	0.63%	0.46%	0.45%	0.43%	0.41%
391	2007	2,203,418	0	0	0	0.00%	0.87%	0.83%	0.94%	0.75%	0.62%	0.40%	0.32%	0.31%	0.30%
391	2008	1,991,130	0	0	0	0.00%	0.00%	0.46%	0.45%	0.52%	0.46%	0.40%	0.30%	0.25%	0.25%
391	2009	273,154	0	0	0	0.00%	0.00%	0.00%	0.44%	0.43%	0.49%	0.44%	0.39%	0.29%	0.24%
391	2010	603,291	0	0	0	0.00%	0.00%	0.00%	0.00%	0.39%	0.38%	0.44%	0.39%	0.35%	0.27%
391	2011	172,055	0	-1,000	1,000	0.58%	0.13%	0.10%	0.03%	0.02%	0.39%	0.38%	0.44%	0.40%	0.36%
391.1 Computer Equipment															
391.1	1987	1,182	0	0	0	0.00%									
391.1	1988	511,339	83,500	0	83,500	16.33%	16.29%								
391.1	1989	14,769	0	0	0	0.00%	15.87%	15.84%							
391.1	1990	166,520	0	0	0	0.00%	0.00%	12.06%	12.03%						
391.1	1991	1,605,116	122,147	0	122,147	7.61%	6.89%	6.84%	8.95%	8.95%					
391.1	1992	569,201	13,195	0	13,195	2.32%	6.22%	5.78%	5.75%	7.63%	7.63%				
391.1	1993	1,521,380	0	0	0	0.00%	0.63%	3.66%	3.50%	3.49%	4.99%	4.99%			
391.1	1994	1,489,229	1,000	0	1,000	0.07%	0.03%	0.40%	2.63%	2.55%	2.54%	3.74%	3.74%		
391.1	1995	2,102,007	400	0	400	0.02%	0.04%	0.03%	0.26%	1.88%	1.83%	1.83%	2.76%	2.76%	
391.1	1996	7,127,234	0	0	0	0.00%	0.00%	0.01%	0.01%	0.11%	0.95%	0.94%	0.94%	1.46%	1.46%
391.1	1997	5,752,981	1,000	0	1,000	0.02%	0.01%	0.01%	0.01%	0.01%	0.08%	0.68%	0.68%	0.68%	1.06%
391.1	1998	454,126	0	0	0	0.00%	0.02%	0.01%	0.01%	0.01%	0.01%	0.08%	0.67%	0.66%	0.66%
391.1	1999	1,472,385	57,120	0	57,120	3.88%	2.96%	0.76%	0.39%	0.35%	0.32%	0.30%	0.35%	0.88%	0.88%
391.1	2000	74,049	1,800	0	1,800	2.43%	3.81%	2.95%	0.77%	0.40%	0.36%	0.33%	0.31%	0.36%	0.89%
391.1	2001	3,870,670	0	0	0	0.00%	0.05%	1.09%	1.00%	0.52%	0.32%	0.29%	0.27%	0.26%	0.30%
391.1	2002	1,988,257	0	0	0	0.00%	0.00%	0.03%	0.80%	0.75%	0.44%	0.29%	0.26%	0.25%	0.24%
391.1	2003	2,311,685	0	0	0	0.00%	0.00%	0.00%	0.02%	0.61%	0.58%	0.38%	0.26%	0.24%	0.23%
391.1	2004	527,982	15,876	0	15,876	3.01%	0.56%	0.33%	0.18%	0.20%	0.73%	0.70%	0.46%	0.32%	0.30%
391.1	2005	1,967,362	21,650	0	21,650	1.10%	1.50%	0.78%	0.55%	0.35%	0.37%	0.79%	0.76%	0.53%	0.38%
391.1	2006	1,090,976	22,652	0	22,652	2.08%	1.45%	1.68%	1.02%	0.76%	0.51%	0.52%	0.90%	0.87%	0.62%
391.1	2007	2,630,861	0	0	0	0.00%	0.61%	0.78%	0.97%	0.71%	0.57%	0.42%	0.43%	0.75%	0.73%
391.1	2008	6,835,404	0	0	0	0.00%	0.00%	0.21%	0.35%	0.46%	0.39%	0.35%	0.28%	0.29%	0.52%
391.1	2009	1,761,590	2,522	0	2,522	0.14%	0.03%	0.02%	0.20%	0.33%	0.42%	0.37%	0.33%	0.27%	0.28%
391.1	2010	926,239	2,666	0	2,666	0.29%	0.19%	0.05%	0.04%	0.21%	0.33%	0.42%	0.36%	0.33%	0.27%
391.1	2011	2,448,114	26,341	0	26,341	1.08%	0.86%	0.61%	0.26%	0.22%	0.35%	0.43%	0.50%	0.45%	0.41%
392.11 Transportation Equipment															
392.11	1987	69,446	2,706	0	2,706	3.90%									
392.11	1988	183,866	6,533	0	6,533	3.55%	3.65%								
392.11	1989	206,022	13,566	0	13,566	6.58%	5.16%	4.96%							
392.11	1990	240,588	62,066	0	62,066	25.80%	16.93%	13.03%	12.13%						

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392.11	1991	195,997	6,762	0	6,762	3.45%	15.77%	12.82%	10.76%	10.23%					
392.11	1992	36,775	1,254	0	1,254	3.41%	3.44%	14.81%	12.31%	10.45%	9.96%				
392.11	1993	327,269	43,851	0	43,851	13.40%	12.39%	9.26%	14.23%	12.67%	11.26%	10.85%			
392.11	1994	191,386	53,178	0	53,178	27.79%	18.71%	17.69%	13.98%	16.85%	15.08%	13.55%	13.09%		
392.11	1995	231,960	44,986	0	44,986	19.39%	23.19%	18.92%	18.20%	15.26%	17.33%	15.78%	14.39%	13.95%	
392.11	1996	126,200	28,854	0	28,854	22.86%	20.62%	23.11%	19.49%	18.84%	16.12%	17.85%	16.36%	15.00%	14.58%
392.11	1997	236,902	29,293	0	29,293	12.37%	16.01%	17.33%	19.88%	17.97%	17.51%	15.46%	17.03%	15.83%	14.69%
392.11	1998	67,466	16,874	0	16,874	25.01%	15.17%	17.42%	18.11%	20.28%	18.37%	17.92%	15.92%	17.35%	16.16%
392.11	1999	391,059	142,417	0	142,417	36.42%	34.74%	27.12%	26.46%	24.91%	25.35%	22.86%	22.42%	20.36%	21.00%
392.11	2000	308,538	10,115	0	10,115	3.28%	21.80%	22.09%	19.79%	20.13%	20.01%	20.97%	19.65%	19.34%	17.86%
392.11	2001	377,482	122,683	0	122,683	32.50%	19.36%	25.55%	25.52%	23.26%	23.23%	22.72%	23.22%	21.80%	21.50%
392.11	2002	398,945	91,061	0	91,061	22.83%	27.53%	20.63%	24.82%	24.82%	23.17%	23.15%	22.74%	23.15%	21.95%
392.11	2003	555,149	150,617	0	150,617	27.13%	25.33%	27.36%	22.83%	25.45%	25.43%	24.11%	24.04%	23.64%	23.92%
392.11	2004	308,961	162,368	0	162,368	52.55%	36.22%	31.99%	32.11%	27.54%	29.03%	28.91%	27.43%	27.22%	26.62%
392.11	2005	590,139	112,688	0	112,688	19.10%	30.59%	29.27%	27.88%	28.66%	25.58%	27.03%	26.98%	25.91%	25.80%
392.11	2006	569,329	93,471	0	93,471	16.42%	17.78%	25.10%	25.65%	25.19%	26.17%	23.90%	25.30%	25.30%	24.49%
392.11	2007	449,239	85,822	0	85,822	19.10%	17.60%	18.15%	23.69%	24.46%	24.24%	25.20%	23.30%	24.60%	24.60%
392.11	2008	555,351	77,861	0	77,861	14.02%	16.29%	16.34%	17.09%	21.52%	22.55%	22.58%	23.57%	22.04%	23.29%
392.11	2009	501,357	47,517	0	47,517	9.48%	11.87%	14.02%	14.68%	15.66%	19.49%	20.69%	20.91%	21.93%	20.68%
392.11	2010	610,180	155,924	0	155,924	25.55%	18.30%	16.88%	17.35%	17.15%	17.50%	20.52%	21.41%	21.53%	22.38%
392.11	2011	490,297	79,913	0	79,913	16.30%	21.43%	17.69%	16.74%	17.15%	17.02%	17.35%	20.01%	20.87%	21.02%
392.12 Transp Equipment, Heavy															
392.12	2008		0	0	0	NA									
392.12	2009		0	0	0	NA	NA								
392.12	2010		0	0	0	NA	NA	NA							
392.12	2011		0	0	0	NA	NA	NA	NA						
392.32 Transp Equipment-Aircraft															
392.32	2011		0	0	0	NA									
393 Stores Equipment															
393	1993	4,226	0	0	0	0.00%									
393	1994	0	0	0	0	NA	0.00%								
393	1995	0	0	0	0	NA	NA	0.00%							
393	1996	0	0	0	0	NA	NA	NA	0.00%						
393	1997	0	0	0	0	NA	NA	NA	NA	0.00%					
393	1998	557	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
393	1999	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
393	2000	11,193	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		

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393	2001	6,016	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
393	2002	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2003	5,324	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2004	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2005	0	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2006	0	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2007	0	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2008	14,343	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
393	2009	5,765	1,405	0	1,405	24.37%	6.99%	6.99%	6.99%	6.99%	6.99%	5.52%	5.52%	4.47%	3.29%
393	2010	0	0	0	0	NA	24.37%	6.99%	6.99%	6.99%	6.99%	6.99%	5.52%	5.52%	4.47%
393	2011	0	0	0	0	NA	NA	24.37%	6.99%	6.99%	6.99%	6.99%	6.99%	5.52%	5.52%
394	Tools, Shop & Garage														
394	1989	6,288	0	0	0										
394	1990	0	0	0	0	NA									
394	1991	5,448	0	0	0	0.00%	0.00%								
394	1992	0	0	0	0	NA	0.00%	0.00%							
394	1993	8,916	0	0	0	0.00%	0.00%	0.00%	0.00%						
394	1994	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%					
394	1995	0	0	0	0	NA	NA	0.00%	0.00%	0.00%	0.00%				
394	1996	0	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
394	1997	1,332	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
394	1998	424	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
394	1999	2,380	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2000	64,136	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2001	30,674	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2002	26,047	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2003	14,059	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2004	41,869	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2005	14,494	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2006	10,072	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
394	2007	48,065	6,750	0	6,750	14.04%	11.61%	9.29%	5.90%	5.25%	4.37%	3.64%	2.71%	2.68%	2.68%
394	2008	35,560	0	0	0	0.00%	8.07%	7.20%	6.24%	4.50%	4.11%	3.55%	3.06%	2.37%	2.35%
394	2009	24,555	0	0	0	0.00%	0.00%	6.24%	5.71%	5.08%	3.87%	3.58%	3.14%	2.75%	2.18%
394	2010	6,867	0	0	0	0.00%	0.00%	0.00%	5.87%	5.39%	4.83%	3.72%	3.45%	3.05%	2.68%
394	2011	7,203	0	0	0	0.00%	0.00%	0.00%	0.00%	5.52%	5.10%	4.60%	3.58%	3.33%	2.95%
395	Laboratory Equipment														
395	1991	398	0	0	0	0.00%									
395	1992	0	0	0	0	NA	0.00%								
395	1993	11,827	0	0	0	0.00%	0.00%	0.00%							
395	1994	0	0	0	0	NA	0.00%	0.00%	0.00%						

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395	1995	0	0	0	0	NA	NA	0.00%	0.00%	0.00%					
395	1996	0	0	0	0	NA	NA	NA	0.00%	0.00%	0.00%				
395	1997	0	0	0	0	NA	NA	NA	NA	0.00%	0.00%	0.00%			
395	1998	4,979	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
395	1999	15,336	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
395	2000	20,265	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2001	15,515	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2002	2,466	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2003	5,972	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2004	11,622	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2005	30,702	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2006	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2007	8,705	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2008	17,416	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2009	105,926	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2010	3,315	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
395	2011	13,081	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
396 Power Operated Equipment															
396	2009	0	0	0	0	NA									
396	2010	0	0	0	0	NA	NA								
396	2011	0	0	0	0	NA	NA	NA							
397 Communication Equipment															
397	1988	5,400	0	320	(320)	-5.93%									
397	1989	1,072	0	0	0	0.00%	-4.94%								
397	1990	0	0	0	0	NA	0.00%	-4.94%							
397	1991	0	0	0	0	NA	NA	0.00%	-4.94%						
397	1992	0	0	0	0	NA	NA	NA	0.00%	-4.94%					
397	1993	1,441	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	-4.04%				
397	1994	869,629	2,557	0	2,557	0.29%	0.29%	0.29%	0.29%	0.29%	0.29%	0.25%			
397	1995	150,761	0	0	0	0.00%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.22%		
397	1996	0	0	0	0	NA	0.00%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.22%	
397	1997	12,880	400	0	400	3.11%	3.11%	0.24%	0.29%	0.29%	0.29%	0.29%	0.29%	0.29%	0.25%
397	1998	6,824	0	0	0	0.00%	2.03%	2.03%	0.23%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%
397	1999	9,915	0	0	0	0.00%	0.00%	1.35%	1.35%	0.22%	0.28%	0.28%	0.28%	0.28%	0.28%
397	2000	54,323	0	0	0	0.00%	0.00%	0.00%	0.48%	0.48%	0.17%	0.27%	0.27%	0.27%	0.27%
397	2001	166,016	0	0	0	0.00%	0.00%	0.00%	0.00%	0.16%	0.16%	0.10%	0.23%	0.23%	0.23%
397	2002	39,820	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.14%	0.14%	0.09%	0.23%	0.23%
397	2003	567,211	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.05%	0.04%	0.16%
397	2004	11,774	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.05%	0.04%
397	2005	2,114	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.05%

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397	2006	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%
397	2007	21,792	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2008	120,379	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2009	503,169	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2010	106,486	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397	2011	2,289,092	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397.2 Telemetering Equipment															
397.2	1998	992,784	0	0	0	0.00%									
397.2	1999	0	0	0	0	NA	0.00%								
397.2	2000	11,296	0	0	0	0.00%	0.00%	0.00%							
397.2	2001	0	0	0	0	NA	0.00%	0.00%	0.00%						
397.2	2002	0	0	0	0	NA	NA	0.00%	0.00%	0.00%					
397.2	2003	56,450	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
397.2	2004	15,957	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
397.2	2005	127,621	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
397.2	2006	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
397.2	2007	1,460	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397.2	2008	259,593	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397.2	2009	0	0	0	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397.2	2010	3,729	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397.2	2011	22,176	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398 Miscellaneous Equipment															
398	1988	9,319	4,000	0	4,000	42.92%									
398	1989	24,476	0	0	0	0.00%	11.84%								
398	1990	1	0	0	0	0.00%	0.00%	11.84%							
398	1991	10,106	405	0	405	4.01%	4.01%	1.17%	10.03%						
398	1992	349	0	0	0	0.00%	3.87%	3.87%	1.16%	9.95%					
398	1993	0	0	0	0	NA	0.00%	3.87%	3.87%	1.16%	9.95%				
398	1994	0	0	0	0	NA	NA	0.00%	3.87%	3.87%	1.16%	9.95%			
398	1995	0	0	0	0	NA	NA	NA	0.00%	3.87%	3.87%	1.16%	9.95%		
398	1996	346	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	3.75%	1.15%	9.88%	
398	1997	279,659	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.14%	0.14%	0.13%	1.36%
398	1998	4,113	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.14%	0.14%	0.13%
398	1999	80,057	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%	0.11%
398	2000	137,977	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%
398	2001	155,842	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2002	89,842	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2003	47,016	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2004	112,673	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2005	59,535	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE - NET SALVAGE ANALYSIS

FERC	Activity Year	Reserve Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
398	2006	47,551	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2007	33,237	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2008	156,188	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2009	87,114	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2010	34,033	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
398	2011	13,455	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Southwest Gas Corporation
System Allocable Plant
Comparison of Existing and Proposed Depreciation Rates
Exhibit No. DAW-4

Line No.	Description	Account Number	Gas Plant at 11/30/2015	Existing Rates %	Existing Rates Annual Amount	Proposed Rates %	Proposed Rates Annual Amount	Net Change of Depreciation Expense
	Depreciable Plant							
	General Plant							
1	Structures & Improvements - Owned	390.10	$ 29,574,025	2.79%	$ 825,115	2.30%	$ 680,203	$ (144,912)
2	Office Furniture & Equipment	391.00	8,444,555	6.67%	563,252	6.67%	563,252	0
3	Computer Equipment	391.10	16,823,808	20.00%	3,364,762	20.00%	3,364,762	0
4	Transportation Equipment - Light	392.11	3,640,102	10.00%	364,010	10.37%	377,479	13,469
5	Transportation Equipment - Heavy	392.12	0	10.00%	0	8.18%	0	0
6	Transportation Equipment - Aircraft	392.21	8,221,361	4.00%	328,854	4.00%	328,854	0
7	Stores Equipment	393.00	35,615	6.67%	2,376	6.67%	2,376	0
8	Tools, Shop, & Garage Equipment	394.00	624,456	6.67%	41,651	6.67%	41,651	0
9	Laboratory Equipment	395.00	915,434	5.00%	45,772	5.00%	45,772	0
10	Power Operated Equipment	396.00	11,760	6.67%	784	5.66%	666	(118)
11	Communication Equipment	397.00	6,674,859	6.67%	445,213	6.67%	445,213	0
12	Telemetry Equipment	397.20	2,241	16.66%	373	16.66%	373	0
13	Miscellaneous Equipment	398.00	1,150,303	6.67%	76,725	6.67%	76,725	0
14	Total General Plant		76,118,519		6,058,887		5,927,326	(131,561)
15	Total Depreciable Plant		76,118,519		$ 6,058,887		$ 5,927,326	$ (131,561)
	Non-Depreciable Plant							
	Intangible Plant							
16	Organization	301.00	61,816					
17	Miscellaneous Intangible	303.00	194,847,174					
18	Total Intangible Plant		194,908,990					
	General Plant							
19	Land & Land Rights	389.00	4,216,706					
20	Structures & Improvements - Leased	390.20	4,356,208					
21	Total General Plant		8,572,914					
22	Total Non-Depreciable Plant		203,481,904					
23	Total Gas Plant in Service		$ 279,600,423					

Tab G

Direct Testimony

of

Randi L. Cunningham

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
RANDI L. CUNNINGHAM

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 2, 2016

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Prepared Direct Testimony
of

RANDI L. CUNNINGHAM

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Appendix A – Summary of Qualifications of Randi L. Cunningham

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
RANDI L. CUNNINGHAM

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Cunningham. My business address is 5241 Spring Mountain Road, Las Vegas, NV 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Regulation department. My title is Regulatory Professional.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (Commission), the Public Utilities Commission of Nevada (PUCN), and the California Public Utilities Commission (CPUC).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I provide a broad overview of the test year results and the major components that comprise the Company's deficiency. I describe Southwest Gas' operations and cost allocation methods. I also sponsor the development of the Company's revenue requirement, the financial statements and statistical schedules in

Schedule E, from Schedule E-1 to E-6 and E-8 and E-9, and the projections and forecasts in Schedule F.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- An overview of the current proceeding, including test year results, the revenue deficiency as shown on Schedule A-1, and the fair value rate of return (FVROR) requested by the Company.
- The major components comprising the deficiency in this application, and some of the efforts the Company has undertaken to minimize the rate increase.
- An overview of Southwest Gas' natural gas utility operations, including a description of the Company's state and federal ratemaking jurisdictions.
- The methodologies employed by Southwest Gas for cost responsibility and allocations (excluding the Company's class cost of service study) contained in Schedule C-1.
- The computation of the Company's rate base, as presented in Schedule B, and the ratemaking adjustments to determine the appropriate level of cost of service.
- Southwest Gas' adjusted test year income statements included in Schedule C-1 with the exception of Sheet 2, and the majority of Company's pro forma adjustments included in Schedule C-2.
- The computation of the gross revenue conversion factor and state and federal income tax rates as shown on Schedule C-3.

II. OVERVIEW OF CURRENT PROCEEDING

Q. 7 What is the test year in this general rate case (GRC) application?

A. 7 Southwest Gas, as part of the Settlement Agreement (Settlement) authorized in Decision No. 72723, agreed to file a GRC application with a test period ending no earlier than November 30, 2015. Since the Company determined that a revenue deficiency existed at this date, the test year in this GRC is the twelve months ended November 30, 2015.

The recorded test year results were adjusted to annualize and normalize the effects of known and measurable changes that occurred through November 30, 2015, and certain known and measurable costs that were effective after the end of the test year.

Q. 8 How does the Company determine if a revenue deficiency exists?

A. 8 A revenue deficiency exists when the Company's annualized and normalized revenue at its present rates is less than the Company's adjusted cost of service at its proposed weighted average cost of capital.

Q. 9 What does the term "revenue" mean in the context of the Company's revenue deficiency?

A. 9 The term "revenue" in this instance refers to the non-gas and non-surcharge revenues that Southwest Gas receives through base rates. Because there is a separate purchased gas mechanism to ensure that the Company's customers only pay the actual cost incurred by the Company to purchase natural gas (i.e. Southwest Gas earns no profit on the natural gas commodity), these revenues are excluded from the GRC. Similarly, because Southwest Gas has separate regulatory mechanisms to recover certain other costs outside of base rates, as described in the prepared direct testimony of Company witness Edward Gieseking, these revenues are also excluded from the GRC. Another term that is used interchangeably with "revenue" in this context is "margin".

Q. 10 What is the Company's revenue deficiency in its Arizona operations, and how was it determined?

A. 10 The Company's revenue deficiency is $31.9 million. Schedule A-1, Sheet 2, Column (e) shows that margin needs to be adjusted upward to approximately $481.7 million at present rates; this yields a rate of return (ROR) of 6.68 percent on rate base of $1,336,049,260. This equates to a FVROR of 6.01 percent on fair value rate base (FVRB) of $1,812,414,666. Accordingly, to produce a 6.01 percent FVROR, a revenue increase of approximately $31.9 million is required.

III. MAJOR COMPONENTS COMPRISING THE DEFICIENCY

Q. 11 What are the major causes of the Company's revenue deficiency?

A. 11 The Company has identified several major upward and downward changes to the cost of service since the last GRC, which was filed with a June 30, 2010 test year. The net impact of these changes contribute to the $31.9 million deficiency. Authorized revenues need to be updated to reflect the overall changes in the level of operating expenses currently experienced by the Company, and to reflect the significant amount of capital investments that have been made in the natural gas distribution system since its last rate case that are not presently included in rates. Each of these items and its cost of service impact are as follows:

1) Increased capital investment and related depreciation expense: approximately $52.6 million;
2) Increased administrative and general expenses: approximately $16.7 million;
3) Increased property tax expense: approximately $14 million;
4) Increased distribution expenses: approximately $10.9 million;

5) Reduction in depreciation rates per the filed depreciation study: approximately $41.7 million;

6) Reduction in debt cost: approximately $20.3 million; and

7) Decreased customer accounts expenses: approximately $5.6 million.

Q. 12 What is the Company's proposed annual percentage increase over revenue at present rates?

A. 12 The proposed annual percentage increase is 4.25 percent, which is calculated by dividing the $31.9 million proposed rate increase over revenue at present rates of approximately $751.1 million. This is a modest increase of less than one percent per year on average since rates were last established using a cost of service from almost five and a half years ago. This demonstrates the Company's efforts in efficiently managing operations and containing costs.

Q. 13 Please describe some of the cost saving efforts the Company has engaged in since its last general rate case.

A. 13 My testimony highlights five major cost reduction initiatives which resulted in significant cost savings since the last GRC. These cost savings have positively contributed to minimizing the deficiency in this case and will be passed through to customers when rates from this proceeding become effective:

1) Paperless billing: the Company pursued increased customer enrollment in paperless billing. For each bill not mailed, the Company saves approximately $.43 cents due to avoided postage, printing, handling, and receiving costs. Between 2012 and the end of the test year, Southwest Gas avoided mailing 17,989,267 additional bills due to higher customer enrollment in paperless billing companywide. Total savings from 2012 through the end of the test

year was approximately $7.7 million companywide, of which $4.3 million is allocated to Arizona.

2) CheckFree: Southwest Gas renegotiated its contract with its on-line processing agent, CheckFree, to lower its cost per bill for bill presentment. The cost was lowered by one cent per bill. Southwest Gas realizes a savings from not mailing bills to customers who use CheckFree. The difference between the current postage rate and the CheckFree bill presentment charge is 24 cents per bill. The total savings related to CheckFree from 2012 through the end of the test year was approximately $2.0 million companywide, of which $1.1 million is allocated to Arizona.

3) Interest Savings: Southwest Gas took advantage of historically low interest rates and improved credit ratings resulting from the Company's decoupled rate structure[1] to refinance a portion of its long term debt. The cost of long term debt authorized in the Company's last GRC was 8.34%, and the Company is requesting a cost of long term debt of 5.21% in this proceeding. As described above, the savings to Arizona customers will be over $20 million per year.

4) Disconnect for Non-Pay (DNP) Initiative: Southwest Gas began using contractors to field DNP work orders so Company employees could focus on more complicated work order types. Using a contractor results in an approximate $23.42 per hour savings. The Company uses 16 full-time contractors in Arizona, resulting in an annual savings of approximately $0.8 million per year.

[1] Prepared direct testimony of Company witness Theodore K. Wood.

These cost reduction initiatives far exceed the commitment the Company made in the settlement agreement in its last GRC (Docket No. G-01551A-10-0458) to reduce its annual expenses by at least $2.5 million per year (or $10 million total), beginning in 2012 through the end of the test year of this general rate case.

Q. 14 Did Southwest Gas include PTY adjustments as part of its cost of service in this application?

A. 14 Yes. Southwest Gas made several PTY adjustments, primarily consisting of the following: 1) the 2016 wage increase and twelve months of PTY within-grade movement; 2) including PTY new and expired software amortizations and non-revenue producing plant closings in the PTY plant adjustment; 3) including December 2015 Customer Owned Yard Line (COYL) plant additions in the COYL adjustment; and 4) adjusting test year end recorded deferred federal taxes for bonus depreciation, and synchronizing deferred taxes. All of these items are addressed later in my testimony.

Q. 15 Why has Southwest Gas included these PTY items in its application?

A. 15 In the Company's prior Arizona GRCs, the Commission has allowed adjustments similar to those the Company has proposed in this proceeding if the events are known or reasonably certain to occur and are measurable prior to hearing. By including these PTY adjustments, the proposed cost of service more accurately reflects the level of costs Southwest Gas will incur when rates approved in this proceeding will be effective. Further, these post-test year adjustments are easily reconcilable to test year accounts without distortion or mismatching.

IV. OVERVIEW OF NATURAL GAS OPERATIONS

Q. 16 Please provide a brief summary of Southwest Gas' natural gas operations.

A. 16 Southwest Gas is primarily a natural gas local distribution company, providing service to over 1.9 million customers in three states. At the end of the test year, Southwest Gas served over 1.0 million customers in Arizona, comprising approximately 53.4 percent of its total customer base.

Southwest Gas' operations are divided geographically into five operating divisions: Central Arizona, Southern Arizona, Southern California, Northern Nevada, and Southern Nevada. Each division operates independently of the others and may include portions of multiple ratemaking jurisdictions. All divisions are supported by staff located at the Company's corporate headquarters in Las Vegas, Nevada.

At the state level, Southwest Gas' retail gas utility operations currently consist of six rate jurisdictions: Arizona, subject to the regulation of the Commission; Southern Nevada and Northern Nevada, subject to regulation by the PUCN; and Southern California, Northern California, and South Lake Tahoe, California, subject to regulation by the CPUC. Southwest Gas' remaining two rate jurisdictions, Paiute Pipeline Company (Paiute) and Southwest Gas Transmission Company (SGTC), are both regulated by the Federal Energy Regulatory Commission (FERC).

V. JURISDICTIONAL COST RESPONSIBILITY AND ALLOCATIONS

Q. 17 Briefly describe how costs associated with Southwest Gas' natural gas operations are treated in this application.

A. 17 Both operating and capital costs are incurred at the Arizona division level and at the corporate level. Costs incurred at the division level are charged directly to the rate jurisdiction incurring them. Costs at the corporate level may be charged to one or more rate jurisdictions if the cost/activity was incurred on its behalf (i.e.,

"corporate direct" costs). In instances where corporate costs are beneficial to all of the Company's rate jurisdictions, or where the effort of tracking the jurisdictional allocation of the costs is not practical, such costs are allocated to all rate jurisdictions (i.e. "common" or "system allocable" costs).

Q. 18 What are system allocable costs?

A. 18 System allocable costs consist primarily of corporate administrative and general (A&G) expenses, the costs associated with intangible plant (mainly software) and general plant used to support the corporate administrative staff.

Q. 19 How does the Company allocate system allocable costs to Paiute and SGTC?

A. 19 System allocable A&G expenses (except Account 924, Property Insurance) are first allocated to Paiute and SGTC using the Modified Massachusetts Formula (MMF), a FERC-authorized methodology that is calculated on Schedule C-1, Sheet 18. Property insurance is allocated using an insurable property factor (WP Schedule C-2, Adjustment No. 11, Sheets 3-4). Paiute is also charged a rental fee for its use of system allocable intangible and general plant.

System allocable costs that are allocated and charged to Paiute are transferred to and recorded on Paiute's books monthly, and to SGTC's books annually. Consequently, system allocable A&G expenses shown on Southwest Gas' books are net of the allocations to Paiute and SGTC.

For this rate application, the MMF, the insurable property factor, and the Paiute rental charge were recalculated using end of test year data. The resulting pro forma adjustment is presented in Adjustment No. 11, which is discussed in further detail later in my testimony.

Q. 20 After system allocable costs are allocated to Paiute and SGTC, how are the remaining costs allocated to Southwest Gas' retail rate jurisdictions?

A. 20 Property insurance costs are allocated to each retail rate jurisdiction using the same insurable property factor discussed previously, and the remaining system allocable costs are allocated using the 4-Factor Allocation Methodology (4-Factor) described below.

Q. 21 Please describe the 4-Factor methodology.

A. 21 The 4-Factor is based on the average of four equally-weighted components: (a) direct operating expense; (b) average gross plant; (c) direct operating labor; and (d) average number of customers. The 4-Factor has been used for ratemaking purposes by Southwest Gas since the 1950s, and has been accepted and approved by each of the Company's state regulatory commissions. Schedule C-1, Sheet 17 provides the development of the 4-Factor allocation percentages for the test year.

VI. RATE BASE

Q. 22 What is the fair value and original cost rate base that Southwest Gas requests in its application?

A. 22 Southwest Gas proposes and supports a FVRB of $1,812,414,666. The FVRB was determined by giving equal weight (50/50) to the adjusted original cost rate base of $1,336,049,260 and the reconstruction cost new rate base of $2,288,780,073. Schedule B-1 is a high-level summary of the various components that comprise rate base. Rate base is presented on this schedule at original cost, reconstruction cost new, and at fair value. All rate base measurements were performed at November 30, 2015, or for the thirteen months ended November 30, 2015. Details of the various rate base components can be found in Schedules B-2 through B-6.

Q. 23 Please describe and explain Southwest Gas' Schedules B-3 and B-4.

A. 23 Schedule B-3 is a summary of the reconstruction cost new study. The schedule contains both the direct and system allocable plant assigned to Arizona. The reconstruction cost new data is utilized to develop the FVRB. The detail supporting Schedule B-3 is contained in Schedule B-4 which contains the Handy-Whitman indices that were used to trend original cost plant and deferred taxes to obtain the reconstruction cost new data, and the reconstruction cost new data by vintage year, by FERC account.

Q. 24 Please describe and explain the other rate base items contained in Southwest Gas' Schedule B-5 and B-6 that do not use the end of test year balance.

A. 24 Schedules B-5 and B-6 contain four items that employ the 13-month average balance method for inclusion in rate base: 1) materials and supplies; 2) prepayments; 3) customer deposits; and 4) customer advances for construction. The use of the 13-month average balance as the method of calculation has been accepted by the Commission in the Company's past several rate cases.

Q. 25 Please describe and explain the items contained in Schedule B-5 and B-6 that do not employ the 13-month average balance method.

A. 25 The cash working capital allowance and the accumulated balance of deferred income taxes do not use the 13-month average balance method of calculation.

The cash working capital allowance was determined through a comprehensive lead/lag study. The Company used the number of lead/lag study days derived from the lead/lag study days performed in its last GRC and applied this information to adjusted test year amounts in this GRC. Deferred taxes are based on the recorded balance at the end of the test year, and adjusted as explained further below.

Q. 26 Is the Company proposing any adjustments to the recorded rate base amounts at November 2015?

A. 26 Yes. The Company is proposing three adjustments to recorded rate base amounts: 1) PTY Plant; 2) COYL; and 3) Deferred Tax Adjustments.

Adjustment No. 18 – PTY Plant

Q. 27 Please describe and explain Adjustment No. 18 - PTY Plant.

A. 27 The PTY Plant adjustment serves two purposes. The first is to include the non-revenue producing plant projects included in Construction Work in Progress (CWIP) at the end of the test year that were serving customers at the end of the test year or shortly thereafter, and that will be serving customers during the rate effective period. Non-revenue producing plant represents plant that was constructed to improve service or enhance reliability and safety for existing customers. The Company will not realize any incremental operating revenues from the construction and addition of this plant at the time it is placed into service. Examples of PTY plant included in this adjustment are replacement pipe, franchise-related replacements, pressure reinforcements, measuring and regulating station equipment, and general plant.

Although the work orders for this PTY plant included in this adjustment were still in CWIP at the end of the test year, primarily due to delays in entering the required information into the Company's computer systems, the adjustment is appropriate because the corresponding plant projects were in fact in service at the end of the test year or shortly thereafter. The Company's customers at the end of the test year are the primary beneficiaries of these capital expenditures, and will be during the rate effective period. Consequently, the inclusion of PTY plant in rate base more accurately matches the Company's

investment needed to serve the customers in its system at the end of the test year.

Second, system allocable miscellaneous intangible plant was adjusted in the PTY Plant adjustment. Most of the items in system allocable miscellaneous intangible plant (Account 101) are software projects with three to five-year amortization periods. These amortization periods are roughly equivalent to the Company's Arizona rate case cycle. Absent an adjustment, customers may end up double-paying for certain projects through rates, while never paying for other projects. To mitigate this potential outcome, the Company proposes an adjustment to remove all projects with an amortization period expiring August 31, 2016 or earlier from rate base, and to add estimated amounts for projects to be closed to plant prior to August 31, 2016 to rate base. This is a conservative adjustment because many small software projects spend a relatively short time in construction work in progress before being transferred to plant. Consequently, between the date this rate case was prepared and August 2016, more projects may close to plant than are indicated by the estimated balances included in the Company's application. Indeed, this adjustment strikes a fair balance between project amortizations that will expire shortly after the end of the test year, and projects commencing amortization and serving customers approximately one year prior to rates from this proceeding going into effect. Further, the Company's estimated amounts can be verified by intervening parties prior to the hearing in this proceeding.

Q. 28 What is the total impact of the PTY Plant adjustment on rate base?

A. 28 This adjustment increases rate base by $39,417,890.

Adjustment No. 19 – COYL

Q. 29 Please describe and explain Adjustment No. 19 - COYL.

A. 29 An adjustment was made to include the December 2015 COYL Program capital expenditures in this application, and to normalize COYL leak survey O&M costs based on a 3-year average.

Q. 30 Why does the Company propose a post-test year adjustment to include December 2015 COYL Program capital expenditures?

A. 30 In its last rate case, Southwest Gas was authorized to implement a COYL Cost Recovery Mechanism (CCRM) in order to recover the revenue requirement on the COYL program between rate cases. The reporting requirement on the COYL program, and the resulting revenue requirement calculation, is based on calendar year capital expenditures as COYLs are replaced with Company-owned facilities. Absent this adjustment, only the capital expenditures from inception of the COYL program through the end of the test year (November 2015) will be included in base rates after rates from this proceeding are effective. In order to keep all COYL-related investments synchronized, and to avoid the administrative inefficiency of tracking one month of COYL additions, it is appropriate to include this last month of capital additions in base rates in this proceeding.

Q. 31 What is the total impact of the COYL adjustment to include December 2015 COYL program capital expenditures on rate base?

A. 31 This adjustment increases rate base by $653,859.

Q. 32 How were COYL leak survey O&M costs normalized?

A. 32 The test year COYL leak survey O&M recorded amount of $485,546 was compared to the three year average amount recorded from December 2012 to

November 2015, which was $3,889,703 divided by 3, or $1,296,568 per year. The difference is $811,024, which is the amount by which this adjustment increases expenses.

Q. 33 Why was the COYL leak survey recorded amount so low during the test year?

A. 33 In order to ensure that all known COYL accounts had a leak survey conducted by the Company within a three year period, the leak survey work was front loaded during the first two years. As such, the test year does not represent the annual level of COYL leak survey expenditures expected to occur during the rate effective period, and an adjustment is necessary.

Adjustment No. 20 – Deferred Tax Adjustments

Q. 34 Please describe and explain Adjustment No. 20 - Deferred Taxes Adjustments.

A. 34 There are four adjustments to recorded test year deferred tax balances, as summarized on WP B-6. The first adjustment was made to tie deferred taxes to recorded plant at the end of the test year. The second adjustment was made to reflect the retroactive enactment of bonus depreciation for 2015 capital additions included in rate base. The third and fourth adjustments are to calculate the deferred taxes on the PTY- and COYL-related plant additions.

Q. 35 What is the total impact of the Deferred Taxes adjustment on rate base?

A. 35 This adjustment decreases rate base by $38,781,654.

VII. OPERATING EXPENSES

Q. 36 Please describe and explain Southwest Gas' Schedule C-1.

A. 36 Schedule C-1 begins with the Company's adjusted income statement on Sheet 1, and the subsequent sheets summarize recorded and adjusted operations and maintenance (O&M) expenses, administrative and general (A&G) expenses, depreciation and amortization expenses, other taxes, and income taxes.

Schedule C-1 is rounded out by the calculations supporting the 4-Factor and MMF allocations, which are described in greater detail above.

Q. 37 Please describe and explain Southwest Gas' Schedule C-2.

A. 37 Schedule C-2 provides a summary, by function, of all of the pro forma adjustments proposed in this proceeding. The remaining C-2 schedules provide support for each pro forma adjustment.

Q. 38 Please describe and explain Southwest Gas' Schedule C-3.

A. 38 Schedule C-3 shows the calculation of the gross revenue conversion factor, and the income tax rates used in this proceeding.

Adjustment No. 3 – Labor and Labor Loading Annualization

Q. 39 Please describe and explain Adjustment No. 3 - Labor and Labor Loading Annualization.

A. 39 Adjustment No. 3 annualizes the labor and related labor loadings of Arizona and Corporate employees employed by the Company at the end of the test period - November 30, 2015. This adjustment increases operating expenses by $2,860,666.

The labor and labor loading annualization adjustment includes three components. First, a salary annualization is made for all Arizona and corporate employees with salaries in effect at the end of the last pay period beginning prior to June 30, 2015. Second, labor loadings are annualized at the end of the test year and those costs are applied to the employees on Southwest Gas' payroll at the end of the test year. Finally, the labor adjustment reflects an estimated 2.75 percent general wage increase to be effective in June 2016, along with additional wage increases as a result of within-grade movement during the twelve months subsequent to the end of the test year (i.e., through November 2016).

Q. 40 Why is it appropriate to adjust labor expense for the 2016 general wage increase and within-grade movement?

A. 40 Under current Commission guidelines for processing major rate applications, it is not expected that the hearing in this proceeding will be conducted before December 2016. Historically, the Company has granted general wage increases effective each June, after being approved by the Company's Board of Directors in May. Therefore, the 2016 general wage increase and post-test year within-grade wage increases will be known and measurable prior to the hearing in this proceeding. As such, Staff and other intervenors will have an opportunity to verify and quantify the 2016 general wage increase and PTY within grade movement.

Q. 41 Does this PTY adjustment adhere to the matching principle?

A. 41 Yes. This adjustment only applies to employees on the Company's payroll at November 30, 2015, the end of the test year. It does not apply to any employees hired after November 30, 2015 to meet customer growth, changes to work requirements, etc. Therefore, the number of employees at the end of the test year is synchronized with test year customers that those employees serve. Indeed, this adjustment preserves the matching principle by ensuring rates approved in this proceeding better reflect the costs that will be incurred by the Company during the period rates will be effective. This adjustment simply recognizes that by the time rates become effective, test year customers will be served by test year employees who, on average, will be paid more than the wages that were in effect at the end of the test year.

Q. 42 Have previous Commission rulings in the Company's rate applications addressed this adjustment?

A. 42 Yes. The Commission has consistently approved Southwest Gas' post-test year wage increases. In Decision No. 70665, the Commission concluded that Southwest Gas' post-test year wage increase ". . . should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses."

Q. 43 Please describe the labor loading process.

A. 43 Pensions, benefits and payroll taxes are accumulated at the corporate level. These costs are then distributed among the various rate jurisdictions through a labor loading process. The labor loading rate is adjusted at the beginning of each year, based on budgeted pensions, benefits, paid time off, payroll taxes, and expected employee levels. The labor loading process applies the labor loading rate to each labor dollar, assigning an appropriate amount of pensions, benefits, paid time off, and payroll taxes to each account to which labor has been charged.

Q 44 How were labor loadings for Arizona and corporate employees annualized in this proceeding?

A. 44 For benefits with premiums or regular monthly payments, the amount recorded in November 2015 was multiplied by twelve months to more accurately reflect current expenses. Southwest Gas used the most recent actuarial amounts, which are also used by the Company to accrue related expenses for 2016, as the basis for annualizing pension, PBOP, and SERP costs. Consistent with prior Commission decisions, the Company removed certain items recorded in the Miscellaneous Benefits subaccount from the cost of service, such as costs

related to service awards, retirement gifts and parties, and employee recognition. Also, adjustments were made to remove out of period charges from the test year, and to bring in test year charges recorded out of period. In addition, payroll taxes, 401k match, and indirect time were adjusted for the impact of annualizing payroll and overtime. For the remaining costs in Account 926, recorded test year costs were used as the basis for the annualization. These adjustments are consistent with prior Commission decisions.

There were two methods used to allocate labor loading costs to Arizona. First, the total cost of pensions, PBOP, SERP, executive deferred compensation, and employee investment plan (401k) was allocated based on each rate jurisdiction's labor cost as a percentage of total Company labor. Second, for the remaining benefits, a cost per employee was calculated based on the adjusted costs divided by the total number of Company employees at the end of the test year. The cost per employee was multiplied by the number of Arizona jurisdictional employees at the end of the test year to determine the amount allocated to Arizona for ratemaking purposes.

Q. 45 Once the annualized labor and labor loadings were calculated, how was the adjustment determined?

A. 45 The annualized labor and labor loadings were assigned to each account based on the historical test year relationships. For example, during the test year, approximately 73 percent of Arizona direct labor and loadings were charged to operations and maintenance (O&M) accounts. Therefore, 73 percent of the annualized Arizona direct labor and loadings were assigned to O&M accounts. The difference between the annualized labor and loadings assigned to the O&M accounts and the recorded labor and loadings is the adjustment for that account.

Since 73 percent of the annualized Arizona direct labor and loadings were assigned to O&M, the remaining 27 percent were assigned to capital and deferred accounts, and do not impact the revenue requirement requested in this application. A similar assignment was performed for corporate staff annualized labor and loadings to determine the adjustment required.

Adjustment No. 4 – Call Center and Customer Support Allocation and Annualization

Q. 46 Please explain Adjustment No. 4 - Call Center and Customer Support Allocation and Annualization.

A. 46 There are two parts to this adjustment. The first part of this adjustment allocates the proper percentage of this function to Arizona customers. The second part of this adjustment annualizes the call center function to reflect a full year of contract employees at the end of the test year, to synchronize with the number of Company call center employees at the end of the test year. This adjustment preserves the matching principle by ensuring rates approved in this proceeding better reflect the costs that will be incurred by the Company during the period rates will be effective. This adjustment increases operating expenses by $2,180,175.

Q. 47 Please describe the Company's call center and customer support function.

A. 47 There are presently three customer assistance call centers in Southwest Gas' service territory: Phoenix, Tucson, and Las Vegas, Nevada. There are also remote agents that are staffed by contract employees. Customers call a toll-free telephone number, and the call is routed to the next available agent, no matter where that agent is located. The agents are trained to respond to customer inquiries regardless of where the customer is located. There are also Company employees who provide back office customer support primarily in Victorville,

California and Carson City, Nevada. All call centers and both customer support locations handle customer inquiries and reporting for the entire Company.

Q. 48 Why is an adjustment necessary to properly allocate these costs to Arizona?

A. 48 Call center and customer support function costs are aggregated on Southwest Gas' books by operating division for cost management purposes. However, since Southwest Gas is requesting recovery for Arizona jurisdiction-related costs in this proceeding, an adjustment is necessary. These costs are therefore aggregated on a total company basis, and then reallocated to Arizona based on number of customers, which is the Factor IV component of the 4-Factor discussed earlier in my testimony, and is calculated on Schedule C-1, Sheet 17, Line 8. The adjustment reflects the difference between the amount recorded on Southwest Gas' books and the reallocated amount.

Adjustment No. 5 – Cost of Service Analysis

Q. 49 Please explain Adjustment No. 5 - Cost of Service Analysis.

A. 49 Southwest Gas conducted an analysis of its operating expenses to: 1) determine if there were costs recorded during the test year for which Southwest Gas is not requesting recovery in this proceeding; 2) adjust recorded expenses so a full year's worth of expense is reflected- no more and no less; 3) annualize items with significant cost changes; and 4) determine whether the test year contains material, non-recurring costs. Adjustment No. 5 reflects the results of this analysis. The amounts removed from and added to the cost of service are summarized by account in Schedule C-2, Adjustment No. 5, and the supporting workpapers categorize all transactions by the type of cost. This adjustment reduces operating expenses by $429,388.

Adjustment No. 6 – Employee Vehicle Compensation

Q. 50 Please explain Adjustment No. 6 - Employee Vehicle Compensation.

A. 50 Adjustment No. 6 removes from test year expenses the cost of Company vehicles related to personal use by employees. This adjustment is consistent with those approved in Southwest Gas' last several rate cases. This adjustment reduces operating expenses by $62,108.

Adjustment No. 7 – Uncollectible Expense Annualization

Q. 51 Please explain Adjustment No. 7 - Uncollectible Expense Annualization.

A. 51 Adjustment No. 7 annualizes the recorded amounts in Account 904, Uncollectible Expenses, to reflect the test year net closing bill write-offs as a percentage of gross revenues. The write-off percent applied to present revenues determines the annualized amount, which is then compared to the recorded uncollectible expense to determine the adjustment amount. This adjustment is consistent with those approved in Southwest Gas' last several rate cases. This adjustment increases operating expenses by $582,100.

Adjustment No. 8 – Leak Survey and Repair

Q. 52 Please explain Adjustment No. 8 - Leak Survey and Repair.

A. 52 Adjustment No. 8, Leak Survey and Repair, reduces test year accelerated leak survey and leak repair expense related to Aldyl HD pipe consistent with prior Commission decisions. This adjustment reduces operating expenses by $33.

Q. 53 Why is the amount of this adjustment so small as compared to the Company's prior rate case?

A. 53 All known Aldyl A pipe has already been replaced in southern Arizona. With the exception of some short segments totaling approximately 1,000 feet, the replacement of all known Aldyl HD pipe was complete in southern Arizona by

the end of 2012. As such, test year expenses related to leak survey and leak repair on these pipe types in southern Arizona were minimal.

Adjustment No. 9 – Injuries and Damages

Q. 54 Please explain Adjustment No. 9 - Injuries and Damages.

A. 54 Adjustment No. 9 adjusts the recorded self-insured accruals charged to Account 925 during the test year to a normalized level.

Q. 55 What was the Company's level of self-insurance for general liability claims at the end of the test year?

A. 55 The Company is self-insured for up to $1 million of claims expense for each occurrence (per occurrence component). To the extent that a specific claim exceeds $1 million, the Company is self-insured for the excess over $1 million up to an aggregate (aggregate component) of $4 million. Once the $4 million aggregate is reached, any amount paid above the $4 million is the responsibility of the insurance carrier.

The $4 million aggregate can be the result of payouts from more than one incident that may occur in more than one rate jurisdiction. Given the potential multi-jurisdictional nature of amounts recorded beyond the $1 million per occurrence component and up to the $4 million aggregate, the Company treats the aggregate component as a system allocable expense. The $4 million aggregate results in a lower insurance premium expense than if the Company maintained a lower aggregate component, or had no aggregate component. Accordingly, any amounts recorded under the aggregate component of injuries and damages expense should be treated similarly as the insurance premium expense and be treated as a system allocable expense.

The up to $1 million per occurrence component has no annual limit as to the number of claims, is claim specific, and does not include costs emanating from more than one rate jurisdiction. Indeed, the per occurrence component of injuries and damages expense should be treated as a direct jurisdictional expense.

Q. 56 Please explain the accounting for the self-insured portion of liability claims.

A. 56 When an incident is identified that may require payment, the Company accrues the estimated payment as a self-insured retention expense. The entry is a debit to Account 925, Injuries and Damages, and a credit to Account 228.2, Accumulated Provision for Injuries and Damages. Once the outcome of the claim becomes final, any costs paid are charged against the accrual in Account 228.2. If the amounts paid are different than the amount accrued, then the net difference is removed from Account 228.2 and charged back against Account 925.

Q. 57 Given the method used to account for the self-insured portion of liability claims, does the test year expense reflect on-going operations?

A. 57 No. It is not unusual to have fluctuations in the net charges to Account 925 from period-to-period because of the nature of the method used to account for this process, and the fact that large claims that reach the $4 million aggregate do not occur every year. This can result in Account 925 having an expense level during any given recorded period not being representative of on-going operations. For this reason, it is appropriate to normalize this cost based on claims experience over the last ten years.

Q. 58 Please explain the normalized adjustment to self-insured expense.

A. 58 The Company uses a ten-year average of self-insured amounts to normalize this expense for ratemaking purposes. Schedule C-2, Adjustment No. 9, shows that the ten-year average of Arizona direct claims is $626,035 compared to the test year amount of $106,354, requiring a $519,680 adjustment. The ten-year average system allocable expense is $950,885 compared to the test year amount of $622,500, requiring a $328,385 adjustment. After allocating a portion of this expense to Paiute, the Arizona portion of this adjustment is an increase of $176,517. The total impact of this adjustment on Arizona's operating expenses is $696,197.

Adjustment No. 10 – AGA Dues

Q. 59 Please explain Adjustment No. 10 - AGA Dues.

A. 59 Adjustment No. 10 removes $13,516 from operating expenses, which is the portion of the Company's dues to the American Gas Association (AGA) identified as lobbying in nature.

Adjustment No. 11 – Paiute Pipeline/SGTC Allocation Annualization

Q. 60 Please explain Adjustment No. 11 - Paiute Pipeline/SGTC Allocation Annualization, which you previously referred to in your response to Question No. 10.

A. 60 Adjustment No. 11 annualizes the system allocable A&G amounts allocated to Paiute through the MMF allocation methodology, the insurable property factor, and the rent revenue that Southwest Gas receives from Paiute for the test year ended November 30, 2015. The supporting workpapers to Adjustment No. 11 show the detailed calculations needed to derive the Paiute rent expense and insurable property factor at November 30, 2015. This adjustment is consistent

with the methodology approved by the Commission in the Company's last several rate cases.

The annualized MMF allocation factors are also used in the pro forma adjustments that impact system allocable A&G costs, in order to allocate a portion of the adjustment to Paiute and SGTC before calculating the portion that is allocated to Arizona. This adjustment reduces operating expenses by $90,012.

Adjustment No. 12 – Rate Case Expense

Q. 61 Please explain Adjustment No. 12 - Rate Case Expense.

A. 61 The Company estimated the incremental costs that would be incurred to prepare and process this general rate case, including printing, postage, court reporting, noticing, publication, travel, and outside consultants. The total incremental costs are divided by four, which is roughly equal to the number of years in one rate case cycle, to calculate an annual amortization to Account 928. The adjustment, which increases operating expenses by $35,112, is the difference between this new amortization amount and the amount of rate case expense amortized on the Company's books during the test year.

Adjustment No. 13 – Depreciation and Amortization Expense Annualization

Q. 62 Please explain Adjustment No. 13 - Depreciation and Amortization Expense Annualization.

A. 62 Adjustment No. 13 annualizes depreciation and amortization expense based on adjusted plant in service at November 30, 2015, using currently approved depreciation rates. This adjustment increases operating expenses by $8,195,254.

Q. 63 Please explain why an adjustment is necessary to annualize depreciation and amortization expense for the test year.

A. 63 This adjustment is necessary to synchronize the depreciation and amortization expense with the plant in service at the end of the test year, as adjusted. Like many utilities, Southwest Gas employs a depreciation convention based on the month the plant is actually placed into service. Southwest Gas begins depreciation on plant the month subsequent to the month it is first placed in service, and in turn, takes a full month's depreciation in the month it is removed or retired from service. As a result, plant that is placed in service or retired after the beginning of the test year has a partial year's depreciation expense recorded on the books of the Company. To allow Southwest Gas the opportunity to recover its reasonable and necessary operating expenses and to avoid charging customers for assets removed or retired from service, depreciation and amortization must be annualized based on end of test year plant balances, as adjusted. This adjustment accomplishes those objectives, and is consistent with the methodology approved by the Commission in the Company's previous rate cases.

Adjustment No. 14 – Depreciation and Amortization Expense at New Rates

Q. 64 Please explain Adjustment No. 14 - Depreciation and Amortization Expense at New Rates.

A. 64 The Settlement Agreement from the Company's last GRC required Southwest Gas to file a comprehensive depreciation study in this proceeding. A depreciation study for Arizona plant was prepared for this GRC, and a System Allocable plant depreciation study was prepared for and approved in the Company's last Nevada general rate case. Both of these studies were prepared and sponsored by Company witness Dane Watson. The use of the most recently approved System Allocable depreciation study filed in Nevada for updating the

related depreciation rates is consistent with the Company's previous Arizona rate cases. This adjustment calculates the difference in depreciation expense due solely to the change in depreciation rates proposed by the Company. This adjustment decreases operating expenses by $41,806,078.

Adjustment No. 15 – Property Tax Annualization

Q. 65 Please explain Adjustment No. 15 - Property Tax Annualization.

A. 65 Adjustment No. 15 annualizes property taxes on the Company's adjusted investment in plant and materials as of the end of the test year. For Arizona properties, the Company determines an estimated full cash value by using adjusted net plant in service at November 30, 2015, adding materials and supplies, and subtracting transportation equipment and land rights. The estimated full cash value is then multiplied by the assessment ratio of 18 percent to determine the assessed value. The assessed value is then multiplied by the composite property tax rate of 14.11 percent, which is then reduced by capitalized property taxes to determine the annualized property tax expense. This adjustment increases operating expenses by $7,337,348.

Adjustment No. 16 – Interest on Customer Deposits

Q. 66 Please explain Adjustment No. 16 - Interest on Customer Deposits.

A. 66 Adjustment No. 16 synchronizes interest expense on customer deposits with the amount of customer deposits used as a rate base reduction. The customer deposit balance used as a rate base reduction is multiplied by the customer deposit rate of six percent to determine the adjusted interest on customer deposit balance expense. The difference between the adjusted amount and the recorded amount is the adjustment. Consistent with prior Commission

decisions, interest expense is treated as an above-the-line expense. This adjustment increases operating expenses by $35,049.

Adjustment No. 17 – Surcharge Adjustment

Q. 67 Please explain Adjustment No. 17 - Surcharge Adjustment.

A. 67 Adjustment No. 17 removes expenses from base rates that are recovered through various surcharges, including the Gas Research Fund (GRF) surcharge, the Demand Side Management Program surcharge, and the Transmission Integrity Management Program surcharge. This adjustment reduces operating expenses by $8,015,970. In addition, the Company proposes to increase funding for natural gas research to $820,000 per year, and to include this amount in base rates instead of a surcharge.

Q. 68 Why does Southwest Gas propose to increase funding for natural gas research?

A. 68 The level of annual funding for natural gas research is $688,712, which was authorized by the Commission in the Company's 2004 GRC (Decision No. 68487) and has remained at the same level for the last decade. When the GRF surcharge was initially approved by the Commission, it was recognized that there is a need for, and a gap in, industry-wide funding. The GRF filled some of that gap. The need for natural gas research funding still exists, and inflation has eroded the contribution that authorized GRF dollars are making to fund these worthwhile projects.

Q. 69 What level does Southwest Gas propose to increase its annual funding to be recovered through the GRF surcharge, and what is this increase based on?

A. 69 Southwest Gas proposes to increase the annual amount from $688,712 to $820,000. This increase keeps the GRF cost per customer at approximately the

same level as it was in the 2004 GRC when the GRF was initially approved by the Commission.

Q. 70 Does Southwest Gas propose any changes to Finding of Fact No. 37 in Decision No. 68487 that..."Southwest Gas should have the flexibility, subject to Staff oversight, to select appropriate entities for use of the research funds."

A. 70 No. Southwest Gas will continue to file an annual plan that provides a list and description of the research programs to be funded by the Company through the GRF, in order to allow Staff to maintain its oversight over this program.

Q. 71 The Settlement Agreement from the Company's last GRC required Southwest Gas to include the progress and money spent on early vintage plastic pipe (EVPP) replacement. What is the progress and money spent on EVPP since the Company's last GRC?

A. 71 EVPP consists primarily of polyvinyl chloride (PVC) pipe, Aldyl A polyethylene pipe, and Aldyl HD polyethylene pipe. Since the last GRC, Southwest Gas has replaced approximately 408,000 feet of PVC pipe, 700,000 feet of Aldyl HD pipe, and 2.2 million feet of Aldyl A pipe in Arizona. The cost to replace this pipe was approximately $169 million.

Q. 72 Does this conclude your prepared direct testimony?

A. 72 Yes.

SUMMARY OF QUALIFICATIONS
RANDI L. CUNNINGHAM

I graduated from the University of Washington in Seattle, Washington with a Bachelor of Arts in Business Administration, Accounting. My areas of concentration were accounting and finance. I graduated from the University of Nevada, Las Vegas with a Masters in Business Administration (MBA), with Beta Gamma Sigma honors. I am a Certified Management Accountant (CMA) and a member of the Institute of Management Accountants.

One year before completing my bachelor's degree, I accepted employment at Washington Mutual Savings Bank in Seattle, Washington as an Asset/Liability Management intern. Upon graduation in 1993, I accepted a full-time position as a Financial Analyst Trainee in the Financial Forecasting Department. In 1994, I was promoted to Financial Analyst I. My responsibilities included assisting in the budget and forecasting process and various financial analyses.

In February 1995, I accepted a position as a Budget Analyst in the Budget and Forecasting Department at PriMerit Bank in Las Vegas, Nevada, which was a subsidiary of Southwest Gas at the time. In April 1996, I transferred to Southwest Gas as a Corporate Accountant I in the Accounting Control Department. In January 1998, I was promoted to Analyst I/Accounting. In February 1998, I transferred to the Revenue Requirements department as an Analyst. In January 2001 I was promoted to Specialist, in July 2003 I was promoted to Senior Specialist, in May 2007 I was promoted to Supervisor, and in April 2009 I was promoted to Manager. Subsequent to a reorganization in October 2014, I have worked in the Regulation department in my present position.

I have attended numerous training and technical conferences related to utility ratemaking, regulatory, and accounting issues.

I taught the Cost of Service Problem for "The Basics" conference presented by the Center for Public Utilities at New Mexico State University and the National Association of Regulatory Utility Commissioners from 2003 to 2014.

Tab H

Direct Testimony

of

Theodore K. Wood

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
THEODORE K. WOOD

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
Prepared Direct Testimony
of
THEODORE K. WOOD

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Appendix A – Summary of Qualifications of Theodore K. Wood

Exhibit No.__(TKW-1)

Exhibit No.__(TKW-2)

Exhibit No.__(TKW-3)

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
THEODORE K.WOOD

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Theodore K. Wood. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Financial Services department. My title is Assistant Treasurer & Director/Financial Services.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (ACC or Commission), the Public Utilities Commission of Nevada (PUCN), and the California Public Utilities Commission (CPUC). I have also provided written testimony to the Federal Energy Regulatory Commission (FERC).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's overall requested rate of return. Specifically, my direct testimony details the requested capital structure and the embedded cost of long-

term debt used for determining the appropriate cost of capital for the Company's Arizona rate jurisdiction. In addition, I discuss the importance of the Company's overall rate of return on the Company's bond ratings and financial profile. I also discuss the appropriate fair value rate of return (FVROR) methodology for ratemaking and to how that methodology should be applied in conjunction with the Company's proposed Gas Infrastructure Modernization (GIM) mechanism.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key topics:

- The development of a FVROR necessary for the Company to earn a fair return on its Arizona properties;
- A review of the Company's financial profile, addressing the Company's credit ratings and their importance in accessing the capital markets. In doing so, I comment on the actual credit rating impacts from decoupling and the potential impacts from the change in depreciation rates and the Company's proposed GIM mechanism. I also comment on the need for Southwest Gas to offer a competitive rate of return to continue to attract capital and discuss why Southwest Gas' requested overall FVROR is necessary to support and sustain the Company's financial profile and credit ratings;
- The Company's requested capital structure for ratemaking, which is composed of 51.69 percent common equity and 48.31 percent long-term debt. The requested capital structure is the Company's actual capital structure for the test period ended November 30, 2015;

- The development of the embedded cost of long-term debt for the Company's Arizona jurisdiction, which is 5.21 percent for the test period ended November 30, 2015; and
- The rationale for what is the appropriate FVROR methodology for ratemaking and to how that methodology should be applied in conjunction with the Company's proposed GIM mechanism.

Q. 7 Are you sponsoring any schedules and exhibits in support of your prepared direct testimony?

A. 7 Yes. I sponsor Schedule A-3 and Schedule D-1 through Schedule D-4. In addition, I sponsor Exhibit Nos. ____ (TKW-1) through ____ (TKW-3), which are attached. These schedules and exhibits were prepared by me or under my supervision.

II. SOUTHWEST GAS' FAIR VALUE RATE OF RETURN

Q. 8 Have you determined a reasonable rate of return necessary for Southwest Gas to earn a fair return on its Arizona properties?

A. 8 Yes. An overall FVROR of 6.01 percent for the Arizona jurisdiction is reasonable in this proceeding and properly reflects the Company's level of business, financial, and regulatory risks. The FVROR was developed from the estimated weighted average cost of capital (WACC) for the original cost rate base (OCRB), summarized as follows:

Southwest Gas Corporation
Arizona Rate Jurisdiction

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48.31%	5.21%	2.52%
Common Equity	51.69%	10.25%	5.30%
Total	100.00%		7.82%

The resulting FVROR to be applied to the fair value rate base is 6.01 percent (the prepared direct testimony of Company witness Robert Hevert details the methodology used to derive the FVROR).

Q. 9 Why is the proposed rate of return appropriate and necessary for Southwest Gas?

A. 9 This rate of return is necessary to maintain the Company's financial integrity, to allow the Company to attract new capital and to permit the Company's equity holders the opportunity to earn a fair and reasonable rate of return (ROR).

Moreover, this rate of return meets the standard of reasonableness established by the United States Supreme Court in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923)(Bluefield):

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

This rate of return also satisfies the comparability standard set by the Court in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944)(Hope):

> . . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

An explanation regarding the practical application of these two court rulings to a diversified utility such as Southwest Gas is appropriate.

The Company has, since the late 1950s, filed rate cases as a "diversified" utility. The multi-jurisdictional rate case filings are based on the fact that Southwest Gas, as a natural gas utility, serves three states with several different ratemaking jurisdictions. The Company requests only gas distribution utility required rates of return in all filings within each jurisdiction. The capital costs requested in this filing are utility-only costs. Southwest Gas' practices assure that the costs of utility operations attributable to each of its jurisdictions are properly insulated from the impact of any non-utility activities.

In summary, Southwest Gas' requested rate of return in this proceeding is fair to both customers and shareholders and properly reflects the risks and returns appropriate for its gas distribution properties.

III. SOUTHWEST GAS' FINANCIAL PROFILE

A. Credit Ratings

Q. 10 What is a credit rating?

A. 10 A credit rating reflects an independent rating agency's opinion of the creditworthiness of a particular company, security, or obligation. Credit ratings play an important role in capital markets by providing an effective and objective tool for market participants to evaluate and assess credit risk. In a report on the role and function of credit rating agencies, the Securities and Exchange Commission (SEC) concluded:

> The importance of credit ratings to investors and other market participants had increased significantly, impacting an issuer's access to and cost of capital, the structure of financial transactions, and the ability of fiduciaries and others to make particular investments.[1]

[1] SEC, "Report on the Role and Function of Credit Rating Agencies in the Operation of the Securities Markets," January 24, 2003.

As a result, the Company's credit ratings are a key factor in determining the required yield on the Company's debt securities and bank facilities, and the amount and terms of available unsecured trade credit. Credit rating agencies use both quantitative and qualitative information in the process of developing a credit rating.

Q. 11 How important is the regulatory environment in the determination of a credit rating for a public utility?

A. 11 For a public utility, credit rating agencies regard regulation as a significant factor in determining financial performance, as regulation defines the environment in which the utility operates. The importance of regulation on the credit rating for a utility is reflected in the following statement from Standard & Poor's (S&P):

> Based on Standard & Poor's Ratings Services' experience in rating U.S. investor-owned utilities, we believe that the fundamental regulatory environment can be one of the most important factors we analyze when assigning utility credit ratings.[2]

Similarly, Moody's Investors Service (Moody's) states:

> For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors.[3]

Q. 12 What are the Company's current long-term unsecured debt credit ratings?

A. 12 Currently, Southwest Gas' long-term unsecured debt credit ratings are "A" from Fitch, Inc. (Fitch), "A3" from Moody's, and "BBB+" from S&P.

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[2] Standard & Poor's RatingsDirect, *Credit FAQ: Standard & Poor's Assessments Of Regulatory Climates For U.S Investor-Owned Utilities,* November 25, 2008, p. 2.

[3] Moody's Investors Service, Moody's Rating Methodology, *Regulated Electric and Gas Utilities*, August 2009, p. 6.

Q. 13 What is the Company's current credit rating outlook?

A. 13 Credit rating agencies also provide a credit ratings outlook, which is an assessment of the direction of the credit rating over the intermediate to longer term. The current credit rating outlooks for Southwest Gas provided by each of the three rating agencies are "stable." The latest available credit agency reports are included in Exhibit No.__(TKW-1).

Q. 14 Have there been any changes in Southwest Gas' credit ratings since the Company's last Arizona general rate case?

A. 14 Yes. The table below displays the Company's unsecured credit ratings at June 30, 2010 (the test period for the Company's last general rate case) compared to the current ratings.

Rating Agency	Last Change	Current	June 30, 2010
S&P	October 2014	BBB+	BBB
Moody's	January 2014	A3	Baa2
Fitch	May 2013	A	BBB

Since the last general rate case, the Company's credit ratings and financial profile have improved. The improved financial profile reflects the combined outcome from the significant common stock issuances over the last decade[4] and improved operating results. Given the improved credit ratings and the low interest rate environment, the Company has been able to significantly reduce the embedded cost of debt, going from the authorized 8.34 percent in the Company's last general rate case to a now-requested 5.21 percent cost of debt.

[4] Over the period December 31, 2005 to December 31, 2015, the Company has issued 8,049,284 shares of common stock, which is approximately 17 percent of the shares outstanding.

Q 15 Has the Company taken any action to maintain its strong investment grade credit rating?

A 15 Yes. Southwest Gas filed a Notice of Intent in Docket No. G-01551A-15-0351 requesting authority to implement a Plan of reorganization (Plan) that will result in a holding company structure. A holding company structure will further the separation between the Company's utility operations and its construction services affiliates. The proposed holding company structure will also work to reduce financial and legal risk to the utility, and offers greater flexibility in financing by allowing both the utility and the holding company to individually access capital markets. A key benefit is that it will enable the utility business of Southwest Gas to obtain separate credit ratings apart from the new consolidated entity, which should help insulate the utility from the impacts of a larger construction services business. In addition, the proposed holding company structure will provide optionality in managing the construction services segment percentage of the consolidated entity.

Q 16 What other steps has the Company taken to maintain its strong investment grade credit ratings?

A 16 Southwest Gas is committed to maintaining an appropriate capital structure to support its strong investment grade credit ratings. This commitment by Southwest Gas has been demonstrated by its willingness to continue to issue new equity to finance its investment in utility plant and maintain its capital structure with the establishment of a $100 million Equity Shelf Program[5] During

[5] In March 2015, the Company filed with the SEC a shelf registration statement which includes a prospectus detailing the Company's plans to sell up to $100 million of the Company's common stock over a period of time. In March 2015, the Company entered into a Sales Agency Agreement with BNY Mellon Capital Markets, LLC relating to this issuance and sale of shares of the Company's common stock ("Equity

2015, the Company issued 645,225 shares of common stock under this program, raising net proceeds of $35.2 million.

B. Energy Efficiency Enabling Provision

Q. 17 Is the Company requesting the continuation of the decoupled rate design which is contained in the previously approved Energy Efficiency Enabling Provision (EEP)?

A. 17 Yes. The prepared direct testimony of Company witness Edward Gieseking details the rationale for the Company's proposed continuation of the EEP.

Q. 18 Has the Company's decoupled rate design been a positive credit rating factor?

A. 18 Yes. The decoupled rate design has been a positive contributing factor in Southwest Gas' ability to improve its credit ratings in two ways: (1) improved credit metrics due to less volatile cash flows and revenues; and (2) as a sign of increased regulatory support by the ACC. In its last general rate case, Southwest Gas stated that one of the key benefits of the Company's EEP would be to its credit ratings, as the EEP would be viewed by rating agencies as being credit supportive and, over time, would help to strengthen Southwest Gas' financial metrics leading to improved ratings.[6] With the approval of decoupling, in conjunction with improved operating results and an improved capital structure - stemming from the significant common stock issuances over the last decade while maintaining a conservative dividend policy, improved credit ratings have been realized. The improved credit ratings have contributed to a

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Shelf Program"). Sales of the shares will continue to be made at market prices prevailing at the time of sale. Net proceeds from the sale of shares of common stock under the Equity Shelf Program will be used for general corporate purposes, including the acquisition of property for the construction, completion, extension or improvement of pipeline systems and facilities located in and around the communities Southwest Gas serves.

[6] Prepared direct testimony of Theodore K. Wood, Docket No. G-01551A-10-0458, p.7-9.

significant reduction in the embedded cost of debt since the Company's last general rate case. The approval of a decoupled rate design has been cited by the rating agencies as a contributing positive factor in the upgrades. For example, Fitch, in its press release for the Company's upgrade to BBB+ from BBB (June 2, 2011), stated:

> . . . a push toward more decoupled rate structures within SWX's operating jurisdictions has helped to lower some of the revenue volatility associated with the effects of weather and conservation. Fitch generally views the implementation of rate mechanisms such as decoupling that reduce cash flow volatility favorably;[7]

In addition, with the upgrade by Moody's to Baa1 from Baa2 (March 15, 2012), Moody's stated, "...the implementation of gas de-coupling [is] supportive to Southwest's credit quality".[8] S&P directly pointed out the improved regulatory environment in Arizona for Southwest Gas due to the approval of decoupling, stating:

> In our opinion, regulation in Arizona (historically considered one of the less credit-supportive jurisdictions) has improved substantially because the ACC approved a decoupled rate design in Southwest Gas's latest rate case.[9]

C. Change in Depreciation Rates

Q. 19 Is the Company proposing a change in the book depreciation rates for its Arizona jurisdiction?

A. 19 Yes. As part of the settlement agreement approved by the Commission in the Company's last general rate case,[10] the Company agreed to file a

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[7] Fitch Ratings, *Fitch Ratings Upgrades Southwest Gas Corp. to 'BBB+'; Outlook Stable*, June 2, 2011, p.1..

[8] Moody's Investors Service, *Rating Action: Moody's Upgrades Southwest Gas Corp to Baa1 from Baa2; Outlook Stable,* March 15, 2012, p.1

[9] Standard & Poor's RatingsDirect, *Summary: Southwest Gas Corp.*, March 20, 2013, p. 4.

[10] Decision No. 72723.

comprehensive depreciation study in this proceeding. The prepared direct testimony of Company witness Dane Watson contains the depreciation study. As a result of the study, the Company is proposing significant decreases in its authorized book depreciation rates. The annual revenue requirement impact is a $42 million reduction in depreciation expense.

Q. 20 What impact will this reduction in depreciation expense have on the Company?

A. 20 The $42 million reduction in depreciation expense will have a negative effect on the Company's cash flows and resulting credit metrics, which in large part are measured on a cash flow basis.

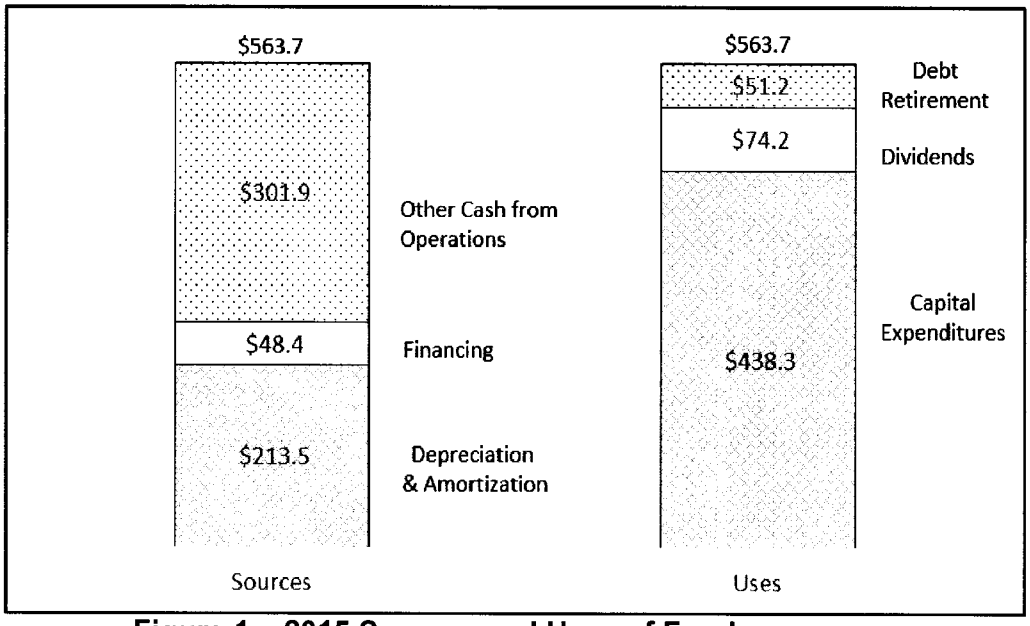

Figure 1 – 2015 Sources and Uses of Funds

As displayed in Figure 1, depreciation supplied approximately 38 percent of the funds primarily used to fund capital expenditures. The $42 million reduction in depreciation expense represents a 7.5 percent decline in the sources of funds. For Southwest Gas, which has an elevated capital expenditure program and a growing rate base, the reduction in cash flow from depreciation will require the Company to fund a larger portion of the capital expenditures from external

sources, both debt and equity. At the same time, the cash flow based credit metrics of the Company will be negatively impacted due to the reduction in cash flows, which in turn could increase the cost of borrowing on a going forward basis. The negative impact to the credit ratings from the lower depreciation rates can possibly be mitigated by the Commission's approval of the Company's proposed GIM mechanism.

D. Gas Infrastructure Modernization Mechanism

Q. 21 Please briefly describe the Company's proposed GIM mechanism.

A. 21 Southwest Gas is proposing a GIM mechanism with respect to its investment in certain non-revenue-producing gas infrastructure, non-revenue-producing pipeline replacement programs, and the funding of unfunded government mandates between general rate cases. The GIM would include the Company's currently-approved Customer-Owned Yard Line (COYL) Program. The specific details of the Company's proposed GIM mechanism are described in the prepared direct testimony of Company witnesses Edward Gieseking and Kevin M. Lang.

Q. 22 How will the Company's proposed GIM help sustain the Company's financial profile?

A. 22 The proposed GIM would improve Southwest Gas' ability to recover costs associated with its non-revenue-producing infrastructure investments on a more timely basis, which over time would help maintain Southwest Gas' financial metrics, including its ability to earn its authorized ROR, and increase the likelihood for Southwest Gas to improve its credit ratings. From a capital attraction standpoint, the GIM would make Southwest Gas more comparable to other natural gas utilities with similar mechanisms, or other mechanisms

that allow for timely recovery of infrastructure replacement costs. As reported by Company witness Robert Hevert, all six of the proxy group companies used to estimate the cost of common equity in this proceeding have infrastructure recovery mechanisms.[11]

Q. 23 Would approval of the proposed GIM be recognized as a positive factor for the Company's credit rating?

A. 23 Yes. Rating agencies would view Commission approval of the GIM as a positive regulatory support factor. As discussed below, this positive reaction from the credit rating agencies was recognized following the Commission's approval of the Company's COYL program. As the Company continues to make significant investments in non-revenue producing infrastructure, it will continue to experience increased expenses (capital costs, depreciation, and property taxes), with the revenue increases associated with these capital expenditures not being experienced until the Company's next general rate case. From a credit ratings standpoint, this will cause key financial metrics, such as funds from operations (FFO) to debt and FFO interest coverage, to decline between general rate cases.

Specifically, rating agencies recognize the benefit from such mechanisms, with S&P stating:

> A utility's credit quality during construction projects will depend on credit-supportive regulation. We believe supportive and timely cost recovery that helps avoid large rate increases will become more critical to utilities' ability to maintain cash flow, earnings power, and, ultimately, credit quality. Cost recovery options generally include base-rate increases when projects

[11] Prepared Direct Testimony of Company Witness Robert Hevert, p.49.

> are complete, along with rate surcharges and riders during construction.[12]

Similarly, Moody's states:

> An increasing array of accelerated cost recovery mechanisms in various state jurisdictions is helping to support the credit qualities of gas utilities.[13]

In addition, Moody's has specifically cited the approval of such infrastructure recovery mechanisms for Southwest Gas as reflecting constructive regulatory treatment and being credit positive, stating:

> In recent years, there have been meaningful improvements in the regulatory frameworks under which Southwest Gas operates. For example, infrastructure tracker mechanisms were approved in Arizona and Nevada. In Arizona and more recently in California, Southwest Gas was granted a Customer-Owned Yard line program (COYL), and an Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) for timely cost recovery of qualifying non-revenue producing capital expenditures associated with the enhancement and replacement of gas infrastructure. A gas infrastructure recovery (GIR) mechanism has been implemented in Nevada with the 2014 GIR advance application authorizing $14.4 million of replacement work for 2015. Also, all three jurisdictions implemented decoupling mechanisms albeit the actual mechanism varies state by state. Constructive regulatory framework developments and signs of an improving regulatory environment are credit positive.[14]

Q. 24 Please summarize the importance of the potential credit rating impacts resulting from this proceeding to Southwest Gas.

A. 24 The importance to the Company's credit rating is due to the capital-intensive nature of the natural gas distribution business. Southwest Gas needs to make

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[12] Standard & Poor's RatingsDirect, U.S. Utilities' Capital Spending Is Rising, And Cost Recovery Is Vital, May 14, 2012.

[13] Moody's Investors Service, Special Comment, *Pipeline Safety Costs Rising As Alternative Rate Designs Sought*, April 25, 2012, p. 1.

[14] Moody's Investors Service, *Credit Opinion: Southwest Gas Corporation,* March 24, 2015, p.2

continuing and substantial investments to provide reliable and safe service to customers. On a total company basis, Southwest Gas anticipates capital expenditures over the next three-year period ending December 31, 2018, to be in the range of $1.4 billion to $1.6 billion. Accordingly, Southwest Gas needs to have continuing access to capital and credit capacity at reasonable costs. This is especially relevant given that the Company is proposing to decrease its book depreciation rates, which will lower its current depreciation expense, and therefore, its cash flows by approximately $42 million a year.[15] While the change in depreciation expense will be seen as a negative credit rating factor, Commission approval of the proposed GIM would be seen as positive credit rating factor, as it would reduce regulatory lag and somewhat mitigate the depreciation effect. Approval of the GIM mechanism, combined with the continuation of the Company's decoupled rate design and approval of the Company's requested FVROR will provide the Company the opportunity to sustain its credit ratings, which benefits both its customers and its investors.

E. Capital Attraction

Q. 25 Given the Company's operating environment, what are the key factors that will enable the Company to continue to attract the capital necessary to meet its ongoing capital requirements?

A. 25 Generally, investors will choose between alternative investments based on the risk and reward characteristics of the available investment opportunities. Consequently, the Company must compete with other utilities and alternative investment opportunities in fully competitive global capital markets to attract

[15] See the Prepared Direct Testimony of Company witness Dane Watson.

equity capital. For Southwest Gas to successfully attract equity capital, it must demonstrate an ability to achieve a competitive return on that equity capital. The prepared direct testimony of Company witness Robert B. Hevert discusses the development of a fair and reasonable cost of common equity of 10.25 percent, considering the Company's specific risk factors and costs of common equity for proxy groups of "similar" natural gas utilities.

Q. 26 What are the historic and projected earned returns on book common equity for the proxy group companies used to estimate the cost of common equity?

A. 26 Investors commonly use historic and projected earned returns on book value equity as an important financial metric when evaluating alternative investments. Exhibit No.__(TKW-2) provides the average and median historical returns for the time period 2011-2015, and the projected returns for the periods 2016, 2017, and 2019-2021 for each proxy group member firm.[16] The analysis of the proxy groups of natural gas distribution companies can be summarized as follows:

Proxy Group of Six LDCs

	Historical ROE 2011—2015	Projected ROE 2016, 2017, 2019—21
Average ROE	10.37%	10.50%
Median ROE	9.84%	11.00%

This comparable earnings analysis demonstrates that the Company's requested 10.25 percent ROE is both conservative and reasonable relative to the proxy group.[17]

[16] Information was derived from the Value Line Investment Survey, March 4, 2016. The proxy group of six natural gas distribution companies was developed and used by Company witness Robert Hevert.
[17] Prepared direct testimony of Company witness Robert B. Hevert.

Q. 27 What other factors should the Commission consider in establishing the recommended ROR on common equity?

A. 27 Current and expected capital market conditions are important considerations, as the new rates established in this proceeding will be in effect for some length of time in the future. Since the financial crisis began in 2007, the level of interest rates has been low from a historical perspective, due in large part to the aggressive monetary policy conducted by the Federal Reserve. It is therefore important to take into consideration the projected path of interest rates during the time new rates will be in effect. The April 2016 interest rate forecast provided by Global Insight projects significant increases in interest rates over the next few years.

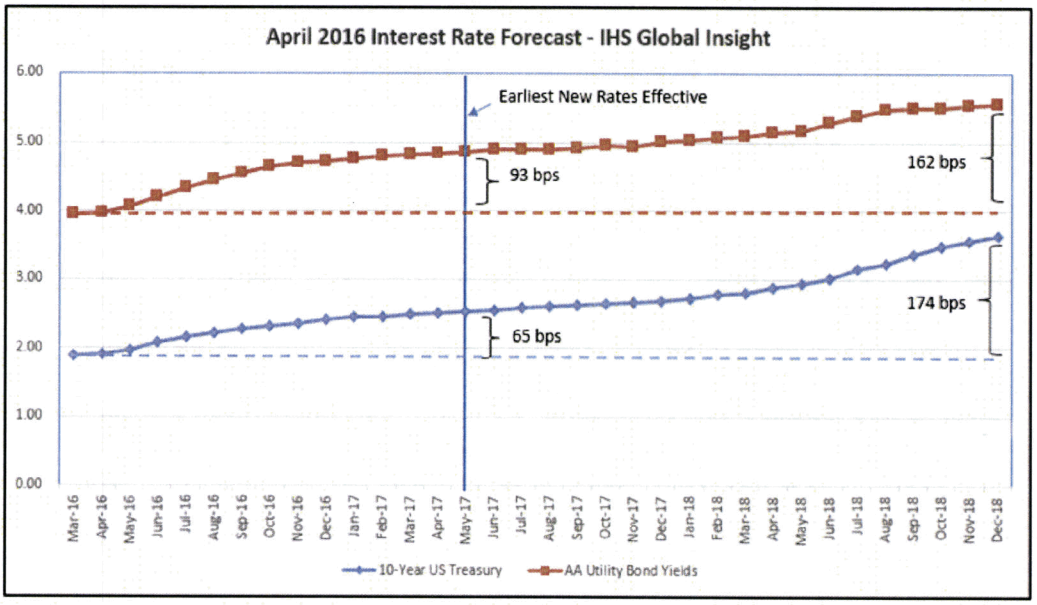

Figure 2 – IHS Global Insight – April 2016 Interest Rate Forecast

Figure 2 displays that the yields of both AA Utility Bonds and the 10-Year US Treasury Notes are expected to materially increase between now and May 2017, when new rates from this proceeding are expected to be effective, and are

projected to continue to increase significantly thereafter. Given that current interest rates are still low from a historical perspective and are forecasted to increase significantly over the next few years, the Commission should incorporate this information in selecting an ROE to ensure it remains reasonable on average in the near-term, when new rates from this proceeding will be in effect.

Q. 28 How does the overall FVROR balance the interests of both customers and investors of the Company?

A. 28 The Company's financial health is, over time, important in determining the rates it must charge its customers. The Company's credit ratings are significantly influenced by its financial strength. The Company's cost of debt is in large part determined by the Company's credit ratings. All other things being equal, with higher credit ratings, the Company's cost of capital and the rates it charges its customers would be lower.

It is also important that investors be given the opportunity to earn an ROR commensurate with the level of risk associated with their investment. Investor confidence in Southwest Gas is important for both its existing shareholders and for the Company's future ability to issue additional common equity. If the overall allowed ROR is set below the Company's actual cost of capital, the Company may be unable to attract sufficient financing at reasonable rates to continue to fund required capital expenditures and maintain its quality of customer service. The Company's requested overall FVROR will help sustain the Company's improved financial condition and support continued improvement. In the long-run, this will benefit both the Company's customers and investors.

In summary, the improved regulatory environment in Arizona has been recognized as a key factor for the improved financial profiles for the state's utilities[18]. With the constructive regulatory support of the Commission in approving the Company's proposed overall FVROR, Southwest Gas can continue to sustain the substantial progress it has made in improving its financial profile and credit ratings. Such improvement has and will continue to benefit Southwest Gas' customers by reducing the long-run average capital costs embedded in customer rates – as demonstrated by the sizeable reduction in debt costs since the Company's last general rate case.

IV. RECOMMENDED CAPITAL STRUCTURE

Q. 29 What is Southwest Gas' current Commission-authorized ratemaking capital structure and overall ROR?

A. 29 In the Company's last general rate case (Decision No. 72723 in Docket No. G-01551A-10-0458), the Commission adopted the following capital structure, capital costs and overall ROR:

Southwest Gas Corporation
ACC Authorized Rate of Return
Decision No. 72723

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	52.30%	8.34%	4.97%
Common Equity	47.70%	9.50%	3.98%
Total	100.00%		8.95%

The authorized FVROR on fair value rate base was 6.92 percent.

[18] FitchRatings, *Special Report: Arizona Regulation: Improved Regulatory Compact*, January 7, 2016.

Q. 30 What is the Company's recommended capital structure for ratemaking purposes in this proceeding?

A. 30 The Company requests a capital structure at the end of the test period, November 30, 2015, composed of 51.69 percent common equity and 48.31 percent long-term debt. This capital structure is consistent with the utility only portion of the Company's proposed reorganized holding company structure that the Company expects to be in place when new rates go into effect from this proceeding.

V. EMBEDDED COST OF LONG-TERM DEBT

Q. 31 Have you determined the test period embedded cost rate for long-term debt capital?

A. 31 Yes. Southwest Gas' cost rate for long-term debt is 5.21 percent for the test period ended November 30, 2015. This rate is summarized on line 1, column (c), of Schedule D-1, Sheet 1 of 2. Schedule D-2, Sheets 1 through 4, contains the development of the long-term debt cost rate. The cost of debt is comprised of the cost of fixed-rate debentures and notes, fixed-rate medium-term notes, and a variable-rate term facility.

Q. 32 Please describe the development of the cost rates of the debentures and notes.

A. 32 The Company had three outstanding debenture and note issues, totaling $825 million of gross principal, at the end of the test year. The debentures and notes had a weighted average cost of 5.66 percent, as shown on line 6, column (e), of Schedule D-2, Sheet 2 of 4.

Q. 33 Please describe the cost rate of the medium-term notes.

A. 33 The Company established a $150 million medium-term note program in November 1997. The name is somewhat of a misnomer as medium-term notes

can be issued with maturities ranging from nine months to 30 years. The Company issued its entire medium-term note program and had four outstanding medium-term note issues totaling $82.5 million of gross principal at November 30, 2015. The medium-term notes had a weighted average cost of 7.75 percent, as shown on line 11, column (e), of Schedule D-2, Sheet 2 of 4.

Q. 34 How are the effective cost rates of debentures, notes, and medium-term notes calculated?

A. 34 The effective cost rates of debentures, notes, and medium-term notes are calculated through the use of the yield-to-maturity (YTM) or effective interest rate method.

Q. 35 Please describe and discuss the cost of unamortized loss on reacquired debt.

A. 35 In March 2010, the Company redeemed at par $100 million in Trust Originated Preferred Securities (TOPrS), which had an effective cost of 8.20 percent. The redemption expenses and the remaining unamortized balance are being amortized on a straight-line basis to the original maturity date of the called Subordinate Debentures, September 2043.

The effective cost for the unamortized loss on reacquired debt is calculated by dividing the annual amortization, $171,862 by the remaining recorded amount, $(4,783,486) as shown on line 12, column (f) and column (d), of Schedule D-2, Sheet 2 of 4.

Q. 36 Please describe and discuss the development of the cost rate for the variable-rate term facility debt.

A. 36 The Company has a five-year $300 million revolving credit facility, which was originated in May 2012 and was recently extended to expire in March 2021. In addition, the Company has a $50 million uncommitted F-2 commercial paper

program, supported by the revolving credit facility. The Company continues to view $150 million of the facility as a permanent intermediate-term component of its debt portfolio. Accordingly, the Company has classified it as long-term debt. Southwest Gas continues to use the remaining $150 million of the facility to fund recurring seasonal working capital needs.

At the end of the test period, the Company had $100 million outstanding in LIBOR loans and $50 million outstanding as commercial paper. The all-in effective rate of the long-term debt portion of the facility at the end of the test period was 1.10 percent as shown on line 1, column (e), of Schedule D-2, Sheet 3 of 4. The all-in rate effective rate includes the interest on the loans/commercial paper, an annual fee, and unused commitment fees for amounts outstanding as commercial paper and amortization of debt expenses incurred to establish the term facility.

Q. 37 Why are the Industrial Development Revenue Bonds (IDRBs) excluded in calculating the cost of long-term debt?

A. 37 Southwest Gas issued IDRBs in two of its rate jurisdictions – Clark County, Nevada and Big Bear, California. The IDRB issues outstanding at the end of the test period are as follows: (1) the Clark County, Nevada IDRBs (2003 Series A, 2005 Series A, 2006 Series A, 2008 Series A and 2009 Series A) for the Company's Southern Nevada rate jurisdiction; and (2) the City of Big Bear, California IDRBs (1993 Series A) for its Southern California rate jurisdiction. As reflected in the IDRB indentures and financing agreements, the proceeds from the issuance of this type of debt are restricted to funding qualified construction expenditures for additions and improvements in the specific distribution systems to which the IDRBs relate. In addition, there are strict Internal Revenue Service

(IRS) rules which mandate that the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the specific jurisdiction to which the IDRBs apply. Deviation from the requirements of this IRS ruling could result in the loss of the IDRB tax-exempt status which would, in turn, cause the Company to refinance its debt at a much higher cost.

Q. 38 How have this and other regulatory commissions treated the cost of Southwest Gas' IDRBs in past regulatory proceedings?

A. 38 Southwest Gas has historically excluded the IDRBs from the cost of debt calculation in all regulatory jurisdictions, except for the specific jurisdictions (Southern Nevada for Clark County IDRBs and Southern California for City of Big Bear IDRBs), to which the relevant IDRBs apply. This Commission, the PUCN, the CPUC, and the FERC have accepted this treatment for IDRBs in past regulatory proceedings.

VI. FAIR VALUE RATE OF RETURN (FVROR) FOR INCREMENTAL INVESTMENTS

Q. 39 What is the purpose of this section of your testimony?

A. 39 In this section of my testimony, I present the rationale for the appropriate FVROR to be applied in conjunction with an infrastructure recovery mechanism such as the Company's proposed GIM mechanism.[19] In doing so, I start with a review of the calculation of the fair value rate base (FVRB), then examine two alternative Commission-accepted FVROR methodologies by using some simple examples to demonstrate which methodology is more appropriate. I then explain why an incremental FVROR should be computed in conjunction with the GIM mechanism requested by the Company.

[19] Prepared direct testimony of Company witness Edward Gieseking, p.5-10.

Q. 40 Please explain the concept of FVRB, as used for ratemaking purposes.

A. 40 Article XV, section 14 of the Arizona Constitution provides that "the Corporation Commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the State of every public service corporation doing business therein . . ." This requires a fair value determination of a utility's rate base. The term FVRB for ratemaking purposes is defined as being somewhere between the original OCRB and the reproduction cost new depreciated (RCND) rate base.[20] In Arizona, the standard convention for computing the FVRB has been based on a simple 50/50 weighted average of the OCRB and RCND rate base.

Q. 41 Please explain how the RCND rate base is computed.

A. 41 This RCND rate base is computed by using the Handy-Whitman utility construction indices to trend original cost utility plant and certain other rate base items to obtain the current reproduction cost new, by vintage year of construction. The Handy-Whitman indices are well recognized and commonly used by utility regulatory bodies to trend earlier valuations and original cost records to estimate reproduction cost at prices prevailing at a certain date.

Q. 42 Based on the methodology used to compute the FVRB, what is a key property concerning the relationship between the OCRB and the FVRB?

A. 42 A key property is that the difference between the OCRB and FVRB is a function of the average age of the utility plant where, holding all else constant, a utility with a greater average utility plant age will result in a greater difference between the OCRB and FVRB and therefore a larger ratio of FVRB to OCRB

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[20] See, Charles F. Phillips, Jr., *The Regulation of Public Utilities - Theory and Practice* 358 (Public Utilities Reports, Inc., 2d ed. 1988, Chapter 8, for the historical evolution of the fair value rate base concept.

(FVRB/OCRB). At the time of any new investment in utility plant, the OCRB for that plant will be equivalent to the RCND rate base for that plant and therefore, by definition, will also be equal to the FVRB for that plant. As the age of the utility plant increases, so does the difference between the OCRB and the FVRB due to a greater level of inflation embedded in the calculation of the FVRB.

Q. 43 Please give a simple example to demonstrate this mathematical relationship.

A. 43 For example, assume a utility only has one asset that had an initial cost of $1,000. In addition, assume the annual inflation rate embedded in the Handy-Whitman index for computing the RCND rate base new through time is 3 percent, and the annual book and tax depreciation rate is 5 percent (no deferred taxes). The following table displays the OCRB, the RCND rate base, and the FVRB over the first three years of the rate base.

	Year 0	Year 1	Year 2	Year 3
Gross Plant	$ 1,000.0	$ 1,000.0	$ 1,000.0	$ 1,000.0
Accumulated Depreciation	-	(50.0)	(100.0)	(150.0)
Net Plant	$ 1,000.0	$ 950.0	$ 900.0	$ 850.0
OCRB	$ 1,000.0	$ 950.0	$ 900.0	$ 850.0
Handy-Whitman Index	1.00	1.03	1.06	1.09
RCND rate base	$ 1,000.0	$ 978.5	$ 954.8	$ 928.8
FVRB[1]	$ 1,000.0	$ 964.3	$ 927.4	$ 889.4
FVRB/OCRB	1.00	1.02	1.03	1.05

[1] FVRB = 0.5 X OCRB + 0.5 X RCND rate base

Table 1. Example of the OCRB and FVRB through time

As can be seen from this table, as the utility plant ages, the difference between the OCRB and the FVRB increases.

Q. 44 Please explain the FVROR used in conjunction with the FVRB for ratemaking purposes.

A. 44 In conjunction with the FVRB, a FVROR must be developed to compute the revenue requirement to recover a utility's fair value capital costs. The starting point to develop the FVROR is a utility's WACC for the OCRB. The Commission, in Decision No. 70441, concluded that the WACC was related to the OCRB and that an adjustment to the WACC was appropriate in determining a rate of return on the FVRB. In previous rate proceedings, the Commission has accepted two primary methods to adjust the WACC to compute the FVROR, which were initially proposed in the remand proceeding for Chaparral City Water Company in Docket No. W-02113A-04-0616. The first method, which was proposed by the Residential Utility Consumer Office (RUCO), is to start with the utility's WACC and adjust by the expected rate of inflation. A variation of this approach, which the Commission approved in Decision No. 70441, is to adjust only the equity rate of return component of the WACC by the expected rate of inflation. Henceforth, this method will be referred to as the RUCO method. The second method, which was proposed by the ACC Staff (Staff), is to begin with the WACC and if the cost attributed to the FVRB increment is above the OCRB, that cost should be no larger than the real risk-free rate of return, which had been adjusted for inflation. Henceforth, this method will be referred to as the Staff method. With the Staff method, the range of return for the fair value increment ranged from zero up to the real risk-free rate of return. Both the RUCO and Staff methods were developed to adjust for inflation in the FVROR so as not to double count inflation in the ratemaking process since the FVRB includes an inflation factor.

Q. 45 Please provide a simple example to demonstrate the RUCO and Staff FVROR methods.

A. 45 We can use two hypothetical utilities, Utility A and Utility B, to demonstrate the properties of the RUCO and Staff methods. For this example, both utilities have the same OCRB of $10,000, the same capital structure and WACC of 7.75 percent, and the only difference is in the average age of the utility plant, where Utility A has an average age of 10 years and Utility B has an average age of 15 years. Exhibit No.__(TKW-3), Sheets 1 through Sheet 2, displays the OCRB, RCND rate base, FVRB, WACC and the FVRORs computed for both the Staff and RUCO methods for the two utilities.

Q. 46 Please explain the computation of the FVROR for both utilities using the Staff method.

A. 46 The starting point for computing the FVROR is the WACC associated with the OCRB. The WACC is comprised of a capital structure containing a 50 percent equity component with a cost rate of 10.25 percent and a 50 percent debt component with a cost rate of 5.25 percent, which results in a WACC of 7.75 percent. Next, the Staff method develops a fair value capital structure which begins with the OCRB capital structure and adds the fair value rate base increment above the OCRB. The debt and equity capital components cost rates are the same as the WACC associated with the OCRB and a cost factor is assigned to the fair value increment, ranging between zero and the real-risk free rate of return. In this example, a 1 percent rate is assigned to the fair value increment. For Utility A, this method results in a FVROR of 6.77 percent and for Utility B, the FVROR is computed to be 6.27 percent. Again, the difference between the FVROR between Utility A and Utility B is a function of the difference

in the age of the utility plant and the resulting difference between the FVRB and the OCRB. Utility A has a FVRB of $11,700 with a fair value increment above the OCRB of $1,700 while Utility B has an FVRB of $12,800 with a fair value increment of $2,800. The computation of the FVROR for both utilities highlights a key property of the Staff method in which, holding all else constant, the FVROR computation for a higher (lower) FVRB results in a lower (higher) FVROR as displayed below.

	Utility A		Utility B
OCRB	$10,000	=	$10,000
FVRB	$11,700	<	$12,800
FVROR	6.77%	>	6.27%

Q. 47 Please explain the computation of the FVROR for both utilities using the RUCO method.

A. 47 Again the starting point is the WACC of 7.75 percent. With the RUCO method, the cost of equity is reduced by an inflation factor. For this example, an inflation factor of 2 percent is used and reduces the common equity cost rate from 10.25 percent to 8.25 percent. Using the same capital structure used to compute the WACC and the new cost of equity results in a FVROR of 6.75 percent for both Utility A and Utility B. The computation of the FVROR for both utilities highlights a key property of the RUCO method, which is holding all else constant, the FVROR is not a function of the age of the utility plant and therefore the degree of inflation embedded in the FVRB, and results in the same FVROR for both higher and lower FVRB as displayed below.

	Utility A		Utility B
OCRB	$10,000	=	$10,000
FVRB	$11,700	<	$12,800
FVROR	6.75%	=	6.75%

Q. 48 Please compare and contrast the relationships between the WACC and the resulting FVRORs developed using the Staff and RUCO methods.

A. 48 The relationship between the WACC and the FVROR for the hypothetical utilities under both the Staff and RUCO methods over a range of the ratio of the FVRB to OCRB from 1 to 1.5 (i.e., different ages of utility plant) can best be illustrated in Figure 3.

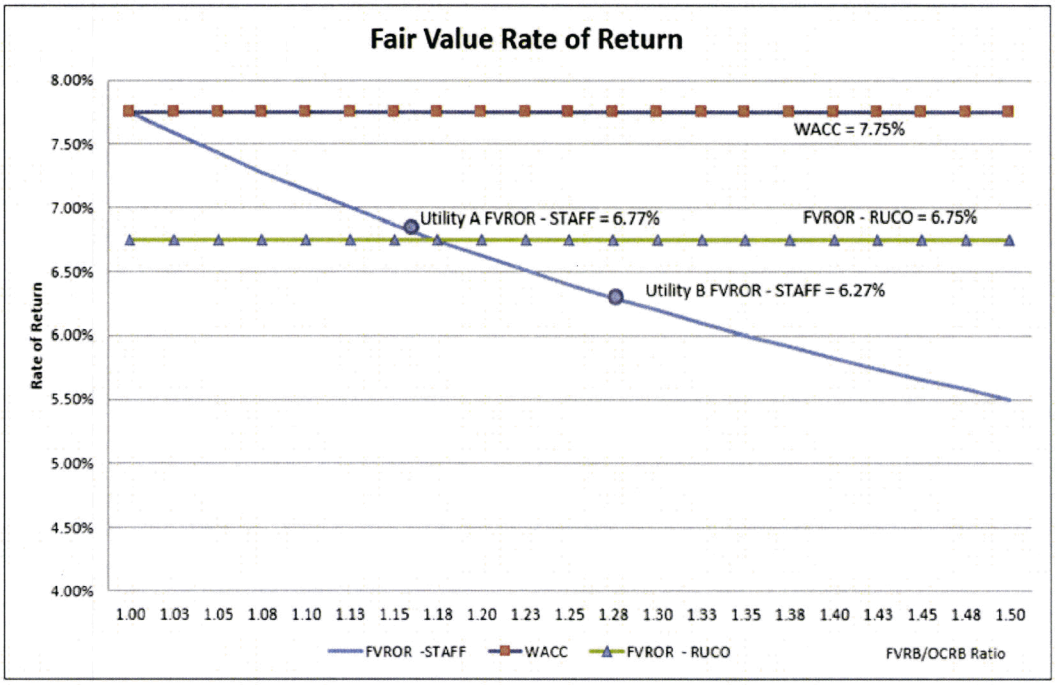

Figure 3 – Fair Value Rate of Return Example

Under the Staff method, the FVROR and WACC are equal at the time of initial investment in rate base, then the FVROR declines as the utility plant ages

and the FVRB increases over the OCRB. The RUCO method results in a constant FVROR because there is no adjustment for the age of the rate base and the amount of inflation in the FVRB. The resulting revenue requirements (computed by multiplying the pretax rates of return[21] by the rate base) under the different methodologies help illustrate the end result of the competing methodologies. Figure 4 displays the OCRB and FVRB for the example utilities over the same range of the ratios of FVRB to OCRB used in Figure 3. Figure 5 displays the revenue requirement for an OCRB of $10,000 over the same range of ratios of FVRB to OCRB using the FVRORs displayed in Figure 3.

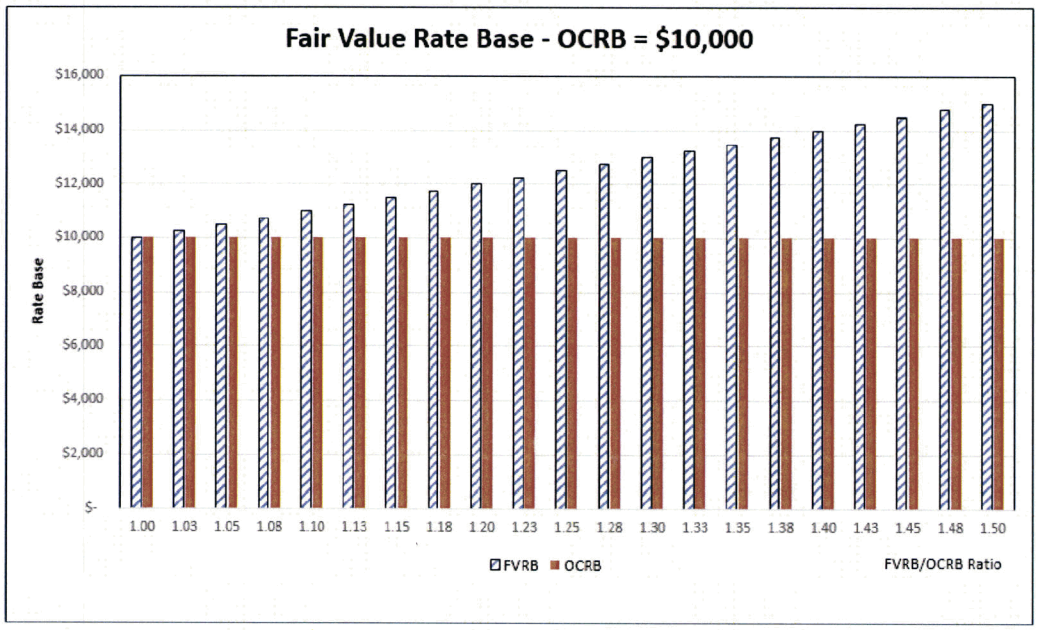

Figure 4 – OCRB and FVRB Example

[21] A gross-up factor of 1.6579 was used for the example to compute the pre-tax rates of return used to compute the revenue requirements.

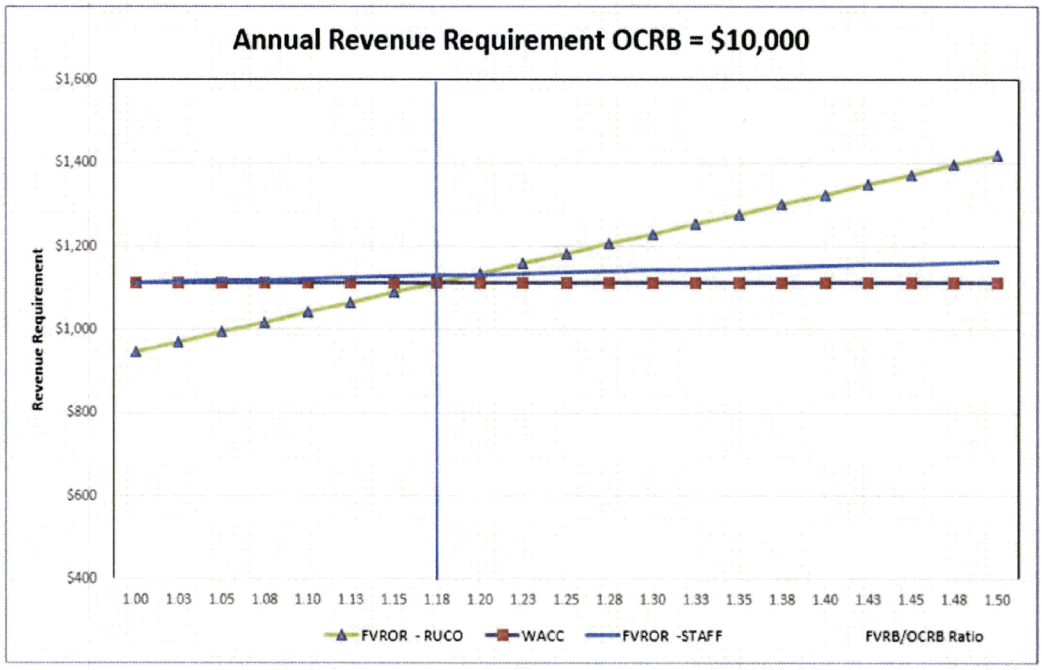

Figure 5 – Revenue Requirements Example

The revenue requirement based on the OCRB of $10,000 and the pre-tax WACC of 11.12% is a constant $1,112. The revenue requirement based on the Staff pre-tax FVROR results in a revenue requirement which is initially equal to the revenue requirement based on the OCRB and then gradually increases just above this level as the ratio of FVRB to OCRB increases.[22] This is the result of the FVROR decreasing and the FVRB increasing. For the RUCO method, since it uses a constant FVROR even with an increasing FVRB over the OCRB, it results in a much wider range of annual revenue requirements. For the initial years in this example, the RUCO revenue requirement is below the utility's WACC revenue requirement and does not equal the WACC revenue requirement until the FVRB/OCRB ratio equals 1.18. For FVRB/OCRB ratio greater than

[22] Any positive cost rate on the fair value increment above the OCRB will result in a higher revenue requirement than under the original cost method. Using a zero cost rate for the fair value increment would result in an equivalent revenue requirement under fair value and original cost methods for any FVRB/OCRB ratio.

1.18, it begins to exceed the WACC and at higher ratios it begins to significantly exceed the WACC.

Q. 49 Which of these two methods does Southwest Gas recommend for computing FVROR?

A. 49 As a result of the properties of the two methods, the Company recommends that the Staff method be adopted for computing the FVROR. The Staff method has the following properties as illustrated in the examples that support its use:

(1) The adjustment to the WACC to compute the FVROR under the Staff method takes into account that the degree of inflation embedded in the FVRB is a function of the age of the utility plant, where the FVROR declines as both the average age of the utility plant and the resulting FVRB increases; and

(2) The Staff method always results in a FVROR that provides a utility the opportunity to recover its cost of capital, and is therefore consistent with the *Hope* and *Bluefield* standards of a fair return.

In contrast, while the RUCO method makes an adjustment to the WACC for inflation, it does so arbitrarily by not taking into account the age of the utility plant, which is a key determinant of the difference between the OCRB and FVRB. As a result, the RUCO method results in a disparate treatment between utilities that have differences in the age of the utility plant and, as demonstrated, could result in a revenue requirement below a utility's actual cost of capital.

Q. 50 For an infrastructure recovery mechanism such as the Company's proposed GIM mechanism, would it be appropriate to use the FVROR authorized in the Company's last general rate case to compute the incremental cost of capital revenue requirement for such a mechanism?

A. 50 No. As explained and demonstrated previously, the FVROR authorized in a general rate case proceeding is a function of the average age for all rate base items, and therefore it would not be appropriate to apply an average authorized FVROR to new incremental investments that are not of the same average age (i.e., the FVRB/OCRB ratio is not equivalent for the average and the incremental rate base). Doing so would not allow a utility to recover its cost of capital on the incremental rate base investments. The appropriate FVROR for incremental rate base investments would be computed using the same methodology in the general rate case, but based only on the incremental rate base.

Q. 51 Can you demonstrate why it is not appropriate to use the FVROR authorized in the Company's last general rate case to compute the incremental cost of capital revenue requirement for the GIM mechanism?

A. 51 Yes. Using the previous example with Utilities A and B, assume that both utilities have an infrastructure recovery mechanism and one year after their last general rate case each utility has an incremental OCRB of $1,000 under such a mechanism. For this example, the first step is to compute the incremental FVRB by using the simple average of the incremental OCRB and incremental RCND rate base, which results in an incremental FVRB of $1,015. Applying the authorized pre-tax FVROR to the incremental FVRB for both Utilities A and B, the annual revenue requirements would be as follows:

Utility	FVRB	Pre-tax FVROR	Revenue Requirement
A	$1,015	9.75%	$99
B	$1,015	9.05%	$92

First, it is nonsensical that two utilities that have the same capital structure and WACC would have different revenue requirements for an identical incremental investment in FVRB. Second, this revenue requirement would not recover the capital costs for the incremental investment in FVRB. The capital costs can be computed using the pre-tax WACC of 11.12 percent for the incremental of OCRB of $1,000, which would result in capital cost of $111.

Q. 52 Can you demonstrate why the appropriate FVROR for incremental rate base investments would be computed using the same methodology in the general rate case, but based only on the incremental rate base.

A. 52 Yes. The incremental FVROR is computed by first developing a fair value capital structure which begins with the authorized OCRB capital structure percentages (50 percent equity and 50 percent debt) to compute the incremental fair value capital component amounts and adds the incremental fair value rate base increment above the incremental OCRB. The debt (5.25 percent) and equity (10.25 percent) capital components cost rates are the same as the authorized WACC associated with the authorized OCRB and the previously authorized 1 percent cost factor is assigned to the fair value increment. The resulting incremental FVROR applicable to the incremental FVRB is 7.65 percent. Using the incremental pre-tax FVROR results in an incremental revenue requirement of $111.5 for both Utility A and Utility B.

Utility	FVRB	Pre-tax FVROR	Revenue Requirement
A	$1,015	10.98%	$111.5
B	$1,015	10.98%	$111.5

The use of the incremental FVROR now results in identical revenue requirements for identical incremental investment in FVRB for utilities that have the same WACC. Moreover, the revenue requirement will allow both utilities to recover the incremental capital costs. In addition, Exhibit No.___(TKW-3), Sheet 3 and Sheet 4, demonstrates that the incremental revenue requirement using the incremental FVROR plus the authorized revenue requirement from the last general rate case will result in an equivalent revenue requirement as if the incremental investment in the FVRB was originally included at the time of the calculation of the FVROR in the last general case.

Q. 53 Please summarize the Company's recommendation on the FVROR for incremental investments.

A. 53 First, Southwest Gas recommends utilizing the Staff method, as it proportionately adjusts for the amount of inflation embedded in the FVRB and always results in a FVROR that provides an opportunity for it's the recovery of capital costs. Second, an incremental FVROR needs to be computed for use with infrastructure recovery mechanisms such as the proposed GIM in order to provide an opportunity to recover capital costs for the incremental rate base investments performed under such a mechanism. In addition, the resulting revenue requirement for the infrastructure recovery mechanism is consistent and equivalent with that of the general rate case process.

Q. 54 Does this conclude your prepared direct testimony?

A. 54 Yes.

SUMMARY OF QUALIFICATIONS
THEODORE K. WOOD

I graduated from the University of Nevada, Reno (UNR) in 1985 with a Bachelor of Science degree with a major in agricultural economics. In 1989, I earned a Master of Science degree from UNR in agricultural economics with a minor in finance. I have attained the professional designations of Chartered Financial Analyst (CFA), Certified Rate of Return Analyst (CRRA), Certified Management Accountant (CMA), Certified in Financial Management (CFM), and Certified Treasury Professional (CTP). I am a member of the Institute of Management Accountants, the CFA Institute, Association for Financial Professionals, Financial Management Association, and the Society of Regulatory and Utility Financial Analysts.

From 1985 to 1988, I was employed as a research associate in the Department of Agricultural Economics at UNR in Reno, Nevada. My primary role was to assist with ongoing research projects in the Department including secondary data collection, statistical analysis, FORTRAN programming, and the development of microcomputer spreadsheets for farm management decision analysis.

In 1989, I was employed by First Interstate Bank of Nevada in Reno, Nevada, as a financial analyst in the Finance Department. My duties entailed maintenance of the general ledger system, creation of monthly management and financial reports, and special projects.

From 1990 to 1992, I was employed as a planning analyst with Valley Bank of Nevada, in Las Vegas, Nevada, in the Planning Department. My primary responsibilities included preparation of the annual budget, quarterly budget variance analysis, supporting the Asset/Liability Committee of the bank, and other financial analyses.

From 1992 to 1994, I was employed by PriMerit Bank, FSB, then a wholly-owned subsidiary of Southwest Gas, as a Senior Financial Analyst in the Budget and Forecasting

Department. My primary responsibilities included creation and maintenance of a microcomputer-based budgeting system, preparation of the annual budget, monthly budget variance analysis, product profitability analysis, and other special projects.

In 1994, I accepted a Senior Financial Analyst position in the Treasury Services Department of Southwest Gas. I was promoted to Supervisor of the Treasury Services Department in May 1997, to Manager in June 2000, to Senior Manager in May 2005 and Assistant Treasurer & Director/Financial Services in December 2009. My responsibilities include directing the Company's treasury and corporate planning functions and assisting with certain investor relations activities, which includes meeting with institutional equity and fixed income analysts, as well as rating agencies. In addition, my responsibilities include representing the Company in various regulatory proceedings in its ratemaking jurisdictions concerning regulatory finance issues.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
5 January 2016

Update

Rate this Research

RATINGS

SOUTHWEST GAS CORPORATION

Domicile	Las Vegas, Nevada, United States
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Date	31 Jan 2014
Outlook	Stable
Date	31 Jan 2014

Please see the ratings section at the end of this report for more information.

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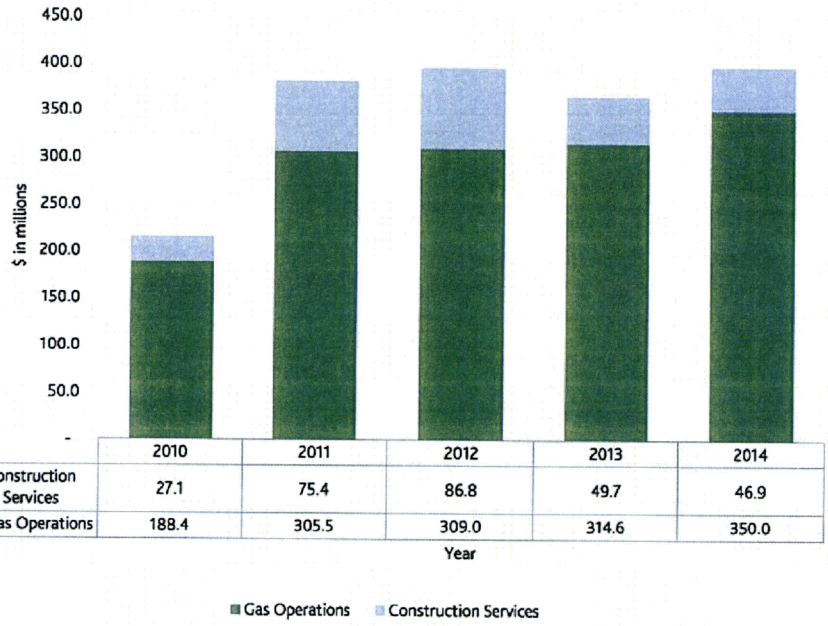
Southwest Gas Corporation

Summary Rating Rationale

The A3 senior unsecured rating is based on Southwest Gas Corporation (Southwest Gas) relatively low business risk profile as a natural gas local distribution company (LDC); an improved regulatory environment with constructive regulatory framework; consistent key financial and credit metrics appropriate for the rating; a conservative dividend payout ratio; and reasonably consistent financial results from the non-regulated construction services segment. We also take into consideration the increased risk resulting from the modest exposure to unregulated operations after the acquisition of affiliated construction services companies.

Exhibit 1
Historical Capital Expenditure by Business Segments



	2010	2011	2012	2013	2014
Construction Services	27.1	75.4	86.8	49.7	46.9
Gas Operations	188.4	305.5	309.0	314.6	350.0

Source: Company Reports

Credit Strengths

» LDC operations with a low business risk profile

» Constructive rate case outcomes and credit supportive regulatory developments

» Stable credit metrics supported by transparent cash flows

Credit Challenges

» Exposure to higher risk non-utility operations through Centuri Construction Group

» Increased foreign currency risk

Rating Outlook

The stable outlook is based on Southwest Gas' low risk operations, improved regulatory environments, the approval of recovery mechanisms that decrease regulatory lag, and our expectation that the company will manage its unregulated construction operations without any credit pressure on its regulated utility. The outlook also assumes that the company's financial profile will not change materially.

Factors that Could Lead to an Upgrade

» Further strengthening in its financial profile

» Improved credit metrics, including cash flow from operations pre-working capital (CFO pre-WC) to debt above 25% on a sustained basis

» Significant improvement in regulatory environments

Factors that Could Lead to a Downgrade

» A sustained deterioration in Southwest Gas' overall credit profile

» A sustained deterioration in credit metrics including CFO pre-WC to debt below the high teens

» Significant expansion of its construction business or other strategic activities that result in higher financial and business risks

Key Indicators

Southwest Gas Corporation	9/30/2015(L)	12/31/2014	12/31/2013	12/31/2012	12/31/2011
CFO pre-WC + Interest / Interest	6.2x	6.9x	7.3x	6.5x	5.8x
CFO pre-WC / Debt	22.6%	23.3%	28.9%	25.7%	25.4%
CFO pre-WC – Dividends / Debt	19.1%	20.2%	25.5%	22.7%	22.5%
Debt / Capitalization	47.3%	49.1%	45.4%	48.0%	48.1%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics™

Source: Moody's Financial Metrics

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

Detailed Rating Considerations

- LDC operations with a low business risk profile

With LDC operations making up the majority of its business, Southwest Gas is generally viewed as having a low business risk profile. At September 30, 2015, the LDC operations contributed approximately 86.5% of the company's $130.9 million net income and 63% of its $2.3 billion revenue. The customer base for the LDC operations is over 99% residential and small commercial, which provides a stable and consistent foundation for its operations. In 2015, its customer growth was approximately 1.4% and we expect a similar growth rate in the next 12-18 months in Southwest Gas' LDC territory.

Southwest Gas is expected to invest approximately $1.3 billion between 2015 and 2017 on its natural gas operations segment. The company has stated it plans to incur $445 million of the $1.3 billion in calendar year 2015. Southwest plans to accelerate projects that improve system flexibility and reliability, including replacement of early vintage plastic and steel pipe. Approximately 40% of the 2015 budgeted capital expenditure will be invested on enhancement and replacement of gas infrastructure, followed by 31% invested on growth, 14% on general plant, 10% on other projects and 5% on replacements under regulatory trackers. We expect Southwest Gas will use a combination of internally generated cash flows and debt and equity proceeds to fund its capital expenditure program.

- Constructive rate case outcomes and credit supportive regulatory developments

In recent years, there have been meaningful improvements in the regulatory frameworks under which Southwest Gas operates. For example, infrastructure tracker mechanisms were approved in Arizona and Nevada. In Arizona and more recently in California, Southwest Gas was granted a Customer-Owned Yard line program (COYL), and an Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) for timely cost recovery of capital expenditures associated with the enhancement and replacement of gas infrastructure. In May 2015, the ACC issued a decision approving the COYL surcharge application, effective in June 2015.

Southwest made a filing in May 2014, referred to as a Gas Infrastructure Replacement (GIR) Advance Application, identifying early vintage plastic pipe (EVPP) and vintage steel pipe (VSP) projects for replacement beginning in January 2015. In October 2014, the Public Utilities Commission of Nevada (PUCN) approved EVPP replacement expenditures of $14.4 million for 2015.

In June 2015, Southwest filed a second GIR Advance Application with the PUCN proposing $43.5 million of additional accelerated pipe replacement for 2016. Once completed, the annualized revenue requirement is estimated at $4.6 million. In October 2015, the PUCN approved the GIR Advance Application, granting Southwest the authority to replace the $43.5 million of infrastructure under the GIR mechanism for 2016. In October 2015, management filed a rate application to reset the GIR surcharge to reflect annualized revenues of $4.5 million. The rate filing was based upon projects placed in service by August 2015, with rates anticipated to be made effective in January 2016.

Also, all three of the company's jurisdictions implemented decoupling mechanisms albeit the actual mechanism varies state by state. Constructive regulatory developments and signs of an improving regulatory environment are credit positive.

The next LDC general rate case will be in 2016 when Southwest Gas files in Arizona. Based on the current rate case moratorium in the state, Southwest Gas could file with the earliest test year ending November 30, 2015. If filed in the second quarter of 2016, the new rates could become effective in May 2017.

In January 2014, Southwest filed an application with the Arizona Corporation Commission (ACC) seeking pre-approval to construct, operate and maintain a 233,000 dekatherm LNG facility in southern Arizona and to recover the actual costs, including the establishment of a regulatory asset. This facility is intended to enhance service reliability and flexibility in natural gas deliveries in the southern Arizona area by providing a local storage option, operated by Southwest and connected directly to its distribution system. The Company purchased the site for the facility in October 2015 and is preparing the construction requirements bid package for potential contractors. The contract to construct the facility is currently expected to be in place near the end of the first quarter of 2016 and construction is expected to take approximately two to three years to complete. The Company anticipates including a proposal for the ratemaking treatment of facility costs as part of its next Arizona rate case filing.

- Stable credit metrics supported by transparent cash flows

The company's financials and key credit metrics are expected to remain consistent with its current credit rating over the next 12-18 months. At September 30, 2015, CFO Pre-WC to debt was 22.6% and the CFO Pre-WC interest coverage ratio was 6.2x. Both key credit metrics decreased compared to a year ago. At the end of 2014, CFO Pre-WC to debt and CFO interest coverage ratios were 23.3% and 6.9x, respectively. Slightly higher 2014 metrics were due to rate relief in all three states and modest customer growth offset by higher expenses associated with the Link-Line companies' acquisition, discussed below. However, improving regulatory environments, the development of supportive cost recovery provisions such as infrastructure recovery mechanisms in Arizona and Nevada, the recent rate case conclusion in California, steady customer growth expectations, and a modest increase in its capital program should allow Southwest Gas to maintain consistent credit metrics and stable financials.

- Exposure to higher risk non-utility operations through Centuri Construction Group

In October 2014, Southwest Gas completed the acquisition of three privately held construction businesses for approximately $221 million via NPL, its existing construction operation. The three acquired companies were: Link-Line Contractors (Link-Line), W.S. Nicholls Construction (W.S. Nicholls) Inc., and Brigadier Pipelines Inc. (Brigadier). As a result of these acquisitions, Centuri Construction Group was formed as a holding company with two direct subsidiaries that house the unregulated companies under Southwest Gas. One of the subsidiaries is Vistus Construction Group Inc. holding NPL, Southwest Administrators and Brigadier. Lynxus Construction Group, the second subsidiary, holds Link-Line and W.S. Nicholls. These affiliated construction companies expand Southwest Gas' construction services business to Ontario, Canada and introduce foreign currency exchange risk to Southwest Gas' portfolio, a credit negative.

Centuri exhibits consistent, albeit modest, profitability. In 2015, Centuri earned and contributed a record $18 million of net income and $949 million of revenue mostly from the newly acquired affiliated companies and additional pipe replacement work. For the twelve months ended September 30, 2015 and 2014, revenues from replacement work were 68% and 70%, respectively, of total revenues. Centuri increases cash flows and earnings volatility for Southwest Gas because its operation is cyclical and significantly impacted by local economies and changes in weather. Southwest Gas' credit rating incorporates the view that Centuri's operations are contracted, thus somewhat insulating the company against some risk associated with non-utility operations, and that Southwest Gas will manage Centuri conservatively and not grow it materially from its current scale.

Liquidity Analysis

Southwest Gas' liquidity is good and sufficient for the company's working cash flow needs.

At September 30, 2015, Southwest Gas had approximately $33 million of cash on hand. The company incurred capital spending of $440 million, paid dividends of $72 million for the twelve months ended September 30, 2015, and reported cash from operations of $497 million for the same time period. The improvement in operating cash flows was primarily attributable to temporary increases in cash flow from working capital components overall.

In March 2014, Southwest Gas extended its $300 million credit facility to March 2020. The company designated $150 million of the $300 million for long-term borrowing and the remaining $150 million for working capital expenses. Southwest Gas also maintains a $50 million commercial paper program supported by the credit facility. In total, Southwest Gas had $97 million outstanding under its credit facility, including the full $50 million of commercial paper, at September 30, 2015. The company was in compliance with all of its debt covenants at year-end 2015.

Centuri entered into a $300 million secured revolving credit and term loan facility after the acquisitions were completed. The new facility is scheduled to expire in October 2019. At September 30, 2015, Centuri had $209 million outstanding under its secured credit facility.

Southwest Gas has $25 million of debt maturing in January 2017 and another $125 million due in December 2020.

Corporate Profile

Southwest Gas has two major business segments: natural gas utility operations and a construction services segment called Centuri Construction Group (Centuri, not rated). Its natural gas local distribution company (LDC) serves central and southern Arizona, the Las Vegas metropolitan area and northern Nevada, and Lake Tahoe and San Bernardino County in California. Centuri was formed

in October 2014 when Southwest Gas' existing construction services company, NPL Construction Co., acquired three privately held construction businesses for approximately $221 million. Natural gas operations represent the majority of its consolidated business with the LDC operations contributing 63% of revenue and 86.5% of net income in 2015. Through its LDC operations, Southwest Gas purchases, transports and distributes natural gas to 1.94 million customers in its service territories. Centuri is a full service underground piping contractor, serving utility customers in 20 major markets in the U.S and 2 major markets in Canada. Although Southwest Gas increased the scale of its construction services segment through the acquisitions in 2014, we expect this segment to remain as a relatively minor, self-funded segment compared to the company's LDC operations.

Natural gas operations are regulated by the ACC, the PUCN, the California Public Utilities Commission (CPUC), and the Federal Energy Regulatory Commission (FERC).

Rating Methodology and Scorecard Factors

Rating Factors				
Southwest Gas Corporation				
Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 9/30/2015**		**Moody's 12-18 Month Forward View As of 1/4/2016 [3]**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.9x	Aa	5.8x - 6.3x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	26.1%	A	20% - 24%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	22.7%	A	16% - 20%	A
d) Debt / Capitalization (3 Year Avg)	46.7%	A	50% - 55%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching			0	0
a) Indicated Rating from Grid		A2		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 9/30/2015(L); Source: Moody's Financial Metrics™

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Ratings

Exhibit 4

Category	Moody's Rating
SOUTHWEST GAS CORPORATION	
Outlook	Stable
Senior Unsecured	A3

Source: Moody's Investors Service

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REPORT NUMBER 1012446

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Summary:
Southwest Gas Corp.

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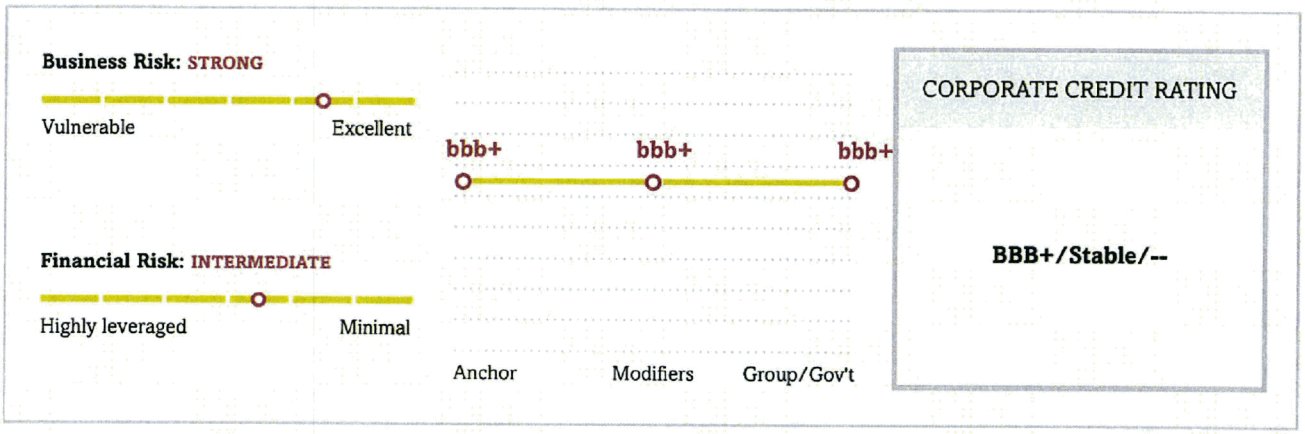
Summary:

Southwest Gas Corp.



Rationale

Business Risk: Strong	Financial Risk: Intermediate
• A mostly low-risk and rate-regulated natural gas distribution business that is offset by a higher-risk non-regulated construction service business. • Regulatory commissions provide credit-supportive recovery mechanisms. • Geographic and regulatory diversity. • The non-regulated construction services business (Centuri Construction Group) accounts for more than 20% of the consolidated company on a forward-looking basis.	• Use of the medial volatility table reflects a low-risk regulated gas utility business model that is offset by a higher-risk non-regulated construction services business. • Core financial measures that reflect the lower-half of the range for the intermediate financial risk profile category. • Annual capital spending averaging about $460 million • Regulated sales growth of about 1.2%

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Outlook: Stable

The stable outlook on Southwest Gas Corp. reflects our expectations that its construction services business will reflect about 20% of the consolidated company and that the company's financial measures will consistently reflect the lower-half of the range for the "intermediate" financial risk profile category.

Downside scenario

We could lower the rating if the business risk profile further weakens either because of a less-than-effective management of regulatory risk or due to a disproportional growth of the construction business so that it represents more than 30% of the consolidated company. We could also lower the rating if financial measures weaken to below the higher-end of the significant financial risk profile, reflecting funds from operations (FFO) to debt that is consistently lower than 21%.

Upside scenario

Although less likely, we could raise the rating if Southwest Gas permanently reduces the size of its higher-risk construction services business to below 20% of the consolidated company or if the company's financial measures improve toward the higher-end of the intermediate financial risk profile category, reflecting FFO to debt that consistently exceeds 32%.

Standard & Poor's Base-Case Scenario

Assumptions

- Regulated utility sales growth of about 1.2%.
- Continued use of the infrastructure riders.
- Non-regulated business that does not exceed 25% of the company's consolidated net income.
- Annual capital spending averaging about $460 million.
- Annual dividends averaging about $80 million
- Refinancing of upcoming debt maturities.

Key Metrics

	2014A	2015E	2016E
FFO/debt (%)	24.9	25-27	25-27
Debt/EBITDA (x)	3.3	3.0–3.3	3.0-3.3
OCF/debt (%)	18.6	22-26	22-26

A--Actual. E--Estimate. OCF--Operating cash flow.

Business Risk: Strong

Southwest Gas' strong business risk profile reflects its mostly low-risk, rate-regulated gas utility business that is offset by its higher-risk construction services business. We view the regulated business as having geographic and regulatory diversity, serving about 1.9 million customers in Arizona, Nevada, and California. In addition, we view the company's management of regulatory risk as average compared with peers. This reflects the company's ability to generally earn close to its authorized return on equity partially by using credit-supportive mechanisms that include purchased gas,

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infrastructure replacement riders, customer-owned yard line, and decoupling.

Centuri Construction mainly does pipe-replacement work for other regulated utilities and operates under multi-year contracts. As such, the potential for margin erosion that could result from higher-than-expected costs or reduced utility capital budgets offsets our overall view of a strong competitive position that stems primarily from the regulated gas utilities business. On a forward-looking basis, we view the higher-risk non-regulated construction services business as representing more than 20% of the consolidated company.

Financial Risk: Intermediate

We assess Southwest Gas' intermediate financial risk profile using our medial volatility table, reflecting the company's lower-risk regulated gas business that is offset by higher-risk Centuri Construction.

Our assessment reflects our expectation that the company's financial measures will reflect the lower-half of the range of the intermediate financial risk profile category. Under our base case scenario that reflects annual capital spending that averages about $460 million, dividend payments averaging about $80 million, regulated sales growth of about 1.2%, and the continued use of existing regulatory mechanisms, we expect FFO to debt of about 26%.

Our choice of the 'bbb+' anchor, given two potential outcomes ('a-' or 'bbb+'), reflects the company's higher-risk construction business, which weakens the company's business risk profile toward the lower-half of the strong business risk profile category.

Liquidity: Adequate

Southwest Gas has adequate liquidity, in our view, and could more than cover its needs for the next 12 months, even if EBITDA declines by 10%. We expect the company's consolidated liquidity sources over the next 12 months will exceed its uses by more than 1.1x. Under our stress scenario, we do not expect Southwest Gas to seek access to the capital markets during that period to meet liquidity needs. The adequate assessment also reflects the company's generally prudent risk management, sound relationships with banks, and a generally satisfactory standing in the credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of about $480 million. • Available credit facility of about $340 million. • Available cash of about $40 million.	• Capital spending of about $460 million. • Debt maturities of about $70 million. • Dividend payments of about $80 million.

Other Credit Considerations

All modifiers are neutral and don't affect the stand-alone credit profile.

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Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/--

Business risk: Strong

- **Country risk:** Very low
- **Industry risk:** Low
- **Competitive position:** Strong

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: bbb+

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : bbb+

- **Group credit profile:** bbb+

Issue Rating

We rate Southwest Gas' senior unsecured debt 'BBB+', the same as its issuer credit rating according to our criteria.

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Key Credit Factors For The Engineering And Construction Industry, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

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- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	**a-/bbb+**	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

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Southwest Gas Corporation

Full Rating Report

Ratings

Long-Term IDR	A–
Short-Term IDR	F2
Senior Unsecured	A
Industrial Development Revenue Bonds	A
Commercial Paper	F2

IDR – Issuer Default Rating.

Rating Outlook

Long-Term IDR	Stable

Financial Summary

Southwest Gas Corporation

($ Mil.)	2015	2014
Adjusted Revenue	2,464	2,122
Operating EBITDAR	563	542
Cash Flow from Operations	547	346
Total Adjusted Debt	1,604	1,699
Total Capitalization	3,179	3,163
Capex/ Depreciation (%)	180.7	156.9
FFO Fixed-Charge Coverage (x)	6.9	6.8
FFO-Adjusted Leverage (x)	3.0	3.2
Total Adjusted Debt/EBITDAR (x)	2.8	3.1

Related Research

Southwest Gas Corporation – Ratings Navigator (September 2015)

Fitch Affirms Southwest Gas Corp. at 'A–'; Outlook Stable (July 2015)

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Key Rating Drivers

Constructive Rate Design: The ratings of Southwest Gas Corporation (Southwest Gas) benefit from a relatively constructive regulatory environment that has improved over recent years. Southwest Gas' natural gas distribution business has revenue decoupling and purchased gas adjustment mechanisms (PGAs) throughout its service territory. These constructive rate mechanisms increase the stability and predictability of earnings and cash flows and provide for more timely recovery of costs.

Modest Regulatory Diversification: Southwest Gas' natural gas distribution business has a modest level of regulatory diversification, which helps limit exposure to any one jurisdiction. In 2015, Arizona and Nevada accounted for 55% and 34%, respectively, of the utility's operating income, while California accounted for 11%.

Strong Financial Metrics: The constructive regulatory environment has enabled Southwest Gas' financial metrics to remain strong. Excluding the beneficial impact of bonus depreciation, Fitch Ratings had forecasted FFO fixed-charge coverage to average 6.1x–6.4x, FFO adjusted leverage 3.3x–3.5x, and adjusted debt/EBITDAR 2.9x–3.0x through 2017, continuing to provide headroom at the existing ratings. FFO metrics should be slightly stronger than originally forecasted in 2015 due to the extension of bonus depreciation.

Moderate Risk in Construction Services Business: The positive credit attributes associated with Southwest Gas' solid financial profile are slightly diminished by the greater business risks at the company's unregulated construction services subsidiary, Centuri Construction Group Inc. (Centuri). Centuri contributed slightly less than 20% of consolidated EBITDA in 2015, and Fitch expects Centuri's EBITDA contribution to remain around that level going forward.

Elevated Capex Program: Southwest Gas is undergoing a period of increased capex, primarily focused on safety and reliability. Fitch expects Southwest Gas' natural gas distribution business to spend a total of $1.4 billion–$1.6 billion over 2016–2018, with the annual amount gradually increasing each year. Concerns regarding the relatively large capex program are mitigated by the utility's various infrastructure replacement cost-recovery mechanisms. Capex at Centuri is self-funded.

Rating Sensitivities

Positive Rating Action: A ratings upgrade is unlikely at this time, but could result from expectations for FFO adjusted leverage to be less than 3.25x and adjusted debt/EBITDAR to remain less than 3.0x on a sustained basis along with further improvement in the regulatory environment that results in reduced regulatory lag.

Negative Rating Action: A negative rating action could result from a significant deterioration of the regulatory environment in Arizona or Nevada or a material expansion of Centuri's business activities that reduces the natural gas distribution segment's share of consolidated EBITDA to 75%. A negative rating action could also result from expectations for FFO adjusted leverage to be greater than 4.0x and adjusted debt/EBITDAR to be greater than 3.75x on a sustained basis.

Financial Overview

Liquidity and Debt Structure

Liquidity is adequate, supported by sufficient availability under Southwest Gas' $300 million five-year revolving credit facility maturing March 25, 2021. Southwest Gas also has an uncommitted $50 million commercial paper (CP) program that is backstopped by the revolving credit facility. As of Dec. 31, 2015, $50 million of CP had been issued and $118 million of borrowings outstanding, leaving $132 million of availability.

Southwest Gas keeps sufficient cash on hand to fund its daily business needs and had $36 million of unrestricted cash and cash equivalents as of Dec. 31, 2015.

Upcoming debt maturities are manageable, with $25 million of unsecured 7.59% medium-term notes maturing in January 2017 and $125 million of unsecured 4.45% debentures maturing in December 2020.

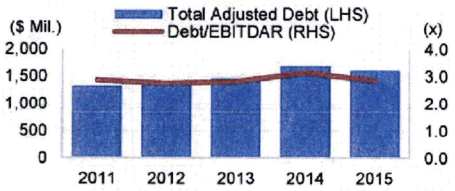
Centuri is self-funding and maintains access to liquidity through its $300 million secured revolving credit facility, which expires in October 2019. As of Dec. 31, 2015, Centuri had $77.4 million of availability under the facility. Centuri assets securing the facility as of Dec. 31, 2015 totaled $437 million.

Debt Maturities and Liquidity

($ Mil., As of Dec. 31, 2015)	
2016	19
2017	42
2018	15
2019	142
Thereafter	1,363
Cash and Cash Equivalents	36
Undrawn Committed Facilities	132

Source: Company data, Fitch.

Total Debt and Leverage



Source: Company data, Fitch.

Related Criteria

Recovery Ratings and Notching Criteria for Utilities (March 2016)

Corporate Rating Methodology — Including Short-Term Ratings and Parent and Subsidiary Linkage (August 2015)

Parent and Subsidiary Rating Linkage (August 2015)

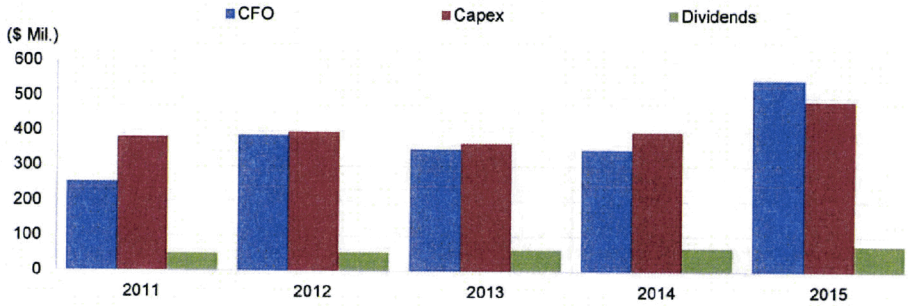
Rating U.S. Utilities, Power and Gas Companies (Sector Credit Factors) (March 2014)

Cash Flow Analysis

Southwest Gas' capex program is focused on projects to enhance safety and maintain the reliability of the natural gas utility local distribution company (LDC) system, with replacement of aging pipe an important component. Southwest Gas plans to spend $1.4 billion–$1.6 billion in total over 2016–2018, and Fitch expects the annual amount to increase each year over that period as growth continues to drive investment. Construction capex is expected to continue to be self-funded.

In light of the large capex program, Southwest Gas is likely to remain modestly FCF negative, funding the vast majority of capex internally. Fitch expects external funding requirements to be financed via a balanced mix of debt and equity to maintain the current capital structure.

CFO and Cash Use



Source: Company data, Fitch.

Peer and Sector Analysis

Peer Group

Issuer	Country
A	
Southern California Gas Co.	U.S.
A–	
Atmos Energy Corporation	U.S.
BBB+	
AGL Resources, Inc.	U.S.

Issuer Rating History

Date	LT IDR (FC)	Outlook/ Watch
Sept. 30, 2015	A–	Stable
July 31, 2015	A–	Stable
Oct. 1, 2014	A–	Stable
July 11, 2014	A–	Stable
April 7, 2014	A–	Stable
May 28, 2013	A–	Stable
May 30, 2012	BBB+	Positive
June 2, 2011	BBB+	Stable
June 1, 2010	BBB	Positive
April 29, 2009	BBB	Stable
Feb. 1, 2008	BBB	Stable
Jan. 17, 2007	BBB	Stable
Dec. 6, 2005	BBB	Stable
Aug. 16, 2005	BBB	Stable
April 28, 2004	BBB	Stable
April 2, 2002	BBB	Stable
July 25, 1996	BBB	Stable
Sept. 14, 1995	BBB–	—
Nov. 30, 1993	BB+	—
Sept. 14, 1990	BBB–	—
May 1, 1977	BBB+	—

LT IDR – Long-Term Issuer Default Rating. FC – Foreign currency.
Source: Fitch.

Peer Group Analysis

($ Mil.)	Southwest Gas Corporation	Southern California Gas Co.	Atmos Energy Corporation	AGL Resources, Inc.
As of	12/31/15	12/31/15	12/31/15	12/31/15
IDR	A–	A	A–	BBB+
Outlook	Rating Outlook Stable	Rating Outlook Stable	Rating Outlook Stable	Rating Watch Positive
Fundamental Ratios (x)				
Operating EBITDAR/ (Gross Interest Expense + Rents)	7.41	8.21	6.30	5.81
FFO Fixed-Charge Coverage	6.95	5.21	6.58	5.71
Total Adjusted Debt/Operating EBITDAR	2.85	2.48	3.65	3.98
FFO/Total Adjusted Debt (%)	32.9	25.8	28.6	24.7
FFO-Adjusted Leverage	3.04	3.88	3.50	4.05
Common Dividend Payout (%)	53.2	11.9	51.3	69.1
Internal Cash/Capex (%)	77.5	38.7	67.4	73.5
Capex/Depreciation (%)	180.7	293.3	361.9	258.7
Return on Equity (%)	8.7	13.3	9.8	9.0
Financial Information				
Revenue	2,464	3,489	3,789	3,941
Revenue Growth (%)	16.1	(9.5)	(23.4)	(26.8)
EBITDA	559	1,069	918	1,201
Operating EBITDA Margin (%)	22.7	30.6	24.2	30.5
FCF	(15)	(523)	(290)	92
Total Adjusted Debt with Equity Credit	1,604	2,752	3,474	4,898
Cash and Cash Equivalents	36	58	79	19
Funds Flow from Operations	452	573	842	999
Capex	(488)	(1,352)	(1,006)	(1,027)

IDR – Issuer Default Rating.
Source: Company data, Fitch.

Key Rating Issues

Constructive Rate Design

The regulatory environment for Southwest Gas' natural gas distribution business has improved over recent years, particularly in Arizona and Nevada, which account for 55% and 34%, respectively, of the utility's operating profit. Management has focused on working with the regulatory commissions to implement mechanisms that reduce regulatory lag.

The Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada (PUCN), and the California Public Utilities Commission (CPUC) have authorized Southwest Gas to implement revenue decoupling, separating the recovery of utility operating margin from customers' natural gas consumption. Southwest Gas has also been authorized to use PGAs throughout its service territory, enabling the utility to file for rate adjustments when its cost of purchased gas changes. These constructive rate mechanisms provide for more timely recovery of costs and increase the stability and predictability of earnings and cash flows.

Recent general rate case (GRC) outcomes have been constructive. The CPUC authorized a $7.1 million base rate increase effective June 2014, based on a 10.1% return on equity (ROE) and a 55% equity ratio. The utility was also granted post-test year attrition increases of 2.75% annually for 2015–2018. The CPUC subsequently approved $2.5 million in new rates effective Jan. 1, 2015 and another $2.5 million effective Jan. 1, 2016 as a part of Southwest Gas' post-test year attrition filings.

Southwest Gas is planning to file a GRC in Arizona in the second quarter of 2016, following the end of its GRC moratorium on April 30, 2016. New rates cannot become effective earlier than May 1, 2017. Southwest Gas' most recent GRC in Arizona resulted in a settlement agreement, with rates effective January 2012. Fitch considers that settlement agreement to have been constructive, supporting credit quality. Base rates were increased $52.6 million, representing 72% of the utility's requested amount, based on a 9.5% ROE and a 52.3% equity ratio. In addition, the ACC approved full revenue decoupling with a monthly weather adjuster.

Strong Financial Metrics

The constructive regulatory environment has enabled Southwest Gas' financial metrics to remain strong. Excluding the beneficial impact of bonus depreciation, Fitch had forecasted FFO fixed-charge coverage to average 6.1x–6.4x, FFO adjusted leverage 3.3x–3.5x, and adjusted debt/EBITDAR 2.9x–3.0x through 2017, continuing to provide headroom at the existing ratings. FFO metrics should be slightly stronger than originally forecasted in 2015 due to the extension of bonus depreciation.

Moderate Risk in Construction Services Business

The positive credit attributes associated with Southwest Gas' solid financial profile are slightly diminished by the greater business risks at Centuri, the company's unregulated construction services subsidiary. Centuri is a full-service contractor that works with LDCs to install, repair, and maintain pipeline distribution systems in the U.S. and Canada.

Centuri primarily operates under unit-price contracts that establish prices for each of the various services performed and often have annual pricing reviews, minimizing the risk of cost overruns for multiyear projects. However, 13% of Centuri's revenue in 2015 was earned under fixed-price contracts, and some of its unit-price contracts have revenue caps. Fixed-price

contracts and unit-price contracts with revenue caps expose Centuri to the possibility of losses, particularly for longer-term projects, due to the necessity of estimating costs far in advance.

Centuri's construction services business has realized strong growth the last few years, benefiting from low interest rates, a regulatory environment more focused on pipeline safety, and capital investment incentives for natural gas utilities related to bonus depreciation. Centuri's EBITDA grew more than 19% in each of the past two years, to $110 million in 2015 from $92 million in 2014 and $77 million in 2013.

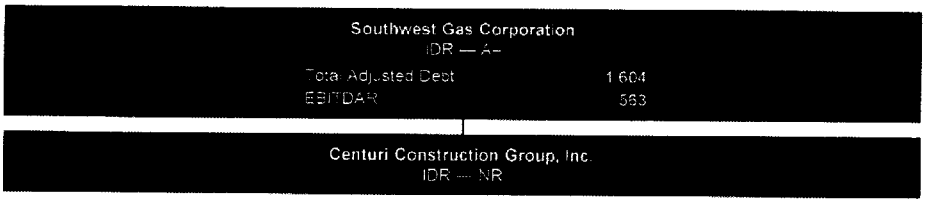
Centuri contributed slightly less than 20% of consolidated EBITDA in 2015, and Fitch expects Centuri's EBITDA contribution to remain around that level going forward. Growth that results in Centuri accounting for 25% of consolidated EBITDA on a sustained basis or an increase in risk associated with the existing operations could lead to a ratings downgrade.

Elevated Capex Program

Southwest Gas is undergoing a period of increased capex, primarily focused on projects to enhance safety and maintain reliability of its natural gas distribution system. Fitch expects Southwest Gas' utility to spend $1.4 billion–$1.6 billion in total over 2016–2018, with the annual amount gradually increasing each year. Concerns regarding the relatively large capex program are mitigated by various infrastructure replacement cost-recovery mechanisms authorized by the ACC, PUCN, and CPUC. Construction capex at Centuri has been self-funded and is expected to remain so going forward.

Organizational Structure

Organizational and Debt Structure — Southwest Gas Corporation
($ Mil., As of Dec. 31, 2015)



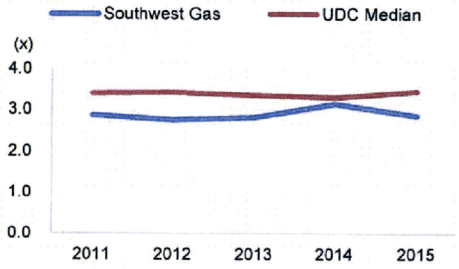
IDR – Issuer Default Rating. NR – Not rated.
Source: Company filings, Fitch.

Key Metrics

Definitions

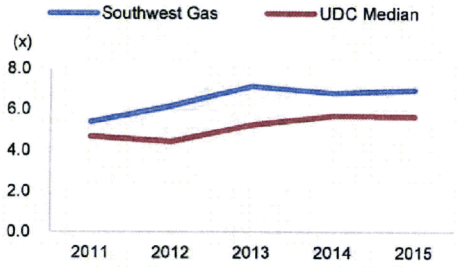
- Total Adjusted Debt/Op. EBITDAR: Total balance sheet adjusted for equity credit and off-balance sheet debt divided by operating EBITDAR.
- FFO Fixed-Charge Coverage: FFO plus gross interest minus interest received plus preferred dividends plus rental payments divided by gross interest plus preferred dividends plus rental payments.
- FFO-Adjusted Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.

Total Adjusted Debt/Op. EBITDAR



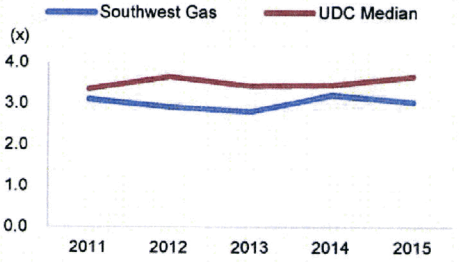
UDC – Utility distribution company.
Source: Company data, Fitch.

FFO Fixed-Charge Coverage



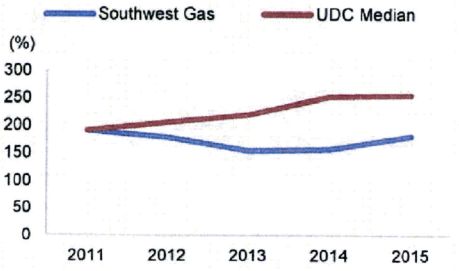
UDC – Utility distribution company.
Source: Company data, Fitch.

FFO-Adjusted Leverage



UDC – Utility distribution company.
Source: Company data, Fitch.

Capex/Depreciation



UDC – Utility distribution company.
Source: Company data, Fitch.

Company Profile

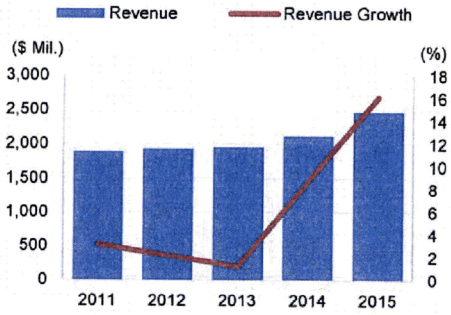
Southwest Gas is a regulated natural gas distribution utility with customers in Arizona, Nevada, and California. It is the largest natural gas distributor in Arizona and Nevada and serves the metropolitan areas of Phoenix, Las Vegas, and Tucson. More than 99% of Southwest Gas' customers are residential or commercial.

Southwest Gas serves nearly 2 million customers, of whom 53%, 37%, and 10% were located in Arizona, Nevada, and California, respectively. For 2015, Arizona and Nevada accounted for 55% and 34%, respectively, of operating income, with California accounting for 11%.

Southwest Gas has a wholly owned, unregulated construction company subsidiary, Centuri, which provides underground piping contractor services for utilities in the U.S. and Canada.

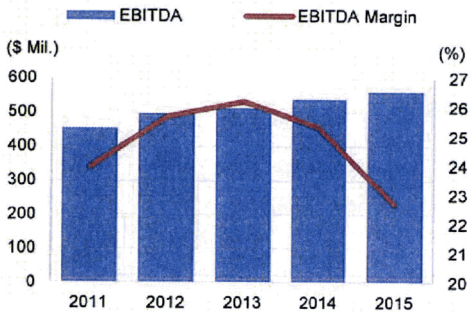
Business Trends

Revenue Dynamics



Source: Company data, Fitch.

EBITDA Dynamics



Source: Company data, Fitch.

Financial Summary — Southwest Gas Corporation

(IDR — A–/Rating Outlook Stable)

($ Mil., As of Dec. 31, 2015)	2012	2013	2014	2015
Fundamental Ratios				
Operating EBITDAR/(Gross Interest Expense + Rents) (x)	6.5	7.1	6.9	7.4
FFO Fixed-Charge Coverage (x)	6.2	7.1	6.8	6.9
Total Adjusted Debt/Operating EBITDAR (x)	2.7	2.8	3.1	2.8
FFO/Total Adjusted Debt (%)	34.4	35.7	31.2	32.9
FFO-Adjusted Leverage (x)	2.9	2.8	3.2	3.0
Common Dividend Payout (%)	39.8	41.4	46.8	53.2
Internal Cash/Capex (%)	86.9	106.3	97.2	77.5
Capex/Depreciation (%)	177.6	153.6	156.9	180.7
Return on Equity (%)	10.2	10.2	9.5	8.7
Profitability				
Revenues	1,928	1,951	2,122	2,464
Revenue Growth (%)	2.2	1.2	8.8	16.1
Net Revenues	1,448	1,515	1,617	1,900
Operating and Maintenance Expense	(369)	(385)	(384)	(393)
Operating EBITDA	495	511	537	559
Operating EBITDAR	503	519	542	563
Depreciation and Amortization Expense	(223)	(237)	(253)	(270)
Operating EBIT	272	274	284	289
Gross Interest Expense	(69)	(65)	(73)	(72)
Net Income for Common	133	145	141	139
Operating Maintenance Expense % of Net Revenues	(25.5)	(25.4)	(23.7)	(20.7)
Operating EBIT % of Net Revenues	18.8	18.1	17.6	15.2
Cash Flow				
Cash Flow from Operations	386	346	346	547
Change in Working Capital	(11)	(101)	(106)	104
Funds from Operations	397	447	452	452
Dividends	(53)	(60)	(66)	(74)
Capex	(396)	(364)	(397)	(488)
FCF	(63)	(78)	(117)	(15)
Net Other Investment Cash Flow	—	18	30	24
Net Change in Debt	64	73	275	(40)
Net Equity Proceeds	2	2	—	35
Capital Structure				
Short-Term Debt	—	—	5	18
Total Long-Term Debt	1,318	1,392	1,650	1,570
Total Debt with Equity Credit	1,318	1,392	1,656	1,571
Total Adjusted Debt with Equity Credit	**1,380**	**1,458**	**1,699**	**1,604**
Total Common Shareholder's Equity	1,310	1,415	1,489	1,594
Total Capital	**2,626**	**2,805**	**3,163**	**3,179**
Total Debt/Total Capital (%)	50	50	52	49
Common Equity/Total Capital (%)	50	50	48	51

IDR – Issuer Default Rating.
Source: Company data, Fitch.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

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SOUTHWEST GAS CORPORATION
PROXY GROUP OF VALUE LINE GAS DISTRIBUTION COMPANIES
ACTUAL AND PROJECTED RETURN ON COMMON EQUITY

		Actual Return on Common Equity						Projected Return on Common Equity				
Line No.	Company	2011	2012	2013	2014	2015	5-Year Average	2016	2017	2019-2021	Average	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Atmos Energy Corp.	8.80%	8.10%	8.90%	9.40%	9.90%	9.02%	10.50%	10.50%	11.00%	10.80%	1
2	Laclede Gas	11.10%	10.40%	5.00%	5.60%	8.70%	8.16%	9.00%	9.00%	11.00%	9.50%	2
3	New Jersey Resources Corp.	13.70%	13.80%	12.80%	18.30%	13.70%	14.46%	12.00%	12.50%	11.50%	11.80%	3
4	Northwest Natural Gas	8.90%	8.20%	8.10%	7.60%	6.90%	7.94%	7.50%	7.50%	9.00%	8.40%	4
5	South Jersey Inds.	13.90%	12.70%	11.70%	11.20%	10.50%	12.00%	10.50%	11.00%	11.50%	11.20%	5
6	WGL Holdings Inc.	9.50%	10.80%	9.30%	11.00%	12.70%	10.66%	12.00%	11.50%	11.00%	11.30%	6
7	**Average**	**10.98%**	**10.67%**	**9.30%**	**10.52%**	**10.40%**	**10.37%**	**10.25%**	**10.33%**	**10.83%**	**10.50%**	7
8	**Median**	**10.30%**	**10.60%**	**9.10%**	**10.20%**	**10.20%**	**9.84%**	**10.50%**	**10.75%**	**11.00%**	**11.00%**	8

[1] Source: Value Line Investment Survey, March 4, 2016.

SOUTHWEST GAS CORPORATION
FVROR EXAMPLE - UTILITY A

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	Line No.
1	Original Cost Rate Base (OCRB)	$ 10,000					1
2	Average Age of Utility Plant (years)	10.00					2
3	Handy-Whitman Index	1.34					3
4	Reproduction Cost New Depreciated (RCND)	$ 13,400					4
5	Fair Value Rate Base (FVRB)	$ 11,700					5
6	FVRB/OCRB Ratio	1.17					6
	Weighted Average Cost of Capital (WACC)	$	%	Rate	Weighted Rate	Pre-tax Weighted Rate	
7	Equity	$ 5,000	50.00%	10.25%	5.13%	8.50% [1]	7
8	Debt	5,000	50.00%	5.25%	2.63%	2.63%	8
9	Total	$ 10,000	100.00%		7.75%	11.12%	9
	ACC STAFF METHOD						
	Fair Value Rate of Return (FVROR)	$	%	Rate	Weighted Rate	Pre-tax Weighted Rate	
10	Equity	$ 5,000	42.74%	10.25%	4.38%	7.26% [1]	10
11	Debt	5,000	42.74%	5.25%	2.24%	2.24%	11
12	FVRB Increment	1,700	14.53%	1.00%	0.15%	0.24% [1]	12
13	Total	$ 11,700	100.00%		6.77%	9.75%	13
	RUCO METHOD						
	Fair Value Rate of Return (FVROR)		%	Rate	Weighted Rate	Pre-tax Weighted Rate	
14	Equity		50.00%	8.25% [2]	4.13%	6.84% [1]	14
15	Debt		50.00%	5.25%	2.63%	2.63%	15
16	Total		100.00%		6.75%	9.46%	16

[1] Grossed up for taxes using a gross-up factor of 1.6579
[2] Cost of Common Equity = 10.25% ROE less 2.00% inflation

SOUTHWEST GAS CORPORATION
FVROR EXAMPLE - UTILITY B

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	Line No.
1	Original Cost Rate Base (OCRB)	$ 10,000					1
2	Average Age of Utility Plant (years)	15.00					2
3	Handy-Whitman Index	1.56					3
4	Reproduction Cost New Depreciated (RCND)	$ 15,600					4
5	Fair Value Rate Base (FVRB)	$ 12,800					5
6	FVRB/OCRB Ratio	1.28					6
	Weighted Average Cost of Capital (WACC)	$	%	Rate	Weighted Rate	Pre-tax Weighted Rate	
7	Equity	$ 5,000	50.00%	10.25%	5.13%	8.50% [1]	7
8	Debt	5,000	50.00%	5.25%	2.63%	2.63%	8
9	Total	$ 10,000	100.00%		7.75%	11.12%	9
	ACC STAFF METHOD						
	Fair Value Rate of Return (FVROR)	$	%	Rate	Weighted Rate	Pre-tax Weighted Rate	
10	Equity	$ 5,000	39.06%	10.25%	4.00%	6.64% [1]	10
11	Debt	5,000	39.06%	5.25%	2.05%	2.05%	11
12	FVRB Increment	2,800	21.88%	1.00%	0.22%	0.36% [1]	12
13	Total	$ 12,800	100.00%		6.27%	9.05%	13
	RUCO METHOD						
	Fair Value Rate of Return (FVROR)		%	Rate	Weighted Rate	Pre-tax Weighted Rate	
14	Equity		50.00%	8.25% [2]	4.13%	6.84% [1]	14
15	Debt		50.00%	5.25%	2.63%	2.63%	15
16	Total		100.00%		6.75%	9.46%	16

[1] Grossed up for taxes using a gross-up factor of 1.6579

[2] Cost of Common Equity = 10.25% ROE less 2.00% inflation

Exhibit No. ___ (TKW-3)
Sheet 2 of 4

SOUTHWEST GAS CORPORATION
FVROR Example - Utility A
FVROR METHODOLOGY - ACC STAFF

Line No.	(a)	(b) Authorized Rate Base	(c) Incremental Rate Base	(d) Adjusted Rate Base	(e)	(f)	(g)	(h)	Line No.
	Authorized Fair Value Rate Base								
1	Original Cost Rate Base (OCRB)	$ 10,000	$ 1,000	$ 11,000					1
2	Reconstruction Cost New Depreciated (RCND) rate base	13,400	1,030	14,430					2
3	Fair Value Rate Base (FVRB)	$ 11,700 [1]	$ 1,015	$ 12,714					3
4	FVRB/OCRB Multiple	1.17	1.03	1.16					4

	Authorized Fair Value Rate of Return (FVROR)	Rate Base	Ratio	Cost	FVROR	Pre-Tax FVROR	Authorized FVRB	FVROR Revenue Requirement	
9	Common Equity	$ 5,000	42.74%	10.25%	4.38%	7.26% [2]	$ 11,700	$ 849.7	9
10	Long-Term Debt	5,000	42.74%	5.25%	2.24%	2.24%	11,700	262.5	10
11	FVRB Increment Above OCRB	1,700	14.53%	1.00%	0.15%	0.24% [2]	11,700	28.2	11
12	Total Capital	$ 11,700	100.00%		6.77%	9.75%		$ 1,140.4	12

	Incremental FVRB	Rate Base	Ratio	Cost	ROR	Pre-Tax FVROR	Incremental FVRB	FVROR Revenue Requirement	
5	Common Equity	$ 500	49.26%	10.25%	5.05%	8.37% [2]	$ 1,015	$ 85.0	5
6	Long-Term Debt	500	49.26%	5.25%	2.59%	2.59%	1,015	26.3	6
7	FVRB Increment Above OCRB	15	1.48%	1.00%	0.01%	0.02%	1,015	0.2	7
8	Total Capital	$ 1,015	100.00%		7.65%	10.98%		$ 111.5	8

13	TOTAL REVENUE REQUIREMENT = Authorized FVRB X Authorized Pre-tax FVROR + Incremental FVRB X Incremental Pre-tax FVROR	$ 1,251.8	13

	Authorized Fair Value Rate of Return (FVROR)- Incremental Utility Plant Adjusted	Rate Base	Ratio	Cost	FVROR	Pre-Tax FVROR	Adjusted FVRB	FVROR Revenue Requirement	
14	Common Equity	$ 5,500	43.26%	10.25%	4.43%	7.35% [2]	$ 12,714	$ 934.6	14
15	Long-Term Debt	5,500	43.26%	5.25%	2.27%	2.27%	12,714	288.8	15
16	FVRB Increment Above OCRB	1,714	13.48%	1.00%	0.13%	0.22% [2]	12,714	28.4	16
17	Total Capital	$ 12,714	100.00%		6.84%	9.85%		$ 1,251.8	17

18	Applying Authorized Pre-tax FVROR to Incremental FVRB	9.75%	1,015	$ 98.9	18
19	Applying Pre-tax WACC to Incremental OCRB	11.12%	1,000	111.2	19
20	Cost of Capital Revenue Requirement Sufficiency / (Deficiency)			$ (12.3)	20
21	Applying Incremental Pre-tax FVROR to Incremental FVRB	10.98%	1,015	$ 111.5	21
22	Applying Pre-tax WACC to Incremental OCRB	11.12%	1,000	111.2	22
23	Cost of Capital Revenue Requirement Sufficiency / (Deficiency)			$ 0.2	23

Notes:
[1] FVRB = 0.5 X OCRB + 0.5 RCND
[2] Grossed up for taxes using the authorized gross-up factor of 1.6579

SOUTHWEST GAS CORPORATION
FVROR Example - Utility B
FVROR METHODOLOGY - ACC STAFF

Line No.	(a)	(b) Authorized Rate Base	(c) Incremental Rate Base	(d) Adjusted Rate Base	(e)	(f)	(g)	(h)	Line No.
	Authorized Fair Value Rate Base								
1	Original Cost Rate Base (OCRB)	$ 10,000	$ 1,000	$ 11,000					1
2	Reconstruction Cost New Depreciated (RCND) rate base	15,600	1,030	16,630					2
3	Fair Value Rate Base (FVRB)	$ 12,800 [1]	$ 1,015	$ 13,814					3
4	FVRB/OCRB Multiple	1.28	1.03	1.26					4
	Authorized Fair Value Rate of Return (FVROR)								
		Rate Base	Ratio	Cost	FVROR	Pre-Tax FVROR	Authorized FVRB	FVROR Revenue Requirement	
9	Common Equity	$ 5,000	39.06%	10.25%	4.00%	6.64% [2]	$ 12,800	$ 849.7	9
10	Long-Term Debt	5,000	39.06%	5.25%	2.05%	2.05%	12,800	262.5	10
11	FVRB Increment Above OCRB	2,800	21.88%	1.00%	0.22%	0.36% [2]	12,800	46.4	11
12	Total Capital	$ 12,800	100.00%		6.27%	9.05%		$ 1,158.6	12
	Incremental FVRB								
		Rate Base	Ratio	Cost	ROR	Pre-Tax FVROR	Incremental FVRB	FVROR Revenue Requirement	
5	Common Equity	$ 500	49.26%	10.25%	5.05%	8.37% [2]	$ 1,015	$ 85.0	5
6	Long-Term Debt	500	49.26%	5.25%	2.59%	2.59%	1,015	26.3	6
7	FVRB Increment Above OCRB	15	1.48%	1.00%	0.01%	0.02%	1,015	0.2	7
8	Total Capital	$ 1,015	100.00%		7.65%	10.98%		$ 111.5	8
13	TOTAL REVENUE REQUIREMENT = Authorized FVRB X Authorized Pre-tax FVROR + Incremental FVRB X Incremental Pre-tax FVROR							$ 1,270.1	13
	Authorized Fair Value Rate of Return (FVROR)- Incremental Utility Plant Adjusted								
		Rate Base	Ratio	Cost	FVROR	Pre-Tax FVROR	Adjusted FVRB	FVROR Revenue Requirement	
14	Common Equity	$ 5,500	39.81%	10.25%	4.08%	6.77% [2]	$ 13,814	$ 934.6	14
15	Long-Term Debt	5,500	39.81%	5.25%	2.09%	2.09%	13,814	288.8	15
16	FVRB Increment Above OCRB	2,814	20.37%	1.00%	0.20%	0.34% [2]	13,814	46.7	16
17	Total Capital	$ 13,814	100.00%		6.37%	9.19%		$ 1,270.1	17
18	Applying Authorized Pre-tax FVROR to Incremental FVRB					9.05%	1,015	$ 91.9	18
19	Applying Pre-tax WACC to Incremental OCRB					11.12%	1,000	111.2	19
20	Cost of Capital Revenue Requirement Sufficiency / (Deficiency)							$ (19.3)	20
21	Applying Incremental Pre-tax FVROR to Incremental FVRB					10.98%	1,015	$ 111.5	21
22	Applying Pre-tax WACC to Incremental OCRB					11.12%	1,000	111.2	22
23	Cost of Capital Revenue Requirement Sufficiency / (Deficiency)							$ 0.2	23

Notes:
[1] FVRB = 0.5 X OCRB + 0.5 RCND
[2] Grossed up for taxes using the authorized gross-up factor of 1.6579

Exhibit No. ___ (TKW-3)
Sheet 4 of 4

Tab I

Direct Testimony

of

Robert B. Hevert

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY

OF

ROBERT B. HEVERT

ON BEHALF OF

SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
Prepared Direct Testimony
of
ROBERT B. HEVERT

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Appendix A – Summary of Qualifications of Robert B. Hevert

Exhibit No.___(RBH-1)

Exhibit No.___(RBH-2)

Exhibit No.___(RBH-3)

Exhibit No.___(RBH-4)

Exhibit No.___(RBH-5)

Exhibit No.___(RBH-6)

Exhibit No.___(RBH-7)

Exhibit No.___(RBH-8)

Exhibit No.___(RBH-9)

Exhibit No.___(RBH-10)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
ROBERT B. HEVERT

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Robert B. Hevert. I am Managing Partner of Sussex Economic Advisors, LLC ("Sussex"). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. 2 On whose behalf are you submitting this testimony?

A. 2 I am submitting this direct testimony ("Direct Testimony") before the Arizona Corporation Commission ("Commission") on behalf of Southwest Gas Corporation ("Southwest Gas" or the "Company").

Q. 3 Please describe your educational background.

A. 3 I hold a Bachelor's degree in Business and Economics from the University of Delaware, and an MBA with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q. 4 Please describe your experience in the energy and utility industries.

A. 4 I have worked in regulated industries for over twenty-five years, having served as an executive and manager with consulting firms, a financial officer of a publicly-traded natural gas utility (at the time, Bay State Gas Company), and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues including corporate and asset-based transactions, asset and enterprise

valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in over 150 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies and the Federal Energy Regulatory Commission. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Attachment A to my Direct Testimony.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. 5 What is the purpose of your Direct Testimony in this proceeding?

A. 5 The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Company's Return on Equity ("ROE").[1] My analyses and conclusions are supported by the data presented in Exhibit No.___(RBH-1) through Exhibit No.___(RBH-10), which have been prepared by me or under my direction.

Q. 6 What are your conclusions regarding the appropriate Cost of Equity?

A. 6 My analyses indicate that the Company's Cost of Equity currently is in the range of 10.00 percent to 10.50 percent. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, I conclude that an ROE of 10.25 percent is reasonable and appropriate.

Q. 7 Please provide a brief overview of the analyses that led to your ROE recommendation.

A. 7 As discussed in more detail in Section VI, in light of recent market conditions, and given the fact that equity analysts and investors tend to use multiple methodologies in developing their return requirements, it is important to consider

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

the results of several analytical approaches in determining the Company's ROE. To develop my ROE recommendation, I therefore applied the Constant Growth and Multi-Stage forms of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium approach.

As discussed throughout my Direct Testimony, it also is important to consider a range of factors, both quantitative and qualitative, in arriving at an ROE determination. As such, my recommendation takes into consideration the capital environment in which the Company operates, the effect of floatation costs and the increased regulatory risk the Company faces relative to the proxy group. Although I did not make explicit adjustments to my ROE estimates for those factors, I did take them into consideration when determining where the Company's Cost of Equity falls within the reasonable range of analytical results.

III. SUMMARY OF CONCLUSIONS

Q. 8 What are the key factors considered in your analyses and upon which you base your recommended ROE?

A. 8 My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[2] that established the standards for determining a fair and reasonable allowed Return on Equity including: consistency of the allowed return with other businesses having similar risk; adequacy of the return to provide access to capital and support credit quality; and that the end result must lead to just and reasonable rates.

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

- The effect of the current capital market conditions on investors' return requirements, and in particular, the Company's continuing need to access the capital markets.
- The Company's business risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q. 9 What are the results of your analyses?

A. 9 The results of my analyses are summarized in Tables 1a and 1b, below.

Table 1a: Summary of Discounted Cash Flow Model Results[3]

	Low	***Mean***	***High***
Constant Growth DCF Results			
30-Day Average	8.39%	9.52%	11.30%
90-Day Average	8.50%	9.64%	11.41%
180-Day Average	8.66%	9.79%	11.57%
Multi-Stage DCF Results			
	Low	***Mean***	***High***
30-Day Average	9.03%	9.33%	9.82%
90-Day Average	9.16%	9.47%	9.97%
180-Day Average	9.32%	9.65%	10.18%

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[3] *See also*, Exhibit No.___(RBH-1) and Exhibit No.___(RBH-3). Results include estimated flotation costs.

Table 1b: Summary of Risk Premium Results[4]

	Bloomberg Derived Market Risk Premium	***Value Line Derived Market Risk Premium***
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.79%)	9.69%	9.26%
Near Term Projected 30-Year Treasury (3.35%)	10.25%	9.83%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.79%)	10.78%	10.28%
Near Term Projected 30-Year Treasury (3.35%)	11.34%	10.85%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (2.79%)	9.98%	
Near Term Projected 30-Year Treasury (3.35%)	10.02%	
Long Term Projected 30-Year Treasury (4.65%)	10.39%	

Based on the analytical results presented in Tables 1a and 1b, and in light of the considerations discussed throughout the balance of my Direct Testimony, it is my view that a reasonable range of estimates is from 10.00 percent to 10.50 percent, and within that range, an ROE of 10.25 percent is reasonable and appropriate, if not somewhat conservative

Q. 10 How is the remainder of your Direct Testimony organized?

A. 10 The balance of my Direct Testimony is organized as follows:

Section IV – Discusses the regulatory guidelines and financial considerations pertinent to the development of the cost of capital;

Section V – Explains my selection of the proxy group of natural gas distribution utilities used to develop my analytical results;

[4] *See also*, Exhibit No.___(RBH-6) and Exhibit No.___(RBH-7).

Section VI – Explains my analyses and the analytical bases for my ROE recommendation;

Section VII – Provides a discussion of specific business risks and other considerations that have a direct bearing on the Company's Cost of Equity;

Section VIII – Discusses current capital market conditions and the effect of those conditions on the Company's Cost of Equity;

Section IX – Summarizes my conclusions and recommendations for the return on the original cost rate base;

Section X – Discusses the fair value rate base; and

Section XI – Summarizes the fair value rate of return.

IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

Q. 11 Before addressing the specific aspects of this proceeding, please provide an overview of the issues surrounding the Cost of Equity in regulatory proceedings, generally.

A. 11 In very general terms, the Cost of Equity is the return that investors require to make an equity investment in a firm. That is, investors will only provide funds to a firm if the return that they *expect* is equal to, or greater than, the return that they *require*. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity"; together, they are referred to as the "Cost of Capital".

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs". Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least

equal to the return expected on alternative, comparable investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Although both debt and equity have required costs, they are different in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate, or yield, on debt securities.[5] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on the firm's cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear that "residual risk", they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: They invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated, or inferred, based on market data and various financial models. As discussed throughout my Direct Testimony, all of those models are subject to certain assumptions, which may be more or less applicable under differing market conditions. In addition, because the Cost of Equity is premised on opportunity costs, those models typically are applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model

[5] The observed interest rate may be adjusted to reflect issuance or other directly observable costs.

results all require the application of judgment. That judgment also should consider data and information that is not necessarily included in the models themselves. In the end, however, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks, and the returns available on comparable investments.

Q. 12 Please now provide a brief summary of the regulatory guidelines established for the purpose of determining the ROE.

A. 12 The Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* (*"Bluefield"*);[6] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[7] In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[8]

The Court therefore recognized that: (1) a regulated company cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the cost of capital (the principle relating to the demand

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

for capital); and (2) a regulated company will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of the same risk (the principle relating to the supply of capital).

Q. 13 Has the Commission provided similar guidance in establishing the appropriate Return on Equity?

A. 13 Yes. The Commission has noted that under the Arizona Constitution, a public utility is entitled to a fair return on the fair value of its property devoted to public uses. The Commission is required to find the fair value of the utility's property and to use that value to establish just and reasonable rates.[9]

Q. 14 Why is it important for a utility to be allowed the opportunity to earn a return adequate to attract equity capital at reasonable terms?

A. 14 A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. In keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. Based on those standards, the Commission's decision in this case should provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms, thereby enabling it to continue to provide safe and reliable natural gas service; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. The allowed ROE should enable the Company to finance capital expenditures at reasonable cost rates and maintain its financial flexibility

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[9] Arizona Corporation Commission Order No. W-02113A-04-0616, Chaparral City Water Company, February 13, 2007, at 11. References Ariz. Water co., 85 Ariz. at 203,335, P.2d at 415.

over the period during which rates are expected to remain in effect. Whereas the "capital attraction" and "financial integrity" standards are important principles in normal economic conditions, the practical implications of those standards are even more pronounced during periods of capital market instability.

Q. 15 How is the Cost of Equity estimated in regulatory proceedings?

A. 15 As noted earlier (and as discussed in more detail throughout my Direct Testimony), the Cost of Equity is estimated by the use of various financial models. By their very nature, those models produce a range of results from which the ROE must be estimated. That estimate must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. The key consideration in determining the ROE is to ensure that the overall analysis reasonably reflects investors' view of the financial markets in general and the subject company (in the context of the proxy companies) in particular. Both practitioners and academics, however, recognize that financial models simply are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the methodology, that is controlling in arriving at ROE determinations. Thus, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results in the context of observable, relevant market information.

V. PROXY GROUP SELECTION

Q. 16 As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for Southwest Gas?

A. 16 First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for the Company's Arizona jurisdictional operations. Because the ROE is a market-based concept, and given the fact that Southwest Gas's jurisdictional operations within Arizona do not make up the entirety of the publicly traded parent company, it is necessary to establish a group of companies that are both publicly traded and comparable to Southwest Gas to serve as its "proxy" for purposes of the ROE estimation process.

Even if Southwest Gas's Arizona jurisdictional assets did constitute the entirety of the parent company's operations, it is possible that transitory events could bias its market value in one way or another over a given period of time. A significant benefit of using a proxy group, therefore, is to moderate the effects of anomalous, temporary events that may be associated with any one company.

Q. 17 Does the selection of a proxy group suggest that analytical results will be tightly clustered around average (i.e., mean) results?

A. 17 Not necessarily. The DCF approach is based on the theory that a stock's current price represents the present value of its future expected cash flows. The DCF model is defined as the sum of the expected dividend yield and projected long-

term growth. Notwithstanding the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to select an ROE estimate from within that range. That determination necessarily must be based on the informed judgment and experience of the analyst.

Q. 18 Please now provide a summary profile of Southwest Gas.

A. 18 Southwest Gas provides natural gas distribution service to approximately 1,045,000 customers in the state of Arizona.[10] The Company also has operations in Nevada and California serving a total of approximately 1,956,000 customers. Southwest Gas currently has senior unsecured ratings of A3, BBB+, and A from Moody's Investors Service, Standard & Poor's, and Fitch Ratings, respectively.[11]

Q. 19 How did you select the companies included in your proxy group?

A. 19 I began with the universe of companies that Value Line classifies as Natural Gas Utilities, which includes a group of 12 domestic U.S. utilities, and applied the following screening criteria:

- I excluded companies that do not consistently pay quarterly cash dividends;
- I excluded companies not covered by at least two utility industry equity analysts;
- I excluded companies that do not have investment grade senior bond and/or corporate credit ratings from Standard and Poor's;

[10] *See*, Southwest Gas Corp., SEC Form 10-K for the fiscal year ended December 31, 2015, at 10.
[11] *See*, Southwest Gas Corp., SEC Form 10-K for the fiscal year ended December 31, 2015, at 25-26.

- To incorporate companies that are primarily regulated gas distribution utilities, I excluded companies with less than 60.00 percent of net operating income from regulated natural gas utility operations; and,
- I excluded companies that are currently known to be party to a merger, or other significant transaction.

Q. 20 Did you include Southwest Gas Corporation in your analysis?

A. 20 No. In order to avoid the circular logic that otherwise would occur, it has been my consistent practice to exclude the subject company (or its parent) from the proxy group.

Q. 21 What companies met those screening criteria?

A. 21 The criteria discussed above resulted in a proxy group of the following six companies:

Table 2: Proxy Group Screening Results

Company	Ticker
Atmos Energy	ATO
Laclede Group, Inc.	LG
New Jersey Resources	NJR
Northwest Natural Gas	NWN
South Jersey Industries	SJI
WGL Holdings, Inc.	WGL

Q. 22 Do you believe that a proxy group of six companies is sufficiently large?

A. 22 Yes. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's Cost of Equity to the extent that the chosen proxy companies are fundamentally comparable to the subject utility. Because all analysts use some form of screening process to arrive at a proxy group, the group, by definition, is not randomly drawn from a larger population. Consequently, there is no reason to place more reliance on the quantitative

results of a larger proxy group simply by virtue of the resulting larger number of observations.

VI. COST OF EQUITY ESTIMATION

Q. 23 Please briefly discuss the ROE in the context of the regulated rate of return.

A. 23 Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment. The overall rate of return ("ROR") for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. Whereas the costs of debt and preferred stock can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market information.

Q. 24 How is the required ROE determined?

A. 24 The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. By their very nature, quantitative models produce a range of results from which the market required ROE must be selected. As discussed throughout my Direct Testimony, that selection must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. Consequently, the key consideration in determining the Cost of Equity is to ensure that the methodologies employed reasonably reflect investors' view of the financial markets in general, and the subject company (in the context of the proxy group) in particular.

Although we cannot directly observe the Cost of Equity, we can observe the methods frequently used by analysts to arrive at their return requirements

and expectations. While investors and analysts tend to use multiple approaches in developing their estimate of return requirements, each methodology requires certain judgment with respect to the reasonableness of assumptions and the validity of proxies in its application. In essence, analysts and academics understand that ROE models are tools to be used in the ROE estimation process and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed and irrelevant conclusions. That position is consistent with the *Hope* and *Bluefield* finding that it is the analytical result, as opposed to the methodology, that is controlling in arriving at ROE determinations. A reasonable ROE estimate therefore considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

In my view, therefore, it is both prudent and appropriate to use multiple methodologies to mitigate the effect of assumptions and inputs associated with relying exclusively on any single approach. Such use, however, must be tempered with due caution as to the results generated by each individual approach. As such, I have considered the results of the Constant Growth and Multi-Stage forms of the DCF model, the Capital Asset Pricing Model, and the Risk Premium approach.

Constant Growth DCF Model

Q. 25 Are DCF models widely used in regulatory proceedings?

A. 25 Yes, in my experience the DCF model is widely recognized in regulatory proceedings. Nonetheless, neither the DCF nor any other model should be applied without considerable judgment in the selection of data and the interpretation of results.

Q. 26 Please describe the DCF approach.

A. 26 The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the Cost of Equity as the sum of the expected dividend yield and long-term growth rate, and is expressed as follows:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P represents the current stock price, $D_1 \ldots D_\infty$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation, which can be simplified and rearranged into the familiar form:

$$k = \frac{D_0\ (1+g)}{P} + g \ [2]$$

Equation [2] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

As explained more fully below, both consensus forecasts and market data indicate meaningful increases in long-term interest rates over the next several years (i.e., the period in which rates will be in effect). Consequently, the fundamental assumption that the return required today is the same return that will be required three or more years from now likely does not hold. As also discussed below, the proxy companies' average P/E multiple recently has traded well in excess of its historical average and at times, in excess of the market-wide P/E multiple. As such, market conditions are inconsistent with the Constant Growth DCF model's fundamental assumptions. As a consequence, the

Constant Growth DCF model's results likely understate the required Cost of Equity since it only measures cash flows related to dividend payments[12], and should be interpreted with considerable caution and reasoned judgment.

Q. 27 What assumptions are required for the Constant Growth DCF model?

A. 27 The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. In addition, the Constant Growth DCF model assumes that the same return will be required every year, in perpetuity (see Equation [1], above).

Q. 28 What market data did you use to calculate the dividend yield component of your DCF model?

A. 28 The dividend yield is based on the proxy companies' current annualized dividend, and average closing stock prices over the 30-, 90-, and 180-trading days as of February 12, 2016.

Q. 29 Why did you use three averaging periods to calculate the average stock price?

A. 29 I did so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, the use of the 30-, 90- and 180-day averaging periods reasonably balances those concerns.

Q. 30 Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

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[12] Ackert, Lucy F., Smith, Brian F., Price Volatility, Ordinary Dividends, and Other Cash Flows to Shareholders,, *Journal of Finance*, September 1993.

A. 30 Yes, I did. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the dividends to be paid during that time.

Q. 31 Is it important to select appropriate measures of long-term growth in applying the DCF model?

A. 31 Yes. In its Constant Growth form, the DCF model (i.e., as presented in Equation [2] above) assumes a single growth estimate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long term, however, dividend growth can only be sustained by earnings growth. Consequently, it is important to incorporate a variety of measures of long-term earnings growth into the Constant Growth DCF model.

Q. 32 Please summarize the findings of academic research on the appropriate measure for estimating equity returns using the DCF model.

A. 32 The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[13] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

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[13] *See*, for example, Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management, Spring 1986.

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[14]

Phillips' conclusion continues to hold true. Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[15] For example, Vander Weide and Carleton state that, "[our] results...are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[16]

Other research specifically notes the importance of analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecast are indeed reflected in stock prices." Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[17] Similarly, Brigham, Shome and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are

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[14] Charles F. Phillips, Jr., The Economics of Regulation, Revised Edition, 1969, Richard D. Irwin, Inc., at 285.

[15] See, for example, Christofi, Christofi, Lori and Moliver, Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate, Journal of Investing (Spring 1999); Harris and Marston, Estimating Shareholder Risk Premia Using Analysts Growth Forecasts, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, Investor Growth Expectations: Analysts vs. History, The Journal of Portfolio Management, Spring 1988.

[16] Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

[17] Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management, Spring 1986.

superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts."[18]

To that point, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth projections do not. Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

Q. 33 Please summarize your inputs to the Constant Growth DCF model.

A. 33 I applied the DCF model to the proxy group of natural gas utility companies using the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended February 12, 2016 for the term P_0; and
2. The annualized dividend per share as of February 12, 2016 for the term D_0.

I then calculated the DCF results using each of the following growth terms:

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates;
3. The Value Line long-term earnings growth estimates;
4. An estimate of Retention Growth.

Q. 34 Please describe the Retention Growth estimate as applied in your Constant Growth DCF model.

[18] Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985.

A. 34 The Retention Growth model, which is a generally recognized and widely taught method of estimating long-term growth, is an alternative approach to the use of analysts' earnings growth estimates. In essence, the model is premised on the proposition that a firm's growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the enterprise. In its simplest form, the model represents long-term growth as the product of the retention ratio (i.e., the percentage of earnings not paid out as dividends, referred to below as ("b") and the expected return on book equity (referred to below as "r")). Thus, the simple "b x r" form of the model projects growth as a function of internally generated funds. That form of the model is limiting, however, in that it does not provide for growth funded from external equity.

The "br + sv" form of the Retention Growth estimate used in my DCF analysis is meant to reflect growth from both internally generated funds *(i.e.,* the "br" term) and from issuances of equity *(*i.e., the "sv" term). The first term, which is the product of the retention ratio (i.e., "b", or the portion of net income not paid in dividends) and the expected return on equity *(*i.e., "r") represents the portion of net income that is "plowed back" into the Company as a means of funding growth. The "sv" term is represented as:

$$\left(\frac{m}{b} - 1\right) \; x \; Growth\ rate\ in\ Common\ Shares \quad [3]$$

In this form, the "sv" term reflects an element of growth as the product of (a) the growth in shares outstanding, and (b) that portion of the market-to-book ratio that exceeds unity. As shown in Exhibit No.___(RBH-2), all of the components of the Retention Growth Model can be derived from data provided by Value Line.

Q. 35 How did you calculate the high and low DCF results?

A. 35 I calculated the proxy-group mean high DCF result by combining each company's dividend yield with the maximum of (1) its EPS growth rate as reported by Value Line, Zacks, or First Call or (2) its retention growth estimate based on Value Line data as described above. The average mean high result then reflects the average maximum DCF result for the proxy group as a whole. I used a similar approach to calculate the mean low results, combining dividend yield with the minimum growth rate data for each proxy group company.

Q. 36 What are the results of your DCF analysis?

A. 36 My Constant Growth DCF results are summarized in Table 3, below (*see* also Exhibit No.___(RBH-1).

Table 3: Constant Growth DCF Results[19]

	Mean Low	Mean	Mean High
30-Day Average	8.39%	9.52%	11.30%
90-Day Average	8.50%	9.64%	11.41%
180-Day Average	8.66%	9.79%	11.57%

Multi-Stage DCF Model

Q. 37 What other forms of the DCF model have you used?

A. 37 In order to address certain limiting assumptions underlying the Constant Growth form of the DCF model, I also considered the results of the Multi-Stage (three-stage) Discounted Cash Flow Model. The Multi-Stage model, which is an extension of the Constant Growth form, enables the analyst to specify growth

[19] Results include estimated flotation costs, which are discussed in Section VII.

rates over three distinct stages. As with the Constant Growth form of the DCF model, the Multi-Stage form defines the Cost of Equity as the discount rate that sets the current price equal to the discounted value of future cash flows. Unlike the Constant Growth form, however, the Multi-Stage model must be solved in an iterative fashion.

Q. 38 Please now summarize why you have included the Multi-Stage DCF method in your Cost of Equity estimation.

A. 38 First, as noted earlier, it is both prudent and appropriate to use multiple methodologies in order to mitigate the effects of assumptions and inputs associated with any single approach. Second, the Constant Growth DCF model assumes that earnings, dividends, and book value will grow at the same constant rate in perpetuity; that the payout ratio will remain constant in perpetuity; and that the Price/Earnings ratio will remain constant. In addition, the model assumes that the return required today will be the same return required every year in the future. However, those assumptions are not likely to hold. In particular, given near-term capital expenditures associated with infrastructure replacement and growth needs, it is likely that payout ratios will increase from their current levels.[20] In my view, the Multi-Stage DCF model enables analysts to consider such issues, and to address the limiting, and likely unrealistic assumptions underlying the Constant Growth form of the model.

Q. 39 Please generally describe the structure of your Multi-Stage model.

A. 39 As noted above, the model sets the subject company's stock price equal to the present value of future cash flows received over three "stages". In the first two

[20] See, for example, SNL Energy, *Financial Focus Special Report: Capital Expenditure Update*, November 5, 2015.

stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period (i.e., the "terminal price"). I calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the Cost of Equity (i.e., the discount rate) and the long-term expected growth rate. In essence, the terminal price is defined by the present value of the remaining "cash flows" in perpetuity. In each of the three stages, the dividend is the product of the projected earnings per share and the expected dividend payout ratio. A summary description of the model is provided in Table 4 (below).

Table 4: Multi-Stage DCF Structure

Stage	**0**	**1**	**2**	**3**
Cash Flow Component	Initial Stock Price	Expected Dividend	Expected Dividend	Expected Dividend + Terminal Value
Inputs	Stock Price Earnings Per Share ("EPS") Dividends Per Share ("DPS")	Expected EPS Expected DPS	Expected EPS Expected DPS	Expected EPS Expected DPS Terminal Value
Assumptions	30-, 90-, and 180-day average stock price	EPS Growth Rate Payout Ratio	Growth Rate Change Payout Ratio Change	Long-term Growth Rate Long-term Payout Ratio

Q. 40 What are the analytical benefits of your Multi-Stage model?

A. 40 The primary benefits relate to the flexibility provided by the model's formulation. Since the models provide the ability to specify near, intermediate, and long-term growth rates, for example, it avoids the sometimes limiting assumption that the subject company will grow at the same, constant rate during all stages of growth. In addition, by calculating the dividend as the product of earnings and the payout

ratio, the model enables analysts to reflect assumptions regarding the timing and extent of changes in the payout ratio to reflect, for example, increases or decreases in expected capital spending, or transition from current payout levels to long-term expected levels. In that regard, because the model relies on multiple sources of earnings growth rate assumptions, it is not limited to a single source, such as Value Line, for all inputs, and mitigates the potential bias associated with relying on a single source of growth estimates.[21]

The model also enables the analyst to assess the reasonableness of the inputs and results by reference to certain market-based metrics. For example, the stock price estimate can be divided by the expected earnings per share in the final year to calculate an average Price to Earnings ("P/E") ratio. Similarly the terminal P/E ratio can be divided by the terminal growth rate to develop a Price to Earnings Growth ("PEG") ratio. To the extent that either the projected P/E or PEG ratios are inconsistent with either historical or expected levels, it may indicate incorrect or inconsistent assumptions within the balance of the model.

Q. 41 Please summarize your inputs to the Multi-Stage DCF model.

A. 41 I applied the Multi-Stage model to the proxy group described earlier in my Direct Testimony. My assumptions with respect to the various model inputs are described in Table 5 (below).

[21] *See*, for example, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992).

Table 5: Multi-Stage DCF Model Assumptions

Stage	Initial	First	Transition	Terminal
Stock Price	30-, 90-, and 180-day average stock price as of February 12, 2016			
Earnings Growth	2014 actual EPS escalated by Period 1 growth rate	EPS growth as average of (1) Value Line; (2) Zacks; (3) First Call; (4) Retention Growth rates	Transition to Long-term GDP growth	Long-term GDP growth
Payout Ratio		Value Line company-specific	Transition to long-term industry payout ratio	Long-term expected payout ratio
Terminal Value				Expected dividend in final year divided by solved Cost of Equity less long-term growth rate

Q. 42 How did you calculate the long-term GDP growth rate?

A. 42 The long-term growth rate of 5.31 percent is based on the real Gross Domestic Product (GDP) growth rate of 3.24 percent from 1929 through 2015,[22] and an inflation rate of 2.01 percent.[23] The GDP growth rate is calculated as the compound growth rate in the chain-weighted GDP for the period from 1929 through 2015. The rate of inflation of 2.01 percent is a an average of the compound annual forward rate starting in ten years (i.e., 2025, which is the beginning of the terminal period) and is based on the 180-day average projected

[22] *See*, Bureau of Economic Analysis, accessed on February 12, 2016.
[23] *See*, Board of Governors of the Federal Reserve System, Table H.15 Selected Interest Rates and Blue Chip Financial Forecasts December 1, 2015 at 14.

inflation based on the spread between yields on long-term nominal Treasury Securities and long-term Treasury Inflation Protected Securities, known as the "TIPS spread" of 1.82 percent and the projected Blue Chip Financial Forecast of CPI for 2022 – 2026 of 2.20 percent.

I averaged these two measures of inflation because nominal Treasury yields are related to inflation, which includes the effect of commodities such as oil, which may cause the current TIPS spread to somewhat understate long-term expected inflation. My long-term inflation rate, therefore, is the average of those two estimates, or 2.01 percent.

Q. 43 What were your specific assumptions with respect to the payout ratio?

A. 43 As noted in Table 5, for the first two periods I relied on the first year and long-term projected payout ratios reported by Value Line[24] for each of the proxy group companies. I then assumed that by the end of the second period (i.e., the end of year 10), the payout ratio will converge to the industry expected ratio of 67.67 percent.[25]

Q. 44 Please summarize the results of your Multi-Stage DCF analyses.

A. 44 Table 6 (below) (*see* also Exhibit No.___(RBH-3) presents the results of the Multi-Stage DCF analyses. The Multi-Stage DCF analysis produces a range of results from 9.03 percent to 10.18 percent.

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[24] As reported in the Value Line Investment Survey as "All Div'ds to Net Prof."
[25] Source: Bloomberg Professional.

Table 6: Multi-Stage Discounted Cash Flow Model Results[26]

	Low	Mean	High
30-Day Average	9.03%	9.33%	9.82%
90-Day Average	9.16%	9.47%	9.97%
180-Day Average	9.32%	9.65%	10.18%

CAPM Analysis

Q. 45 Please briefly describe the general form of the CAPM analysis.

A. 45 The CAPM is a risk premium model that estimates the Cost of Equity as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [4], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$k = r_f + \beta(r_m - r_f) \quad [4]$$

where:

k = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In Equation [4], the term ($r_m - r_f$) represents the Market Risk Premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

[26] Results include estimated flotation costs, which are discussed in Section VII.

$$\beta_j = \frac{\sigma_j}{\sigma_m} x \, \rho_{j,m} \, [5]$$

where σ_j is the standard deviation of returns for company "*j*"; σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. Thus, the Beta coefficient represents both relative volatility (i.e., the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. 46 What assumptions regarding the risk-free rate did you include in your CAPM analysis?

A. 46 Because utility assets represent long-term investments, I used two different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (i.e., 2.79 percent); and (2) the near-term (that is, through the second calendar quarter of 2017) projected 30-year Treasury yield (i.e., 3.35 percent).

Q. 47 What Market Risk Premium did you use in your CAPM model?

A. 47 I developed a forward-looking (*ex-ante*) estimate of the Market Risk Premium.

Q. 48 Please describe your *ex-ante* approach to estimating the Market Risk Premium.

A. 48 The approach is based on the market required return, less the current 30-year Treasury bond yield. To do so, I relied on data from two sources: (1) Bloomberg; and (2) Value Line. For Bloomberg, I calculated the market capitalization weighted expected dividend yield (using the same one-half growth rate assumption described earlier), and combined that amount with the market capitalization weighted projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I then subtracted the current 30-

year Treasury yield from that amount to arrive at the market DCF-derived ex-ante Market Risk Premium estimate. For Value Line, I calculated the projected long-term market return based on the implied annual price appreciation and dividend yield for Value Line's composite index. The results of those two calculations are provided in Exhibit No.___(RBH-4).

Q. 49 How did you apply your expected Market Risk Premium and risk-free rate estimates?

A. 49 I relied on the *ex-ante* Market Risk Premia discussed above, together with the current and near-term projected 30-year Treasury bond yields as inputs to my CAPM analyses.

Q. 50 What Beta coefficient did you use in your CAPM model?

A. 50 As shown in Exhibit No.___(RBH-5), I considered the Beta coefficients reported by two sources: Bloomberg, and Value Line. Although both services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. 51 What are the results of your CAPM analyses?

A. 51 The results of my CAPM analysis are summarized in Table 7 (*see also,* Exhibit No.___(RBH-6).

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Table 7: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.79%)	9.69%	9.26%
Near Term Projected 30-Year Treasury (3.35%)	10.25%	9.83%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.79%)	10.78%	10.28%
Near Term Projected 30-Year Treasury (3.35%)	11.34%	10.85%

Bond Yield Plus Risk Premium Approach

Q. 52 Please generally describe the Bond Yield Plus Risk Premium approach.

A. 52 This approach is based on the financial tenet that equity investors bear the residual risk of ownership and therefore require a premium over the returns available to debt holders. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of an Equity Risk Premium and a bond yield. The Equity Risk Premium is the difference between the historical Cost of Equity and long-term Treasury yields. Because we are calculating the risk premium for natural gas utilities, a reasonable approach is to use actual authorized returns for natural gas utilities as the historical measure of the Cost of Equity.

Q. 53 Please now explain how you performed your Bond Yield Plus Risk Premium analysis.

A. 53 As suggested above, I first defined the Risk Premium as the difference between the authorized ROE and the then-prevailing level of long-term (i.e., 30-year) Treasury yield. I then gathered data for 1,031 natural gas rate proceedings between January, 1980 and February 12, 2016 as reported by Regulatory Research Associates ("RRA"). In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the

final order (the "lag period"). To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 188 days).

Because the data cover a number of economic cycles,[27] the analysis also may be used to assess the stability of the Equity Risk Premium. Prior research, for example, has shown that the Equity Risk Premium is inversely related to the level of interest rates.[28] That is, although interest rates and the Cost of Equity generally are directionally related, they do not move in lock-step. That finding is particularly relevant given the historically low level of current Treasury yields.

Q. 54 How did you model the relationship between interest rates and the Equity Risk Premium?

A. 54 The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Because the analytical period includes interest rates and authorized ROEs that during one period (i.e., the 1980's) are quite high and another (the post-Lehman bankruptcy period) that are quite low relative to the long-term historical average, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta(\mathrm{LN}(T_{30})) \quad [6]$$

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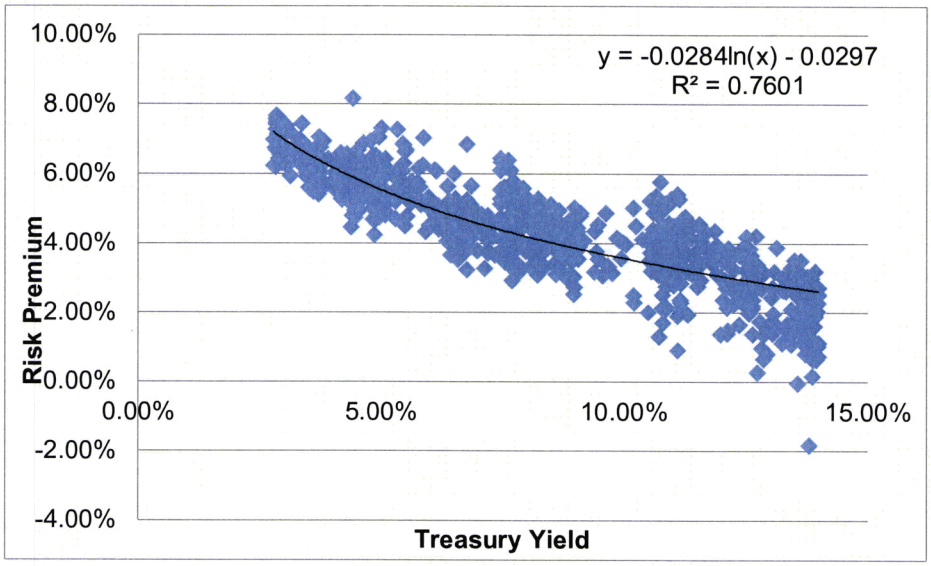
[27] National Bureau of Economic Research, U.S. Business Cycle Expansion and Contractions.

[28] *See*, for example, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

As shown on Chart 1 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

Chart 1: Equity Risk Premium



As Chart 1 demonstrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.52 percent (*see* Exhibit No.___(RBH-7) would significantly under-state the Cost of Equity; assuming the near-term projected 30-year Treasury yield of 3.35 percent, for example, the simple average Equity Risk Premium would suggest an ROE of 7.87.[29] That, of course, is well below any reasonable estimate. Based on the regression coefficients in Chart 1,

[29] 7.87% = 4.52% + 3.35%

however, the implied ROE ranges from 9.98 percent to 10.39 percent (*see* Exhibit No.___(RBH-7).

VII. BUSINESS RISKS AND OTHER CONSIDERATIONS

Q. 55 With regard to the DCF and CAPM models, do the mean results for the proxy group provide an appropriate estimate of the Cost of Equity for the Company?

A. 55 Not necessarily. In my view, there are additional factors that must be considered when determining where the Company's Cost of Equity falls within the range of results, in particular flotation costs and the increased regulatory risk relative to the proxy group.

Flotation Costs

Q. 56 What are flotation costs?

A. 56 Flotation costs are the costs associated with the sale of new issues of common stock. Such costs include out-of-pocket expenditures for preparation, filing, underwriting and other issuance costs of common stock.

Q. 57 Why is it important to recognize flotation costs in the allowed ROE?

A. 57 To attract and retain new investors, a regulated utility must have the opportunity to earn a return that is both competitive and compensatory. To the extent the opportunity to recover prudently incurred flotation costs is denied, actual returns will fall short of expected (or required) returns, thereby diminishing its ability to attract adequate capital on reasonable terms.

Q. 58 Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. 58 Flotation costs, which are a permanent reduction to common equity, are reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore are not reflected on the income statement. Rather, like

investments in rate base or the issuance costs of long-term debt, flotation costs are recognized over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year, but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, recovery of flotation costs is appropriate even if no new issuances are planned in the near future because failure to allow such cost recovery may deny Southwest Gas the opportunity to earn its required rate of return in the future.

Q. 59 Do the DCF and CAPM models already incorporate investor expectations of a return in order to compensate for flotation costs?

A. 59 No. The models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM and the Bond Yield Plus Risk Premium model). Therefore, it is appropriate to consider flotation costs when determining where within the range of reasonable results Southwest Gas' return should fall.

Q. 60 Is the need to consider flotation costs recognized by the academic and financial communities?

A. 60 Yes. The need to reimburse investors for equity issuance costs is justified by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. As explained by Dr. Shannon Pratt:

> Flotation costs occur when a company issues new stock. The business usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the business. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs.

> Because of this reduction in proceeds, the business's required returns must be greater to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the net cash flow to discount, or by incorporating the cost into the cost of equity capital. Since flotation costs typically are not applied to operating cash flow, they must be incorporated into the cost of equity capital.[30]

Q. 61 Have you calculated the effect of flotation costs on the Return on Equity?

A. 61 Yes, I have. I modified the DCF calculation to derive the dividend yield that would reimburse investors for direct issuance costs. Based on the approximate issuance cost of 1.00 percent experienced by Southwest Gas in 2015[31] shown in Exhibit No.___(RBH-8), a reasonable estimate of the effect of flotation costs on the Company's ROE is approximately 0.03 percent (three basis points).

Regulatory Risks

Q. 62 Is there any precedent that identifies the regulatory risk faced by utilities?

A. 62 Yes. In *Hope*, the Supreme Court noted that it is not the theory, but the impact of the rate order which counts.[32] In *Duquesne*, the Supreme Court noted the risks to utilities of ratemaking treatment and the importance of establishing ratemaking treatment that does not continuously favor customers to the continuous detriment of investors:

> [t]he risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in essential service, and so relatively immune to the usual market risks. Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions.[33]

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[30] Shannon P. Pratt, Roger J. Grabowski, Cost of Capital: Applications and Examples, 4th ed. (John Wiley & Sons, Inc., 2010), at 586.
[31] 2015 SEC Form 10-K at page 56.
[32] Hope, 320 U.S., at 602, 64 S.Ct., at 288.
[33] Duquesne, 109 S.Ct. 609 (1989) at 9.

Q. 63 How does the regulatory environment in which a utility operates affect its access to and Cost of Capital?

A. 63 The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "the predictability and supportiveness of the regulatory framework in which a regulated utility operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."[34] Moody's further noted that:

> For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor.[35]

S&P notes that regulatory commissions should eliminate, or at least greatly reduce, the issue of rate-case lag.[36] Moody's agrees that timely cost recovery is an important determinant of credit quality, stating that "[t]he ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities, as the lack of timely recovery of such costs has caused financial stress for utilities on several

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[34] Moody's Global Infrastructure Finance, Regulated Electric and Gas Utilities, August 2009, at 6.
[35] Ibid.
[36] Standard and Poor's, Assessing Vertically Integrated Utilities' Business Risk Drivers, U.S. Utilities and Power Commentary, November 2006, at 10.

occasions"[37] Similarly, Fitch Ratings ("Fitch") notes that in the current environment of rising costs, utilities will require more frequent rate increases to maintain financial results, resulting in further exposure to regulatory risks.[38]

Q. 64 Please summarize the financial community's perceptions of regulatory risk in Arizona and how the Commission's focus on regulatory lag has affected those perceptions.

A. 64 In general, the financial community has observed that the Commission's recent efforts to address regulatory lag by allowing rate mechanisms and shortening the time needed to complete the rate case process has reduced the effect of regulatory lag on the Company's credit profile. Moody's, for example, has noted that "[b]ased on the length of recent rate cases, we believe the ACC is more committed to finalizing cases in about a year or less, which is more consistent with the average of utility regulatory commissions across the US."[39] Looking to the nature of regulation in Arizona in general, Moody's stated, "[w]e believe the long term credit support provided by the Arizona regulatory environment has improved significantly over the last 10 years and this has had a positive impact on the financial performance of its regulated utilities."[40] In general, Moody's views the regulatory environment in Arizona as becoming increasingly credit supportive, with reduced rate case lag, and the increased use of rate mechanisms.

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[37] Moody's, Global Infrastructure Finance, Regulated Electric and Gas Utilities, August 2009, at 7.
[38] FitchRatings, U.S. Utilities, Power, and Gas 2010 Outlook, December 4, 2009, at 1.
[39] Moody's Investors Service, *Arizona's Constructive Regulatory Environment Supports the Credit Quality of Its Investor-Owned Regulated Utilities*, February 23, 2015.
[40] Moody's Investors Service, *Arizona's Constructive Regulatory Environment Supports the Credit Quality of Its Investor-Owned Regulated Utilities*, February 23, 2015.

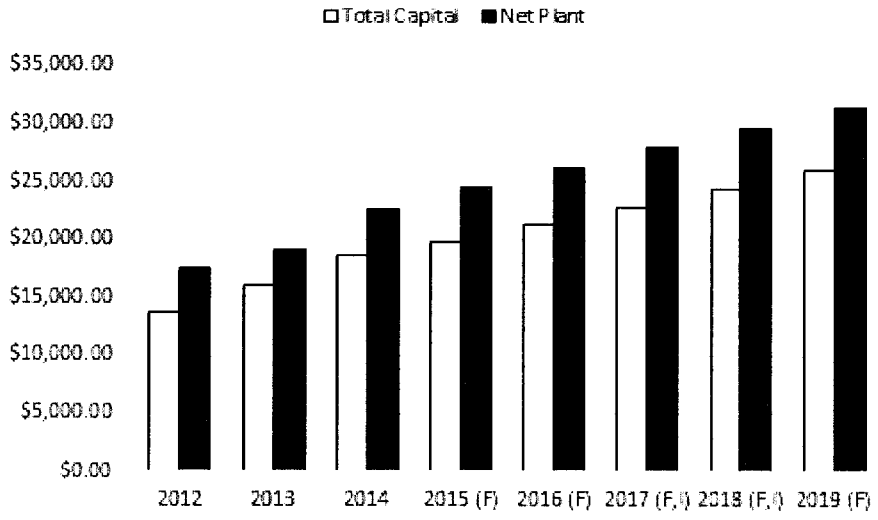
Q. 65 Please summarize your conclusions regarding the effect of increasing capital investments and regulatory lag on the Company's operating income and Cost of Equity.

A. 65 The need to invest significant amounts of capital in non-revenue producing infrastructure presents financial challenges, in particular as those investments put pressure on earnings and cash flow. That pressure becomes even more acute when the rate of capital expenditures accelerates, as currently is the case for Southwest Gas.

Q. 66 Is the need for increased capital investment unique to Southwest Gas?

A. 66 No. Value Line has recognized that the natural gas utility industry likely is in a period of increased capital investment and related funding requirements. In that regard, Value Line expects significant increases in both Net Plant and Total Capital within the Proxy Group (see Chart 2, below).

Chart 2: Proxy Group Net Plant and Total Capital, 2012 – 2019 (in millions)[41]



[41] Source: Value Line. F: Forecast; I: Interpolated

Value Line's perspective that Total Capital must increase to support additional investment is an important consideration. The ability to efficiently acquire the capital needed to fund the growing level of infrastructure investments is dependent on the ability to recover that investment in a timely manner. As noted by the American Gas Association:

> Timely cost recovery of prudently incurred safety and reliability investments is of utmost importance to the financial stability of natural gas utilities. Because traditional ratemaking allows recovery of infrastructure investments only following approval in a rate case, there is often a multi-year delay before the recovery of such investments begins. Investments that are recovered long after they are incurred cause the utility to bear carrying costs without the opportunity to recover these prudent expenditures. Credit agencies criticize companies with lag in the recovery of their costs and assign a lower credit rating to such utilities that ultimately translates into higher rates for customers. The only alternative is to file a rate case each year, which is a costly activity that also leads to higher rates for customers.[42]

In essence, absent timely rate relief, increasing capital investment creates a circumstance in which each dollar of invested assets produces fewer dollars of revenue. As the American Gas Association noted, absent other solutions the only alternative to funding those investments is more frequent rate filings. Otherwise, the Company will be incentivized to reduce its infrastructure replacement activity and associated capital investment.

The combined effect of the factors that determine the Return on Rate Base can be seen in the following relationships:

[42] American Gas Association, *Infrastructure Cost Recovery Update*, June, 2012, at 2.

Figure 1: Factors Determining Return on Rate Base

$$\begin{array}{ccccc} Operating\ Margin & \times & Asset\ Turnover & = & Return\ on\ Rate\ Base \\ \downarrow & & \downarrow & & \downarrow \\ \dfrac{Operating\ Income}{Non-Gas\ Revenue} & \times & \dfrac{Non-Gas\ Revenue}{Rate\ Base} & = & \dfrac{Operating\ Income}{Rate\ Base} \end{array}$$

Figure 1 notes that in general, the overall Return on Rate Base depends on: (1) the percentage of margin generated by each dollar of revenue (*i.e.,* the Operating Margin; and (2) the dollars of revenue generated by each dollar of assets (*i.e.*, the Asset Turnover). As Figure 1 also suggests, returns are directly related to increased non-growth related capital investments, which further reduce the Asset Turnover. In very real sense, profitability will be squeezed by high investment, despite a continuing focus on operating expense control.

Q. 67 How do the Company's Energy Efficiency Enabling Provision ("EEP") and its Gas Infrastructure Modernization (GIM) Mechanism affect the factors that you have discussed above?

A. 67 By stabilizing revenue and mitigating the effect of declining use per customer, the EEP provides some relief to what otherwise would be a more dilutive effect on the ratio of Revenue/Rate Base. Similarly, the Company's proposed GIM Mechanism enables the more timely recovery of costs associated with capital investments, again helping to contain the dilutive effect of increased, non-growth related capital investments.

Q. 68 Given those concerns, are decoupling and infrastructure recovery mechanisms common among the proxy companies?

A. 68 Yes. As Exhibit No. ___(RBH-9) demonstrates, all six companies have both decoupling and infrastructure mechanisms in place.

Q. 69 What conclusions do you draw from the analyses discussed above?

A. 69 In essence, the need to invest increasing amounts of capital in non-revenue producing assets would prevent the Company from earning a reasonable rate of return. In my view, the increasingly constructive regulatory environment in Arizona may mitigate the dilutive effect of regulatory lag if it enables the Company to recover capital investments in a more timely fashion.

Because estimating the Cost of Equity is a comparative exercise, the relevant analytical issue is whether the cost recovery mechanisms are so risk mitigating relative to mechanisms in place at the proxy companies that investors would knowingly and measurably reduce their return requirements for Southwest Gas. As discussed above, decoupling and gas infrastructure replacement mechanisms are common in the industry in general, and within the proxy group, in particular. As a result, investors have become accustomed to these mechanisms and there is no reason to assume that the Company would be seen as materially less risky than its peers as a result of either the EEP or the GIM Mechanism.

VIII. CAPITAL MARKET ENVIRONMENT

Q. 75 Do economic conditions influence the required cost of capital and required return on common equity?

A. 75 Yes. As discussed in Section VI, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected

capital market conditions. To the extent that certain ROE estimates are incompatible with such data or inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q. 76 Do you have any general observations regarding the relationship between current capital market conditions and the Company's Cost of Equity?

A. 76 Yes, I do. Much has been reported about the Federal Reserve's market intervention since 2007, and its effect on interest rates. Although the Federal Reserve completed its Quantitative Easing initiative in October 2014, it was not until December 2015 that it raised the Federal Funds rate, and began the process of rate normalization.[43] A significant issue, then, is how investors will react as that process continues, and eventually is completed. A viable outcome is that investors will perceive greater chances for economic growth, which will increase the growth rates included in the Constant Growth DCF model. At the same time, higher growth and the absence of Federal market intervention could provide the opportunity for interest rates to increase, thereby increasing the dividend yield portion of the DCF model. In that case, both terms of the Constant Growth DCF model would increase, producing higher ROE estimates.

At this time, however, market data remains somewhat disjointed. As a consequence, it is difficult to rely on a single model to estimate the Company's Cost of Equity. A more reasoned approach is to understand the relationships among Federal Reserve policies, interest rates and risk, and assess how those factors may affect different models and their results. For the reasons discussed

[43] *See* Federal Reserve Press Release (December 16, 2015).

below, the current market is one in which it is very important to consider a broad range of data and models when determining the Cost of Equity.

Q. 77 Please summarize the effect of recent Federal Reserve policies on interest rates and the cost of capital.

A. 77 Beginning in 2008, the Federal Reserve proceeded on a steady path of initiatives intended to lower long-term Treasury yields.[44] The Federal Reserve policy actions "were designed to put downward pressure on longer-term interest rates by having the Federal Reserve take onto its balance sheet some of the duration and prepayment risks that would otherwise have been borne by private investors."[45] Under that policy, "Securities held outright" on the Federal Reserve's balance sheet increased from approximately $489 billion at the beginning of October 2008 to $4.24 trillion by mid-February 2016.[46] To put that increase in context, the securities held by the Federal Reserve represented approximately 3.29 percent of GDP at the end of September 2008, and had risen to approximately 23.37 percent of GDP in February 2016.[47] As such, the Federal Reserve policy actions have represented a significant source of liquidity, and have had a substantial effect on capital markets.

Just as market intervention by the Federal Reserve has reduced interest rates, it also has had the effect of reducing market volatility. As shown in Chart 3 (below), each time the Federal Reserve began to purchase bonds (as evidenced by the increase in "Securities Held Outright" on its balance sheet),

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[44] *See* Federal Reserve Press Release (June 19, 2013).

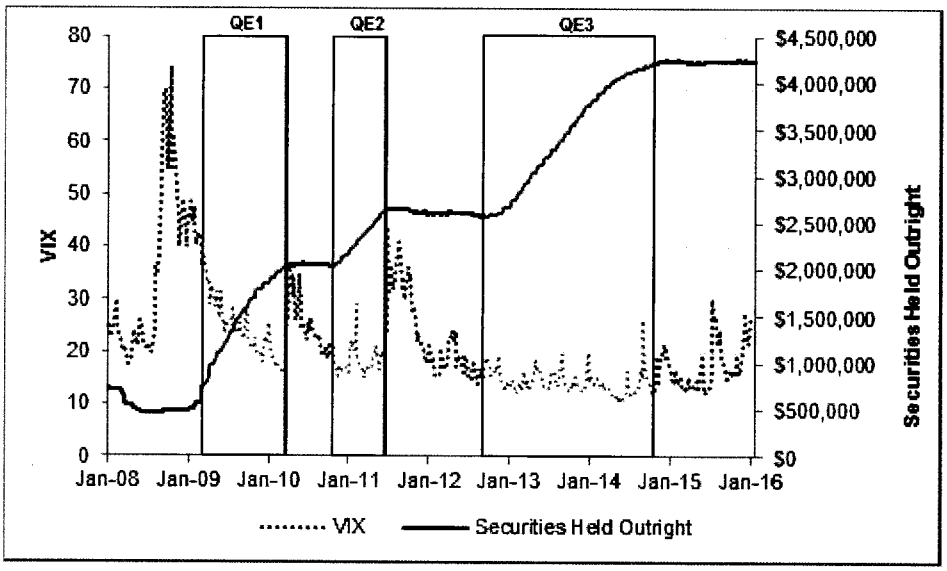
[45] Federal Reserve Bank of New York, *Domestic Open Market Operations During 2012*, April 2013, at 29.

[46] Source: Federal Reserve Board Schedule H.4.1. "Securities held outright" include U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities.

[47] Source: Federal Reserve Board Schedule H.4.1; Bureau of Economic Analysis.

volatility subsequently declined. In fact, in September 2012, when the Federal Reserve began to purchase long-term securities at a pace of $85 billion per month, volatility (as measured by the CBOE Volatility Index, known as the "VIX") fell, and through October 2014 remained in a relatively narrow range. The reason is quite straight-forward: Investors became confident that the Federal Reserve would intervene if markets were to become unstable.

Chart 3: VIX and Federal Reserve Asset Purchases[48]



The important analytical issue is whether we can infer that risk aversion among investors is at a historically low level, implying a Cost of Equity that is well below recently authorized returns. Given the negative correlation between the expansion of the Federal Reserve's balance sheet and the VIX, it is difficult to conclude that fundamental risk aversion and investor return requirements have fallen. If it were the case that investors believe that volatility will remain at low levels (that is, that market risk and uncertainty will remain low), it is not clear

[48] Source: Federal Reserve Economic Data (FRED), Federal Reserve Bank of St. Louis; Federal Reserve Statistical Release H.4.1, Factors Affecting Reserve Balances.

why they would decrease their return requirements for defensive sectors such as utilities. In that respect, it appears that the Constant Growth DCF results are at odds with market conditions.

Q. 78 Has the Federal Reserve's quantitative easing policy been associated with changes in the proxy companies' trading levels?

A. 78 Yes, that appears to be the case. From January 2000 through the end of August 2012 (that is, immediately prior to the third round of Quantitative Easing), the proxy group's average P/E ratio traded at a 10.00 percent discount to the market. From September 2012 through May 2013, when the Federal Reserve announced it would begin to taper its asset purchases, the proxy group traded at a 14.00 percent premium to the market. In fact, between September 2012 and February 12, 2016, the proxy group P/E ratio traded at a 9.00 percent premium to the market.

Q. 79 Does your recommendation also consider the interest rate environment?

A. 79 Yes. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although I appreciate that all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increased interest rates during the period in which the rates set in this proceeding will be in effect.

As to long-term interest rates, the approximately 50 economists surveyed by Blue Chip Financial Forecast see the 30-year Treasury yield as increasing to 4.00 percent by 2017 and 4.40 percent by 2018.[49] Those projections are supported by the fact that investors recently have been willing to pay nearly twice the premium for the option to sell long-term Government bonds in January 2018 (with an exercise price equal to the current price) than they have been willing to pay for the option to buy those bonds.[50] Because the prices of bonds move inversely to interest rates,[51] those option prices indicate that investors believe it is considerably more likely that interest rates will increase over the coming year, than it is likely that they will decrease. As noted in Section VI (above), all else remaining equal an increase in interest rates would increase the return required by equity holders.

Given that: (1) Federal monetary policy has begun its process of "normalization"; and (2) economists and market data indicate expectations for increasing interest rates into 2018 and beyond, I believe that an ROE in the range of 10.00 percent to 10.50 percent reflects the prevailing and expected interest rate environment.

Q. 80 What conclusions do you draw from your analyses of capital market conditions?

A. 80 From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE determination, including assessments of capital market conditions, are consistent with the conclusion itself. Although I appreciate that all analyses require an element of judgment, the application of that judgment

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[49] *See,* Blue Chip Financial Forecast, Vol. 34 No. 12, December 1, 2015, at 14.
[50] Source: http://www.nasdaq.com/symbol/tlt/option-chain?dateindex=7
[51] That is, as interest rates move up (down), bond prices move down (up).

must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, I believe that it is important to review and consider a variety of data points; doing so enables us to put in context both quantitative analyses and the associated recommendations.

IX. CONCLUSIONS AND RECOMMENDATIONS FOR THE RATE OF RETURN ON THE ORIGINAL COST RATE BASE

Q. 81 What is your conclusion regarding the company's Cost of Equity?

A. 81 I believe that a rate of return on common equity in the range of 10.00 percent to 10.50 percent represents the range of equity investors' required rate of return for investment in natural gas utilities. Within that range, I recommend an ROE of 10.25 percent. Tables 10a and 10b summarize my analytical results. In addition to the methodologies included in Tables 10a and 10b, my recommendation also takes into consideration the capital environment in which the Company operates and the Company's small size relative to the proxy companies.

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Table 10a: Summary of Constant Growth DCF Results[52]

	Mean Low	Mean	Mean High
Constant Growth DCF Results			
30-Day Average	8.39%	9.52%	11.30%
90-Day Average	8.50%	9.64%	11.41%
180-Day Average	8.66%	9.79%	11.57%
Multi-Stage DCF Results			
	Low	***Mean***	***High***
30-Day Average	9.03%	9.33%	9.82%
90-Day Average	9.16%	9.47%	9.97%
180-Day Average	9.32%	9.65%	10.18%

Table 10b: Summary of Risk Premium Results[53]

Market Risk Premium Derived By	***Bloomberg***	***Value Line***
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.79%)	9.69%	9.26%
Near Term Projected 30-Year Treasury (3.35%)	10.25%	9.83%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.79%)	10.78%	10.28%
Near Term Projected 30-Year Treasury (3.35%)	11.34%	10.85%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (2.79%)	9.98%	
Near Term Projected 30-Year Treasury (3.35%)	10.02%	
Long Term Projected 30-Year Treasury (4.65%)	10.39%	

[52] *See also*. Exhibit No.___(RBH-1) and Exhibit No.___(RBH-3). Results include estimated flotation costs.

[53] *See also*, Exhibit No.___(RBH-6) and Exhibit No.___(RBH-7).

X. FAIR VALUE RATE BASE

Q. 82 Please briefly summarize the Fair Value standard in Arizona.

A. 82 As noted in Chapparal,[54] the Arizona Constitution requires the use of a fair value rate base in establishing rates. Article 15 para. 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it- in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.

Although I am not an attorney, I understand that, as interpreted by the Arizona Court of Appeals, this paragraph requires the Commission to find the fair value of a public service corporation's property and to use that value to set just and reasonable rates.[55]

Q. 83 Are you aware of references in academic literature regarding the use of fair value to set rates?

A. 83 Yes. As Phillips states:

> There is a third measure of value, which depends upon the two discussed above: fair value. *Fair Value* is a figure somewhere between original cost and reproduction cost, arrived at by the exercise of "enlightened judgment" or by specific formula.
>
> ***
>
> With respect to the second question concerning the weighting problem, the commissions generally do not allow the full valuation estimate based upon reproduction cost or trended original cost. As

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[54] In the Matter of the Application of Chapparal City Water Company, an Arizona Corporation, for a Determination of the Current Fair Value of its Utility Plant and Property and for Increases in its Rates and Charges for Utility Service Based Thereon, Docket No. W-02113A-04-0616, Arizona Corporation Commission Decision No. 70441, July 28, 2008, at 20-21.

[55] Ibid.

a result, the final valuation figure chosen represents a compromise.[56]

Q. 84 How did the Company establish the Fair Value Rate Base?

A. 84 As is discussed in the testimony of Company witness Cunningham the Company calculated the fair value rate base ("FVRB") as the simple average of the original cost rate base ("OCRB") and the reconstruction cost new less depreciation ("RCND") of the utility system, which is estimated to be $2,288,780,072.[57] The OCRB of $1,336,049,260 is based on the Company's plant accounting records, as of 11/30/2015, (see page 1 of Exhibit No. _(RBH-10)). The resulting FVRB is $1,812,414,665.

Q. 85 Do you agree with the Company's estimate of the FVRB?

A. 85 Yes, I believe that the Company's proposed FVRB is a reasonable, if not conservative estimate of the current market value of the Company's gas distribution system assets.

XI. FAIR VALUE RATE OF RETURN

Q. 86 Does the Fair Value standard also require consideration of the fair return on the fair value of the Company's assets?

A. 86 Yes. As noted above, the Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property. In establishing the revenue requirement, the Commission would also need to establish the appropriate ROE to apply to the equity component of the FVRB.

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[56] Phillips, Charles F., The Regulation of Public Utilities, Third Edition, Public Utilities Reports, Inc., pp. 319, 339 (*emphasis included*).

[57] Prepared direct testimony of Randi L. Cunningham.

Q. 87 Have you calculated the fair value of return ("FVROR") on the FVRB?

A. 87 Yes. As shown on page 2 of Exhibit No. _(RBH-10), I estimate that FVROR to be 6.01 percent.

Q. 88 Please Explain How You Calculated the FVROR.

A. 88 As shown in Exhibit No. _(RBH-10), and in Table 11 (below), I calculated the difference between the OCRB and the Company's proposed FVRB. That this difference represents the appreciation in the value of the assets based on the current market value of the OCRB, and has been commonly referred to as the "fair value increment."[58] I then weighted the OCRB using the Company's proposed capital structure weighting, which includes the debt and equity component of the OCRB, and the appreciation in the value of the assets which, when added to the OCRB, results in the FVRB.

Q. 89 How did you apply the equity and debt costs to derive the FVROR?

A. 89 As shown in Table 11, I applied the Company's actual cost of debt to the debt component of the OCRB and my recommended ROE to the equity component of the OCRB. Consistent with Commission's decision in Decision No. 70665.[59] I applied 50.00 percent of the risk free rate of return of 1.86 percent to the market appreciation of the FVRB.

Q. 90 How did you estimate the risk free rate of return?

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[58] Arizona Corporation Commission, Decision No. 70665, at 32.

[59] Arizona Corporation Commission Decision No. 70665, In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona, December 24, 2008 at 31. In that decision, the Commission determined that the Staff's approach of applying one-half of the risk free rate to the fair value increment was appropriate.

A. 90 My estimate of the nominal risk free rate of return is the average of the short-term projected yield on 30-year Treasury bonds of 3.35 percent and the long-term projected yield on the 30-year Treasury bonds of 4.65 percent of as reported in the Blue Chip Financial Forecast. I then adjusted the nominal risk free rate of 4.00 percent by the rate of inflation, which I estimated to be 2.10 percent. The resulting real risk free rate is then 1.86 percent.[60]

Q. 91 How did you estimate the rate of inflation?

A. 91 I calculated the rate of inflation rate of 2.10 percent based on the average of two measures of inflation: the B*lue Chip Financial Forecast* estimate of the long term change in the Consumer Price Index ("CPI") for 2022 through 2026, which is 2.20 percent; and the *EIA Annual Energy Outlook* estimate of the change in CPI for the period from 2013 through 2040, of 2.00 percent.

Q. 92 What is the resulting FVROR using that approach?

A. 92 As shown on page 2 of Exhibit No.__(RBH-10), based on the calculation discussed previously, the FVROR that would be applied to the FVRB is 6.01 percent.

Table 11: Calculation of the Fair Value Rate of Return[61]

Capital	Amount	Percent	Cost Rate	Weighted Cost Rate
Long-Term Debt	$ 645,445,398	35.61%	5.21%	1.86%
Common Equity	690,603,862	38.10%	10.25%	3.91%
Capital Financing OCRB	$1,335,140,284	73.71%		5.74%
Appreciation above OCRB not recognized on utility's books	476,365,405	26.28%	0.93%	0.24%
Total	$1,812,091,361	100.00%		6.01%

[60] The real risk free rate = ((1+ nominal Treasury rate)/(inflation rate+l))-1. Please see page 2 of Exhibit No. __(RBH-10),

[61] Consistent with the methodology that the Arizona Corporation Commission determined was appropriate in Decision No. 70665, at 31. Amounts may not add due to rounding.

Q. 93 Do you believe that the FVROR is a reasonable estimate of the Company's Cost of Capital?

A. 93 The FVROR of 6.01 percent provided in Table 11 (above) is a conservative estimate of the appropriate cost of capital for Southwest Gas. Applying 50.00 percent weight to the OCRB, which is a measure of book value, and 50.00 percent to the RCND, a measure of market value, produces a conservative estimate of FVRB, which is a proxy for market value. Further, applying only 50.00 percent of the risk free rate to the appreciation in the fair value increment also is a conservative estimate of the return that would be required by investors. In my view, the combined effect of those two approaches is to produce a FVROR that is somewhat conservative.

Q. 94 Does this conclude your prepared direct testimony?

A. 94 Yes.

Robert B. Hevert, CFA
Managing Partner
Sussex Economic Advisors, LLC

Mr. Hevert is a financial and economic consultant with broad experience in the energy and utility industries. He has an extensive background in the areas of corporate finance, mergers and acquisitions, project finance, asset and business unit valuation, rate and regulatory matters, energy market assessment, and corporate strategic planning. Mr. Hevert has provided expert testimony on a wide range of financial, strategic and economic matters on over 100 occasions at both the state and federal levels.

REPRESENTATIVE PROJECT EXPERIENCE

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including: cost of capital for ratemaking purposes; the proposed transfer of power purchase agreements; procurement of residual service electric supply; the legal separation of generation assets; merger-related synergies; assessment of economic damages; and specific financing transactions. Services provided include collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises. Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last resort

obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the U.S. and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

PROFESSIONAL HISTORY

Sussex Economic Advisors, LLC (2012 – Present)
Managing Partner

Concentric Energy Advisors, Inc. (2002 – 2012)
President

Navigant Consulting, Inc. (1997 – 2001)
Managing Director (2000 – 2001)
Director (1998 – 2000)
Vice President, REED Consulting Group (1997 – 1998)

Bay State Gas Company (now Columbia Gas Company of Massachusetts) (1987 – 1997)
Vice President and Assistant Treasurer

Boston College (1986 – 1987)
Financial Analyst

General Telephone Company of the South (1984 – 1986)
Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts at Amherst, 1984
B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991
Association for Investment Management and Research
Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics, including:

- Generation Asset Valuation and the Use of Real Options
- Retail and Wholesale Market Entry Strategies
- The Use Strategic Alliances in Restructured Energy Markets
- Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
- Nuclear Asset Valuation and the Divestiture Process

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
Altalink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	Altalink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 General Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	11/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 15-098-U	Return on Equity
SourceGas Arkansas, Inc.	03/15	SourceGas Arkansas, Inc.	Docket No. 15-011-U	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	12/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Xcel Energy, Inc.	03/15	Public Service Company of Colorado	Docket No. 15AL-0135G	Return on Equity (gas)
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Public Utilities Regulatory Authority				
Connecticut Light and Power Company	06/14	Connecticut Light and Power Company	Docket No. 14-05-06	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 13-115	Return on Equity
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	03/12	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Washington Gas Light Company	02/16	Washington Gas Light Company	Formal Case No. FC1137	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Potomac Electric Power Company	03/13	Potomac Electric Power Company	Formal Case No. FC1103-2013-E	Return on Equity
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. FC1087	Return on Equity
Federal Energy Regulatory Commission				
Sabine Pipeline, LLC	09/15	Sabine Pipeline, LLC	Docket No. RP15-1322-000	Return on Equity
Nextera Energy Transmission West, LLC	07/15	Nextera Energy Transmission West, LLC	Docket No. ER15-2239-000	Return on Equity
Maritimes & Northeast Pipeline, LLC	05/15	Maritimes & Northeast Pipeline, LLC	Docket No. RP15-1026-000	Return on Equity
Public Service Company of New Mexico	12/12	Public Service Company of New Mexico	Docket No. ER13-685-000	Return on Equity
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Florida Public Service Commission				
Florida Power & Light Company	03/16	Florida Power & Light Company	Docket No. 160021-EI	Return on Equity
Tampa Electric Company	04/13	Tampa Electric Company	Docket No. 130040-EI	Return on Equity
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Hawaii Public Utilities Commission				
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318	Return on Equity
Hawaiian Electric Company	06/14	Hawaiian Electric Light Company	Docket No. 2013-0373	Return on Equity
Hawaii Electric Light Company	08/12	Hawaiian Electric Light Company	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/15	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 15-0142	Return on Equity
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	03/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Docket No. 14-0371	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/13	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 13-0192	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Duke Energy Indiana, Inc.	12/15	Duke Energy Indiana, Inc.	Cause No. 44720	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Duke Energy Indiana, Inc.	12/14	Duke Energy Indiana, Inc.	Cause No. 44526	Return on Equity
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	Assessment of Valuation Approaches
Kansas Corporation Commission				
Kansas City Power & Light Company	01/15	Kansas City Power & Light Company	Docket No. 15-KCPE-116-RTS	Return on Equity
Maine Public Utilities Commission				
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Potomac Electric Power Company	12/13	Potomac Electric Power Company	Case No. 9336	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 9317	Return on Equity
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
National Grid	11/15	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 15-155	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	06/15	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 15-80	Return on Equity
NSTAR Gas Company	12/14	NSTAR Gas Company	DPU 14-150	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Fitchburg Gas and Electric Light Company d/b/a Unitil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 13-90	Return on Equity
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	09/15	Minnesota Energy Resources Corporation	Docket No. G-011/GR-15-736	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-15-424	Return on Equity
Xcel Energy, Inc.	11/13	Northern States Power Company	Docket No. E002/GR-13-868	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/13	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-13-316	Return on Equity
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	Northern States Power Company - Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	Northern States Power Company - Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Public Service Commission				
Kansas City Power & Light Company	02/16	Kansas City Power & Light Company	Case No. ER-2016-0156	Return on Equity (electric)
Kansas City Power & Light Company	10/14	Kansas City Power & Light Company	Case No. ER-2014-0370	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	07/14	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2014-0258	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	06/14	Union Electric Company d/b/a Ameren Missouri	Case No. EC-2014-0223	Return on Equity (electric)
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	02/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Case No. GR-2014-0152	Return on Equity
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation d/b/a Northwestern Energy	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
Liberty Utilities d/b/a EnergyNorth Natural Gas	08/14	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 14-180	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Liberty Utilities d/b/a Granite State Electric Company	03/13	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 13-063	Return on Equity
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	BPU Docket No. GM15101196	Merger Approval
Pepco Holdings, Inc.	04/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Mexico Public Regulation Commission				
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 13-00390-UT	Cost of Capital and Financial Integrity
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/15	Consolidated Edison Company of New York, Inc.	Case No. 15-E-0050	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	11/14	Orange and Rockland Utilities, Inc.	Case Nos. 14-E-0493 and 14-G-0494	Return on Equity (electric and gas)
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity (electric)
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity (electric)
North Dakota Public Service Commission				
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
Duke Energy Carolinas, LLC	03/13	Duke Energy Carolinas, LLC	Docket No. 2013-59-E	Return on Equity
South Carolina Electric & Gas	06/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
Southwestern Public Service Company	02/16	Southwestern Public Service Company	Docket No. 44524	Return on Equity (electric)
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Return on Equity
Cross Texas Transmission	12/14	Cross Texas Transmission	Docket No. 43950	Return on Equity
Southwestern Public Service Company	12/14	Southwestern Public Service Company	Docket No. 43695	Return on Equity (electric)
Sharyland Utilities, L.P.	05/13	Sharyland Utilities, L.P.	Docket No. 41474	Return on Equity
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Centerpoint Energy Resources Corp. d/b/a Centerpoint Energy Entex and Centerpoint Energy Texas Gas	03/15	Centerpoint Energy Resources Corp. d/b/a Centerpoint Energy Entex and Centerpoint Energy Texas Gas	GUD 10432	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10175	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10171	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-0058; PUE-2015-0059; PUE-2015-0060; PUE-2015-0061; PUE-2015-0075; PUE-2015-0089; PUE-2015-0102; PUE-2015-0104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas Of Virginia, Inc.	06/06	Columbia Gas Of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Expert Report

United States District Court, Western District of Texas, Austin Division				
Southwestern Public Service Company	02/12	Southwestern Public Service Company	C.A. No. A-09-CA-917-SS	PURPA and FERC regulations

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Retention Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
Atmos Energy Corporation	ATO	$1.68	$65.65	2.56%	2.65%	6.60%	6.40%	7.00%	8.21%	7.05%	9.04%	9.70%	10.87%
Laclede Group, Inc. (The)	LG	$1.96	$61.14	3.21%	3.30%	4.80%	4.78%	10.00%	4.90%	6.12%	8.06%	9.42%	13.37%
New Jersey Resources Corporation	NJR	$0.96	$34.36	2.79%	2.87%	6.50%	6.50%	4.00%	5.81%	5.70%	6.85%	8.58%	9.38%
Northwest Natural Gas Company	NWN	$1.87	$51.25	3.65%	3.73%	4.00%	4.00%	7.00%	3.73%	4.68%	7.45%	8.42%	10.78%
South Jersey Industries, Inc.	SJI	$1.06	$24.21	4.36%	4.50%	NA	6.00%	7.50%	6.56%	6.69%	10.49%	11.19%	12.02%
WGL Holdings, Inc.	WGL	$1.95	$64.08	3.04%	3.14%	7.30%	8.00%	5.50%	5.11%	6.48%	8.23%	9.62%	11.16%
Proxy Group Mean				3.27%	3.37%	5.84%	5.95%	6.83%	5.72%	6.12%	8.35%	9.49%	11.26%
Proxy Group Median				3.12%	3.22%	6.50%	6.20%	7.00%	5.46%	6.30%	8.14%	9.52%	11.02%
Flotation Costs											0.03%	0.03%	0.03%
Proxy Group Mean including Flotation Costs											8.39%	9.52%	11.30%
Proxy Group Median including Flotation Costs											8.18%	9.56%	11.05%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of February 12, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Source: Exhibit No. __ (RBH-2), Value Line
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Retention Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
Atmos Energy Corporation	ATO	$1.68	$62.93	2.67%	2.76%	6.60%	6.40%	7.00%	8.21%	7.05%	9.16%	9.82%	10.99%
Laclede Group, Inc. (The)	LG	$1.96	$58.86	3.33%	3.43%	4.80%	4.78%	10.00%	4.90%	6.12%	8.19%	9.55%	13.50%
New Jersey Resources Corporation	NJR	$0.96	$31.87	3.01%	3.10%	6.50%	6.50%	4.00%	5.81%	5.70%	7.07%	8.80%	9.61%
Northwest Natural Gas Company	NWN	$1.87	$49.19	3.80%	3.89%	4.00%	4.00%	7.00%	3.73%	4.68%	7.61%	8.57%	10.93%
South Jersey Industries, Inc.	SJI	$1.06	$24.38	4.33%	4.47%	NA	6.00%	7.50%	6.56%	6.69%	10.46%	11.16%	11.99%
WGL Holdings, Inc.	WGL	$1.95	$62.07	3.14%	3.24%	7.30%	8.00%	5.50%	5.11%	6.48%	8.33%	9.72%	11.27%
Proxy Group Mean				3.38%	3.48%	5.84%	5.95%	6.83%	5.72%	6.12%	8.47%	9.60%	11.38%
Proxy Group Median				3.24%	3.34%	6.50%	6.20%	7.00%	5.46%	6.30%	8.26%	9.64%	11.13%
Flotation Costs											0.03%	0.03%	0.03%
Proxy Group Mean including Flotation Costs											8.50%	9.64%	11.41%
Proxy Group Median including Flotation Costs											8.29%	9.67%	11.16%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of February 12, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Source: Exhibit No. __ (RBH-2), Value Line
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Retention Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
Atmos Energy Corporation	ATO	$1.68	$58.64	2.86%	2.97%	6.60%	6.40%	7.00%	8.21%	7.05%	9.36%	10.02%	11.19%
Laclede Group, Inc. (The)	LG	$1.96	$55.96	3.50%	3.61%	4.80%	4.78%	10.00%	4.90%	6.12%	8.37%	9.73%	13.68%
New Jersey Resources Corporation	NJR	$0.96	$30.17	3.18%	3.27%	6.50%	6.50%	4.00%	5.81%	5.70%	7.25%	8.98%	9.79%
Northwest Natural Gas Company	NWN	$1.87	$46.50	4.02%	4.12%	4.00%	4.00%	7.00%	3.73%	4.68%	7.83%	8.80%	11.16%
South Jersey Industries, Inc.	SJI	$1.06	$24.55	4.30%	4.44%	NA	6.00%	7.50%	6.56%	6.69%	10.43%	11.13%	11.96%
WGL Holdings, Inc.	WGL	$1.95	$58.67	3.32%	3.43%	7.30%	8.00%	5.50%	5.11%	6.48%	8.51%	9.91%	11.46%
Proxy Group Mean				3.53%	3.64%	5.84%	5.95%	6.83%	5.72%	6.12%	8.62%	9.76%	11.54%
Proxy Group Median				3.41%	3.52%	6.50%	6.20%	7.00%	5.46%	6.30%	8.44%	9.82%	11.32%
Flotation Costs											0.03%	0.03%	0.03%
Proxy Group Mean including Flotation Costs											8.66%	9.79%	11.57%
Proxy Group Median including Flotation Costs											8.47%	9.85%	11.36%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of February 12, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Source: Exhibit No. __ (RBH-2), Value Line
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Retention Growth Estimate

Company	Ticker	[1] Projected Earnings per share 2018-20	[2] Projected Dividend Declared per share 2018-20	[3] Retention Ratio (B)	[4] Projected Book Value per Share 2018-20	[5] Return on Book Value (R)	[6] B x R	[7] Projected Common Shares Outstanding 2016	[8] Projected Common Shares Outstanding 2018-20	[9] Common Shares Growth Rate	[10] 2015 High Price	[11] 2015 Low Price	[12] 2015 price midpoint	[13] Projected Book Value per Share 2015	[14] Market/ Book Ratio	[15] "S"	[16] "V"	[17] S x V	[18] BR + SV
Atmos Energy Corporation	ATO	3.80	1.95	48.68%	36.65	10.37%	5.05%	107.00	120.00	3.86%	$ 63.80	$ 50.80	$ 57.30	31.50	1.82	7.01%	45.03%	3.16%	8.21%
Laclede Group, Inc. (The)	LG	4.20	2.20	47.62%	48.10	8.73%	4.16%	43.00	45.00	1.51%	$ 59.40	$ 49.10	$ 54.25	36.34	1.49	2.26%	33.01%	0.74%	4.90%
New Jersey Resources Corporation	NJR	1.95	1.00	48.72%	16.35	11.93%	5.81%	85.00	85.00	0.00%	$ 33.70	$ 26.80	$ 30.25	12.99	2.33	0.00%	57.06%	0.00%	5.81%
Northwest Natural Gas Company	NWN	3.30	2.10	36.36%	33.85	9.75%	3.55%	27.75	28.00	0.30%	$ 52.30	$ 42.00	$ 47.15	28.85	1.63	0.48%	38.81%	0.19%	3.73%
South Jersey Industries, Inc.	SJI	2.30	1.35	41.30%	18.40	12.50%	5.16%	72.00	76.00	1.80%	$ 30.40	$ 22.90	$ 26.65	15.00	1.78	3.20%	43.71%	1.40%	6.56%
WGL Holdings, Inc.	WGL	3.55	1.99	43.94%	30.55	11.62%	5.11%	50.00	50.00	0.00%	$ 63.20	$ 50.90	$ 57.05	24.97	2.28	0.00%	56.23%	0.00%	5.11%
																		Average:	5.72%

Notes:

[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.33 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Source: Value Line
[14] Equals [12] / [13]
[15] Equals [9] x [14]
[16] Equals 1 - (1 / [14])
[17] Equals [15] x [16]
[18] Equals [6] + [17]

Multi-Stage Growth Discounted Cash Flow Model
30 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	Average	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$65.65	6.60%	6.40%	7.00%	8.21%	7.05%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.15%	18.56	3.49
Laclede Group, Inc. (The)	LG	$61.14	4.80%	4.78%	10.00%	4.90%	6.12%	5.31%	56.00%	52.00%	67.67%	($0.00)	8.41%	23.03	4.34
New Jersey Resources Corporation	NJR	$34.36	6.50%	6.50%	4.00%	5.81%	5.70%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.03%	15.10	2.84
Northwest Natural Gas Company	NWN	$51.25	4.00%	4.00%	7.00%	3.73%	4.68%	5.31%	87.00%	64.00%	67.67%	($0.00)	8.52%	22.25	4.19
South Jersey Industries, Inc.	SJI	$24.21	NA	6.00%	7.50%	6.56%	6.69%	5.31%	69.00%	59.00%	67.67%	($0.00)	10.88%	12.81	2.41
WGL Holdings, Inc.	WGL	$64.08	7.30%	8.00%	5.50%	5.11%	6.48%	5.31%	60.00%	56.00%	67.67%	($0.00)	8.80%	20.43	3.84
												Mean	9.30%		
												Max	10.88%		
												Min	8.41%		

Including Flotation Costs																		
												Mean	9.33%					
												Max	10.91%					
												Min	8.44%					

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.17	$3.39	$3.63	$3.89	$4.16	$4.46	$4.76	$5.06	$5.38	$5.69	$6.01	$6.33	$6.67	$7.02	$7.40	$7.79
Laclede Group, Inc. (The)	LG	$2.35	$2.49	$2.65	$2.81	$2.98	$3.16	$3.36	$3.56	$3.77	$3.98	$4.20	$4.43	$4.67	$4.92	$5.18	$5.45	$5.74
New Jersey Resources Corporation	NJR	$2.10	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.27	$3.45	$3.63	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
Northwest Natural Gas Company	NWN	$2.16	$2.26	$2.37	$2.48	$2.59	$2.72	$2.84	$2.98	$3.12	$3.28	$3.45	$3.63	$3.82	$4.02	$4.24	$4.46	$4.70
South Jersey Industries, Inc.	SJI	$1.57	$1.67	$1.79	$1.91	$2.03	$2.17	$2.32	$2.46	$2.62	$2.78	$2.94	$3.10	$3.26	$3.44	$3.62	$3.81	$4.01
WGL Holdings, Inc.	WGL	$2.68	$2.85	$3.04	$3.24	$3.44	$3.67	$3.91	$4.15	$4.40	$4.66	$4.93	$5.20	$5.48	$5.77	$6.07	$6.40	$6.74

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual Cash Flows		[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO		$1.73	$1.85	$1.98	$2.12	$2.38	$2.65	$2.94	$3.25	$3.58	$3.93	$4.29	$4.51	$4.75	$5.01	$5.27	$144.60
Laclede Group, Inc. (The)	LG		$1.48	$1.54	$1.59	$1.64	$1.82	$2.01	$2.21	$2.43	$2.66	$2.90	$3.16	$3.33	$3.50	$3.69	$3.89	$132.23
New Jersey Resources Corporation	NJR		$1.36	$1.38	$1.40	$1.41	$1.56	$1.73	$1.90	$2.09	$2.29	$2.50	$2.73	$2.87	$3.03	$3.19	$3.36	$74.90
Northwest Natural Gas Company	NWN		$2.06	$1.97	$1.86	$1.74	$1.83	$1.94	$2.05	$2.17	$2.30	$2.44	$2.59	$2.72	$2.87	$3.02	$3.18	$104.54
South Jersey Industries, Inc.	SJI		$1.23	$1.25	$1.27	$1.28	$1.39	$1.52	$1.64	$1.77	$1.91	$2.06	$2.21	$2.33	$2.45	$2.58	$2.72	$51.40
WGL Holdings, Inc.	WGL		$1.82	$1.90	$1.97	$2.05	$2.25	$2.46	$2.69	$2.92	$3.17	$3.43	$3.71	$3.90	$4.11	$4.33	$4.56	$137.60

Projected Annual Data Investor Cash Flows		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
Company	Ticker	Initial Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($65.65)	$0.00	$1.79	$1.85	$1.98	$2.12	$2.38	$2.65	$2.94	$3.25	$3.58	$3.93	$4.29	$4.51	$4.75	$5.01	$149.87
Laclede Group, Inc. (The)	LG	($61.14)	$0.00	$1.53	$1.54	$1.59	$1.64	$1.82	$2.01	$2.21	$2.43	$2.66	$2.90	$3.16	$3.33	$3.50	$3.69	$136.12
New Jersey Resources Corporation	NJR	($34.36)	$0.00	$1.40	$1.38	$1.40	$1.41	$1.56	$1.73	$1.90	$2.09	$2.29	$2.50	$2.73	$2.87	$3.03	$3.19	$78.25
Northwest Natural Gas Company	NWN	($51.25)	$0.00	$2.11	$1.97	$1.86	$1.74	$1.83	$1.94	$2.05	$2.17	$2.30	$2.44	$2.59	$2.72	$2.87	$3.02	$107.72
South Jersey Industries, Inc.	SJI	($24.21)	$0.00	$1.27	$1.25	$1.27	$1.28	$1.39	$1.52	$1.64	$1.77	$1.91	$2.06	$2.21	$2.33	$2.45	$2.58	$54.11
WGL Holdings, Inc.	WGL	($64.08)	$0.00	$1.88	$1.90	$1.97	$2.05	$2.25	$2.46	$2.69	$2.92	$3.17	$3.43	$3.71	$3.90	$4.11	$4.33	$142.16

Multi-Stage Growth Discounted Cash Flow Model
30 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	Low Growth	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$65.65	6.60%	6.40%	7.00%	8.21%	6.40%	5.31%	51.00%	51.00%	67.67%	($0.00)	8.98%	19.45	3.66
Laclede Group, Inc. (The)	LG	$61.14	4.80%	4.78%	10.00%	4.90%	4.78%	5.31%	56.00%	52.00%	67.67%	($0.00)	8.11%	25.44	4.79
New Jersey Resources Corporation	NJR	$34.36	6.50%	6.50%	4.00%	5.81%	4.00%	5.31%	58.00%	51.00%	67.67%	($0.00)	9.49%	17.06	3.21
Northwest Natural Gas Company	NWN	$51.25	4.00%	4.00%	7.00%	3.73%	3.73%	5.31%	87.00%	64.00%	67.67%	($0.00)	8.29%	23.93	4.50
South Jersey Industries, Inc.	SJI	$24.21	NA	6.00%	7.50%	6.56%	6.00%	5.31%	69.00%	59.00%	67.67%	($0.00)	10.62%	13.44	2.53
WGL Holdings, Inc.	WGL	$64.08	7.30%	9.00%	5.50%	5.11%	5.11%	5.31%	60.00%	56.00%	67.67%	($0.00)	8.47%	22.59	4.25
												Mean	8.99%		
												Max	10.62%		
												Min	8.11%		

Including Flotation Costs
Mean 9.03%
Max 10.65%
Min 8.15%

Projected Annual
Earnings per Share

Company	Ticker	[15] 2014	[16] 2015	[17] 2016	[18] 2017	[19] 2018	[20] 2019	[21] 2020	[22] 2021	[23] 2022	[24] 2023	[25] 2024	[26] 2025	[27] 2026	[28] 2027	[29] 2028	[30] 2029	[31] 2030
Atmos Energy Corporation	ATO	$2.96	$3.15	$3.35	$3.57	$3.79	$4.04	$4.29	$4.56	$4.84	$5.12	$5.41	$5.71	$6.01	$6.33	$6.67	$7.02	$7.39
Laclede Group, Inc. (The)	LG	$2.35	$2.46	$2.58	$2.70	$2.83	$2.97	$3.11	$3.26	$3.42	$3.60	$3.78	$3.98	$4.19	$4.41	$4.65	$4.89	$5.15
New Jersey Resources Corporation	NJR	$2.10	$2.18	$2.27	$2.36	$2.46	$2.55	$2.66	$2.77	$2.89	$3.03	$3.17	$3.34	$3.51	$3.70	$3.90	$4.10	$4.32
Northwest Natural Gas Company	NWN	$2.16	$2.24	$2.32	$2.41	$2.50	$2.59	$2.69	$2.80	$2.92	$3.05	$3.20	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35
South Jersey Industries, Inc.	SJI	$1.57	$1.66	$1.76	$1.87	$1.98	$2.10	$2.23	$2.36	$2.49	$2.64	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
WGL Holdings, Inc.	WGL	$2.68	$2.82	$2.96	$3.11	$3.27	$3.44	$3.61	$3.80	$4.00	$4.20	$4.42	$4.66	$4.91	$5.17	$5.44	$5.73	$6.03

Projected Annual
Dividend Payout Ratio

Company	Ticker	[32] 2015	[33] 2016	[34] 2017	[35] 2018	[36] 2019	[37] 2020	[38] 2021	[39] 2022	[40] 2023	[41] 2024	[42] 2025	[43] 2026	[44] 2027	[45] 2028	[46] 2029	[47] 2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual
Cash Flows

Company	Ticker	[48] 2015	[49] 2016	[50] 2017	[51] 2018	[52] 2019	[53] 2020	[54] 2021	[55] 2022	[56] 2023	[57] 2024	[58] 2025	[59] 2026	[60] 2027	[61] 2028	[62] 2029	[63] 2030	[64] Terminal Value
Atmos Energy Corporation	ATO		$1.71	$1.82	$1.93	$2.06	$2.29	$2.54	$2.81	$3.10	$3.40	$3.73	$4.07	$4.28	$4.51	$4.75	$5.00	$143.81
Laclede Group, Inc. (The)	LG		$1.44	$1.48	$1.51	$1.54	$1.69	$1.84	$2.01	$2.19	$2.39	$2.60	$2.83	$2.99	$3.14	$3.31	$3.49	$131.08
New Jersey Resources Corporation	NJR		$1.32	$1.31	$1.31	$1.30	$1.42	$1.54	$1.68	$1.83	$2.00	$2.18	$2.38	$2.50	$2.64	$2.78	$2.92	$73.73
Northwest Natural Gas Company	NWN		$2.02	$1.91	$1.79	$1.66	$1.74	$1.82	$1.91	$2.02	$2.13	$2.25	$2.39	$2.52	$2.65	$2.79	$2.94	$104.06
South Jersey Industries, Inc.	SJI		$1.22	$1.23	$1.24	$1.24	$1.34	$1.45	$1.56	$1.69	$1.81	$1.95	$2.09	$2.20	$2.32	$2.44	$2.57	$51.05
WGL Holdings, Inc.	WGL		$1.78	$1.83	$1.88	$1.93	$2.08	$2.25	$2.44	$2.63	$2.85	$3.07	$3.32	$3.50	$3.68	$3.88	$4.08	$136.32

Projected Annual Data
Investor Cash Flows

Company	Ticker	[65] Initial Outflow	[66] 2/12/16	[67] 12/31/16	[68] 6/30/17	[69] 6/30/18	[70] 6/30/19	[71] 6/30/20	[72] 6/30/21	[73] 6/30/22	[74] 6/30/23	[75] 6/30/24	[76] 6/30/25	[77] 6/30/26	[78] 6/30/27	[79] 6/30/28	[80] 6/30/29	[81] 6/30/30
Atmos Energy Corporation	ATO	($65.65)	$0.00	$1.76	$1.82	$1.93	$2.06	$2.29	$2.54	$2.81	$3.10	$3.40	$3.73	$4.07	$4.28	$4.51	$4.75	$148.81
Laclede Group, Inc. (The)	LG	($61.14)	$0.00	$1.48	$1.48	$1.51	$1.54	$1.69	$1.84	$2.01	$2.19	$2.39	$2.60	$2.83	$2.99	$3.14	$3.31	$134.57
New Jersey Resources Corporation	NJR	($34.36)	$0.00	$1.34	$1.31	$1.31	$1.30	$1.42	$1.54	$1.68	$1.83	$2.00	$2.18	$2.38	$2.50	$2.64	$2.78	$76.66
Northwest Natural Gas Company	NWN	($51.25)	$0.00	$2.06	$1.91	$1.79	$1.66	$1.74	$1.82	$1.91	$2.02	$2.13	$2.25	$2.39	$2.52	$2.65	$2.79	$107.00
South Jersey Industries, Inc.	SJI	($24.21)	$0.00	$1.25	$1.23	$1.24	$1.24	$1.34	$1.45	$1.56	$1.69	$1.81	$1.95	$2.09	$2.20	$2.32	$2.44	$53.62
WGL Holdings, Inc.	WGL	($64.08)	$0.00	$1.82	$1.83	$1.88	$1.93	$2.08	$2.25	$2.44	$2.63	$2.85	$3.07	$3.32	$3.50	$3.68	$3.88	$140.40

Multi-Stage Growth Discounted Cash Flow Model
30 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	High Growth	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$65.65	6.60%	6.40%	7.00%	8.21%	8.21%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.48%	17.12	3.22
Laclede Group, Inc. (The)	LG	$61.14	4.80%	4.78%	10.00%	4.90%	10.00%	5.31%	56.00%	52.00%	67.67%	($0.00)	9.39%	17.50	3.29
New Jersey Resources Corporation	NJR	$34.36	6.50%	6.50%	4.00%	5.81%	6.50%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.30%	14.28	2.69
Northwest Natural Gas Company	NWN	$51.25	4.00%	4.00%	7.00%	3.73%	7.00%	5.31%	87.00%	64.00%	67.67%	($0.00)	9.12%	18.72	3.52
South Jersey Industries, Inc.	SJI	$24.21	NA	6.00%	7.50%	6.56%	7.50%	5.31%	69.00%	59.00%	67.67%	($0.00)	11.20%	12.11	2.28
WGL Holdings, Inc.	WGL	$64.08	7.30%	8.00%	5.50%	5.11%	8.00%	5.31%	60.00%	56.00%	67.67%	($0.00)	9.20%	18.31	3.45
												Mean	9.78%		
												Max	11.20%		
												Min	9.12%		

Including Flotation Costs

Mean	9.82%
Max	11.23%
Min	9.15%

Projected Annual
Earnings per Share

		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.20	$3.47	$3.75	$4.06	$4.39	$4.75	$5.12	$5.49	$5.86	$6.23	$6.59	$6.94	$7.31	$7.70	$8.10	$8.54
Laclede Group, Inc. (The)	LG	$2.35	$2.59	$2.84	$3.13	$3.44	$3.78	$4.16	$4.55	$4.93	$5.31	$5.67	$6.02	$6.34	$6.68	$7.03	$7.40	$7.80
New Jersey Resources Corporation	NJR	$2.10	$2.24	$2.38	$2.54	$2.70	$2.88	$3.06	$3.26	$3.46	$3.66	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$5.29
Northwest Natural Gas Company	NWN	$2.16	$2.31	$2.47	$2.65	$2.83	$3.03	$3.24	$3.46	$3.68	$3.91	$4.14	$4.37	$4.60	$4.85	$5.10	$5.38	$5.66
South Jersey Industries, Inc.	SJI	$1.57	$1.69	$1.81	$1.95	$2.10	$2.25	$2.42	$2.60	$2.77	$2.95	$3.13	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28
WGL Holdings, Inc.	WGL	$2.68	$2.89	$3.13	$3.38	$3.65	$3.94	$4.25	$4.57	$4.90	$5.23	$5.55	$5.87	$6.18	$6.51	$6.86	$7.22	$7.60

Projected Annual
Dividend Payout Ratio

		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual
Cash Flows

		[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO		$1.77	$1.91	$2.07	$2.24	$2.54	$2.85	$3.19	$3.55	$3.92	$4.30	$4.70	$4.94	$5.21	$5.48	$5.78	$146.11
Laclede Group, Inc. (The)	LG		$1.59	$1.71	$1.84	$1.97	$2.26	$2.57	$2.90	$3.24	$3.58	$3.94	$4.29	$4.52	$4.76	$5.01	$5.28	$136.42
New Jersey Resources Corporation	NJR		$1.38	$1.41	$1.44	$1.47	$1.64	$1.82	$2.01	$2.22	$2.43	$2.67	$2.91	$3.06	$3.23	$3.40	$3.58	$75.50
Northwest Natural Gas Company	NWN		$2.15	$2.10	$2.03	$1.94	$2.09	$2.25	$2.41	$2.58	$2.76	$2.93	$3.11	$3.28	$3.45	$3.64	$3.83	$105.96
South Jersey Industries, Inc.	SJI		$1.25	$1.28	$1.31	$1.33	$1.46	$1.60	$1.74	$1.89	$2.04	$2.20	$2.36	$2.48	$2.61	$2.75	$2.90	$51.83
WGL Holdings, Inc.	WGL		$1.88	$1.98	$2.09	$2.21	$2.45	$2.71	$2.99	$3.27	$3.57	$3.87	$4.18	$4.40	$4.64	$4.89	$5.14	$139.23

Projected Annual Data
Investor Cash Flows

		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
Company	Ticker	Initial Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($65.65)	$0.00	$1.84	$1.91	$2.07	$2.24	$2.54	$2.85	$3.19	$3.55	$3.92	$4.30	$4.70	$4.94	$5.21	$5.48	$151.89
Laclede Group, Inc. (The)	LG	($61.14)	$0.00	$1.67	$1.71	$1.84	$1.97	$2.26	$2.57	$2.90	$3.24	$3.58	$3.94	$4.29	$4.52	$4.76	$5.01	$141.69
New Jersey Resources Corporation	NJR	($34.36)	$0.00	$1.43	$1.41	$1.44	$1.47	$1.64	$1.82	$2.01	$2.22	$2.43	$2.67	$2.91	$3.06	$3.23	$3.40	$79.08
Northwest Natural Gas Company	NWN	($51.25)	$0.00	$2.23	$2.10	$2.03	$1.94	$2.09	$2.25	$2.41	$2.58	$2.76	$2.93	$3.11	$3.28	$3.45	$3.64	$109.79
South Jersey Industries, Inc.	SJI	($24.21)	$0.00	$1.30	$1.28	$1.31	$1.33	$1.46	$1.60	$1.74	$1.89	$2.04	$2.20	$2.36	$2.48	$2.61	$2.75	$54.73
WGL Holdings, Inc.	WGL	($64.08)	$0.00	$1.95	$1.98	$2.09	$2.21	$2.45	$2.71	$2.99	$3.27	$3.57	$3.87	$4.18	$4.40	$4.64	$4.89	$144.37

Multi-Stage Growth Discounted Cash Flow Model
90 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	Average	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$62.93	6.60%	6.40%	7.00%	8.21%	7.05%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.31%	17.82	3.35
Laclede Group, Inc. (The)	LG	$58.86	4.80%	4.78%	10.00%	4.90%	6.12%	5.31%	56.00%	52.00%	67.67%	($0.00)	8.52%	22.19	4.18
New Jersey Resources Corporation	NJR	$31.87	6.50%	6.50%	4.00%	5.81%	5.70%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.39%	14.03	2.64
Northwest Natural Gas Company	NWN	$49.19	4.00%	4.00%	7.00%	3.73%	4.68%	5.31%	87.00%	64.00%	67.67%	($0.00)	8.66%	21.32	4.01
South Jersey Industries, Inc.	SJI	$24.38	NA	6.00%	7.50%	6.56%	6.69%	5.31%	69.00%	59.00%	67.67%	($0.00)	10.84%	12.90	2.43
WGL Holdings, Inc.	WGL	$62.07	7.30%	8.00%	5.50%	5.11%	6.48%	5.31%	60.00%	56.00%	67.67%	($0.00)	8.91%	19.80	3.73
												Mean	9.44%		
												Max	10.84%		
												Min	8.52%		

Including Flotation Costs

Mean	9.47%
Max	10.87%
Min	8.56%

Projected Annual
Earnings per Share

		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.17	$3.39	$3.63	$3.89	$4.16	$4.46	$4.76	$5.06	$5.38	$5.69	$6.01	$6.33	$6.67	$7.02	$7.40	$7.79
Laclede Group, Inc. (The)	LG	$2.35	$2.49	$2.65	$2.81	$2.98	$3.16	$3.36	$3.56	$3.77	$3.98	$4.20	$4.43	$4.67	$4.92	$5.18	$5.45	$5.74
New Jersey Resources Corporation	NJR	$2.10	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.27	$3.45	$3.63	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
Northwest Natural Gas Company	NWN	$2.16	$2.26	$2.37	$2.48	$2.59	$2.72	$2.84	$2.98	$3.12	$3.28	$3.45	$3.63	$3.82	$4.02	$4.24	$4.46	$4.70
South Jersey Industries, Inc.	SJI	$1.57	$1.67	$1.79	$1.91	$2.03	$2.17	$2.32	$2.46	$2.62	$2.78	$2.94	$3.10	$3.26	$3.44	$3.62	$3.81	$4.01
WGL Holdings, Inc.	WGL	$2.68	$2.85	$3.04	$3.24	$3.44	$3.67	$3.91	$4.15	$4.40	$4.66	$4.93	$5.20	$5.48	$5.77	$6.07	$6.40	$6.74

Projected Annual
Dividend Payout Ratio

			[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO			51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG			56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR			58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN			87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI			69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL			60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual
Cash Flows

			[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO			$1.73	$1.85	$1.98	$2.12	$2.38	$2.65	$2.94	$3.25	$3.58	$3.93	$4.29	$4.51	$4.75	$5.01	$5.27	$138.83
Laclede Group, Inc. (The)	LG			$1.48	$1.54	$1.59	$1.64	$1.82	$2.01	$2.21	$2.43	$2.66	$2.90	$3.16	$3.33	$3.50	$3.69	$3.89	$127.41
New Jersey Resources Corporation	NJR			$1.36	$1.38	$1.40	$1.41	$1.56	$1.73	$1.90	$2.09	$2.29	$2.50	$2.73	$2.87	$3.03	$3.19	$3.36	$69.61
Northwest Natural Gas Company	NWN			$2.06	$1.97	$1.86	$1.74	$1.83	$1.94	$2.05	$2.17	$2.30	$2.44	$2.59	$2.72	$2.87	$3.02	$3.18	$100.20
South Jersey Industries, Inc.	SJI			$1.23	$1.25	$1.27	$1.28	$1.39	$1.52	$1.64	$1.77	$1.91	$2.06	$2.21	$2.33	$2.45	$2.58	$2.72	$51.76
WGL Holdings, Inc.	WGL			$1.82	$1.90	$1.97	$2.05	$2.25	$2.46	$2.69	$2.92	$3.17	$3.43	$3.71	$3.90	$4.11	$4.33	$4.56	$133.35

Projected Annual Data
Investor Cash Flows

		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
		Initial																
Company	Ticker	Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($62.93)	$0.00	$1.79	$1.85	$1.98	$2.12	$2.38	$2.65	$2.94	$3.25	$3.58	$3.93	$4.29	$4.51	$4.75	$5.01	$144.10
Laclede Group, Inc. (The)	LG	($58.86)	$0.00	$1.53	$1.54	$1.59	$1.64	$1.82	$2.01	$2.21	$2.43	$2.66	$2.90	$3.16	$3.33	$3.50	$3.69	$131.30
New Jersey Resources Corporation	NJR	($31.87)	$0.00	$1.40	$1.38	$1.40	$1.41	$1.56	$1.73	$1.90	$2.09	$2.29	$2.50	$2.73	$2.87	$3.03	$3.19	$72.96
Northwest Natural Gas Company	NWN	($49.19)	$0.00	$2.11	$1.97	$1.86	$1.74	$1.83	$1.94	$2.05	$2.17	$2.30	$2.44	$2.59	$2.72	$2.87	$3.02	$103.38
South Jersey Industries, Inc.	SJI	($24.38)	$0.00	$1.27	$1.25	$1.27	$1.28	$1.39	$1.52	$1.64	$1.77	$1.91	$2.06	$2.21	$2.33	$2.45	$2.58	$54.47
WGL Holdings, Inc.	WGL	($62.07)	$0.00	$1.88	$1.90	$1.97	$2.05	$2.25	$2.46	$2.69	$2.92	$3.17	$3.43	$3.71	$3.90	$4.11	$4.33	$137.91

Multi-Stage Growth Discounted Cash Flow Model
90 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	Low Growth	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$62.93	6.60%	6.40%	7.00%	8.21%	6.40%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.13%	18.67	3.51
Laclede Group, Inc. (The)	LG	$58.86	4.80%	4.78%	10.00%	4.90%	4.78%	5.31%	56.00%	52.00%	67.67%	($0.00)	8.22%	24.50	4.61
New Jersey Resources Corporation	NJR	$31.87	6.50%	6.50%	4.00%	5.81%	4.00%	5.31%	58.00%	51.00%	67.67%	($0.00)	9.81%	15.84	2.98
Northwest Natural Gas Company	NWN	$49.19	4.00%	4.00%	7.00%	3.73%	3.73%	5.31%	87.00%	64.00%	67.67%	($0.00)	8.42%	22.93	4.32
South Jersey Industries, Inc.	SJI	$24.38	NA	6.00%	7.50%	6.56%	6.00%	5.31%	69.00%	59.00%	67.67%	($0.00)	10.58%	13.53	2.55
WGL Holdings, Inc.	WGL	$62.07	7.30%	8.00%	5.50%	5.11%	5.11%	5.31%	60.00%	56.00%	67.67%	($0.00)	8.57%	21.89	4.12
												Mean	9.12%		
												Max	10.58%		
												Min	8.22%		

Including Flotation Costs	
Mean	9.16%
Max	10.61%
Min	8.26%

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.15	$3.35	$3.57	$3.79	$4.04	$4.29	$4.56	$4.84	$5.12	$5.41	$5.71	$6.01	$6.33	$6.67	$7.02	$7.39
Laclede Group, Inc. (The)	LG	$2.35	$2.46	$2.58	$2.70	$2.83	$2.97	$3.11	$3.26	$3.42	$3.60	$3.78	$3.98	$4.19	$4.41	$4.65	$4.89	$5.15
New Jersey Resources Corporation	NJR	$2.10	$2.18	$2.27	$2.36	$2.46	$2.55	$2.66	$2.77	$2.89	$3.03	$3.17	$3.34	$3.51	$3.70	$3.90	$4.10	$4.32
Northwest Natural Gas Company	NWN	$2.16	$2.24	$2.32	$2.41	$2.50	$2.59	$2.69	$2.80	$2.92	$3.05	$3.20	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35
South Jersey Industries, Inc.	SJI	$1.57	$1.66	$1.76	$1.87	$1.98	$2.10	$2.23	$2.36	$2.49	$2.64	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
WGL Holdings, Inc.	WGL	$2.68	$2.82	$2.96	$3.11	$3.27	$3.44	$3.61	$3.80	$4.00	$4.20	$4.42	$4.66	$4.91	$5.17	$5.44	$5.73	$6.03

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual Cash Flows		[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO		$1.71	$1.82	$1.93	$2.06	$2.29	$2.54	$2.81	$3.10	$3.40	$3.73	$4.07	$4.28	$4.51	$4.75	$5.00	$138.04
Laclede Group, Inc. (The)	LG		$1.44	$1.48	$1.51	$1.54	$1.69	$1.84	$2.01	$2.19	$2.39	$2.60	$2.83	$2.99	$3.14	$3.31	$3.49	$126.26
New Jersey Resources Corporation	NJR		$1.32	$1.31	$1.31	$1.30	$1.42	$1.54	$1.68	$1.83	$2.00	$2.18	$2.38	$2.50	$2.64	$2.78	$2.92	$68.46
Northwest Natural Gas Company	NWN		$2.02	$1.91	$1.79	$1.66	$1.74	$1.82	$1.91	$2.02	$2.13	$2.25	$2.39	$2.52	$2.65	$2.79	$2.94	$99.72
South Jersey Industries, Inc.	SJI		$1.22	$1.23	$1.24	$1.24	$1.34	$1.45	$1.56	$1.69	$1.81	$1.95	$2.09	$2.20	$2.32	$2.44	$2.57	$51.41
WGL Holdings, Inc.	WGL		$1.78	$1.83	$1.88	$1.93	$2.08	$2.25	$2.44	$2.63	$2.85	$3.07	$3.32	$3.50	$3.68	$3.88	$4.08	$132.08

Projected Annual Data Investor Cash Flows		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
Company	Ticker	Initial Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($62.93)	$0.00	$1.76	$1.82	$1.93	$2.06	$2.29	$2.54	$2.81	$3.10	$3.40	$3.73	$4.07	$4.28	$4.51	$4.75	$143.04
Laclede Group, Inc. (The)	LG	($58.86)	$0.00	$1.48	$1.48	$1.51	$1.54	$1.69	$1.84	$2.01	$2.19	$2.39	$2.60	$2.83	$2.99	$3.14	$3.31	$129.75
New Jersey Resources Corporation	NJR	($31.87)	$0.00	$1.34	$1.31	$1.31	$1.30	$1.42	$1.54	$1.68	$1.83	$2.00	$2.18	$2.38	$2.50	$2.64	$2.78	$71.38
Northwest Natural Gas Company	NWN	($49.19)	$0.00	$2.06	$1.91	$1.79	$1.66	$1.74	$1.82	$1.91	$2.02	$2.13	$2.25	$2.39	$2.52	$2.65	$2.79	$102.66
South Jersey Industries, Inc.	SJI	($24.38)	$0.00	$1.25	$1.23	$1.24	$1.24	$1.34	$1.45	$1.56	$1.69	$1.81	$1.95	$2.09	$2.20	$2.32	$2.44	$53.98
WGL Holdings, Inc.	WGL	($62.07)	$0.00	$1.82	$1.83	$1.88	$1.93	$2.08	$2.25	$2.44	$2.63	$2.85	$3.07	$3.32	$3.50	$3.68	$3.88	$136.16

Multi-Stage Growth Discounted Cash Flow Model
90 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	High Growth	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$62.93	6.60%	6.40%	7.00%	8.21%	8.21%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.65%	16.44	3.09
Laclede Group, Inc. (The)	LG	$58.86	4.80%	4.78%	10.00%	4.90%	10.00%	5.31%	56.00%	52.00%	67.67%	($0.00)	9.54%	16.87	3.18
New Jersey Resources Corporation	NJR	$31.87	6.50%	6.50%	4.00%	5.81%	6.50%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.68%	13.27	2.50
Northwest Natural Gas Company	NWN	$49.19	4.00%	4.00%	7.00%	3.73%	7.00%	5.31%	87.00%	64.00%	67.67%	($0.00)	9.28%	17.95	3.38
South Jersey Industries, Inc.	SJI	$24.38	NA	6.00%	7.50%	6.56%	7.50%	5.31%	69.00%	59.00%	67.67%	($0.00)	11.16%	12.19	2.29
WGL Holdings, Inc.	WGL	$62.07	7.30%	8.00%	5.50%	5.11%	8.00%	5.31%	60.00%	56.00%	67.67%	($0.00)	9.33%	17.75	3.34
												Mean	9.94%		
												Max	11.16%		
												Min	9.28%		

Including Flotation Costs	
Mean	9.97%
Max	11.19%
Min	9.32%

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.20	$3.47	$3.75	$4.06	$4.39	$4.75	$5.12	$5.49	$5.86	$6.23	$6.59	$6.94	$7.31	$7.70	$8.10	$8.54
Laclede Group, Inc. (The)	LG	$2.35	$2.59	$2.84	$3.13	$3.44	$3.78	$4.16	$4.55	$4.93	$5.31	$5.67	$6.02	$6.34	$6.68	$7.03	$7.40	$7.80
New Jersey Resources Corporation	NJR	$2.10	$2.24	$2.38	$2.54	$2.70	$2.88	$3.06	$3.26	$3.46	$3.66	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$5.29
Northwest Natural Gas Company	NWN	$2.16	$2.31	$2.47	$2.65	$2.83	$3.03	$3.24	$3.46	$3.68	$3.91	$4.14	$4.37	$4.60	$4.85	$5.10	$5.38	$5.66
South Jersey Industries, Inc.	SJI	$1.57	$1.69	$1.81	$1.95	$2.10	$2.25	$2.42	$2.60	$2.77	$2.95	$3.13	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28
WGL Holdings, Inc.	WGL	$2.68	$2.89	$3.13	$3.38	$3.65	$3.94	$4.25	$4.57	$4.90	$5.23	$5.55	$5.87	$6.18	$6.51	$6.86	$7.22	$7.60

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual Cash Flows		[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO		$1.77	$1.91	$2.07	$2.24	$2.54	$2.85	$3.19	$3.55	$3.92	$4.30	$4.70	$4.94	$5.21	$5.48	$5.78	$140.33
Laclede Group, Inc. (The)	LG		$1.59	$1.71	$1.84	$1.97	$2.26	$2.57	$2.90	$3.24	$3.58	$3.94	$4.29	$4.52	$4.76	$5.01	$5.28	$131.57
New Jersey Resources Corporation	NJR		$1.38	$1.41	$1.44	$1.47	$1.84	$1.82	$2.01	$2.22	$2.43	$2.67	$2.91	$3.06	$3.23	$3.40	$3.58	$70.20
Northwest Natural Gas Company	NWN		$2.15	$2.10	$2.03	$1.94	$2.09	$2.25	$2.41	$2.58	$2.76	$2.93	$3.11	$3.28	$3.45	$3.64	$3.83	$101.61
South Jersey Industries, Inc.	SJI		$1.25	$1.28	$1.31	$1.33	$1.46	$1.60	$1.74	$1.89	$2.04	$2.20	$2.36	$2.48	$2.61	$2.75	$2.90	$52.19
WGL Holdings, Inc.	WGL		$1.88	$1.98	$2.09	$2.21	$2.45	$2.71	$2.99	$3.27	$3.57	$3.87	$4.18	$4.40	$4.64	$4.89	$5.14	$134.97

Projected Annual Data Investor Cash Flows		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
Company	Ticker	Initial Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($62.93)	$0.00	$1.84	$1.91	$2.07	$2.24	$2.54	$2.85	$3.19	$3.55	$3.92	$4.30	$4.70	$4.94	$5.21	$5.48	$146.10
Laclede Group, Inc. (The)	LG	($58.86)	$0.00	$1.67	$1.71	$1.84	$1.97	$2.26	$2.57	$2.90	$3.24	$3.58	$3.94	$4.29	$4.52	$4.76	$5.01	$136.85
New Jersey Resources Corporation	NJR	($31.87)	$0.00	$1.43	$1.41	$1.44	$1.47	$1.64	$1.82	$2.01	$2.22	$2.43	$2.67	$2.91	$3.06	$3.23	$3.40	$73.78
Northwest Natural Gas Company	NWN	($49.19)	$0.00	$2.23	$2.10	$2.03	$1.94	$2.09	$2.25	$2.41	$2.58	$2.76	$2.93	$3.11	$3.28	$3.45	$3.64	$105.44
South Jersey Industries, Inc.	SJI	($24.38)	$0.00	$1.30	$1.28	$1.31	$1.33	$1.46	$1.60	$1.74	$1.89	$2.04	$2.20	$2.36	$2.48	$2.61	$2.75	$55.09
WGL Holdings, Inc.	WGL	($62.07)	$0.00	$1.95	$1.98	$2.09	$2.21	$2.45	$2.71	$2.99	$3.27	$3.57	$3.87	$4.18	$4.40	$4.64	$4.89	$140.12

Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term		Payout Ratio		Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	Average	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$58.64	6.60%	6.40%	7.00%	8.21%	7.05%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.59%	16.65	3.13
Laclede Group, Inc. (The)	LG	$55.96	4.80%	4.78%	10.00%	4.90%	6.12%	5.31%	56.00%	52.00%	67.67%	($0.00)	8.69%	21.12	3.98
New Jersey Resources Corporation	NJR	$30.17	6.50%	6.50%	4.00%	5.81%	5.70%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.67%	13.30	2.50
Northwest Natural Gas Company	NWN	$46.50	4.00%	4.00%	7.00%	3.73%	4.68%	5.31%	87.00%	64.00%	67.67%	($0.00)	8.85%	20.12	3.79
South Jersey Industries, Inc.	SJI	$24.55	NA	6.00%	7.50%	6.56%	6.69%	5.31%	69.00%	59.00%	67.67%	($0.00)	10.80%	12.99	2.44
WGL Holdings, Inc.	WGL	$58.67	7.30%	8.00%	5.50%	5.11%	6.48%	5.31%	60.00%	56.00%	67.67%	($0.00)	9.12%	18.73	3.53
												Mean	9.62%		
												Max	10.80%		
												Min	8.69%		

Including Flotation Costs
Mean 9.65%
Max 10.83%
Min 8.72%

Projected Annual
Earnings per Share

Company	Ticker	[15] 2014	[16] 2015	[17] 2016	[18] 2017	[19] 2018	[20] 2019	[21] 2020	[22] 2021	[23] 2022	[24] 2023	[25] 2024	[26] 2025	[27] 2026	[28] 2027	[29] 2028	[30] 2029	[31] 2030
Atmos Energy Corporation	ATO	$2.96	$3.17	$3.39	$3.63	$3.89	$4.16	$4.46	$4.76	$5.06	$5.38	$5.69	$6.01	$6.33	$6.67	$7.02	$7.40	$7.79
Laclede Group, Inc. (The)	LG	$2.35	$2.49	$2.65	$2.81	$2.98	$3.16	$3.36	$3.56	$3.77	$3.98	$4.20	$4.43	$4.67	$4.92	$5.18	$5.45	$5.74
New Jersey Resources Corporation	NJR	$2.10	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.27	$3.45	$3.63	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
Northwest Natural Gas Company	NWN	$2.16	$2.26	$2.37	$2.48	$2.59	$2.72	$2.84	$2.98	$3.12	$3.28	$3.45	$3.63	$3.82	$4.02	$4.24	$4.46	$4.70
South Jersey Industries, Inc.	SJI	$1.57	$1.67	$1.79	$1.91	$2.03	$2.17	$2.32	$2.46	$2.62	$2.78	$2.94	$3.10	$3.26	$3.44	$3.62	$3.81	$4.01
WGL Holdings, Inc.	WGL	$2.68	$2.85	$3.04	$3.24	$3.44	$3.67	$3.91	$4.15	$4.40	$4.66	$4.93	$5.20	$5.48	$5.77	$6.07	$6.40	$6.74

Projected Annual
Dividend Payout Ratio

Company	Ticker	[32] 2015	[33] 2016	[34] 2017	[35] 2018	[36] 2019	[37] 2020	[38] 2021	[39] 2022	[40] 2023	[41] 2024	[42] 2025	[43] 2026	[44] 2027	[45] 2028	[46] 2029	[47] 2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual
Cash Flows

Company	Ticker	[48] 2015	[49] 2016	[50] 2017	[51] 2018	[52] 2019	[53] 2020	[54] 2021	[55] 2022	[56] 2023	[57] 2024	[58] 2025	[59] 2026	[60] 2027	[61] 2028	[62] 2029	[63] 2030	[64] Terminal Value
Atmos Energy Corporation	ATO		$1.73	$1.85	$1.98	$2.12	$2.38	$2.65	$2.94	$3.25	$3.58	$3.93	$4.29	$4.51	$4.75	$5.01	$5.27	$129.72
Laclede Group, Inc. (The)	LG		$1.48	$1.54	$1.59	$1.64	$1.82	$2.01	$2.21	$2.43	$2.66	$2.90	$3.16	$3.33	$3.50	$3.69	$3.89	$121.26
New Jersey Resources Corporation	NJR		$1.36	$1.38	$1.40	$1.41	$1.56	$1.73	$1.90	$2.09	$2.29	$2.50	$2.73	$2.87	$3.03	$3.19	$3.36	$65.99
Northwest Natural Gas Company	NWN		$2.06	$1.97	$1.86	$1.74	$1.83	$1.94	$2.05	$2.17	$2.30	$2.44	$2.59	$2.72	$2.87	$3.02	$3.18	$94.55
South Jersey Industries, Inc.	SJI		$1.23	$1.25	$1.27	$1.28	$1.39	$1.52	$1.64	$1.77	$1.91	$2.06	$2.21	$2.33	$2.45	$2.58	$2.72	$52.12
WGL Holdings, Inc.	WGL		$1.82	$1.90	$1.97	$2.05	$2.25	$2.46	$2.69	$2.92	$3.17	$3.43	$3.71	$3.90	$4.11	$4.33	$4.56	$126.17

Projected Annual Data
Investor Cash Flows

Company	Ticker	[65] Initial Outflow	[66] 2/12/16	[67] 12/31/16	[68] 6/30/17	[69] 6/30/18	[70] 6/30/19	[71] 6/30/20	[72] 6/30/21	[73] 6/30/22	[74] 6/30/23	[75] 6/30/24	[76] 6/30/25	[77] 6/30/26	[78] 6/30/27	[79] 6/30/28	[80] 6/30/29	[81] 6/30/30
Atmos Energy Corporation	ATO	($58.64)	$0.00	$1.79	$1.85	$1.98	$2.12	$2.38	$2.65	$2.94	$3.25	$3.58	$3.93	$4.29	$4.51	$4.75	$5.01	$134.99
Laclede Group, Inc. (The)	LG	($55.96)	$0.00	$1.53	$1.54	$1.59	$1.64	$1.82	$2.01	$2.21	$2.43	$2.66	$2.90	$3.16	$3.33	$3.50	$3.69	$125.15
New Jersey Resources Corporation	NJR	($30.17)	$0.00	$1.40	$1.38	$1.40	$1.41	$1.56	$1.73	$1.90	$2.09	$2.29	$2.50	$2.73	$2.87	$3.03	$3.19	$69.35
Northwest Natural Gas Company	NWN	($46.50)	$0.00	$2.11	$1.97	$1.86	$1.74	$1.83	$1.94	$2.05	$2.17	$2.30	$2.44	$2.59	$2.72	$2.87	$3.02	$97.73
South Jersey Industries, Inc.	SJI	($24.55)	$0.00	$1.27	$1.25	$1.27	$1.28	$1.39	$1.52	$1.64	$1.77	$1.91	$2.06	$2.21	$2.33	$2.45	$2.58	$54.84
WGL Holdings, Inc.	WGL	($58.67)	$0.00	$1.88	$1.90	$1.97	$2.05	$2.25	$2.46	$2.69	$2.92	$3.17	$3.43	$3.71	$3.90	$4.11	$4.33	$130.73

Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
Low EPS Growth Rate Estimate In First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	Low Growth	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$58.64	6.60%	6.40%	7.00%	8.21%	6.40%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.40%	17.44	3.28
Laclede Group, Inc. (The)	LG	$55.96	4.80%	4.78%	10.00%	4.90%	4.78%	5.31%	56.00%	52.00%	67.67%	($0.00)	8.37%	23.31	4.39
New Jersey Resources Corporation	NJR	$30.17	6.50%	6.50%	4.00%	5.81%	4.00%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.06%	15.01	2.82
Northwest Natural Gas Company	NWN	$46.50	4.00%	4.00%	7.00%	3.73%	3.73%	5.31%	67.00%	64.00%	67.67%	($0.00)	8.61%	21.63	4.07
South Jersey Industries, Inc.	SJI	$24.55	NA	6.00%	7.50%	6.56%	6.00%	5.31%	69.00%	59.00%	67.67%	($0.00)	10.54%	13.63	2.57
WGL Holdings, Inc.	WGL	$58.67	7.30%	8.00%	5.50%	5.11%	5.11%	5.31%	60.00%	56.00%	67.67%	($0.00)	8.76%	20.70	3.90
												Mean	9.29%		
												Max	10.54%		
												Min	8.37%		

Including Flotation Costs	
Mean	9.32%
Max	10.58%
Min	8.40%

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.15	$3.35	$3.57	$3.79	$4.04	$4.29	$4.56	$4.84	$5.12	$5.41	$5.71	$6.01	$6.33	$6.67	$7.02	$7.39
Laclede Group, Inc. (The)	LG	$2.35	$2.46	$2.58	$2.70	$2.83	$2.97	$3.11	$3.26	$3.42	$3.60	$3.78	$3.98	$4.19	$4.41	$4.65	$4.89	$5.15
New Jersey Resources Corporation	NJR	$2.10	$2.18	$2.27	$2.36	$2.46	$2.55	$2.66	$2.77	$2.89	$3.03	$3.17	$3.34	$3.51	$3.70	$3.90	$4.10	$4.32
Northwest Natural Gas Company	NWN	$2.16	$2.24	$2.32	$2.41	$2.50	$2.59	$2.69	$2.80	$2.92	$3.05	$3.20	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35
South Jersey Industries, Inc.	SJI	$1.57	$1.66	$1.76	$1.87	$1.98	$2.10	$2.23	$2.36	$2.49	$2.64	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
WGL Holdings, Inc.	WGL	$2.68	$2.82	$2.96	$3.11	$3.27	$3.44	$3.61	$3.80	$4.00	$4.20	$4.42	$4.66	$4.91	$5.17	$5.44	$5.73	$6.03

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual Cash Flows		[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO		$1.71	$1.82	$1.93	$2.06	$2.29	$2.54	$2.81	$3.10	$3.40	$3.73	$4.07	$4.28	$4.51	$4.75	$5.00	$128.95
Laclede Group, Inc. (The)	LG		$1.44	$1.48	$1.51	$1.54	$1.69	$1.84	$2.01	$2.19	$2.39	$2.60	$2.83	$2.99	$3.14	$3.31	$3.49	$120.12
New Jersey Resources Corporation	NJR		$1.32	$1.31	$1.31	$1.30	$1.42	$1.54	$1.68	$1.83	$2.00	$2.18	$2.38	$2.50	$2.64	$2.78	$2.92	$64.85
Northwest Natural Gas Company	NWN		$2.02	$1.91	$1.79	$1.66	$1.74	$1.82	$1.91	$2.02	$2.13	$2.25	$2.39	$2.52	$2.65	$2.79	$2.94	$94.08
South Jersey Industries, Inc.	SJI		$1.22	$1.23	$1.24	$1.24	$1.34	$1.45	$1.56	$1.69	$1.81	$1.95	$2.09	$2.20	$2.32	$2.44	$2.57	$51.77
WGL Holdings, Inc.	WGL		$1.78	$1.83	$1.88	$1.93	$2.08	$2.25	$2.44	$2.63	$2.85	$3.07	$3.32	$3.50	$3.68	$3.88	$4.08	$124.90

Projected Annual Data Investor Cash Flows		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
Company	Ticker	Initial Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($58.64)	$0.00	$1.76	$1.82	$1.93	$2.06	$2.29	$2.54	$2.81	$3.10	$3.40	$3.73	$4.07	$4.28	$4.51	$4.75	$133.95
Laclede Group, Inc. (The)	LG	($55.96)	$0.00	$1.48	$1.48	$1.51	$1.54	$1.69	$1.84	$2.01	$2.19	$2.39	$2.60	$2.83	$2.99	$3.14	$3.31	$123.61
New Jersey Resources Corporation	NJR	($30.17)	$0.00	$1.34	$1.31	$1.31	$1.30	$1.42	$1.54	$1.68	$1.83	$2.00	$2.18	$2.38	$2.50	$2.64	$2.78	$67.78
Northwest Natural Gas Company	NWN	($46.50)	$0.00	$2.06	$1.91	$1.79	$1.66	$1.74	$1.82	$1.91	$2.02	$2.13	$2.25	$2.39	$2.52	$2.65	$2.79	$97.02
South Jersey Industries, Inc.	SJI	($24.55)	$0.00	$1.25	$1.23	$1.24	$1.24	$1.34	$1.45	$1.56	$1.69	$1.81	$1.95	$2.09	$2.20	$2.32	$2.44	$54.34
WGL Holdings, Inc.	WGL	($58.67)	$0.00	$1.82	$1.83	$1.88	$1.93	$2.08	$2.25	$2.44	$2.63	$2.85	$3.07	$3.32	$3.50	$3.68	$3.88	$128.99

Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
		Stock	EPS Growth Rate Estimates					Long-Term		Payout Ratio		Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Retention Growth	High Growth	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
Atmos Energy Corporation	ATO	$58.64	6.60%	6.40%	7.00%	8.21%	8.21%	5.31%	51.00%	51.00%	67.67%	($0.00)	9.95%	15.37	2.89
Laclede Group, Inc. (The)	LG	$55.96	4.80%	4.78%	10.00%	4.90%	10.00%	5.31%	56.00%	52.00%	67.67%	($0.00)	9.74%	16.08	3.03
New Jersey Resources Corporation	NJR	$30.17	6.50%	6.50%	4.00%	5.81%	6.50%	5.31%	58.00%	51.00%	67.67%	($0.00)	10.97%	12.59	2.37
Northwest Natural Gas Company	NWN	$46.50	4.00%	4.00%	7.00%	3.73%	7.00%	5.31%	87.00%	64.00%	67.67%	($0.00)	9.52%	16.95	3.19
South Jersey Industries, Inc.	SJI	$24.55	NA	6.00%	7.50%	6.56%	7.50%	5.31%	69.00%	59.00%	67.67%	($0.00)	11.12%	12.28	2.31
WGL Holdings, Inc.	WGL	$58.67	7.30%	8.00%	5.50%	5.11%	8.00%	5.31%	60.00%	56.00%	67.67%	($0.00)	9.55%	16.81	3.16
												Mean	10.14%		
												Max	11.12%		
												Min	9.52%		

Including Flotation Costs
Mean 10.18%
Max 11.15%
Min 9.55%

Projected Annual Earnings per Share		[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]
Company	Ticker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO	$2.96	$3.20	$3.47	$3.75	$4.06	$4.39	$4.75	$5.12	$5.49	$5.86	$6.23	$6.59	$6.94	$7.31	$7.70	$8.10	$8.54
Laclede Group, Inc. (The)	LG	$2.35	$2.59	$2.84	$3.13	$3.44	$3.78	$4.16	$4.55	$4.93	$5.31	$5.67	$6.02	$6.34	$6.68	$7.03	$7.40	$7.80
New Jersey Resources Corporation	NJR	$2.10	$2.24	$2.38	$2.54	$2.70	$2.88	$3.06	$3.26	$3.46	$3.66	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$5.29
Northwest Natural Gas Company	NWN	$2.16	$2.31	$2.47	$2.65	$2.83	$3.03	$3.24	$3.46	$3.68	$3.91	$4.14	$4.37	$4.60	$4.85	$5.10	$5.38	$5.66
South Jersey Industries, Inc.	SJI	$1.57	$1.69	$1.81	$1.95	$2.10	$2.25	$2.42	$2.60	$2.77	$2.95	$3.13	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28
WGL Holdings, Inc.	WGL	$2.68	$2.89	$3.13	$3.38	$3.65	$3.94	$4.25	$4.57	$4.90	$5.23	$5.55	$5.87	$6.18	$6.51	$6.86	$7.22	$7.60

Projected Annual Dividend Payout Ratio		[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]	[47]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Atmos Energy Corporation	ATO		51.00%	51.00%	51.00%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Laclede Group, Inc. (The)	LG		56.00%	54.67%	53.33%	52.00%	54.24%	56.48%	58.72%	60.95%	63.19%	65.43%	67.67%	67.67%	67.67%	67.67%	67.67%
New Jersey Resources Corporation	NJR		58.00%	55.67%	53.33%	51.00%	53.38%	55.76%	58.14%	60.53%	62.91%	65.29%	67.67%	67.67%	67.67%	67.67%	67.67%
Northwest Natural Gas Company	NWN		87.00%	79.33%	71.67%	64.00%	64.52%	65.05%	65.57%	66.10%	66.62%	67.15%	67.67%	67.67%	67.67%	67.67%	67.67%
South Jersey Industries, Inc.	SJI		69.00%	65.67%	62.33%	59.00%	60.24%	61.48%	62.72%	63.95%	65.19%	66.43%	67.67%	67.67%	67.67%	67.67%	67.67%
WGL Holdings, Inc.	WGL		60.00%	58.67%	57.33%	56.00%	57.67%	59.33%	61.00%	62.67%	64.34%	66.00%	67.67%	67.67%	67.67%	67.67%	67.67%

Projected Annual Cash Flows		[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]	[63]	[64]
Company	Ticker	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Terminal Value
Atmos Energy Corporation	ATO		$1.77	$1.91	$2.07	$2.24	$2.54	$2.85	$3.19	$3.55	$3.92	$4.30	$4.70	$4.94	$5.21	$5.48	$5.78	$131.20
Laclede Group, Inc. (The)	LG		$1.59	$1.71	$1.84	$1.97	$2.26	$2.57	$2.90	$3.24	$3.58	$3.94	$4.29	$4.52	$4.76	$5.01	$5.28	$125.39
New Jersey Resources Corporation	NJR		$1.38	$1.41	$1.44	$1.47	$1.64	$1.82	$2.01	$2.22	$2.43	$2.67	$2.91	$3.06	$3.23	$3.40	$3.58	$66.58
Northwest Natural Gas Company	NWN		$2.15	$2.10	$2.03	$1.94	$2.09	$2.25	$2.41	$2.58	$2.76	$2.93	$3.11	$3.28	$3.45	$3.64	$3.83	$95.96
South Jersey Industries, Inc.	SJI		$1.25	$1.28	$1.31	$1.33	$1.46	$1.60	$1.74	$1.89	$2.04	$2.20	$2.36	$2.48	$2.61	$2.75	$2.90	$52.56
WGL Holdings, Inc.	WGL		$1.88	$1.98	$2.09	$2.21	$2.45	$2.71	$2.99	$3.27	$3.57	$3.87	$4.18	$4.40	$4.64	$4.89	$5.14	$127.77

Projected Annual Data Investor Cash Flows		[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]	[80]	[81]
Company	Ticker	Initial Outflow	2/12/16	12/31/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27	6/30/28	6/30/29	6/30/30
Atmos Energy Corporation	ATO	($58.64)	$0.00	$1.84	$1.91	$2.07	$2.24	$2.54	$2.85	$3.19	$3.55	$3.92	$4.30	$4.70	$4.94	$5.21	$5.48	$136.98
Laclede Group, Inc. (The)	LG	($55.96)	$0.00	$1.67	$1.71	$1.84	$1.97	$2.26	$2.57	$2.90	$3.24	$3.58	$3.94	$4.29	$4.52	$4.76	$5.01	$130.67
New Jersey Resources Corporation	NJR	($30.17)	$0.00	$1.43	$1.41	$1.44	$1.47	$1.64	$1.82	$2.01	$2.22	$2.43	$2.67	$2.91	$3.06	$3.23	$3.40	$70.16
Northwest Natural Gas Company	NWN	($46.50)	$0.00	$2.23	$2.10	$2.03	$1.94	$2.09	$2.25	$2.41	$2.58	$2.76	$2.93	$3.11	$3.28	$3.45	$3.64	$99.79
South Jersey Industries, Inc.	SJI	($24.55)	$0.00	$1.30	$1.28	$1.31	$1.33	$1.46	$1.60	$1.74	$1.89	$2.04	$2.20	$2.36	$2.48	$2.61	$2.75	$55.45
WGL Holdings, Inc.	WGL	($58.67)	$0.00	$1.95	$1.98	$2.09	$2.21	$2.45	$2.71	$2.99	$3.27	$3.57	$3.87	$4.18	$4.40	$4.64	$4.89	$132.92

Multi-Stage DCF Notes:

[1] Source: Bloomberg; based on 30-, 90-, and 180-day historical average as of February 12, 2016
[2] Source: Zacks
[3] Source: Yahoo! Finance
[4] Source: Value Line
[5] Source: Exhibit No. __ (RBH-2), Value Line
[6] Equals indicated value (average, minimum, maximum) from Columns [2], [3], [4], [5]
[7] Source: Federal Reserve, Bureau of Economic Analysis, Blue Chip Financial Forecasts
[8] Source: Value Line
[9] Source: Value Line
[10] Source: Bloomberg Professional
[11] Equals Column [1] + Column [65]
[12] Equals result of Excel Solver function; goal: Column [11] equals $0.00
[13] Equals Column [64] / Column [31]
[14] Equals Column [13] / (Column [7] x 100)
[15] Source: Value Line
[16] Equals Column [15] x (1 + Column [6])
[17] Equals Column [16] x (1 + Column [6])
[18] Equals Column [17] x (1 + Column [6])
[19] Equals Column [18] x (1 + Column [6])
[20] Equals Column [19] x (1 + Column [6])
[21] Equals Column [20] x (1 + Column [6])
[22] Equals (1 + (Column [6] + (((Column [7] − Column [6]) / (2026 − 2021 + 1)) x (2021 − 2020)))) x Column [21]
[23] Equals (1 + (Column [6] + (((Column [7] − Column [6]) / (2026 − 2021 + 1)) x (2022 − 2020)))) x Column [22]
[24] Equals (1 + (Column [6] + (((Column [7] − Column [6]) / (2026 − 2021 + 1)) x (2023 − 2020)))) x Column [23]
[25] Equals (1 + (Column [6] + (((Column [7] − Column [6]) / (2026 − 2020 + 1)) x (2024 − 2020)))) x Column [24]
[26] Equals (1 + (Column [6] + (((Column [7] − Column [6]) / (2026 − 2020 + 1)) x (2025 − 2019)))) x Column [24]
[27] Equals Column [26] x (1 + Column [7])
[28] Equals Column [27] x (1 + Column [7])
[29] Equals Column [28] x (1 + Column [7])
[30] Equals Column [29] x (1 + Column [7])
[31] Equals Column [30] x (1 + Column [7])
[32]
[33] Equals Column [8]
[34] Equals Column [33] + ((Column [36] − Column [33]) / 3)
[35] Equals Column [34] + ((Column [36] − Column [33]) / 3)
[36] Equals Column [9]
[37] Equals Column [36] + ((Column [43] − Column [36]) / 7)
[38] Equals Column [37] + ((Column [43] − Column [36]) / 7)
[39] Equals Column [38] + ((Column [43] − Column [36]) / 7)
[40] Equals Column [39] + ((Column [43] − Column [36]) / 7)
[41] Equals Column [40] + ((Column [43] − Column [36]) / 7)
[42] Equals Column [41] + ((Column [43] − Column [36]) / 7)
[43] Equals Column [10]
[44] Equals Column [10]
[45] Equals Column [10]
[46] Equals Column [10]
[47] Equals Column [10]
[48]
[49] Equals Column [17] x Column [33]
[50] Equals Column [18] x Column [34]
[51] Equals Column [19] x Column [35]
[52] Equals Column [20] x Column [36]
[53] Equals Column [21] x Column [37]
[54] Equals Column [22] x Column [38]
[55] Equals Column [23] x Column [39]
[56] Equals Column [24] x Column [40]
[57] Equals Column [25] x Column [41]
[58] Equals Column [26] x Column [42]
[59] Equals Column [27] x Column [43]
[60] Equals Column [28] x Column [44]
[61] Equals Column [29] x Column [45]
[62] Equals Column [30] x Column [46]
[63] Equals Column [31] x Column [47]
[64] Equals (Column [63] x (1 + Column [7])) / (Column [12] − Column [7])
[65] Equals negative net present value; discount rate equals Column [12], cash flows equal Column [66] through Column [81]
[66] Equals $0.00
[67] Equals Column [48] x (1 + (0.5 x Column [6]))
[68] Equals Column [50]
[69] Equals Column [51]
[70] Equals Column [52]
[71] Equals Column [53]
[72] Equals Column [54]
[73] Equals Column [55]
[74] Equals Column [56]
[75] Equals Column [57]
[76] Equals Column [58]
[77] Equals Column [59]
[78] Equals Column [60]
[79] Equals Column [61]
[80] Equals Column [62]
[81] Equals Column [63] + [64]

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
13.44%	2.79%	10.65%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	11,871.79	0.07%	1.31%	9.60%	10.97%	0.0076%
ALCOA INC	AA	10,075.13	0.06%	1.56%	9.77%	11.40%	0.0067%
AMERICAN AIRLINES GROUP INC	AAL	23,838.91	0.14%	1.15%	9.17%	10.37%	0.0144%
ADVANCE AUTO PARTS INC	AAP	10,309.52	0.06%	0.17%	11.80%	11.98%	0.0072%
APPLE INC	AAPL	521,135.36	3.03%	2.30%	14.40%	16.87%	0.5116%
ABBVIE INC	ABBV	85,954.99	0.50%	4.32%	12.10%	16.68%	0.0835%
AMERISOURCEBERGEN CORP	ABC	17,589.64	0.10%	1.55%	12.50%	14.14%	0.0145%
ABBOTT LABORATORIES	ABT	55,387.56	0.32%	2.81%	11.59%	14.56%	0.0469%
ACCENTURE PLC-CL A	ACN	62,308.34	0.36%	2.31%	9.85%	12.28%	0.0445%
ADOBE SYSTEMS INC	ADBE	38,206.99	0.22%	0.00%	21.33%	21.33%	0.0474%
ANALOG DEVICES INC	ADI	15,418.66	0.09%	3.28%	11.00%	14.46%	0.0130%
ARCHER-DANIELS-MIDLAND CO	ADM	19,364.21	0.11%	3.68%	7.72%	11.54%	0.0130%
AUTOMATIC DATA PROCESSING	ADP	37,392.06	0.22%	2.51%	10.29%	12.92%	0.0281%
ALLIANCE DATA SYSTEMS CORP	ADS	11,166.91	0.07%	0.00%	14.00%	14.00%	0.0091%
AUTODESK INC	ADSK	10,121.52	0.06%	0.00%	15.83%	15.83%	0.0093%
ADT CORP/THE	ADT	4,441.92	0.03%	3.21%	6.47%	9.78%	0.0025%
AMEREN CORPORATION	AEE	10,979.22	0.06%	3.67%	6.61%	10.40%	0.0066%
AMERICAN ELECTRIC POWER	AEP	29,743.53	0.17%	3.72%	5.56%	9.38%	0.0162%
AES CORP	AES	6,170.15	0.04%	4.36%	3.95%	8.39%	0.0030%
AETNA INC	AET	34,625.91	0.20%	1.04%	11.83%	12.93%	0.0261%
AFLAC INC	AFL	24,456.39	0.14%	2.91%	8.70%	11.74%	0.0167%
ALLERGAN PLC	AGN	110,544.05	0.64%	0.00%	12.01%	12.01%	0.0773%
AMERICAN INTERNATIONAL GROUP	AIG	65,561.66	0.38%	2.38%	9.50%	11.99%	0.0458%
APARTMENT INVT & MGMT CO -A	AIV	5,639.07	0.03%	3.67%	11.91%	15.79%	0.0052%
ASSURANT INC	AIZ	4,415.83	0.03%	3.08%	7.08%	10.27%	0.0026%
AKAMAI TECHNOLOGIES INC	AKAM	9,032.18	0.05%	0.00%	16.83%	16.83%	0.0088%
ALLSTATE CORP	ALL	24,752.74	0.14%	2.00%	10.02%	12.12%	0.0175%
ALLEGION PLC	ALLE	5,514.94	0.03%	0.82%	13.72%	14.59%	0.0047%
ALEXION PHARMACEUTICALS INC	ALXN	31,790.86	0.19%	0.00%	23.90%	23.90%	0.0442%
APPLIED MATERIALS INC	AMAT	18,322.65	0.11%	2.57%	14.06%	16.81%	0.0179%
AMETEK INC	AME	10,854.58	0.06%	0.87%	8.59%	9.49%	0.0060%
AFFILIATED MANAGERS GROUP	AMG	6,723.28	0.04%	0.00%	13.06%	13.06%	0.0051%
AMGEN INC	AMGN	108,842.62	0.63%	2.77%	8.70%	11.59%	0.0734%
AMERIPRISE FINANCIAL INC	AMP	13,955.04	0.08%	3.66%	13.00%	16.89%	0.0137%
AMERICAN TOWER CORP	AMT	36,287.26	0.21%	2.10%	13.81%	16.06%	0.0339%
AMAZON.COM INC	AMZN	238,754.58	1.39%	0.00%	41.88%	41.88%	0.5820%
AUTONATION INC	AN	5,163.95	0.03%	0.00%	8.74%	8.74%	0.0026%
ANTHEM INC	ANTM	31,722.56	0.18%	2.10%	9.06%	11.25%	0.0208%
AON PLC	AON	25,693.40	0.15%	1.36%	11.17%	12.60%	0.0188%
APACHE CORP	APA	13,808.86	0.08%	2.74%	0.60%	3.35%	0.0027%
ANADARKO PETROLEUM CORP	APC	19,212.88	0.11%	2.86%	2.17%	5.06%	0.0057%
AIR PRODUCTS & CHEMICALS INC	APD	28,110.02	0.16%	2.53%	6.11%	8.72%	0.0143%
AMPHENOL CORP-CL A	APH	15,271.26	0.09%	1.17%	9.27%	10.49%	0.0093%
AIRGAS INC	ARG	10,147.23	0.06%	1.70%	10.00%	11.79%	0.0070%
ACTIVISION BLIZZARD INC	ATVI	20,560.89	0.12%	0.92%	12.00%	12.98%	0.0155%
AVALONBAY COMMUNITIES INC	AVB	22,505.35	0.13%	3.28%	6.18%	9.56%	0.0125%
BROADCOM LTD	AVGO	50,052.57	0.29%	1.45%	17.86%	19.44%	0.0566%
AVERY DENNISON CORP	AVY	5,828.72	0.03%	2.46%	6.55%	9.09%	0.0031%
AMERICAN EXPRESS CO	AXP	51,830.39	0.30%	2.29%	8.57%	10.96%	0.0331%
AUTOZONE INC	AZO	22,040.58	0.13%	0.00%	12.37%	12.37%	0.0159%
BOEING CO/THE	BA	71,967.79	0.42%	3.83%	11.39%	15.43%	0.0647%
BANK OF AMERICA CORP	BAC	124,429.13	0.72%	2.27%	24.88%	27.43%	0.1987%
BAXTER INTERNATIONAL INC	BAX	20,026.32	0.12%	1.26%	10.50%	11.83%	0.0138%
BED BATH & BEYOND INC	BBBY	7,024.45	0.04%	0.00%	6.23%	6.23%	0.0025%
BB&T CORP	BBT	24,637.14	0.14%	3.60%	10.69%	14.49%	0.0208%
BEST BUY CO INC	BBY	9,637.28	0.06%	4.28%	9.60%	14.08%	0.0079%
CR BARD INC	BCR	13,545.08	0.08%	0.53%	14.08%	14.65%	0.0115%
BECTON DICKINSON AND CO	BDX	29,614.07	0.17%	1.89%	11.26%	13.26%	0.0229%
FRANKLIN RESOURCES INC	BEN	19,154.32	0.11%	2.30%	3.99%	6.33%	0.0071%
BROWN-FORMAN CORP-CLASS B	BF/B	20,369.85	0.12%	1.38%	8.28%	9.71%	0.0115%
BAKER HUGHES INC	BHI	17,399.86	0.10%	1.66%	-4.10%	-2.48%	-0.0025%
BIOGEN INC	BIIB	54,060.27	0.31%	0.00%	9.61%	9.61%	0.0302%
BANK OF NEW YORK MELLON CORP	BK	36,974.59	0.22%	2.19%	9.95%	12.25%	0.0264%
BLACKROCK INC	BLK	50,967.95	0.30%	2.99%	11.53%	14.69%	0.0436%
BALL CORP	BLL	9,237.50	0.05%	0.67%	8.27%	8.96%	0.0048%
BRISTOL-MYERS SQUIBB CO	BMY	100,501.44	0.59%	2.56%	19.53%	22.33%	0.1306%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
BERKSHIRE HATHAWAY INC-CL B	BRK/B	317,235.55	1.85%	0.00%	6.05%	6.05%	0.1117%
BOSTON SCIENTIFIC CORP	BSX	22,384.05	0.13%	0.00%	10.51%	10.51%	0.0137%
BORGWARNER INC	BWA	6,939.59	0.04%	1.70%	9.45%	11.23%	0.0045%
BAXALTA INC	BXLT	26,268.05	N/A	0.72%	N/A	N/A	N/A
BOSTON PROPERTIES INC	BXP	16,679.92	0.10%	2.84%	6.51%	9.43%	0.0092%
CITIGROUP INC	C	111,831.30	0.65%	1.11%	14.48%	15.67%	0.1020%
CA INC	CA	11,544.33	0.07%	3.62%	8.50%	12.27%	0.0082%
CONAGRA FOODS INC	CAG	18,059.79	0.11%	2.41%	8.17%	10.68%	0.0112%
CARDINAL HEALTH INC	CAH	25,967.59	0.15%	1.81%	11.70%	13.61%	0.0206%
CAMERON INTERNATIONAL CORP	CAM	12,331.31	0.07%	0.00%	5.05%	5.05%	0.0036%
CATERPILLAR INC	CAT	36,768.06	0.21%	4.92%	9.00%	14.14%	0.0303%
CHUBB LTD	CB	52,712.10	0.31%	2.45%	10.00%	12.57%	0.0386%
CBRE GROUP INC - A	CBG	8,133.61	0.05%	0.00%	12.50%	12.50%	0.0059%
CBS CORP-CLASS B NON VOTING	CBS	20,024.82	0.12%	1.55%	14.36%	16.02%	0.0187%
COCA-COLA ENTERPRISES	CCE	10,955.43	0.06%	2.37%	6.55%	9.00%	0.0057%
CROWN CASTLE INTL CORP	CCI	27,746.44	0.16%	4.32%	15.50%	20.16%	0.0326%
CARNIVAL CORP	CCL	34,730.93	0.20%	2.80%	17.70%	20.74%	0.0419%
CELGENE CORP	CELG	80,081.53	0.47%	0.00%	21.32%	21.32%	0.0994%
CERNER CORP	CERN	18,781.55	0.11%	0.00%	17.28%	17.28%	0.0189%
CF INDUSTRIES HOLDINGS INC	CF	6,992.26	0.04%	4.00%	20.00%	24.40%	0.0099%
CITIZENS FINANCIAL GROUP	CFG	9,967.06	0.06%	2.55%	10.00%	12.67%	0.0074%
CHURCH & DWIGHT CO INC	CHD	11,614.87	0.07%	1.61%	9.11%	10.79%	0.0073%
CHESAPEAKE ENERGY CORP	CHK	1,057.46	0.01%	12.96%	0.62%	13.61%	0.0008%
C.H. ROBINSON WORLDWIDE INC	CHRW	10,076.72	0.06%	2.41%	9.68%	12.21%	0.0072%
CIGNA CORP	CI	33,565.27	0.20%	0.03%	11.21%	11.25%	0.0220%
CINCINNATI FINANCIAL CORP	CINF	10,121.13	N/A	N/A	N/A	N/A	N/A
COLGATE-PALMOLIVE CO	CL	58,927.78	0.34%	2.43%	8.25%	10.78%	0.0370%
CLOROX COMPANY	CLX	16,509.49	0.10%	2.43%	6.57%	9.08%	0.0087%
COMERICA INC	CMA	5,818.11	0.03%	2.65%	8.60%	11.36%	0.0038%
COMCAST CORP-CLASS A	CMCSA	138,679.38	0.81%	1.96%	12.62%	14.71%	0.1187%
CME GROUP INC	CME	30,830.25	0.18%	5.71%	12.79%	18.86%	0.0339%
CHIPOTLE MEXICAN GRILL INC	CMG	14,438.37	0.08%	0.00%	17.57%	17.57%	0.0148%
CUMMINS INC	CMI	16,910.86	0.10%	4.18%	4.45%	8.73%	0.0086%
CMS ENERGY CORP	CMS	10,893.65	0.06%	3.16%	6.31%	9.58%	0.0061%
CENTERPOINT ENERGY INC	CNP	7,731.81	0.05%	5.51%	5.33%	10.99%	0.0049%
CONSOL ENERGY INC	CNX	1,784.33	0.01%	0.51%	20.55%	21.12%	0.0022%
CAPITAL ONE FINANCIAL CORP	COF	33,274.11	0.19%	2.71%	6.55%	9.34%	0.0181%
CABOT OIL & GAS CORP	COG	8,174.02	0.05%	0.41%	36.06%	36.54%	0.0174%
COACH INC	COH	9,588.85	0.06%	3.91%	10.17%	14.28%	0.0080%
ROCKWELL COLLINS INC	COL	10,615.09	0.06%	1.63%	8.89%	10.59%	0.0065%
CONOCOPHILLIPS	COP	40,619.72	0.24%	3.04%	6.00%	9.13%	0.0216%
COSTCO WHOLESALE CORP	COST	65,372.89	0.38%	1.12%	9.55%	10.73%	0.0408%
CAMPBELL SOUP CO	CPB	18,056.18	0.11%	2.33%	3.85%	6.22%	0.0065%
COLUMBIA PIPELINE GROUP	CPGX	6,334.81	N/A	2.13%	N/A	N/A	N/A
SALESFORCE.COM INC	CRM	39,627.52	0.23%	0.00%	29.70%	29.70%	0.0685%
CISCO SYSTEMS INC	CSCO	127,460.35	0.74%	3.74%	7.56%	11.44%	0.0849%
CSRA INC	CSRA	4,177.43	0.02%	41.55%	10.00%	53.63%	0.0130%
CSX CORP	CSX	23,298.60	0.14%	3.10%	5.96%	9.15%	0.0124%
CINTAS CORP	CTAS	8,975.91	0.05%	1.25%	12.18%	13.51%	0.0071%
CENTURYLINK INC	CTL	15,707.01	0.09%	7.55%	-0.95%	6.57%	0.0060%
COGNIZANT TECH SOLUTIONS-A	CTSH	32,756.67	0.19%	0.00%	15.87%	15.87%	0.0303%
CITRIX SYSTEMS INC	CTXS	9,892.45	0.06%	0.00%	19.98%	19.98%	0.0115%
CABLEVISION SYSTEMS-NY GRP-A	CVC	8,974.02	0.05%	1.57%	8.25%	9.89%	0.0052%
CVS HEALTH CORP	CVS	105,301.33	0.61%	1.75%	14.17%	16.04%	0.0983%
CHEVRON CORP	CVX	160,782.40	0.94%	5.06%	-3.58%	1.39%	0.0130%
DOMINION RESOURCES INC/VA	D	41,042.30	0.24%	4.03%	6.56%	10.72%	0.0256%
DELTA AIR LINES INC	DAL	33,468.09	0.19%	1.40%	23.70%	25.27%	0.0492%
DU PONT (E.I.) DE NEMOURS	DD	50,906.17	0.30%	2.69%	8.30%	11.10%	0.0329%
DEERE & CO	DE	24,750.86	0.14%	3.13%	5.52%	8.73%	0.0126%
DISCOVER FINANCIAL SERVICES	DFS	19,031.58	0.11%	2.69%	7.28%	10.07%	0.0112%
DOLLAR GENERAL CORP	DG	20,499.25	0.12%	1.25%	12.95%	14.27%	0.0170%
QUEST DIAGNOSTICS INC	DGX	8,873.35	0.05%	2.53%	8.78%	11.42%	0.0059%
DR HORTON INC	DHI	8,952.10	0.05%	1.32%	14.06%	15.47%	0.0081%
DANAHER CORP	DHR	58,194.43	0.34%	0.68%	12.15%	12.87%	0.0436%
WALT DISNEY CO/THE	DIS	148,717.62	0.87%	1.60%	10.15%	11.83%	0.1024%
DISCOVERY COMMUNICATIONS-A	DISCA	16,077.25	0.09%	0.00%	15.17%	15.17%	0.0142%
DELPHI AUTOMOTIVE PLC	DLPH	16,996.16	0.10%	1.88%	10.54%	12.52%	0.0124%
DOLLAR TREE INC	DLTR	17,663.70	0.10%	0.00%	20.67%	20.67%	0.0212%
DUN & BRADSTREET CORP	DNB	3,448.90	0.02%	1.98%	7.35%	9.40%	0.0019%
DIAMOND OFFSHORE DRILLING	DO	2,320.73	0.01%	0.92%	14.27%	15.25%	0.0021%
DOVER CORP	DOV	9,175.01	0.05%	2.92%	10.68%	13.75%	0.0073%
DOW CHEMICAL CO/THE	DOW	51,398.34	0.30%	3.97%	6.00%	10.09%	0.0302%
DR PEPPER SNAPPLE GROUP INC	DPS	17,372.40	0.10%	2.09%	7.70%	9.86%	0.0100%
DARDEN RESTAURANTS INC	DRI	7,523.63	0.04%	3.49%	12.39%	16.09%	0.0070%
DTE ENERGY COMPANY	DTE	15,025.70	0.09%	3.55%	5.29%	8.93%	0.0078%
DUKE ENERGY CORP	DUK	52,478.61	0.31%	4.29%	4.41%	8.79%	0.0269%
DAVITA HEALTHCARE PARTNERS I	DVA	13,200.16	0.08%	0.00%	11.15%	11.15%	0.0086%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
DEVON ENERGY CORP	DVN	8,914.59	0.05%	4.43%	5.40%	9.94%	0.0052%
ELECTRONIC ARTS INC	EA	18,326.59	0.11%	0.00%	11.70%	11.70%	0.0125%
EBAY INC	EBAY	26,509.08	0.15%	0.00%	7.25%	7.25%	0.0112%
ECOLAB INC	ECL	31,488.21	0.18%	1.22%	13.22%	14.52%	0.0266%
CONSOLIDATED EDISON INC	ED	20,734.56	0.12%	3.68%	2.99%	6.72%	0.0081%
EQUIFAX INC	EFX	11,547.82	0.07%	1.35%	9.37%	10.78%	0.0072%
EDISON INTERNATIONAL	EIX	20,122.10	0.12%	2.73%	5.10%	7.90%	0.0093%
ESTEE LAUDER COMPANIES-CL A	EL	32,548.96	0.19%	1.29%	11.69%	13.05%	0.0247%
EMC CORP/MA	EMC	46,805.69	0.27%	2.00%	10.94%	13.05%	0.0355%
EASTMAN CHEMICAL CO	EMN	9,014.53	0.05%	2.79%	5.70%	8.57%	0.0045%
EMERSON ELECTRIC CO	EMR	29,596.19	0.17%	4.15%	7.20%	11.50%	0.0198%
ENDO INTERNATIONAL PLC	ENDP	11,342.85	0.07%	0.00%	11.03%	11.03%	0.0073%
EOG RESOURCES INC	EOG	37,216.96	0.22%	0.88%	1.26%	2.14%	0.0046%
EQUINIX INC	EQIX	17,653.69	0.10%	2.37%	17.00%	19.57%	0.0201%
EQUITY RESIDENTIAL	EQR	25,968.23	0.15%	15.59%	6.26%	22.34%	0.0338%
EQT CORP	EQT	9,018.29	0.05%	3.57%	25.00%	29.01%	0.0152%
EVERSOURCE ENERGY	ES	16,972.90	0.10%	3.33%	6.67%	10.12%	0.0100%
EXPRESS SCRIPTS HOLDING CO	ESRX	45,540.43	0.27%	0.00%	13.60%	13.60%	0.0361%
ESSEX PROPERTY TRUST INC	ESS	12,912.51	0.08%	3.22%	5.84%	9.15%	0.0069%
ENSCO PLC-CL A	ESV	1,973.28	0.01%	7.16%	-4.00%	3.02%	0.0003%
E*TRADE FINANCIAL CORP	ETFC	6,196.27	0.04%	0.04%	19.10%	19.14%	0.0069%
EATON CORP PLC	ETN	25,083.76	0.15%	4.39%	8.40%	12.97%	0.0189%
ENTERGY CORP	ETR	12,565.57	0.07%	4.75%	2.76%	7.58%	0.0055%
EDWARDS LIFESCIENCES CORP	EW	17,481.11	0.10%	0.00%	16.40%	16.40%	0.0167%
EXELON CORP	EXC	28,020.91	0.16%	4.12%	6.36%	10.62%	0.0173%
EXPEDITORS INTL WASH INC	EXPD	8,519.09	0.05%	1.56%	9.16%	10.79%	0.0054%
EXPEDIA INC	EXPE	15,396.85	0.09%	0.88%	24.01%	25.00%	0.0224%
EXTRA SPACE STORAGE INC	EXR	10,048.16	0.06%	2.75%	7.06%	9.91%	0.0058%
FORD MOTOR CO	F	45,847.88	0.27%	6.08%	10.85%	17.25%	0.0460%
FASTENAL CO	FAST	12,412.90	0.07%	2.89%	13.68%	16.77%	0.0121%
FACEBOOK INC-A	FB	290,349.07	1.69%	0.00%	29.67%	29.67%	0.5015%
FREEPORT-MCMORAN INC	FCX	6,391.96	0.04%	0.74%	-38.33%	-37.73%	-0.0140%
FEDEX CORP	FDX	35,444.12	0.21%	0.78%	13.50%	14.33%	0.0296%
FIRSTENERGY CORP	FE	13,909.61	0.08%	4.38%	2.89%	7.33%	0.0059%
F5 NETWORKS INC	FFIV	6,038.63	0.04%	0.00%	12.77%	12.77%	0.0045%
FIDELITY NATIONAL INFO SERV	FIS	16,243.58	0.09%	1.90%	12.75%	14.77%	0.0140%
FISERV INC	FISV	21,270.10	0.12%	0.00%	12.25%	12.25%	0.0152%
FIFTH THIRD BANCORP	FITB	11,811.70	0.07%	3.77%	4.20%	8.05%	0.0055%
FLIR SYSTEMS INC	FLIR	4,109.28	0.02%	1.57%	12.50%	14.17%	0.0034%
FLUOR CORP	FLR	6,179.97	0.04%	1.92%	5.73%	7.71%	0.0028%
FLOWSERVE CORP	FLS	5,342.08	0.03%	1.76%	7.54%	9.36%	0.0029%
FMC CORP	FMC	4,682.15	0.03%	1.90%	10.30%	12.30%	0.0034%
TWENTY-FIRST CENTURY FOX-A	FOXA	47,181.94	0.27%	1.30%	14.39%	15.78%	0.0433%
FEDERAL REALTY INVS TRUST	FRT	10,094.47	0.06%	2.68%	5.32%	8.07%	0.0047%
FIRST SOLAR INC	FSLR	6,155.12	0.04%	0.00%	1.67%	1.67%	0.0006%
FMC TECHNOLOGIES INC	FTI	5,270.91	0.03%	0.00%	-11.80%	-11.80%	-0.0036%
FRONTIER COMMUNICATIONS CORP	FTR	4,953.22	0.03%	9.91%	3.00%	13.05%	0.0038%
AGL RESOURCES INC	GAS	7,780.44	0.05%	3.28%	7.00%	10.40%	0.0047%
GENERAL DYNAMICS CORP	GD	40,507.04	0.24%	2.25%	8.93%	11.28%	0.0266%
GENERAL ELECTRIC CO	GE	266,714.27	1.55%	3.37%	8.58%	12.09%	0.1877%
GENERAL GROWTH PROPERTIES	GGP	22,556.57	0.13%	3.03%	7.49%	10.63%	0.0140%
GILEAD SCIENCES INC	GILD	128,899.16	0.75%	2.10%	3.26%	5.40%	0.0405%
GENERAL MILLS INC	GIS	33,755.41	0.20%	3.15%	7.54%	10.81%	0.0212%
CORNING INC	GLW	20,465.08	0.12%	2.88%	6.38%	9.35%	0.0111%
GENERAL MOTORS CO	GM	42,797.89	0.25%	5.40%	9.66%	15.31%	0.0382%
KEURIG GREEN MOUNTAIN INC	GMCR	13,461.91	0.08%	1.43%	15.00%	16.53%	0.0130%
GAMESTOP CORP-CLASS A	GME	2,824.01	0.02%	3.56%	11.78%	15.55%	0.0026%
ALPHABET INC-CL C	GOOG	476,820.49	2.78%	0.00%	16.54%	16.54%	0.4592%
GENUINE PARTS CO	GPC	13,246.06	N/A	2.92%	N/A	N/A	N/A
GAP INC/THE	GPS	9,537.14	0.06%	3.87%	8.01%	12.04%	0.0067%
GARMIN LTD	GRMN	6,540.15	0.04%	5.85%	5.07%	11.07%	0.0042%
GOLDMAN SACHS GROUP INC	GS	65,077.99	0.38%	1.86%	15.20%	17.20%	0.0652%
GOODYEAR TIRE & RUBBER CO	GT	7,928.49	0.05%	0.96%	7.00%	7.99%	0.0037%
WW GRAINGER INC	GWW	13,254.03	0.08%	2.34%	9.92%	12.37%	0.0095%
HALLIBURTON CO	HAL	24,986.34	0.15%	2.51%	12.46%	15.13%	0.0220%
HARMAN INTERNATIONAL	HAR	4,995.63	0.03%	2.02%	16.00%	18.18%	0.0053%
HASBRO INC	HAS	8,733.62	0.05%	2.82%	9.97%	12.92%	0.0066%
HUNTINGTON BANCSHARES INC	HBAN	6,723.81	0.04%	3.48%	6.48%	10.08%	0.0039%
HANESBRANDS INC	HBI	10,410.61	0.06%	1.64%	15.58%	17.34%	0.0105%
HCA HOLDINGS INC	HCA	26,910.14	0.16%	0.00%	10.75%	10.75%	0.0168%
WELLTOWER INC	HCN	19,251.05	0.11%	6.07%	4.43%	10.63%	0.0119%
HCP INC	HCP	12,224.86	0.07%	8.79%	2.58%	11.49%	0.0082%
HOME DEPOT INC	HD	147,479.95	0.86%	2.02%	14.07%	16.24%	0.1394%
HESS CORP	HES	12,624.83	0.07%	2.50%	-16.88%	-14.59%	-0.0107%
HARTFORD FINANCIAL SVCS GRP	HIG	16,707.99	0.10%	2.17%	9.00%	11.27%	0.0110%
HARLEY-DAVIDSON INC	HOG	7,428.82	0.04%	3.46%	11.38%	15.03%	0.0065%
HONEYWELL INTERNATIONAL INC	HON	79,609.53	0.46%	2.34%	9.19%	11.64%	0.0539%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
STARWOOD HOTELS & RESORTS	HOT	10,817.34	0.06%	2.34%	8.23%	10.67%	0.0067%
HELMERICH & PAYNE	HP	5,120.78	0.03%	5.80%	10.00%	16.09%	0.0048%
HEWLETT PACKARD ENTERPRIS	HPE	21,381.04	0.12%	1.79%	4.51%	6.34%	0.0079%
HP INC	HPQ	16,265.11	0.09%	5.23%	2.58%	7.88%	0.0075%
H&R BLOCK INC	HRB	7,956.23	0.05%	2.39%	11.00%	13.52%	0.0063%
HORMEL FOODS CORP	HRL	21,930.99	0.13%	1.30%	7.15%	8.49%	0.0108%
HARRIS CORP	HRS	8,982.58	N/A	2.80%	N/A	N/A	N/A
HENRY SCHEIN INC	HSIC	13,027.97	0.08%	0.00%	10.78%	10.78%	0.0082%
HOST HOTELS & RESORTS INC	HST	10,838.23	0.06%	5.55%	5.67%	11.37%	0.0072%
HERSHEY CO/THE	HSY	19,446.36	0.11%	2.70%	8.18%	10.98%	0.0124%
HUMANA INC	HUM	23,770.67	0.14%	0.74%	12.94%	13.73%	0.0190%
INTL BUSINESS MACHINES CORP	IBM	117,422.13	0.68%	4.38%	6.75%	11.28%	0.0771%
INTERCONTINENTAL EXCHANGE IN	ICE	28,090.78	0.16%	1.44%	14.37%	15.91%	0.0260%
INTL FLAVORS & FRAGRANCES	IFF	8,566.71	0.05%	2.11%	9.10%	11.31%	0.0056%
ILLUMINA INC	ILMN	20,894.21	0.12%	0.00%	17.52%	17.52%	0.0213%
INTEL CORP	INTC	135,295.36	0.79%	3.60%	8.69%	12.44%	0.0980%
INTUIT INC	INTU	24,964.25	0.15%	1.27%	17.21%	18.59%	0.0270%
INTERNATIONAL PAPER CO	IP	14,161.61	0.08%	5.23%	6.90%	12.31%	0.0102%
INTERPUBLIC GROUP OF COS INC	IPG	8,289.50	0.05%	2.70%	6.50%	9.28%	0.0045%
INGERSOLL-RAND PLC	IR	13,181.44	0.08%	2.51%	8.78%	11.40%	0.0087%
IRON MOUNTAIN INC	IRM	5,785.59	0.03%	6.98%	7.30%	14.54%	0.0049%
INTUITIVE SURGICAL INC	ISRG	19,859.39	0.12%	0.00%	12.31%	12.31%	0.0142%
ILLINOIS TOOL WORKS	ITW	33,422.90	0.19%	2.42%	7.70%	10.22%	0.0199%
INVESCO LTD	IVZ	11,232.35	0.07%	4.29%	9.53%	14.02%	0.0092%
HUNT (JB) TRANSPRT SVCS INC	JBHT	8,529.83	0.05%	1.19%	15.60%	16.88%	0.0084%
JOHNSON CONTROLS INC	JCI	22,565.07	0.13%	3.27%	9.28%	12.70%	0.0167%
JACOBS ENGINEERING GROUP INC	JEC	4,421.14	0.03%	0.00%	8.45%	8.45%	0.0022%
JOHNSON & JOHNSON	JNJ	281,730.20	1.64%	3.05%	6.07%	9.20%	0.1509%
JUNIPER NETWORKS INC	JNPR	8,427.01	0.05%	1.88%	9.57%	11.54%	0.0057%
JPMORGAN CHASE & CO	JPM	211,628.15	1.23%	3.23%	7.70%	11.06%	0.1362%
NORDSTROM INC	JWN	8,992.98	0.05%	12.86%	7.78%	21.14%	0.0111%
KELLOGG CO	K	26,569.20	0.15%	2.77%	5.50%	8.35%	0.0129%
KEYCORP	KEY	8,674.44	0.05%	3.22%	6.44%	9.77%	0.0049%
KRAFT HEINZ CO/THE	KHC	87,271.74	0.51%	2.67%	16.75%	19.64%	0.0998%
KIMCO REALTY CORP	KIM	10,865.93	0.06%	3.91%	4.90%	8.91%	0.0056%
KLA-TENCOR CORP	KLAC	9,929.85	0.06%	3.26%	13.12%	16.59%	0.0096%
KIMBERLY-CLARK CORP	KMB	46,422.53	0.27%	2.84%	7.79%	10.74%	0.0290%
KINDER MORGAN INC	KMI	33,384.08	0.19%	3.35%	6.47%	9.92%	0.0193%
CARMAX INC	KMX	8,539.67	0.05%	0.00%	13.53%	13.53%	0.0067%
COCA-COLA CO/THE	KO	187,484.75	1.09%	3.25%	6.16%	9.51%	0.1037%
MICHAEL KORS HOLDINGS LTD	KORS	8,894.39	0.05%	0.00%	4.63%	4.63%	0.0024%
KROGER CO	KR	37,361.12	0.22%	1.07%	10.39%	11.51%	0.0250%
KOHLS CORP	KSS	7,746.56	0.05%	4.41%	6.52%	11.07%	0.0050%
KANSAS CITY SOUTHERN	KSU	8,614.80	0.05%	1.74%	8.30%	10.11%	0.0051%
LOEWS CORP	L	12,706.73	N/A	0.74%	N/A	N/A	N/A
L BRANDS INC	LB	23,695.99	0.14%	4.95%	11.03%	16.26%	0.0224%
LEGGETT & PLATT INC	LEG	5,760.93	N/A	3.04%	N/A	N/A	N/A
LENNAR CORP-A	LEN	8,151.52	0.05%	0.40%	12.13%	12.56%	0.0060%
LABORATORY CRP OF AMER HLDGS	LH	10,425.62	0.06%	0.00%	10.26%	10.26%	0.0062%
L-3 COMMUNICATIONS HOLDINGS	LLL	9,040.46	0.05%	2.46%	5.02%	7.55%	0.0040%
LINEAR TECHNOLOGY CORP	LLTC	9,968.75	0.06%	2.97%	6.66%	9.73%	0.0056%
ELI LILLY & CO	LLY	78,972.62	0.46%	2.87%	12.87%	15.92%	0.0732%
LEGG MASON INC	LM	2,869.34	0.02%	3.01%	14.95%	18.19%	0.0030%
LOCKHEED MARTIN CORP	LMT	63,327.46	0.37%	3.26%	7.21%	10.58%	0.0390%
LINCOLN NATIONAL CORP	LNC	8,079.93	0.05%	3.07%	10.30%	13.53%	0.0064%
LOWE'S COS INC	LOW	59,362.84	0.35%	1.64%	17.02%	18.79%	0.0649%
LAM RESEARCH CORP	LRCX	10,494.94	0.06%	1.80%	8.34%	10.21%	0.0062%
LEUCADIA NATIONAL CORP	LUK	5,355.36	0.03%	1.69%	18.00%	19.84%	0.0062%
SOUTHWEST AIRLINES CO	LUV	23,123.66	0.13%	0.91%	15.07%	16.04%	0.0216%
LEVEL 3 COMMUNICATIONS INC	LVLT	16,623.42	0.10%	0.00%	-1.51%	-1.51%	-0.0015%
LYONDELLBASELL INDU-CL A	LYB	34,364.47	0.20%	4.19%	4.18%	8.46%	0.0169%
MACY'S INC	M	12,338.93	0.07%	3.51%	6.60%	10.23%	0.0073%
MASTERCARD INC-CLASS A	MA	94,290.61	0.55%	0.90%	15.23%	16.20%	0.0889%
MACERICH CO/THE	MAC	11,920.49	0.07%	6.30%	5.86%	12.34%	0.0086%
MARRIOTT INTERNATIONAL -CL A	MAR	16,404.82	0.10%	1.49%	12.23%	13.81%	0.0132%
MASCO CORP	MAS	8,622.11	0.05%	1.47%	13.40%	14.97%	0.0075%
MATTEL INC	MAT	10,438.53	0.06%	5.00%	8.97%	14.19%	0.0086%
MCDONALD'S CORP	MCD	108,286.84	0.63%	3.09%	9.81%	13.06%	0.0823%
MICROCHIP TECHNOLOGY INC	MCHP	8,223.48	0.05%	3.49%	7.81%	11.44%	0.0055%
MCKESSON CORP	MCK	34,523.49	0.20%	0.69%	12.78%	13.51%	0.0272%
MOODY'S CORP	MCO	16,272.69	0.09%	1.81%	13.00%	14.93%	0.0141%
MONDELEZ INTERNATIONAL INC-A	MDLZ	60,547.28	0.35%	1.83%	11.80%	13.73%	0.0484%
MEDTRONIC PLC	MDT	103,211.83	0.60%	2.07%	8.84%	11.00%	0.0661%
METLIFE INC	MET	41,608.18	0.24%	4.38%	8.60%	13.17%	0.0319%
MCGRAW HILL FINANCIAL INC	MHFI	22,688.46	0.13%	1.69%	10.88%	12.66%	0.0167%
MOHAWK INDUSTRIES INC	MHK	11,474.17	N/A	N/A	N/A	N/A	N/A
MEAD JOHNSON NUTRITION CO	MJN	13,146.79	0.08%	2.57%	9.15%	11.84%	0.0091%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
MCCORMICK & CO-NON VTG SHRS	MKC	11,392.14	0.07%	1.92%	6.50%	8.48%	0.0056%
MARTIN MARIETTA MATERIALS	MLM	8,787.43	0.05%	1.26%	21.93%	23.33%	0.0119%
MARSH & MCLENNAN COS	MMC	29,254.03	0.17%	2.33%	11.69%	14.16%	0.0241%
3M CO	MMM	93,151.68	0.54%	2.90%	9.13%	12.15%	0.0659%
MALLINCKRODT PLC	MNK	6,977.89	0.04%	0.00%	8.44%	8.44%	0.0034%
MONSTER BEVERAGE CORP	MNST	24,987.14	0.15%	0.00%	19.38%	19.38%	0.0282%
ALTRIA GROUP INC	MO	117,581.95	0.68%	3.97%	7.64%	11.76%	0.0805%
MONSANTO CO	MON	38,324.13	0.22%	2.50%	9.74%	12.36%	0.0276%
MOSAIC CO/THE	MOS	8,076.12	0.05%	4.85%	13.40%	18.57%	0.0087%
MARATHON PETROLEUM CORP	MPC	16,911.27	0.10%	4.20%	2.34%	6.59%	0.0065%
MERCK & CO. INC.	MRK	136,967.42	0.80%	3.76%	7.28%	11.17%	0.0891%
MARATHON OIL CORP	MRO	5,072.68	0.03%	9.08%	7.67%	17.09%	0.0050%
MORGAN STANLEY	MS	44,707.41	0.26%	3.00%	16.32%	19.56%	0.0509%
MICROSOFT CORP	MSFT	399,419.79	2.32%	2.79%	9.60%	12.52%	0.2911%
MOTOROLA SOLUTIONS INC	MSI	10,907.98	0.06%	2.25%	9.00%	11.36%	0.0072%
M & T BANK CORP	MTB	18,831.20	0.11%	2.72%	3.75%	6.52%	0.0071%
MICRON TECHNOLOGY INC	MU	10,395.31	0.06%	0.00%	-0.14%	-0.14%	-0.0001%
MURPHY OIL CORP	MUR	2,888.30	N/A	8.30%	N/A	N/A	N/A
MYLAN NV	MYL	20,566.98	0.12%	0.00%	9.92%	9.92%	0.0119%
NAVIENT CORP	NAVI	3,307.88	N/A	7.19%	N/A	N/A	N/A
NOBLE ENERGY INC	NBL	12,297.41	0.07%	2.52%	0.92%	3.46%	0.0025%
NASDAQ INC	NDAQ	10,069.34	0.06%	1.67%	7.90%	9.63%	0.0056%
NEXTERA ENERGY INC	NEE	51,428.04	0.30%	3.11%	6.42%	9.63%	0.0288%
NEWMONT MINING CORP	NEM	13,640.65	0.08%	0.40%	1.43%	1.83%	0.0015%
NETFLIX INC	NFLX	37,414.30	0.22%	0.00%	39.63%	39.63%	0.0863%
NEWFIELD EXPLORATION CO	NFX	3,949.68	0.02%	0.00%	4.68%	4.68%	0.0011%
NISOURCE INC	NI	6,781.32	0.04%	3.90%	4.00%	7.98%	0.0031%
NIKE INC -CL B	NKE	96,091.63	0.56%	1.08%	13.98%	15.14%	0.0847%
NIELSEN HOLDINGS PLC	NLSN	17,216.30	0.10%	2.50%	12.33%	14.98%	0.0150%
NORTHROP GRUMMAN CORP	NOC	32,795.96	0.19%	1.86%	6.90%	8.83%	0.0168%
NATIONAL OILWELL VARCO INC	NOV	10,351.85	0.06%	6.67%	-11.14%	-4.84%	-0.0029%
NRG ENERGY INC	NRG	3,009.81	0.02%	6.10%	-24.70%	-19.36%	-0.0034%
NORFOLK SOUTHERN CORP	NSC	21,637.29	0.13%	3.33%	5.00%	8.42%	0.0106%
NETAPP INC	NTAP	6,399.41	0.04%	3.29%	8.87%	12.30%	0.0046%
NORTHERN TRUST CORP	NTRS	13,144.87	0.08%	2.64%	11.48%	14.28%	0.0109%
NUCOR CORP	NUE	12,794.18	0.07%	3.75%	11.63%	15.61%	0.0116%
NVIDIA CORP	NVDA	13,842.74	0.08%	1.53%	8.53%	10.13%	0.0082%
NEWELL RUBBERMAID INC	NWL	9,292.41	0.05%	2.35%	8.48%	10.93%	0.0059%
NEWS CORP - CLASS A	NWSA	6,343.33	0.04%	1.86%	11.45%	13.42%	0.0050%
REALTY INCOME CORP	O	15,152.55	0.09%	3.88%	4.41%	8.38%	0.0074%
OWENS-ILLINOIS INC	OI	2,099.21	0.01%	0.00%	9.09%	9.09%	0.0011%
ONEOK INC	OKE	4,223.22	0.02%	12.10%	8.25%	20.85%	0.0051%
OMNICOM GROUP	OMC	17,573.97	0.10%	2.87%	5.75%	8.70%	0.0089%
ORACLE CORP	ORCL	149,311.36	0.87%	1.71%	7.75%	9.53%	0.0828%
O'REILLY AUTOMOTIVE INC	ORLY	24,957.88	0.15%	0.00%	15.69%	15.69%	0.0228%
OCCIDENTAL PETROLEUM CORP	OXY	51,216.13	0.30%	4.51%	8.00%	12.69%	0.0378%
PAYCHEX INC	PAYX	17,664.71	0.10%	3.43%	9.33%	12.92%	0.0133%
PEOPLE'S UNITED FINANCIAL	PBCT	4,454.95	0.03%	4.71%	12.40%	17.40%	0.0045%
PITNEY BOWES INC	PBI	3,326.21	0.02%	4.44%	14.00%	18.75%	0.0036%
PACCAR INC	PCAR	17,672.79	0.10%	4.10%	8.60%	12.87%	0.0132%
P G & E CORP	PCG	27,077.96	0.16%	3.30%	5.75%	9.14%	0.0144%
PLUM CREEK TIMBER CO	PCL	6,269.21	0.04%	4.94%	22.48%	27.98%	0.0102%
PRICELINE GROUP INC/THE	PCLN	52,671.85	0.31%	0.00%	18.62%	18.62%	0.0571%
PATTERSON COS INC	PDCO	4,223.79	0.02%	2.15%	9.93%	12.19%	0.0030%
PUBLIC SERVICE ENTERPRISE GP	PEG	21,194.74	0.12%	3.72%	3.76%	7.55%	0.0093%
PEPSICO INC	PEP	142,358.70	0.83%	3.01%	6.57%	9.68%	0.0802%
PFIZER INC	PFE	181,239.34	1.05%	4.07%	5.37%	9.55%	0.1008%
PRINCIPAL FINANCIAL GROUP	PFG	10,317.71	0.06%	4.56%	9.02%	13.79%	0.0083%
PROCTER & GAMBLE CO/THE	PG	219,042.76	1.28%	3.34%	7.35%	10.81%	0.1378%
PROGRESSIVE CORP	PGR	18,343.00	0.11%	2.08%	9.25%	11.43%	0.0122%
PARKER HANNIFIN CORP	PH	13,138.73	0.08%	2.59%	8.57%	11.27%	0.0086%
PULTEGROUP INC	PHM	5,589.87	0.03%	2.25%	12.20%	14.59%	0.0047%
PERKINELMER INC	PKI	4,971.00	0.03%	0.63%	11.51%	12.18%	0.0035%
PROLOGIS INC	PLD	18,902.38	0.11%	4.60%	4.11%	8.80%	0.0097%
PHILIP MORRIS INTERNATIONAL	PM	137,980.27	0.80%	4.69%	7.49%	12.35%	0.0992%
PNC FINANCIAL SERVICES GROUP	PNC	41,096.72	0.24%	2.64%	7.66%	10.40%	0.0249%
PENTAIR PLC	PNR	8,003.26	0.05%	3.02%	8.06%	11.20%	0.0052%
PINNACLE WEST CAPITAL	PNW	7,451.32	0.04%	3.59%	4.87%	8.55%	0.0037%
PEPCO HOLDINGS INC	POM	6,743.68	0.04%	4.06%	6.00%	10.18%	0.0040%
PPG INDUSTRIES INC	PPG	24,713.53	0.14%	1.61%	8.40%	10.08%	0.0145%
PPL CORP	PPL	24,047.50	0.14%	4.27%	4.66%	9.03%	0.0126%
PERRIGO CO PLC	PRGO	20,291.33	0.12%	0.37%	12.57%	12.96%	0.0153%
PRUDENTIAL FINANCIAL INC	PRU	27,676.36	0.16%	4.61%	10.67%	15.52%	0.0250%
PUBLIC STORAGE	PSA	40,450.88	N/A	2.78%	N/A	N/A	N/A
PHILLIPS 66	PSX	40,114.71	0.23%	3.15%	7.61%	10.88%	0.0254%
PVH CORP	PVH	6,010.75	0.03%	0.20%	7.47%	7.68%	0.0027%
QUANTA SERVICES INC	PWR	2,821.33	0.02%	0.00%	8.00%	8.00%	0.0013%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
PRAXAIR INC	PX	29,575.51	0.17%	2.86%	8.23%	11.21%	0.0193%
PIONEER NATURAL RESOURCES CO	PXD	18,631.53	0.11%	0.09%	0.15%	0.24%	0.0003%
PAYPAL HOLDINGS INC	PYPL	41,937.78	0.24%	0.00%	16.67%	16.67%	0.0407%
QUALCOMM INC	QCOM	66,612.18	0.39%	4.35%	10.80%	15.39%	0.0597%
QORVO INC	QRVO	5,148.28	0.03%	0.00%	14.64%	14.64%	0.0044%
RYDER SYSTEM INC	R	2,896.15	0.02%	3.14%	7.63%	10.88%	0.0018%
REYNOLDS AMERICAN INC	RAI	68,226.92	0.40%	3.53%	10.08%	13.78%	0.0547%
ROYAL CARIBBEAN CRUISES LTD	RCL	15,129.08	0.09%	2.23%	26.52%	29.04%	0.0256%
REGENERON PHARMACEUTICALS	REGN	39,715.75	0.23%	0.00%	20.92%	20.92%	0.0484%
REGIONS FINANCIAL CORP	RF	9,921.56	0.06%	3.49%	4.47%	8.03%	0.0046%
ROBERT HALF INTL INC	RHI	4,954.50	0.03%	2.27%	11.45%	13.84%	0.0040%
RED HAT INC	RHT	11,708.10	0.07%	0.00%	18.03%	18.03%	0.0123%
TRANSOCEAN LTD	RIG	3,286.77	0.02%	11.85%	10.02%	22.47%	0.0043%
RALPH LAUREN CORP	RL	7,304.24	0.04%	2.31%	12.77%	15.23%	0.0065%
ROCKWELL AUTOMATION INC	ROK	12,659.98	0.07%	3.00%	6.82%	9.92%	0.0073%
ROPER TECHNOLOGIES INC	ROP	16,490.72	0.10%	0.70%	11.53%	12.27%	0.0118%
ROSS STORES INC	ROST	21,769.02	0.13%	0.87%	10.63%	11.55%	0.0146%
RANGE RESOURCES CORP	RRC	4,645.81	0.03%	0.59%	3.25%	3.85%	0.0010%
REPUBLIC SERVICES INC	RSG	15,243.24	0.09%	2.77%	5.97%	8.82%	0.0078%
RAYTHEON COMPANY	RTN	35,951.52	0.21%	2.37%	7.65%	10.11%	0.0212%
STARBUCKS CORP	SBUX	82,566.67	0.48%	1.47%	17.91%	19.51%	0.0938%
SCANA CORP	SCG	9,203.85	0.05%	3.38%	5.55%	9.02%	0.0048%
SCHWAB (CHARLES) CORP	SCHW	30,043.06	0.17%	1.27%	18.63%	20.01%	0.0350%
SPECTRA ENERGY CORP	SE	19,128.49	0.11%	5.71%	5.40%	11.27%	0.0125%
SEALED AIR CORP	SEE	8,536.61	0.05%	1.26%	6.58%	7.88%	0.0039%
SHERWIN-WILLIAMS CO/THE	SHW	23,894.25	0.14%	1.23%	15.15%	16.47%	0.0229%
SIGNET JEWELERS LTD	SIG	7,844.24	0.05%	0.86%	15.20%	16.13%	0.0074%
JM SMUCKER CO/THE	SJM	15,189.14	0.09%	2.12%	11.37%	13.61%	0.0120%
SCHLUMBERGER LTD	SLB	88,227.98	0.51%	2.92%	11.40%	14.49%	0.0744%
SL GREEN REALTY CORP	SLG	8,181.97	0.05%	3.63%	4.26%	7.97%	0.0038%
SNAP-ON INC	SNA	8,133.46	0.05%	2.21%	3.40%	5.64%	0.0027%
SANDISK CORP	SNDK	13,566.46	0.08%	1.63%	9.75%	11.46%	0.0091%
SCRIPPS NETWORKS INTER-CL A	SNI	6,906.61	0.04%	1.69%	10.08%	11.86%	0.0048%
SOUTHERN CO/THE	SO	43,547.26	0.25%	4.66%	3.92%	8.67%	0.0220%
SIMON PROPERTY GROUP INC	SPG	56,787.50	0.33%	3.61%	7.55%	11.29%	0.0373%
STAPLES INC	SPLS	5,354.94	0.03%	5.77%	3.21%	9.07%	0.0028%
STERICYCLE INC	SRCL	9,086.57	0.05%	0.00%	15.60%	15.60%	0.0083%
SEMPRA ENERGY	SRE	23,200.23	0.14%	2.97%	8.94%	12.04%	0.0163%
SUNTRUST BANKS INC	STI	17,087.32	0.10%	3.05%	10.57%	13.79%	0.0137%
ST JUDE MEDICAL INC	STJ	14,246.08	0.08%	2.43%	11.17%	13.74%	0.0114%
STATE STREET CORP	STT	22,062.62	0.13%	2.63%	7.83%	10.57%	0.0136%
SEAGATE TECHNOLOGY	STX	8,857.09	0.05%	7.77%	5.42%	13.41%	0.0069%
CONSTELLATION BRANDS INC-A	STZ	27,474.65	0.16%	0.90%	13.68%	14.64%	0.0234%
STANLEY BLACK & DECKER INC	SWK	13,738.89	0.08%	2.40%	10.67%	13.20%	0.0106%
SKYWORKS SOLUTIONS INC	SWKS	11,045.85	0.06%	1.85%	17.69%	19.70%	0.0127%
SOUTHWESTERN ENERGY CO	SWN	3,433.39	0.02%	0.00%	5.61%	5.61%	0.0011%
SYNCHRONY FINANCIAL	SYF	21,154.16	0.12%	0.98%	5.84%	6.84%	0.0084%
STRYKER CORP	SYK	36,302.36	0.21%	1.55%	12.11%	13.76%	0.0291%
SYMANTEC CORP	SYMC	12,490.06	0.07%	3.16%	7.37%	10.65%	0.0077%
SYSCO CORP	SYY	24,396.51	0.14%	2.84%	8.75%	11.71%	0.0166%
AT&T INC	T	224,363.44	1.31%	5.28%	3.80%	9.19%	0.1200%
MOLSON COORS BREWING CO -B	TAP	18,016.83	0.10%	2.03%	13.30%	15.47%	0.0162%
TERADATA CORP	TDC	3,068.31	0.02%	0.00%	7.69%	7.69%	0.0014%
TECO ENERGY INC	TE	6,393.57	0.04%	3.39%	6.02%	9.51%	0.0035%
TE CONNECTIVITY LTD	TEL	20,143.73	0.12%	2.55%	10.00%	12.68%	0.0149%
TEGNA INC	TGNA	4,914.93	N/A	2.53%	N/A	N/A	N/A
TARGET CORP	TGT	43,092.81	0.25%	3.07%	10.49%	13.71%	0.0344%
TENET HEALTHCARE CORP	THC	2,392.06	0.01%	0.00%	18.95%	18.95%	0.0026%
TIFFANY & CO	TIF	7,914.52	0.05%	2.55%	9.05%	11.72%	0.0054%
TJX COMPANIES INC	TJX	46,780.00	0.27%	1.20%	10.89%	12.15%	0.0331%
TORCHMARK CORP	TMK	6,181.31	0.04%	1.14%	7.56%	8.74%	0.0031%
THERMO FISHER SCIENTIFIC INC	TMO	50,477.88	0.29%	0.49%	12.57%	13.09%	0.0385%
TRIPADVISOR INC	TRIP	8,636.78	0.05%	0.00%	17.66%	17.66%	0.0089%
T ROWE PRICE GROUP INC	TROW	16,764.51	0.10%	3.30%	9.24%	12.69%	0.0124%
TRAVELERS COS INC/THE	TRV	31,707.12	0.18%	2.36%	8.25%	10.71%	0.0198%
TRACTOR SUPPLY COMPANY	TSCO	11,214.20	0.07%	0.99%	15.41%	16.47%	0.0108%
TYSON FOODS INC-CL A	TSN	23,767.41	0.14%	1.06%	10.53%	11.65%	0.0161%
TESORO CORP	TSO	8,556.15	0.05%	2.87%	5.39%	8.33%	0.0042%
TOTAL SYSTEM SERVICES INC	TSS	7,245.50	0.04%	1.03%	10.00%	11.08%	0.0047%
TIME WARNER CABLE	TWC	52,402.19	0.31%	1.67%	7.73%	9.47%	0.0289%
TIME WARNER INC	TWX	49,775.63	0.29%	2.52%	13.06%	15.75%	0.0456%
TEXAS INSTRUMENTS INC	TXN	51,877.03	0.30%	3.00%	9.58%	12.72%	0.0384%
TEXTRON INC	TXT	8,779.35	0.05%	0.34%	9.59%	9.95%	0.0051%
TYCO INTERNATIONAL PLC	TYC	14,233.21	0.08%	2.60%	10.60%	13.34%	0.0110%
UNDER ARMOUR INC-CLASS A	UA	16,464.59	0.10%	0.00%	22.74%	22.74%	0.0218%
UNITED CONTINENTAL HOLDINGS	UAL	18,469.77	0.11%	0.00%	19.92%	19.92%	0.0214%
UNIVERSAL HEALTH SERVICES-B	UHS	10,286.33	0.06%	0.38%	10.35%	10.76%	0.0064%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
UNITEDHEALTH GROUP INC	UNH	106,304.37	0.62%	1.82%	13.35%	15.29%	0.0946%
UNUM GROUP	UNM	6,120.27	0.04%	3.04%	9.00%	12.18%	0.0043%
UNION PACIFIC CORP	UNP	65,343.19	0.38%	2.95%	8.34%	11.42%	0.0434%
UNITED PARCEL SERVICE-CL B	UPS	86,592.83	0.50%	3.19%	9.93%	13.28%	0.0669%
URBAN OUTFITTERS INC	URBN	2,910.74	0.02%	0.00%	12.69%	12.69%	0.0022%
UNITED RENTALS INC	URI	4,134.60	0.02%	0.00%	12.64%	12.64%	0.0030%
US BANCORP	USB	68,565.55	0.40%	2.74%	5.40%	8.22%	0.0328%
UNITED TECHNOLOGIES CORP	UTX	71,891.33	0.42%	3.14%	9.01%	12.30%	0.0515%
VISA INC-CLASS A SHARES	V	169,110.53	0.98%	0.80%	17.12%	17.99%	0.1771%
VARIAN MEDICAL SYSTEMS INC	VAR	7,244.82	0.04%	0.00%	15.00%	15.00%	0.0063%
VF CORP	VFC	25,062.71	0.15%	2.25%	10.68%	13.05%	0.0190%
VIACOM INC-CLASS B	VIAB	13,178.02	0.08%	4.90%	9.50%	14.63%	0.0112%
VALERO ENERGY CORP	VLO	27,806.82	0.16%	4.11%	4.49%	8.69%	0.0141%
VULCAN MATERIALS CO	VMC	12,268.01	0.07%	0.58%	28.41%	29.08%	0.0208%
VORNADO REALTY TRUST	VNO	15,296.32	N/A	3.11%	N/A	N/A	N/A
VERISK ANALYTICS INC	VRSK	11,531.29	0.07%	0.00%	12.00%	12.00%	0.0081%
VERISIGN INC	VRSN	8,582.71	0.05%	0.00%	9.75%	9.75%	0.0049%
VERTEX PHARMACEUTICALS INC	VRTX	20,451.05	0.12%	0.00%	45.07%	45.07%	0.0536%
VENTAS INC	VTR	16,275.89	0.09%	6.21%	2.57%	8.86%	0.0084%
VERIZON COMMUNICATIONS INC	VZ	203,891.23	1.19%	4.56%	5.30%	9.98%	0.1184%
WATERS CORP	WAT	9,669.81	0.06%	0.00%	9.39%	9.39%	0.0053%
WALGREENS BOOTS ALLIANCE INC	WBA	83,149.81	0.48%	1.89%	12.27%	14.27%	0.0691%
WESTERN DIGITAL CORP	WDC	9,562.20	0.06%	4.96%	10.00%	15.20%	0.0085%
WEC ENERGY GROUP INC	WEC	17,574.15	0.10%	3.51%	5.54%	9.15%	0.0094%
WELLS FARGO & CO	WFC	241,650.63	1.41%	3.30%	9.14%	12.59%	0.1772%
WHOLE FOODS MARKET INC	WFM	10,054.42	0.06%	1.78%	9.75%	11.62%	0.0068%
WHIRLPOOL CORP	WHR	10,336.52	0.06%	2.93%	16.71%	19.88%	0.0120%
WILLIS TOWERS WATSON PLC	WLTW	14,891.11	0.09%	1.65%	10.00%	11.73%	0.0102%
WASTE MANAGEMENT INC	WM	24,101.82	0.14%	2.83%	8.33%	11.29%	0.0158%
WILLIAMS COS INC	WMB	10,099.33	0.06%	18.19%	-3.60%	14.26%	0.0084%
WAL-MART STORES INC	WMT	211,901.29	1.23%	2.96%	0.36%	3.33%	0.0410%
WESTROCK CO	WRK	7,876.95	0.05%	4.83%	1.63%	6.51%	0.0030%
WESTERN UNION CO	WU	8,872.73	0.05%	3.62%	5.85%	9.58%	0.0049%
WEYERHAEUSER CO	WY	11,536.80	0.07%	5.69%	5.33%	11.17%	0.0075%
WYNDHAM WORLDWIDE CORP	WYN	7,379.40	0.04%	2.93%	8.75%	11.81%	0.0051%
WYNN RESORTS LTD	WYNN	7,022.45	0.04%	2.95%	8.93%	12.02%	0.0049%
CIMAREX ENERGY CO	XEC	8,006.36	0.05%	0.76%	-6.02%	-5.29%	-0.0025%
XCEL ENERGY INC	XEL	19,701.03	0.11%	3.48%	5.13%	8.70%	0.0100%
XL GROUP PLC	XL	10,296.52	0.06%	2.40%	9.50%	12.01%	0.0072%
XILINX INC	XLNX	12,176.48	0.07%	2.60%	8.87%	11.58%	0.0082%
EXXON MOBIL CORP	XOM	337,322.91	1.96%	3.66%	13.22%	17.13%	0.3363%
DENTSPLY INTERNATIONAL INC	XRAY	7,668.88	0.04%	0.51%	10.30%	10.84%	0.0048%
XEROX CORP	XRX	8,878.77	0.05%	3.59%	8.55%	12.30%	0.0064%
XYLEM INC	XYL	6,643.72	0.04%	1.65%	11.30%	13.04%	0.0050%
YAHOO! INC	YHOO	25,535.36	0.15%	0.00%	8.97%	8.97%	0.0133%
YUM! BRANDS INC	YUM	29,039.81	0.17%	2.81%	11.85%	14.83%	0.0251%
ZIMMER BIOMET HOLDINGS INC	ZBH	18,485.76	0.11%	0.99%	10.61%	11.66%	0.0125%
ZIONS BANCORPORATION	ZION	4,288.14	0.02%	1.45%	9.00%	10.51%	0.0026%
ZOETIS INC	ZTS	20,130.92	N/A	0.92%	N/A	N/A	N/A
ZIONS BANCORPORATION	ZION	5,577.24	0.03%	0.81%	7.15%	7.98%	0.0026%
ZOETIS INC	ZTS	23,860.35	0.14%	0.69%	10.23%	10.96%	0.0152%
Total Market Capitalization:		17,179,578.30					13.44%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
12.78%	2.79%	9.99%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	$ 11,710.45	0.08%	1.30%	2.50%	3.82%	0.0029%
ALCOA INC	AA	$ 9,602.48	0.06%	1.64%	17.00%	18.78%	0.0117%
AMERICAN AIRLINES GROUP INC	AAL	$ 23,357.54	N/A	1.10%	N/A	N/A	N/A
ADVANCE AUTO PARTS INC	AAP	$ 10,136.32	0.07%	0.17%	13.50%	13.68%	0.0090%
APPLE INC	AAPL	$ 519,518.40	3.37%	2.38%	14.00%	16.55%	0.5570%
ABBVIE INC	ABBV	$ 85,301.10	N/A	4.37%	N/A	N/A	N/A
AMERISOURCEBERGEN CORP	ABC	$ 17,444.02	0.11%	1.61%	13.50%	15.22%	0.0172%
ABBOTT LABORATORIES	ABT	$ 54,209.10	0.35%	2.86%	1.00%	3.87%	0.0136%
ACCENTURE PLC-CL A	ACN	$ 60,594.11	0.39%	2.42%	8.00%	10.52%	0.0413%
ADOBE SYSTEMS INC	ADBE	$ 37,305.81	0.24%	0.00%	37.50%	37.50%	0.0906%
ANALOG DEVICES INC	ADI	$ 15,241.06	0.10%	3.28%	13.00%	16.49%	0.0163%
ARCHER-DANIELS-MIDLAND CO	ADM	$ 19,009.63	0.12%	3.79%	8.00%	11.94%	0.0147%
AUTOMATIC DATA PROCESSING	ADP	$ 36,792.33	0.24%	2.87%	9.00%	12.00%	0.0286%
ALLIANCE DATA SYSTEMS CORP	ADS	$ 11,029.65	0.07%	0.00%	15.00%	15.00%	0.0107%
AUTODESK INC	ADSK	$ 9,747.47	0.06%	0.00%	13.50%	13.50%	0.0085%
ADT CORP/THE	ADT	$ 4,358.80	0.03%	3.34%	10.50%	14.02%	0.0040%
AMEREN CORPORATION	AEE	$ 11,006.76	0.07%	3.79%	7.00%	10.92%	0.0078%
AMERICAN ELECTRIC POWER	AEP	$ 30,091.25	0.19%	3.70%	5.00%	8.79%	0.0171%
AES CORP	AES	$ 6,070.15	0.04%	4.89%	8.00%	13.09%	0.0051%
AETNA INC	AET	$ 34,109.84	0.22%	1.02%	11.00%	12.08%	0.0267%
AFLAC INC	AFL	$ 23,772.72	0.15%	2.99%	4.50%	7.56%	0.0116%
ALLERGAN PLC	AGN	$ 108,172.70	0.70%	0.00%	17.00%	17.00%	0.1191%
AMERICAN INTERNATIONAL GROUP	AIG	$ 62,988.08	0.41%	2.22%	5.00%	7.28%	0.0297%
APARTMENT INVT & MGMT CO -A	AIV	$ -	N/A	3.69%	N/A	N/A	N/A
ASSURANT INC	AIZ	$ 4,466.04	0.03%	2.99%	3.50%	6.54%	0.0019%
AKAMAI TECHNOLOGIES INC	AKAM	$ 8,743.87	0.06%	0.00%	15.50%	15.50%	0.0088%
ALLSTATE CORP	ALL	$ 24,304.80	0.16%	1.93%	7.50%	9.50%	0.0150%
ALLEGION PLC	ALLE	$ 5,442.05	N/A	0.85%	N/A	N/A	N/A
ALEXION PHARMACEUTICALS INC	ALXN	$ 30,589.33	0.20%	0.00%	25.50%	25.50%	0.0505%
APPLIED MATERIALS INC	AMAT	$ 18,142.40	0.12%	2.56%	18.50%	21.30%	0.0250%
AMETEK INC	AME	$ 10,711.87	0.07%	0.80%	7.50%	8.33%	0.0058%
AFFILIATED MANAGERS GROUP	AMG	$ 6,573.24	0.04%	0.00%	13.00%	13.00%	0.0055%
AMGEN INC	AMGN	$ 106,788.10	0.69%	2.83%	9.50%	12.46%	0.0862%
AMERIPRISE FINANCIAL INC	AMP	$ 13,348.85	0.09%	3.51%	13.50%	17.25%	0.0149%
AMERICAN TOWER CORP	AMT	$ 35,429.76	0.23%	2.44%	14.50%	17.12%	0.0393%
AMAZON.COM INC	AMZN	$ 236,291.60	N/A	0.00%	N/A	N/A	N/A
AUTONATION INC	AN	$ 5,193.84	0.03%	0.00%	11.50%	11.50%	0.0039%
ANTHEM INC	ANTM	$ 31,318.26	0.20%	2.08%	9.00%	11.17%	0.0227%
AON PLC	AON	$ 25,387.79	0.16%	1.30%	13.50%	14.89%	0.0245%
APACHE CORP	APA	$ 12,996.12	0.08%	2.91%	-3.00%	-0.13%	-0.0001%
ANADARKO PETROLEUM CORP	APC	$ 18,129.01	0.12%	0.56%	10.00%	10.59%	0.0124%
AIR PRODUCTS & CHEMICALS INC	APD	$ 27,432.84	0.18%	2.55%	13.00%	15.72%	0.0279%
AMPHENOL CORP-CL A	APH	$ 15,104.88	0.10%	1.14%	9.50%	10.69%	0.0105%
AIRGAS INC	ARG	$ 10,072.34	0.07%	1.80%	10.00%	11.89%	0.0078%
ACTIVISION BLIZZARD INC	ATVI	$ 22,308.41	0.14%	0.85%	10.00%	10.89%	0.0157%
AVALONBAY COMMUNITIES INC	AVB	$ -	N/A	3.34%	N/A	N/A	N/A
BROADCOM LTD	AVGO	$ 31,974.55	0.21%	1.51%	15.50%	17.13%	0.0355%
AVERY DENNISON CORP	AVY	$ 5,673.83	0.04%	2.41%	7.50%	10.00%	0.0037%
AMERICAN EXPRESS CO	AXP	$ 50,304.76	0.33%	2.45%	3.50%	5.99%	0.0195%
AUTOZONE INC	AZO	$ 21,530.75	0.14%	0.00%	13.00%	13.00%	0.0181%
BOEING CO/THE	BA	$ 72,759.02	0.47%	4.02%	11.00%	15.24%	0.0718%
BANK OF AMERICA CORP	BAC	$ 116,368.70	0.75%	2.15%	27.00%	29.44%	0.2220%
BAXTER INTERNATIONAL INC	BAX	$ 19,619.86	0.13%	1.28%	-7.00%	-5.76%	-0.0073%
BED BATH & BEYOND INC	BBBY	$ 6,901.74	0.04%	0.00%	4.00%	4.00%	0.0018%
BB&T CORP	BBT	$ 23,622.94	0.15%	3.86%	6.50%	10.49%	0.0160%
BEST BUY CO INC	BBY	$ 9,287.16	0.06%	3.42%	6.50%	10.03%	0.0060%
CR BARD INC	BCR	$ 13,410.31	0.09%	0.56%	9.00%	9.59%	0.0083%
BECTON DICKINSON AND CO	BDX	$ 28,513.49	0.18%	2.04%	9.50%	11.64%	0.0215%
FRANKLIN RESOURCES INC	BEN	$ 18,719.95	0.12%	2.39%	8.50%	10.99%	0.0133%
BROWN-FORMAN CORP-CLASS B	BF/B	$ 19,244.27	0.12%	1.44%	9.00%	10.50%	0.0131%
BAKER HUGHES INC	BHI	$ 17,347.54	0.11%	1.71%	2.00%	3.73%	0.0042%
BIOGEN INC	BIIB	$ 54,635.75	0.35%	0.00%	16.50%	16.50%	0.0584%
BANK OF NEW YORK MELLON CORP	BK	$ 35,783.28	0.23%	2.08%	11.50%	13.70%	0.0318%
BLACKROCK INC	BLK	$ 48,227.50	0.31%	3.11%	8.50%	11.74%	0.0367%
BALL CORP	BLL	$ 8,678.87	0.06%	0.81%	9.50%	10.35%	0.0058%
BRISTOL-MYERS SQUIBB CO	BMY	$ 99,296.38	0.64%	2.55%	14.50%	17.23%	0.1109%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
BERKSHIRE HATHAWAY INC-CL B	BRK/B	$ 156.11	N/A	0.00%	N/A	N/A	N/A
BOSTON SCIENTIFIC CORP	BSX	$ 22,297.83	0.14%	0.00%	15.00%	15.00%	0.0217%
BORGWARNER INC	BWA	$ 6,766.94	0.04%	1.72%	8.50%	10.29%	0.0045%
BAXALTA INC	BXLT	N/A	N/A	0.00%	N/A	N/A	N/A
BOSTON PROPERTIES INC	BXP	$ -	N/A	2.59%	N/A	N/A	N/A
CITIGROUP INC	C	$ 104,205.10	0.68%	0.57%	13.50%	14.11%	0.0953%
CA INC	CA	$ 11,197.80	0.07%	3.83%	5.00%	8.93%	0.0065%
CONAGRA FOODS INC	CAG	$ 17,478.07	0.11%	2.48%	6.50%	9.06%	0.0103%
CARDINAL HEALTH INC	CAH	$ 25,449.60	0.16%	2.27%	14.00%	16.43%	0.0271%
CAMERON INTERNATIONAL CORP	CAM	$ 12,007.86	0.08%	0.00%	3.50%	3.50%	0.0027%
CATERPILLAR INC	CAT	$ 35,754.99	0.23%	5.02%	2.50%	7.58%	0.0176%
CHUBB LTD	CB	$ 35,919.03	0.23%	2.42%	8.00%	10.52%	0.0245%
CBRE GROUP INC - A	CBG	$ 7,862.95	0.05%	0.00%	12.50%	12.50%	0.0064%
CBS CORP-CLASS B NON VOTING	CBS	$ 20,652.18	0.13%	1.38%	12.50%	13.97%	0.0187%
COCA-COLA ENTERPRISES	CCE	$ 10,714.40	0.07%	2.54%	5.00%	7.60%	0.0053%
CROWN CASTLE INTL CORP	CCI	$ 27,205.67	0.18%	4.34%	23.50%	28.35%	0.0500%
CARNIVAL CORP	CCL	$ 33,601.82	0.22%	2.78%	14.00%	16.97%	0.0370%
CELGENE CORP	CELG	$ 78,397.24	0.51%	0.00%	16.50%	16.50%	0.0838%
CERNER CORP	CERN	$ 18,456.51	0.12%	0.00%	17.00%	17.00%	0.0203%
CF INDUSTRIES HOLDINGS INC	CF	$ 6,768.44	0.04%	4.82%	6.50%	11.48%	0.0050%
CITIZENS FINANCIAL GROUP	CFG	$ 9,571.34	N/A	2.21%	N/A	N/A	N/A
CHURCH & DWIGHT CO INC	CHD	$ 11,346.61	0.07%	1.64%	8.50%	10.21%	0.0075%
CHESAPEAKE ENERGY CORP	CHK	$ 1,180.98	0.01%	0.00%	7.00%	7.00%	0.0005%
C.H. ROBINSON WORLDWIDE INC	CHRW	$ 9,918.95	0.06%	2.50%	6.50%	9.08%	0.0058%
CIGNA CORP	CI	$ 32,972.67	0.21%	0.03%	14.50%	14.53%	0.0310%
CINCINNATI FINANCIAL CORP	CINF	$ 9,911.54	0.06%	3.17%	7.50%	10.79%	0.0069%
COLGATE-PALMOLIVE CO	CL	$ 57,797.66	0.37%	2.50%	11.00%	13.64%	0.0511%
CLOROX COMPANY	CLX	$ 16,425.75	0.11%	2.47%	8.00%	10.57%	0.0112%
COMERICA INC	CMA	$ 5,495.32	0.04%	2.71%	7.50%	10.31%	0.0037%
COMCAST CORP-CLASS A	CMCSA	$ 137,703.20	0.89%	1.96%	10.00%	12.06%	0.1076%
CME GROUP INC	CME	$ 30,077.53	0.19%	2.69%	10.00%	12.82%	0.0250%
CHIPOTLE MEXICAN GRILL INC	CMG	$ 14,392.14	0.09%	0.00%	16.50%	16.50%	0.0154%
CUMMINS INC	CMI	$ 16,918.40	0.11%	4.09%	6.50%	10.72%	0.0118%
CMS ENERGY CORP	CMS	$ 10,881.72	0.07%	3.16%	5.50%	8.75%	0.0062%
CENTERPOINT ENERGY INC	CNP	$ 7,594.13	N/A	5.84%	N/A	N/A	N/A
CONSOL ENERGY INC	CNX	$ 1,681.26	0.01%	0.55%	8.00%	8.57%	0.0009%
CAPITAL ONE FINANCIAL CORP	COF	$ 32,174.60	0.21%	2.66%	3.50%	6.21%	0.0129%
CABOT OIL & GAS CORP	COG	$ 8,223.68	0.05%	0.40%	30.50%	30.96%	0.0165%
COACH INC	COH	$ 9,339.05	0.06%	4.01%	2.00%	6.05%	0.0037%
ROCKWELL COLLINS INC	COL	$ 10,272.96	0.07%	1.72%	7.00%	8.78%	0.0058%
CONOCOPHILLIPS	COP	$ 39,360.39	0.26%	3.14%	2.50%	5.68%	0.0145%
COSTCO WHOLESALE CORP	COST	$ 64,493.29	0.42%	1.12%	10.50%	11.68%	0.0488%
CAMPBELL SOUP CO	CPB	$ 17,772.30	0.12%	2.18%	4.50%	6.73%	0.0077%
COLUMBIA PIPELINE GROUP	CPGX	N/A	N/A	0.00%	N/A	N/A	N/A
SALESFORCE.COM INC	CRM	$ 39,335.36	N/A	0.00%	N/A	N/A	N/A
CISCO SYSTEMS INC	CSCO	$ 125,423.80	0.81%	4.21%	6.50%	10.85%	0.0881%
CSRA INC	CSRA	$ -	N/A	1.62%	N/A	N/A	N/A
CSX CORP	CSX	$ 22,823.44	0.15%	3.08%	9.00%	12.22%	0.0181%
CINTAS CORP	CTAS	$ 8,879.64	0.06%	1.28%	13.50%	14.87%	0.0086%
CENTURYLINK INC	CTL	$ 15,121.12	0.10%	7.92%	15.00%	23.51%	0.0230%
COGNIZANT TECH SOLUTIONS-A	CTSH	$ 31,682.88	0.21%	0.00%	15.50%	15.50%	0.0318%
CITRIX SYSTEMS INC	CTXS	$ 18,596.23	0.12%	0.00%	14.00%	14.00%	0.0169%
CABLEVISION SYSTEMS-NY GRP-A	CVC	$ 8,861.84	0.06%	0.00%	13.00%	13.00%	0.0075%
CVS HEALTH CORP	CVS	$ 104,195.70	0.68%	1.81%	13.00%	14.93%	0.1008%
CHEVRON CORP	CVX	$ 156,190.30	1.01%	5.16%	2.50%	7.72%	0.0782%
DOMINION RESOURCES INC/VA	D	$ 41,203.00	0.27%	4.13%	8.00%	12.30%	0.0328%
DELTA AIR LINES INC	DAL	$ 33,647.60	0.22%	1.59%	16.00%	17.72%	0.0386%
DU PONT (E.I.) DE NEMOURS	DD	$ 49,616.45	0.32%	2.79%	6.00%	8.87%	0.0285%
DEERE & CO	DE	$ 24,198.05	N/A	3.14%	N/A	N/A	N/A
DISCOVER FINANCIAL SERVICES	DFS	$ 18,576.61	0.12%	2.59%	4.00%	6.64%	0.0080%
DOLLAR GENERAL CORP	DG	$ 20,001.78	0.13%	1.46%	14.00%	15.56%	0.0202%
QUEST DIAGNOSTICS INC	DGX	$ 8,827.20	0.06%	2.61%	9.00%	11.73%	0.0067%
DR HORTON INC	DHI	$ 8,588.76	0.06%	1.38%	15.00%	16.48%	0.0092%
DANAHER CORP	DHR	$ 57,275.86	0.37%	0.65%	13.00%	13.69%	0.0508%
WALT DISNEY CO/THE	DIS	$ 144,496.00	0.94%	1.57%	12.00%	13.66%	0.1279%
DISCOVERY COMMUNICATIONS-A	DISCA	$ 10,473.65	0.07%	0.00%	18.00%	18.00%	0.0122%
DELPHI AUTOMOTIVE PLC	DLPH	$ 16,452.46	0.11%	1.98%	15.50%	17.63%	0.0188%
DOLLAR TREE INC	DLTR	$ 17,241.36	0.11%	0.00%	17.50%	17.50%	0.0195%
DUN & BRADSTREET CORP	DNB	$ 3,225.17	0.02%	2.07%	4.50%	6.62%	0.0014%
DIAMOND OFFSHORE DRILLING	DO	$ 2,363.25	0.02%	0.00%	-2.00%	-2.00%	-0.0003%
DOVER CORP	DOV	$ 8,871.75	0.06%	2.93%	2.50%	5.47%	0.0031%
DOW CHEMICAL CO/THE	DOW	$ 51,905.96	0.34%	4.11%	12.50%	16.87%	0.0567%
DR PEPPER SNAPPLE GROUP INC	DPS	$ 16,942.63	0.11%	2.23%	9.00%	11.33%	0.0124%
DARDEN RESTAURANTS INC	DRI	$ 7,327.41	0.05%	3.50%	11.50%	15.20%	0.0072%
DTE ENERGY COMPANY	DTE	$ 15,090.34	0.10%	3.57%	5.00%	8.66%	0.0085%
DUKE ENERGY CORP	DUK	$ 52,838.40	0.34%	4.41%	5.00%	9.52%	0.0326%
DAVITA HEALTHCARE PARTNERS I	DVA	$ 13,202.90	0.09%	0.00%	11.50%	11.50%	0.0098%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
DEVON ENERGY CORP	DVN	$ 8,733.75	0.06%	4.52%	6.00%	10.66%	0.0060%
ELECTRONIC ARTS INC	EA	$ 18,097.09	0.12%	0.00%	16.50%	16.50%	0.0193%
EBAY INC	EBAY	$ 26,510.42	0.17%	0.00%	3.00%	3.00%	0.0052%
ECOLAB INC	ECL	$ 30,504.49	0.20%	1.36%	11.00%	12.43%	0.0246%
CONSOLIDATED EDISON INC	ED	$ 19,471.34	0.13%	3.74%	2.50%	6.29%	0.0079%
EQUIFAX INC	EFX	$ 11,055.13	0.07%	1.41%	9.00%	10.47%	0.0075%
EDISON INTERNATIONAL	EIX	$ 20,314.31	0.13%	3.13%	3.50%	6.68%	0.0088%
ESTEE LAUDER COMPANIES-CL A	EL	$ 32,153.65	0.21%	1.38%	9.00%	10.44%	0.0218%
EMC CORP/MA	EMC	$ 46,846.24	0.30%	1.90%	3.50%	5.43%	0.0165%
EASTMAN CHEMICAL CO	EMN	$ 8,681.67	0.06%	3.15%	9.50%	12.80%	0.0072%
EMERSON ELECTRIC CO	EMR	$ 29,216.03	0.19%	4.18%	2.00%	6.22%	0.0118%
ENDO INTERNATIONAL PLC	ENDP	$ 10,978.96	N/A	0.00%	N/A	N/A	N/A
EOG RESOURCES INC	EOG	$ 36,036.30	0.23%	1.11%	2.00%	3.12%	0.0073%
EQUINIX INC	EQIX	$ 15,756.51	0.10%	2.46%	25.50%	28.27%	0.0289%
EQUITY RESIDENTIAL	EQR	$ -	N/A	3.37%	N/A	N/A	N/A
EQT CORP	EQT	$ 8,714.61	0.06%	0.21%	14.00%	14.22%	0.0080%
EVERSOURCE ENERGY	ES	$ 17,096.60	0.11%	3.36%	7.00%	10.48%	0.0116%
EXPRESS SCRIPTS HOLDING CO	ESRX	$ 44,886.03	0.29%	0.00%	17.50%	17.50%	0.0509%
ESSEX PROPERTY TRUST INC	ESS	$ -	N/A	3.33%	N/A	N/A	N/A
ENSCO PLC-CL A	ESV	$ 1,896.18	0.01%	7.45%	-18.50%	-11.74%	-0.0014%
E*TRADE FINANCIAL CORP	ETFC	$ 5,875.36	0.04%	0.00%	32.50%	32.50%	0.0124%
EATON CORP PLC	ETN	$ 24,574.68	0.16%	4.14%	5.00%	9.24%	0.0147%
ENTERGY CORP	ETR	$ 12,583.42	0.08%	4.85%	-1.00%	3.83%	0.0031%
EDWARDS LIFESCIENCES CORP	EW	$ 17,025.21	0.11%	0.00%	15.00%	15.00%	0.0165%
EXELON CORP	EXC	$ 27,871.99	0.18%	4.19%	6.50%	10.83%	0.0196%
EXPEDITORS INTL WASH INC	EXPD	$ 8,320.52	0.05%	1.61%	10.50%	12.19%	0.0066%
EXPEDIA INC	EXPE	$ 13,418.56	0.09%	0.93%	22.00%	23.03%	0.0200%
EXTRA SPACE STORAGE INC	EXR	N/A	N/A	0.00%	N/A	N/A	N/A
FORD MOTOR CO	F	$ 43,538.18	0.28%	5.91%	7.00%	13.12%	0.0370%
FASTENAL CO	FAST	$ 12,168.37	0.08%	2.86%	8.50%	11.48%	0.0091%
FACEBOOK INC-A	FB	$ 287,997.70	1.87%	0.00%	34.50%	34.50%	0.6438%
FREEPORT-MCMORAN INC	FCX	$ 5,564.82	0.04%	0.00%	-0.50%	-0.50%	-0.0002%
FEDEX CORP	FDX	$ 34,292.02	0.22%	0.80%	15.00%	15.86%	0.0352%
FIRSTENERGY CORP	FE	$ 13,879.97	0.09%	4.39%	7.50%	12.05%	0.0108%
F5 NETWORKS INC	FFIV	$ 5,978.59	0.04%	0.00%	9.00%	9.00%	0.0035%
FIDELITY NATIONAL INFO SERV	FIS	$ 15,921.72	0.10%	1.84%	12.50%	14.46%	0.0149%
FISERV INC	FISV	$ 21,040.56	0.14%	0.00%	10.50%	10.50%	0.0143%
FIFTH THIRD BANCORP	FITB	$ 11,088.42	0.07%	4.02%	4.00%	8.10%	0.0058%
FLIR SYSTEMS INC	FLIR	$ 3,953.22	0.03%	1.68%	6.50%	8.23%	0.0021%
FLUOR CORP	FLR	$ 5,936.22	0.04%	2.01%	7.50%	9.59%	0.0037%
FLOWSERVE CORP	FLS	$ 5,187.12	0.03%	1.81%	10.00%	11.90%	0.0040%
FMC CORP	FMC	$ 4,480.38	0.03%	2.15%	4.50%	6.70%	0.0019%
TWENTY-FIRST CENTURY FOX-A	FOXA	$ 48,768.96	0.32%	1.22%	6.50%	7.76%	0.0245%
FEDERAL REALTY INVS TRUST	FRT	$ -	N/A	2.65%	N/A	N/A	N/A
FIRST SOLAR INC	FSLR	$ 6,192.39	0.04%	0.00%	7.50%	7.50%	0.0030%
FMC TECHNOLOGIES INC	FTI	$ 5,193.84	0.03%	0.00%	3.00%	3.00%	0.0010%
FRONTIER COMMUNICATIONS CORP	FTR	$ 4,871.47	0.03%	10.07%	18.00%	28.98%	0.0091%
AGL RESOURCES INC	GAS	$ 7,777.70	0.05%	3.28%	6.50%	9.89%	0.0050%
GENERAL DYNAMICS CORP	GD	$ 40,009.08	0.26%	2.15%	9.00%	11.25%	0.0292%
GENERAL ELECTRIC CO	GE	$ 277,498.60	1.80%	3.35%	9.00%	12.50%	0.2248%
GENERAL GROWTH PROPERTIES	GGP	$ -	N/A	3.07%	N/A	N/A	N/A
GILEAD SCIENCES INC	GILD	$ 126,584.60	0.82%	1.97%	22.50%	24.69%	0.2025%
GENERAL MILLS INC	GIS	$ 33,212.94	0.22%	3.23%	5.50%	8.82%	0.0190%
CORNING INC	GLW	$ 21,087.04	0.14%	3.03%	6.00%	9.12%	0.0125%
GENERAL MOTORS CO	GM	$ 43,040.00	0.28%	5.35%	10.00%	15.62%	0.0436%
KEURIG GREEN MOUNTAIN INC	GMCR	$ 13,406.03	0.09%	1.45%	8.50%	10.01%	0.0087%
GAMESTOP CORP-CLASS A	GME	$ 2,797.68	0.02%	5.40%	7.50%	13.10%	0.0024%
ALPHABET INC-CL C	GOOG	$ 469,770.00	3.04%	0.00%	16.50%	16.50%	0.5022%
GENUINE PARTS CO	GPC	$ 13,031.95	0.08%	2.85%	7.00%	9.95%	0.0084%
GAP INC/THE	GPS	$ 9,061.72	0.06%	4.24%	4.00%	8.32%	0.0049%
GARMIN LTD	GRMN	$ 6,441.17	0.04%	6.12%	-2.00%	4.06%	0.0017%
GOLDMAN SACHS GROUP INC	GS	$ 60,009.35	0.39%	1.85%	7.00%	8.91%	0.0347%
GOODYEAR TIRE & RUBBER CO	GT	$ 7,696.09	0.05%	0.98%	10.50%	11.53%	0.0058%
WW GRAINGER INC	GWW	$ 12,832.19	0.08%	2.29%	9.00%	11.39%	0.0095%
HALLIBURTON CO	HAL	$ 24,624.00	0.16%	2.50%	2.00%	4.53%	0.0072%
HARMAN INTERNATIONAL	HAR	$ 4,809.64	0.03%	2.07%	20.00%	22.28%	0.0069%
HASBRO INC	HAS	$ 8,674.69	0.06%	2.93%	10.00%	13.08%	0.0073%
HUNTINGTON BANCSHARES INC	HBAN	$ 6,381.24	0.04%	3.50%	9.00%	12.66%	0.0052%
HANESBRANDS INC	HBI	$ 9,871.12	0.06%	1.75%	16.50%	18.39%	0.0118%
HCA HOLDINGS INC	HCA	$ 26,511.99	0.17%	0.00%	12.50%	12.50%	0.0215%
WELLTOWER INC	HCN	$ -	N/A	6.41%	N/A	N/A	N/A
HCP INC	HCP	$ -	0.00%	8.80%	89.00%	101.72%	0.0000%
HOME DEPOT INC	HD	$ 143,626.40	0.93%	2.23%	13.50%	15.88%	0.1478%
HESS CORP	HES	$ 11,137.76	0.07%	2.57%	-10.00%	-7.56%	-0.0055%
HARTFORD FINANCIAL SVCS GRP	HIG	$ 15,889.06	0.10%	2.17%	13.50%	15.82%	0.0163%
HARLEY-DAVIDSON INC	HOG	$ 7,313.70	0.05%	3.67%	10.50%	14.36%	0.0068%
HONEYWELL INTERNATIONAL INC	HON	$ 78,255.96	0.51%	2.34%	8.50%	10.94%	0.0555%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
STARWOOD HOTELS & RESORTS	HOT	$ 10,515.66	0.07%	2.42%	6.50%	9.00%	0.0061%
HELMERICH & PAYNE	HP	$ 4,930.39	0.03%	6.01%	-10.00%	-4.29%	-0.0014%
HEWLETT PACKARD ENTERPRIS	HPE	N/A	N/A	0.00%	N/A	N/A	N/A
HP INC	HPQ	N/A	N/A	0.00%	N/A	N/A	N/A
H&R BLOCK INC	HRB	$ 7,824.07	0.05%	2.41%	9.50%	12.02%	0.0061%
HORMEL FOODS CORP	HRL	$ 22,029.50	0.14%	1.39%	14.50%	15.99%	0.0228%
HARRIS CORP	HRS	$ 8,921.51	0.06%	2.85%	7.00%	9.95%	0.0058%
HENRY SCHEIN INC	HSIC	$ 13,167.33	0.09%	0.00%	9.00%	9.00%	0.0077%
HOST HOTELS & RESORTS INC	HST	$ -	N/A	5.98%	N/A	N/A	N/A
HERSHEY CO/THE	HSY	$ 19,184.01	0.12%	2.63%	7.00%	9.72%	0.0121%
HUMANA INC	HUM	$ 23,422.20	0.15%	0.73%	10.00%	10.77%	0.0163%
INTL BUSINESS MACHINES CORP	IBM	$ 114,327.50	N/A	4.41%	N/A	N/A	N/A
INTERCONTINENTAL EXCHANGE IN	ICE	$ 25,650.90	0.17%	1.46%	13.50%	15.06%	0.0250%
INTL FLAVORS & FRAGRANCES	IFF	$ 8,074.98	0.05%	2.23%	6.50%	8.80%	0.0046%
ILLUMINA INC	ILMN	$ 20,270.54	0.13%	0.00%	27.50%	27.50%	0.0361%
INTEL CORP	INTC	$ 133,480.60	0.86%	3.69%	10.00%	13.87%	0.1200%
INTUIT INC	INTU	$ 24,163.78	0.16%	1.31%	14.00%	15.40%	0.0241%
INTERNATIONAL PAPER CO	IP	$ 13,730.00	0.09%	5.31%	15.50%	21.22%	0.0189%
INTERPUBLIC GROUP OF COS INC	IPG	$ 8,498.26	0.06%	2.75%	12.50%	15.42%	0.0085%
INGERSOLL-RAND PLC	IR	$ 12,788.79	0.08%	2.61%	9.50%	12.23%	0.0101%
IRON MOUNTAIN INC	IRM	$ 5,616.92	0.04%	7.29%	6.50%	14.03%	0.0051%
INTUITIVE SURGICAL INC	ISRG	$ 19,088.73	0.12%	0.00%	9.50%	9.50%	0.0117%
ILLINOIS TOOL WORKS	ITW	$ 32,568.88	0.21%	2.46%	10.00%	12.58%	0.0266%
INVESCO LTD	IVZ	$ 10,757.62	0.07%	4.26%	14.00%	18.56%	0.0129%
HUNT (JB) TRANSPRT SVCS INC	JBHT	$ 8,362.51	0.05%	1.21%	12.00%	13.28%	0.0072%
JOHNSON CONTROLS INC	JCI	$ 22,176.12	0.14%	3.39%	10.00%	13.56%	0.0195%
JACOBS ENGINEERING GROUP INC	JEC	$ 4,304.56	0.03%	0.00%	6.00%	6.00%	0.0017%
JOHNSON & JOHNSON	JNJ	$ 281,432.50	1.82%	3.15%	5.50%	8.74%	0.1593%
JUNIPER NETWORKS INC	JNPR	$ 8,350.16	0.05%	2.12%	16.00%	18.29%	0.0099%
JPMORGAN CHASE & CO	JPM	$ 195,357.60	1.27%	3.43%	7.00%	10.55%	0.1335%
NORDSTROM INC	JWN	$ 9,119.83	0.06%	3.17%	4.50%	7.74%	0.0046%
KELLOGG CO	K	$ 26,115.52	0.17%	2.82%	4.00%	6.88%	0.0116%
KEYCORP	KEY	$ 8,352.85	0.05%	3.40%	6.50%	10.01%	0.0054%
KRAFT HEINZ CO/THE	KHC	$ 28,430.26	N/A	3.22%	N/A	N/A	N/A
KIMCO REALTY CORP	KIM	$ -	N/A	3.96%	N/A	N/A	N/A
KLA-TENCOR CORP	KLAC	$ 9,788.22	0.06%	3.31%	12.50%	16.02%	0.0102%
KIMBERLY-CLARK CORP	KMB	$ 45,889.70	0.30%	2.78%	7.00%	9.88%	0.0294%
KINDER MORGAN INC	KMI	$ 31,101.40	0.20%	3.58%	13.00%	16.81%	0.0339%
CARMAX INC	KMX	$ 8,327.28	0.05%	0.00%	12.50%	12.50%	0.0067%
COCA-COLA CO/THE	KO	$ 184,398.70	1.19%	3.30%	4.50%	7.87%	0.0941%
MICHAEL KORS HOLDINGS LTD	KORS	$ 8,816.01	0.06%	0.00%	10.50%	10.50%	0.0060%
KROGER CO	KR	$ 35,191.38	0.23%	1.26%	11.50%	12.83%	0.0293%
KOHLS CORP	KSS	$ 7,533.96	0.05%	4.84%	6.50%	11.50%	0.0056%
KANSAS CITY SOUTHERN	KSU	$ 8,462.41	0.05%	1.70%	13.00%	14.81%	0.0081%
LOEWS CORP	L	$ 12,683.94	0.08%	0.70%	11.00%	11.74%	0.0096%
L BRANDS INC	LB	$ 24,444.00	0.16%	2.86%	9.00%	11.99%	0.0190%
LEGGETT & PLATT INC	LEG	$ 5,604.43	0.04%	3.11%	11.50%	14.79%	0.0054%
LENNAR CORP-A	LEN	$ 7,941.37	0.05%	0.42%	19.50%	19.96%	0.0103%
LABORATORY CRP OF AMER HLDGS	LH	$ 10,261.68	0.07%	0.00%	9.00%	9.00%	0.0060%
L-3 COMMUNICATIONS HOLDINGS	LLL	$ 9,064.13	0.06%	2.44%	6.00%	8.51%	0.0050%
LINEAR TECHNOLOGY CORP	LLTC	$ 9,852.90	0.06%	3.11%	6.50%	9.71%	0.0062%
ELI LILLY & CO	LLY	$ 79,138.86	0.51%	2.86%	8.00%	10.97%	0.0563%
LEGG MASON INC	LM	$ 2,714.04	0.02%	3.18%	12.00%	15.37%	0.0027%
LOCKHEED MARTIN CORP	LMT	$ 63,665.38	0.41%	3.26%	9.00%	12.41%	0.0512%
LINCOLN NATIONAL CORP	LNC	$ 7,616.97	0.05%	3.41%	8.00%	11.55%	0.0057%
LOWE'S COS INC	LOW	$ 58,137.80	0.38%	1.86%	15.50%	17.50%	0.0659%
LAM RESEARCH CORP	LRCX	$ 10,181.65	0.07%	1.87%	19.50%	21.55%	0.0142%
LEUCADIA NATIONAL CORP	LUK	N/A	N/A	0.00%	N/A	N/A	N/A
SOUTHWEST AIRLINES CO	LUV	$ 22,886.25	0.15%	0.85%	29.00%	29.97%	0.0444%
LEVEL 3 COMMUNICATIONS INC	LVLT	$ 16,323.09	N/A	0.00%	N/A	N/A	N/A
LYONDELLBASELL INDU-CL A	LYB	$ 33,252.41	0.22%	4.25%	10.50%	14.97%	0.0323%
MACY'S INC	M	$ 11,914.55	0.08%	3.80%	3.50%	7.37%	0.0057%
MASTERCARD INC-CLASS A	MA	$ 92,317.34	0.60%	0.93%	12.50%	13.49%	0.0807%
MACERICH CO/THE	MAC	$ -	N/A	3.74%	N/A	N/A	N/A
MARRIOTT INTERNATIONAL -CL A	MAR	$ 15,836.57	0.10%	1.62%	16.00%	17.75%	0.0182%
MASCO CORP	MAS	$ 8,287.54	0.05%	1.52%	18.50%	20.16%	0.0108%
MATTEL INC	MAT	$ 10,165.43	0.07%	5.07%	4.00%	9.17%	0.0060%
MCDONALD'S CORP	MCD	$ 107,181.50	0.69%	3.05%	4.50%	7.62%	0.0529%
MICROCHIP TECHNOLOGY INC	MCHP	$ 8,051.01	0.05%	3.63%	9.50%	13.30%	0.0069%
MCKESSON CORP	MCK	$ 34,294.91	0.22%	0.75%	12.00%	12.80%	0.0284%
MOODY'S CORP	MCO	$ 15,512.70	0.10%	1.89%	10.00%	11.98%	0.0120%
MONDELEZ INTERNATIONAL INC-A	MDLZ	$ 59,956.08	0.39%	1.91%	11.00%	13.02%	0.0506%
MEDTRONIC PLC	MDT	$ 102,115.00	0.66%	2.18%	7.00%	9.26%	0.0612%
METLIFE INC	MET	$ 39,250.84	0.25%	4.66%	6.00%	10.80%	0.0275%
MCGRAW HILL FINANCIAL INC	MHFI	$ 22,234.88	N/A	1.75%	N/A	N/A	N/A
MOHAWK INDUSTRIES INC	MHK	$ 11,295.84	0.07%	0.00%	15.50%	15.50%	0.0113%
MEAD JOHNSON NUTRITION CO	MJN	$ 13,643.26	0.09%	2.38%	6.50%	8.96%	0.0079%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
MCCORMICK & CO-NON VTG SHRS	MKC	$ 11,567.67	0.07%	1.90%	8.50%	10.48%	0.0079%
MARTIN MARIETTA MATERIALS	MLM	$ 8,558.65	0.06%	1.24%	26.50%	27.90%	0.0155%
MARSH & MCLENNAN COS	MMC	$ 28,700.38	0.19%	2.26%	10.50%	12.88%	0.0239%
3M CO	MMM	$ 92,769.48	0.60%	2.95%	8.00%	11.07%	0.0665%
MALLINCKRODT PLC	MNK	$ 6,811.83	N/A	0.00%	N/A	N/A	N/A
MONSTER BEVERAGE CORP	MNST	$ 24,104.71	0.16%	0.00%	16.50%	16.50%	0.0258%
ALTRIA GROUP INC	MO	$ 117,621.10	0.76%	3.77%	9.50%	13.45%	0.1025%
MONSANTO CO	MON	$ 37,726.65	0.24%	2.52%	6.50%	9.10%	0.0222%
MOSAIC CO/THE	MOS	$ 8,724.18	0.06%	4.77%	5.50%	10.40%	0.0059%
MARATHON PETROLEUM CORP	MPC	$ 16,463.22	0.11%	4.15%	9.00%	13.34%	0.0142%
MERCK & CO. INC.	MRK	$ 136,889.10	0.89%	3.77%	4.00%	7.85%	0.0696%
MARATHON OIL CORP	MRO	$ 4,779.62	0.03%	2.83%	1.00%	3.84%	0.0012%
MORGAN STANLEY	MS	$ 41,996.68	0.27%	2.77%	24.50%	27.61%	0.0751%
MICROSOFT CORP	MSFT	$ 393,793.30	2.55%	2.90%	8.00%	11.02%	0.2811%
MOTOROLA SOLUTIONS INC	MSI	$ 10,687.83	0.07%	2.81%	4.50%	7.37%	0.0051%
M & T BANK CORP	MTB	$ 13,435.08	0.09%	2.78%	5.50%	8.36%	0.0073%
MICRON TECHNOLOGY INC	MU	$ 10,533.03	0.07%	0.00%	1.00%	1.00%	0.0007%
MURPHY OIL CORP	MUR	$ 2,747.24	0.02%	8.77%	-4.00%	4.59%	0.0008%
MYLAN NV	MYL	$ 20,367.70	0.13%	0.00%	21.00%	21.00%	0.0277%
NAVIENT CORP	NAVI	$ 3,047.01	N/A	7.61%	N/A	N/A	N/A
NOBLE ENERGY INC	NBL	$ 12,029.21	0.08%	1.43%	4.50%	5.96%	0.0046%
NASDAQ INC	NDAQ	$ 9,839.70	0.06%	1.67%	9.00%	10.75%	0.0069%
NEXTERA ENERGY INC	NEE	$ 51,585.90	0.33%	3.24%	7.00%	10.35%	0.0346%
NEWMONT MINING CORP	NEM	$ 13,249.12	0.09%	0.40%	-12.00%	-11.62%	-0.0100%
NETFLIX INC	NFLX	$ 36,952.62	0.24%	0.00%	37.50%	37.50%	0.0898%
NEWFIELD EXPLORATION CO	NFX	$ 4,410.30	0.03%	0.00%	9.50%	9.50%	0.0027%
NISOURCE INC	NI	$ 6,719.82	0.04%	2.94%	-1.50%	1.42%	0.0006%
NIKE INC -CL B	NKE	$ 95,592.00	0.62%	1.14%	16.00%	17.23%	0.1067%
NIELSEN HOLDINGS PLC	NLSN	$ 17,230.87	0.11%	2.37%	10.50%	12.99%	0.0145%
NORTHROP GRUMMAN CORP	NOC	$ 33,622.98	0.22%	1.74%	7.50%	9.31%	0.0203%
NATIONAL OILWELL VARCO INC	NOV	$ 9,896.86	0.06%	6.99%	-10.50%	-3.88%	-0.0025%
NRG ENERGY INC	NRG	$ 3,066.26	0.02%	6.05%	23.50%	30.26%	0.0060%
NORFOLK SOUTHERN CORP	NSC	$ 21,398.44	0.14%	3.29%	8.00%	11.42%	0.0158%
NETAPP INC	NTAP	$ 6,345.16	0.04%	3.31%	5.50%	8.90%	0.0037%
NORTHERN TRUST CORP	NTRS	$ 12,601.49	0.08%	2.64%	9.50%	12.27%	0.0100%
NUCOR CORP	NUE	$ 12,257.20	0.08%	3.91%	22.50%	26.85%	0.0213%
NVIDIA CORP	NVDA	$ 13,611.40	0.09%	1.82%	9.00%	10.90%	0.0096%
NEWELL RUBBERMAID INC	NWL	$ 9,017.30	0.06%	2.25%	14.00%	16.41%	0.0096%
NEWS CORP - CLASS A	NWSA	$ 6,046.58	0.04%	1.92%	33.50%	35.74%	0.0140%
REALTY INCOME CORP	O	$ -	N/A	3.96%	N/A	N/A	N/A
OWENS-ILLINOIS INC	OI	$ 2,023.34	0.01%	0.00%	5.50%	5.50%	0.0007%
ONEOK INC	OKE	$ 4,105.94	0.03%	13.41%	9.50%	23.55%	0.0063%
OMNICOM GROUP	OMC	$ 17,415.71	0.11%	2.99%	9.00%	12.12%	0.0137%
ORACLE CORP	ORCL	$ 146,606.70	0.95%	1.72%	7.00%	8.78%	0.0834%
O'REILLY AUTOMOTIVE INC	ORLY	$ 24,632.10	0.16%	0.00%	13.50%	13.50%	0.0215%
OCCIDENTAL PETROLEUM CORP	OXY	$ 50,559.32	0.33%	4.53%	-4.00%	0.44%	0.0014%
PAYCHEX INC	PAYX	$ 17,229.37	0.11%	3.71%	9.50%	13.39%	0.0149%
PEOPLE'S UNITED FINANCIAL	PBCT	$ 4,289.35	0.03%	4.91%	11.00%	16.18%	0.0045%
PITNEY BOWES INC	PBI	$ 3,243.23	0.02%	4.56%	4.00%	8.65%	0.0018%
PACCAR INC	PCAR	$ 17,075.34	0.11%	4.56%	7.00%	11.72%	0.0130%
P G & E CORP	PCG	$ 27,038.22	0.18%	3.30%	10.50%	13.97%	0.0245%
PLUM CREEK TIMBER CO	PCL	$ 6,136.76	0.04%	4.98%	9.50%	14.72%	0.0059%
PRICELINE GROUP INC/THE	PCLN	$ 52,950.89	0.34%	0.00%	16.50%	16.50%	0.0566%
PATTERSON COS INC	PDCO	$ 4,122.37	0.03%	2.32%	9.50%	11.93%	0.0032%
PUBLIC SERVICE ENTERPRISE GP	PEG	$ 21,167.77	0.14%	3.92%	4.00%	8.00%	0.0110%
PEPSICO INC	PEP	$ 141,667.80	0.92%	2.96%	6.00%	9.05%	0.0831%
PFIZER INC	PFE	$ 179,819.50	1.17%	4.12%	9.50%	13.82%	0.1610%
PRINCIPAL FINANCIAL GROUP	PFG	$ 10,078.79	0.07%	4.43%	6.50%	11.07%	0.0072%
PROCTER & GAMBLE CO/THE	PG	$ 216,094.80	1.40%	3.32%	7.50%	10.94%	0.1532%
PROGRESSIVE CORP	PGR	$ 17,672.46	0.11%	2.28%	11.50%	13.91%	0.0159%
PARKER HANNIFIN CORP	PH	$ 13,090.13	0.08%	2.60%	6.50%	9.18%	0.0078%
PULTEGROUP INC	PHM	$ 5,362.75	0.03%	2.34%	14.00%	16.50%	0.0057%
PERKINELMER INC	PKI	$ 4,857.80	0.03%	0.65%	6.50%	7.17%	0.0023%
PROLOGIS INC	PLD	$ -	N/A	4.50%	N/A	N/A	N/A
PHILIP MORRIS INTERNATIONAL	PM	$ 136,864.70	0.89%	4.62%	2.00%	6.67%	0.0591%
PNC FINANCIAL SERVICES GROUP	PNC	$ 42,368.14	0.27%	2.61%	4.50%	7.17%	0.0197%
PENTAIR PLC	PNR	$ 7,765.30	0.05%	3.06%	15.00%	18.29%	0.0092%
PINNACLE WEST CAPITAL	PNW	$ 7,491.04	0.05%	3.79%	4.00%	7.87%	0.0038%
PEPCO HOLDINGS INC	POM	$ 6,674.49	0.04%	4.10%	8.50%	12.77%	0.0055%
PPG INDUSTRIES INC	PPG	$ 24,037.64	0.16%	1.61%	12.50%	14.21%	0.0221%
PPL CORP	PPL	$ 24,117.33	0.16%	4.23%	3.00%	7.29%	0.0114%
PERRIGO CO PLC	PRGO	$ 19,774.25	0.13%	0.37%	14.50%	14.90%	0.0191%
PRUDENTIAL FINANCIAL INC	PRU	$ 26,647.75	0.17%	4.83%	4.50%	9.44%	0.0163%
PUBLIC STORAGE	PSA	$ -	N/A	2.95%	N/A	N/A	N/A
PHILLIPS 66	PSX	$ 38,887.77	0.25%	3.28%	5.00%	8.36%	0.0211%
PVH CORP	PVH	$ 5,783.43	0.04%	0.21%	6.00%	6.22%	0.0023%
QUANTA SERVICES INC	PWR	$ 2,705.14	0.02%	0.00%	10.00%	10.00%	0.0018%

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PRAXAIR INC	PX	$ 29,071.38	0.19%	2.94%	7.50%	10.55%	0.0199%
PIONEER NATURAL RESOURCES CO	PXD	$ 16,543.61	0.11%	0.07%	11.50%	11.57%	0.0124%
PAYPAL HOLDINGS INC	PYPL	$ 40,927.91	N/A	0.00%	N/A	N/A	N/A
QUALCOMM INC	QCOM	$ 64,285.00	0.42%	4.88%	4.50%	9.49%	0.0395%
QORVO INC	QRVO	$ 4,867.90	N/A	0.00%	N/A	N/A	N/A
RYDER SYSTEM INC	R	$ 2,803.21	0.02%	3.13%	11.50%	14.81%	0.0027%
REYNOLDS AMERICAN INC	RAI	$ 69,311.40	0.45%	2.97%	13.50%	16.67%	0.0749%
ROYAL CARIBBEAN CRUISES LTD	RCL	$ 14,952.52	0.10%	2.21%	21.50%	23.95%	0.0232%
REGENERON PHARMACEUTICALS	REGN	$ 37,508.43	0.24%	0.00%	24.50%	24.50%	0.0595%
REGIONS FINANCIAL CORP	RF	$ 9,527.19	0.06%	3.81%	6.00%	9.92%	0.0061%
ROBERT HALF INTL INC	RHI	$ 4,861.70	0.03%	2.29%	12.50%	14.93%	0.0047%
RED HAT INC	RHT	$ 11,316.90	0.07%	0.00%	15.50%	15.50%	0.0114%
TRANSOCEAN LTD	RIG	$ 3,131.63	0.02%	0.00%	-15.50%	-15.50%	-0.0031%
RALPH LAUREN CORP	RL	$ 7,045.35	0.05%	2.65%	6.50%	9.24%	0.0042%
ROCKWELL AUTOMATION INC	ROK	$ 12,350.29	0.08%	3.09%	6.00%	9.18%	0.0073%
ROPER TECHNOLOGIES INC	ROP	$ 16,125.78	0.10%	0.75%	8.00%	8.78%	0.0092%
ROSS STORES INC	ROST	$ 21,287.06	0.14%	1.03%	9.00%	10.08%	0.0139%
RANGE RESOURCES CORP	RRC	$ 4,556.13	0.03%	0.60%	10.00%	10.63%	0.0031%
REPUBLIC SERVICES INC	RSG	$ 15,215.97	0.10%	2.78%	8.00%	10.89%	0.0107%
RAYTHEON COMPANY	RTN	$ 36,776.18	0.24%	2.19%	8.50%	10.78%	0.0257%
STARBUCKS CORP	SBUX	$ 81,589.15	0.53%	1.46%	17.00%	18.58%	0.0982%
SCANA CORP	SCG	$ 9,224.20	0.06%	3.50%	4.50%	8.08%	0.0048%
SCHWAB (CHARLES) CORP	SCHW	$ 29,250.12	0.19%	1.08%	14.50%	15.66%	0.0297%
SPECTRA ENERGY CORP	SE	$ 18,512.89	0.12%	5.87%	5.00%	11.02%	0.0132%
SEALED AIR CORP	SEE	$ 8,360.64	0.05%	1.23%	19.50%	20.85%	0.0113%
SHERWIN-WILLIAMS CO/THE	SHW	$ 23,077.88	0.15%	1.29%	13.00%	14.37%	0.0215%
SIGNET JEWELERS LTD	SIG	$ 7,529.45	0.05%	1.06%	14.50%	15.64%	0.0076%
JM SMUCKER CO/THE	SJM	$ 15,097.25	0.10%	2.17%	7.50%	9.75%	0.0095%
SCHLUMBERGER LTD	SLB	$ 86,801.79	0.56%	2.91%	7.00%	10.01%	0.0563%
SL GREEN REALTY CORP	SLG	$ -	N/A	3.58%	N/A	N/A	N/A
SNAP-ON INC	SNA	$ 8,015.26	0.05%	1.77%	9.50%	11.35%	0.0059%
SANDISK CORP	SNDK	$ 13,504.50	0.09%	0.00%	1.50%	1.50%	0.0013%
SCRIPPS NETWORKS INTER-CL A	SNI	$ 6,830.71	0.04%	1.73%	9.00%	10.81%	0.0048%
SOUTHERN CO/THE	SO	$ 43,663.04	0.28%	4.66%	2.50%	7.22%	0.0204%
SIMON PROPERTY GROUP INC	SPG	$ -	N/A	3.53%	N/A	N/A	N/A
STAPLES INC	SPLS	$ 5,271.10	0.03%	5.86%	-2.00%	3.80%	0.0013%
STERICYCLE INC	SRCL	$ 9,008.10	0.06%	0.00%	10.00%	10.00%	0.0058%
SEMPRA ENERGY	SRE	$ 23,443.43	0.15%	2.97%	9.50%	12.61%	0.0192%
SUNTRUST BANKS INC	STI	$ 16,122.36	0.10%	3.70%	9.00%	12.87%	0.0134%
ST JUDE MEDICAL INC	STJ	$ 13,969.93	0.09%	2.51%	5.00%	7.57%	0.0069%
STATE STREET CORP	STT	$ 21,150.62	0.14%	2.71%	6.50%	9.30%	0.0127%
SEAGATE TECHNOLOGY	STX	$ 8,600.37	0.06%	8.68%	2.00%	10.77%	0.0060%
CONSTELLATION BRANDS INC-A	STZ	$ 27,016.90	0.18%	1.00%	17.00%	18.09%	0.0317%
STANLEY BLACK & DECKER INC	SWK	$ 13,496.30	0.09%	2.44%	10.00%	12.56%	0.0110%
SKYWORKS SOLUTIONS INC	SWKS	$ 10,700.86	0.07%	1.86%	21.00%	23.06%	0.0160%
SOUTHWESTERN ENERGY CO	SWN	$ 3,133.72	0.02%	0.00%	-4.00%	-4.00%	-0.0008%
SYNCHRONY FINANCIAL	SYF	$ 20,428.69	N/A	0.00%	N/A	N/A	N/A
STRYKER CORP	SYK	$ 36,156.16	0.23%	1.58%	15.50%	17.20%	0.0403%
SYMANTEC CORP	SYMC	$ 12,331.89	0.08%	3.20%	-3.50%	-0.36%	-0.0003%
SYSCO CORP	SYY	$ 24,143.76	0.16%	2.91%	12.00%	15.08%	0.0236%
AT&T INC	T	$ 222,772.60	1.44%	5.30%	5.50%	10.95%	0.1580%
MOLSON COORS BREWING CO -B	TAP	$ 15,479.91	0.10%	1.96%	8.50%	10.54%	0.0106%
TERADATA CORP	TDC	$ 3,028.82	0.02%	0.00%	3.50%	3.50%	0.0007%
TECO ENERGY INC	TE	$ 6,371.57	0.04%	3.43%	5.50%	9.02%	0.0037%
TE CONNECTIVITY LTD	TEL	$ 20,159.74	0.13%	2.46%	9.00%	11.57%	0.0151%
TEGNA INC	TGNA	$ 4,806.28	0.03%	2.58%	-0.50%	2.07%	0.0006%
TARGET CORP	TGT	$ 42,095.73	0.27%	3.38%	9.00%	12.53%	0.0342%
TENET HEALTHCARE CORP	THC	$ 2,329.46	0.02%	0.00%	28.00%	28.00%	0.0042%
TIFFANY & CO	TIF	$ 7,788.15	0.05%	2.73%	12.50%	15.40%	0.0078%
TJX COMPANIES INC	TJX	$ 45,467.72	0.29%	1.24%	10.00%	11.30%	0.0333%
TORCHMARK CORP	TMK	$ 6,010.17	0.04%	1.11%	7.50%	8.65%	0.0034%
THERMO FISHER SCIENTIFIC INC	TMO	$ 49,208.79	0.32%	0.49%	12.50%	13.02%	0.0415%
TRIPADVISOR INC	TRIP	$ 8,804.34	0.06%	0.00%	18.50%	18.50%	0.0106%
T ROWE PRICE GROUP INC	TROW	$ 16,481.58	0.11%	3.36%	9.50%	13.02%	0.0139%
TRAVELERS COS INC/THE	TRV	$ 31,566.84	0.20%	2.35%	4.50%	6.90%	0.0141%
TRACTOR SUPPLY COMPANY	TSCO	$ 10,999.15	0.07%	1.13%	15.50%	16.72%	0.0119%
TYSON FOODS INC-CL A	TSN	$ 22,158.45	0.14%	1.00%	12.50%	13.56%	0.0195%
TESORO CORP	TSO	$ 8,696.22	0.06%	2.78%	12.50%	15.45%	0.0087%
TOTAL SYSTEM SERVICES INC	TSS	$ 7,075.79	0.05%	1.04%	11.50%	12.60%	0.0058%
TIME WARNER CABLE	TWC	$ 50,791.92	0.33%	1.67%	6.00%	7.72%	0.0254%
TIME WARNER INC	TWX	$ 50,042.96	0.32%	2.58%	12.00%	14.73%	0.0478%
TEXAS INSTRUMENTS INC	TXN	$ 51,368.96	0.33%	3.02%	11.50%	14.69%	0.0489%
TEXTRON INC	TXT	$ 8,519.85	0.06%	0.26%	17.00%	17.28%	0.0095%
TYCO INTERNATIONAL PLC	TYC	$ 14,103.25	0.09%	2.47%	11.50%	14.11%	0.0129%
UNDER ARMOUR INC-CLASS A	UA	$ 15,663.93	0.10%	0.00%	23.50%	23.50%	0.0239%
UNITED CONTINENTAL HOLDINGS	UAL	$ 17,557.84	0.11%	0.00%	24.50%	24.50%	0.0279%
UNIVERSAL HEALTH SERVICES-B	UHS	$ 10,009.78	0.06%	0.39%	12.00%	12.41%	0.0081%

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UNITEDHEALTH GROUP INC	UNH	$ 105,420.90	0.68%	1.81%	12.50%	14.42%	0.0985%
UNUM GROUP	UNM	$ 5,859.17	0.04%	3.07%	11.00%	14.24%	0.0054%
UNION PACIFIC CORP	UNP	$ 64,640.86	0.42%	2.91%	10.00%	13.06%	0.0547%
UNITED PARCEL SERVICE-CL B	UPS	$ 84,725.19	0.55%	3.32%	10.50%	13.99%	0.0768%
URBAN OUTFITTERS INC	URBN	$ 2,904.95	0.02%	0.00%	15.00%	15.00%	0.0028%
UNITED RENTALS INC	URI	$ 4,023.12	0.03%	0.00%	16.00%	16.00%	0.0042%
US BANCORP	USB	$ 65,672.13	0.43%	2.72%	5.50%	8.29%	0.0353%
UNITED TECHNOLOGIES CORP	UTX	$ 75,095.20	0.49%	3.02%	7.00%	10.13%	0.0493%
VISA INC-CLASS A SHARES	V	$ 149,949.30	0.97%	0.88%	13.00%	13.94%	0.1354%
VARIAN MEDICAL SYSTEMS INC	VAR	$ 7,373.88	0.05%	0.00%	7.50%	7.50%	0.0036%
VF CORP	VFC	$ 24,215.26	0.16%	2.61%	12.00%	14.77%	0.0232%
VIACOM INC-CLASS B	VIAB	$ 12,838.72	0.08%	4.96%	9.00%	14.18%	0.0118%
VALERO ENERGY CORP	VLO	$ 26,841.59	0.17%	4.32%	10.00%	14.54%	0.0253%
VULCAN MATERIALS CO	VMC	$ 11,997.02	0.08%	0.44%	47.50%	48.04%	0.0373%
VORNADO REALTY TRUST	VNO	$ 15,111.56	0.10%	3.14%	6.50%	9.74%	0.0095%
VERISK ANALYTICS INC	VRSK	$ 11,220.05	0.07%	0.00%	12.50%	12.50%	0.0091%
VERISIGN INC	VRSN	$ 8,297.84	0.05%	0.00%	11.00%	11.00%	0.0059%
VERTEX PHARMACEUTICALS INC	VRTX	$ 19,580.44	N/A	0.00%	N/A	N/A	N/A
VENTAS INC	VTR	$ -	N/A	6.49%	N/A	N/A	N/A
VERIZON COMMUNICATIONS INC	VZ	$ 200,967.90	1.30%	4.58%	5.50%	10.21%	0.1329%
WATERS CORP	WAT	$ 9,509.43	0.06%	0.00%	8.00%	8.00%	0.0049%
WALGREENS BOOTS ALLIANCE INC	WBA	$ 81,999.59	0.53%	1.91%	15.00%	17.05%	0.0906%
WESTERN DIGITAL CORP	WDC	$ 9,263.10	0.06%	4.99%	2.00%	7.04%	0.0042%
WEC ENERGY GROUP INC	WEC	$ 17,596.22	0.11%	3.55%	6.00%	9.66%	0.0110%
WELLS FARGO & CO	WFC	$ 230,698.70	1.49%	3.50%	5.50%	9.10%	0.1360%
WHOLE FOODS MARKET INC	WFM	$ 10,093.68	0.07%	1.87%	8.50%	10.45%	0.0068%
WHIRLPOOL CORP	WHR	$ 10,119.72	0.07%	2.78%	13.50%	16.47%	0.0108%
WILLIS TOWERS WATSON PLC	WLTW	N/A	N/A	0.00%	N/A	N/A	N/A
WASTE MANAGEMENT INC	WM	$ 23,644.73	0.15%	2.97%	7.00%	10.07%	0.0154%
WILLIAMS COS INC	WMB	$ 9,954.21	0.06%	19.26%	16.00%	36.80%	0.0237%
WAL-MART STORES INC	WMT	$ 209,677.20	1.36%	3.06%	1.50%	4.58%	0.0623%
WESTROCK CO	WRK	$ 7,694.58	N/A	5.01%	N/A	N/A	N/A
WESTERN UNION CO	WU	$ 8,541.28	0.06%	3.79%	6.00%	9.90%	0.0055%
WEYERHAEUSER CO	WY	$ 11,355.15	0.07%	5.58%	12.50%	18.43%	0.0136%
WYNDHAM WORLDWIDE CORP	WYN	$ 7,385.27	0.05%	2.64%	8.50%	11.25%	0.0054%
WYNN RESORTS LTD	WYNN	$ 6,061.10	0.04%	3.35%	3.50%	6.91%	0.0027%
CIMAREX ENERGY CO	XEC	$ 7,674.41	0.05%	0.79%	4.00%	4.81%	0.0024%
XCEL ENERGY INC	XEL	$ 19,778.34	0.13%	3.49%	4.50%	8.07%	0.0103%
XL GROUP PLC	XL	$ 8,472.08	0.05%	2.41%	9.00%	11.52%	0.0063%
XILINX INC	XLNX	$ 12,074.26	0.08%	2.62%	17.00%	19.84%	0.0155%
EXXON MOBIL CORP	XOM	$ 331,374.80	2.15%	3.67%	2.50%	6.22%	0.1335%
DENTSPLY INTERNATIONAL INC	XRAY	$ 7,900.10	0.05%	0.51%	9.00%	9.53%	0.0049%
XEROX CORP	XRX	$ 8,797.78	0.06%	3.57%	1.50%	5.10%	0.0029%
XYLEM INC	XYL	$ 6,494.84	0.04%	1.71%	9.50%	11.29%	0.0048%
YAHOO! INC	YHOO	$ 25,248.81	0.16%	0.00%	1.50%	1.50%	0.0025%
YUM! BRANDS INC	YUM	$ 28,118.44	0.18%	2.88%	8.50%	11.50%	0.0210%
ZIMMER BIOMET HOLDINGS INC	ZBH	$ 18,611.04	0.12%	0.98%	10.50%	11.53%	0.0139%
ZIONS BANCORPORATION	ZION	$ 4,065.15	0.03%	1.31%	10.00%	11.38%	0.0030%
ZOETIS INC	ZTS	$ 19,614.39	N/A	0.97%	N/A	N/A	N/A
Total Market Capitalization:		15,433,945.18					12.78%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] ÷ [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg, Value Line, and Calculated Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
Atmos Energy Corporation	ATO	0.633	0.80
Laclede Group, Inc. (The)	LG	0.657	0.70
New Jersey Resources Corporation	NJR	0.680	0.80
Northwest Natural Gas Company	NWN	0.611	0.65
South Jersey Industries, Inc.	SJI	0.644	0.80
WGL Holdings, Inc.	WGL	0.663	0.75
Mean		0.648	0.750

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

Capital Asset Pricing Model Results
Bloomberg, and Value Line Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury [7]	2.79%	0.648	10.65%	9.99%	9.69%	9.26%
Projected 30-Year Treasury [8]	3.35%	0.648	10.65%	9.99%	10.25%	9.83%
Mean					9.97%	9.54%

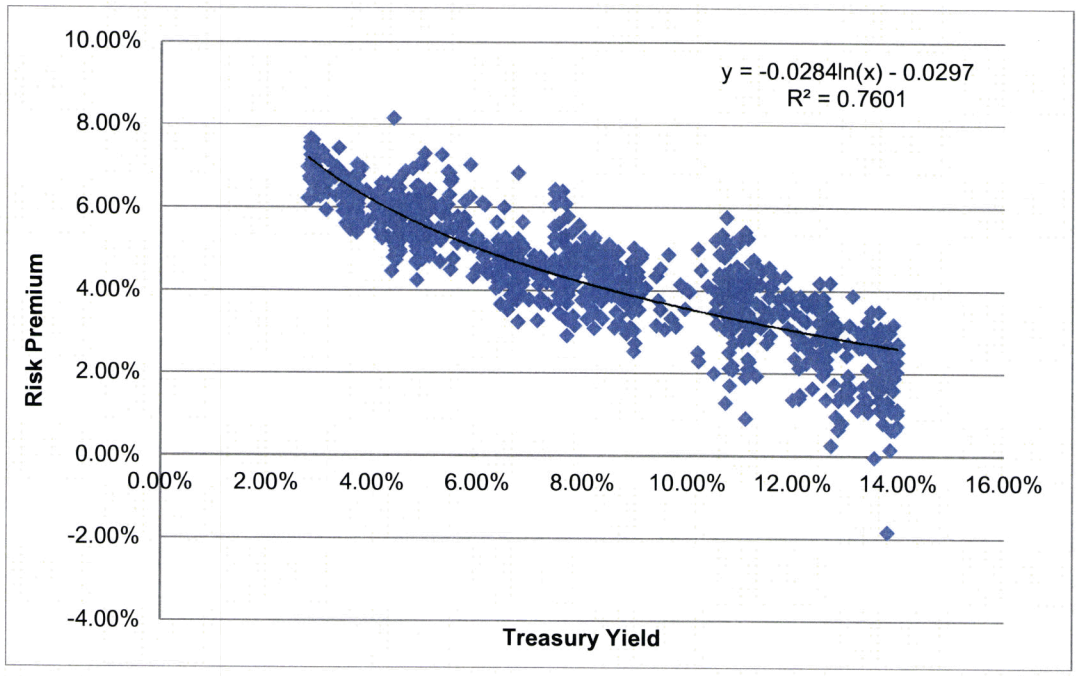
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE VALUE LINE AVERAGE BETA COEFFICIENT						
Current 30-Year Treasury [7]	2.79%	0.750	10.65%	9.99%	10.78%	10.28%
Projected 30-Year Treasury [8]	3.35%	0.750	10.65%	9.99%	11.34%	10.85%
Mean					11.06%	10.56%

Notes:

[1] *See Note [7] and [8].*
[2] Source: Exhibit No. __ (RBH-5).
[3] Source: Exhibit No. __ (RBH-4).
[4] Source: Source: Exhibit No. __ (RBH-4).
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Source: Bloomberg Professional
[8] Source: Blue Chip Financial Forecasts, Vol. 35, No. , February 1, 2016, at 2

Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.97%	-2.84%			
Current 30-Year Treasury		2.79%	7.20%	9.98%
Near-Term Projected 30-Year Treasury		3.35%	6.67%	10.02%
Long-Term Projected 30-Year Treasury		4.65%	5.74%	10.39%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 35, No. 2, February 1, 2016, at 2,
Long Term Projected = Blue Chip Financial Forecasts, Vol. 34, No. 12, December 1, 2015, at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 188-trading day average (i.e. lag period) as of February 12, 2015
[9] Equals [7] - [8]

[6]	[7]	[8]	[9]
Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.85%	4.15%
3/5/1980	14.00%	9.90%	4.10%
3/7/1980	13.50%	9.94%	3.56%
3/14/1980	14.00%	10.03%	3.97%
3/27/1980	12.69%	10.19%	2.50%
4/1/1980	14.75%	10.25%	4.50%
4/29/1980	12.50%	10.50%	2.00%
5/7/1980	14.27%	10.55%	3.72%
5/8/1980	13.75%	10.55%	3.20%
5/19/1980	15.50%	10.61%	4.89%
5/27/1980	14.60%	10.64%	3.96%
5/29/1980	16.00%	10.66%	5.34%
6/10/1980	13.78%	10.70%	3.08%
6/25/1980	14.25%	10.73%	3.52%
7/9/1980	14.51%	10.77%	3.74%
7/17/1980	12.90%	10.78%	2.12%
7/18/1980	13.80%	10.79%	3.01%
7/22/1980	14.10%	10.79%	3.31%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	13.61%	10.87%	2.74%
8/28/1980	14.00%	10.87%	3.13%
9/4/1980	14.00%	10.89%	3.11%
9/24/1980	15.00%	10.98%	4.02%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	12.00%	11.10%	0.90%
10/28/1980	13.00%	11.10%	1.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.13%	3.87%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.15%	4.35%
11/19/1980	13.50%	11.15%	2.35%
12/5/1980	14.60%	11.14%	3.46%
12/8/1980	16.40%	11.14%	5.26%
12/12/1980	15.45%	11.15%	4.30%
12/17/1980	14.20%	11.16%	3.04%
12/17/1980	14.40%	11.16%	3.24%
12/18/1980	14.00%	11.17%	2.83%
12/22/1980	13.45%	11.16%	2.29%
12/26/1980	14.00%	11.15%	2.85%
12/30/1980	14.50%	11.15%	3.35%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/31/1980	14.56%	11.15%	3.41%
1/7/1981	14.30%	11.14%	3.16%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.33%	3.17%
2/20/1981	14.50%	11.39%	3.11%
3/12/1981	15.65%	11.59%	4.06%
3/25/1981	15.30%	11.73%	3.57%
4/1/1981	15.30%	11.81%	3.49%
4/9/1981	15.00%	11.90%	3.10%
4/29/1981	13.50%	12.11%	1.39%
4/29/1981	14.25%	12.11%	2.14%
4/30/1981	13.60%	12.13%	1.47%
4/30/1981	15.00%	12.13%	2.87%
5/21/1981	14.00%	12.37%	1.63%
6/3/1981	14.67%	12.45%	2.22%
6/22/1981	16.00%	12.57%	3.43%
6/25/1981	14.75%	12.59%	2.16%
7/2/1981	14.00%	12.64%	1.36%
7/10/1981	16.00%	12.68%	3.32%
7/14/1981	16.90%	12.71%	4.19%
7/21/1981	15.78%	12.77%	3.01%
7/27/1981	13.77%	12.82%	0.95%
7/27/1981	15.50%	12.82%	2.68%
7/31/1981	13.50%	12.86%	0.64%
7/31/1981	14.20%	12.86%	1.34%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.01%	2.44%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.23%	1.11%
9/24/1981	16.25%	13.25%	3.00%
9/29/1981	14.50%	13.30%	1.20%
9/30/1981	15.94%	13.32%	2.62%
10/2/1981	14.80%	13.35%	1.45%
10/12/1981	16.25%	13.42%	2.83%
10/20/1981	15.25%	13.49%	1.76%
10/20/1981	16.50%	13.49%	3.01%
10/20/1981	17.00%	13.49%	3.51%
10/23/1981	15.50%	13.53%	1.97%
10/26/1981	13.50%	13.55%	-0.05%
10/29/1981	16.50%	13.59%	2.91%
11/4/1981	15.33%	13.62%	1.71%
11/6/1981	15.17%	13.63%	1.54%
11/12/1981	15.00%	13.64%	1.36%
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/30/1981	16.75%	13.65%	3.10%
12/1/1981	15.70%	13.65%	2.05%
12/1/1981	16.00%	13.65%	2.35%
12/15/1981	15.81%	13.68%	2.13%
12/17/1981	14.75%	13.70%	1.05%
12/22/1981	15.70%	13.71%	1.99%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/22/1981	16.00%	13.71%	2.29%
12/30/1981	16.00%	13.74%	2.26%
12/30/1981	16.25%	13.74%	2.51%
1/4/1982	15.50%	13.74%	1.76%
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.85%	0.15%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.87%	1.63%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.91%	1.09%
3/8/1982	17.10%	13.91%	3.19%
3/26/1982	16.00%	13.96%	2.04%
3/31/1982	16.25%	13.97%	2.28%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.98%	1.02%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.98%	1.12%
4/12/1982	16.70%	13.98%	2.72%
4/18/1982	14.70%	13.98%	0.72%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.87%	0.63%
6/7/1982	16.00%	13.86%	2.14%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	15.55%	13.80%	1.75%
7/1/1982	16.00%	13.80%	2.20%
7/2/1982	15.10%	13.79%	1.31%
7/13/1982	16.80%	13.76%	3.04%
7/22/1982	14.50%	13.72%	0.78%
7/28/1982	16.10%	13.69%	2.41%
7/30/1982	14.82%	13.67%	1.15%
8/4/1982	15.58%	13.65%	1.93%
8/6/1982	16.50%	13.63%	2.87%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.58%	2.42%
8/30/1982	16.25%	13.58%	2.67%
9/3/1982	15.50%	13.56%	1.94%
9/9/1982	16.04%	13.55%	2.49%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	14.74%	13.42%	1.32%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
10/1/1982	16.50%	13.41%	3.09%
10/8/1982	15.00%	13.34%	1.66%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/15/1982	15.90%	13.26%	2.64%
10/19/1982	15.90%	13.23%	2.67%
10/27/1982	17.00%	13.13%	3.87%
10/28/1982	14.75%	13.11%	1.64%
11/2/1982	16.25%	13.08%	3.17%
11/4/1982	15.75%	13.04%	2.71%
11/5/1982	14.73%	13.02%	1.71%
11/17/1982	16.00%	12.87%	3.13%
11/23/1982	15.50%	12.79%	2.71%
11/24/1982	14.50%	12.78%	1.72%
11/24/1982	16.02%	12.78%	3.24%
11/30/1982	12.98%	12.73%	0.25%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	15.65%	12.73%	2.92%
11/30/1982	16.00%	12.73%	3.27%
11/30/1982	16.10%	12.73%	3.37%
12/3/1982	15.33%	12.68%	2.65%
12/8/1982	15.75%	12.64%	3.11%
12/13/1982	16.00%	12.59%	3.41%
12/14/1982	16.40%	12.57%	3.83%
12/17/1982	16.25%	12.53%	3.72%
12/20/1982	15.00%	12.51%	2.49%
12/21/1982	15.70%	12.50%	3.20%
12/28/1982	15.25%	12.43%	2.82%
12/28/1982	15.25%	12.43%	2.82%
12/29/1982	16.25%	12.41%	3.84%
12/29/1982	16.25%	12.41%	3.84%
1/11/1983	15.90%	12.26%	3.64%
1/12/1983	15.50%	12.25%	3.25%
1/18/1983	15.00%	12.19%	2.81%
1/24/1983	15.50%	12.14%	3.36%
1/24/1983	16.00%	12.14%	3.86%
1/28/1983	14.90%	12.09%	2.81%
1/31/1983	15.00%	12.07%	2.93%
2/10/1983	15.00%	11.98%	3.02%
2/25/1983	15.70%	11.85%	3.85%
3/2/1983	15.25%	11.80%	3.45%
3/16/1983	16.00%	11.64%	4.36%
3/21/1983	14.96%	11.58%	3.38%
3/23/1983	15.40%	11.54%	3.86%
3/23/1983	16.10%	11.54%	4.56%
3/24/1983	15.00%	11.53%	3.47%
4/12/1983	13.25%	11.31%	1.94%
4/29/1983	15.05%	11.11%	3.94%
5/3/1983	15.40%	11.08%	4.32%
5/9/1983	15.50%	11.01%	4.49%
5/19/1983	14.85%	10.90%	3.95%
5/31/1983	14.00%	10.85%	3.15%
6/2/1983	14.50%	10.83%	3.67%
6/7/1983	14.50%	10.81%	3.69%
6/9/1983	14.85%	10.80%	4.05%
6/20/1983	14.15%	10.74%	3.41%
6/20/1983	16.50%	10.74%	5.76%
6/27/1983	14.50%	10.72%	3.78%
6/30/1983	14.80%	10.71%	4.09%
6/30/1983	15.90%	10.71%	5.19%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/1/1983	14.80%	10.70%	4.10%
7/5/1983	15.00%	10.70%	4.30%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.00%	10.71%	4.29%
7/19/1983	15.10%	10.71%	4.39%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	14.75%	10.86%	3.89%
8/31/1983	15.25%	10.86%	4.39%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.20%	4.70%
12/9/1983	15.30%	11.21%	4.09%
12/12/1983	14.50%	11.21%	3.29%
12/12/1983	15.50%	11.21%	4.29%
12/20/1983	15.40%	11.26%	4.14%
12/20/1983	16.00%	11.26%	4.74%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.29%	3.71%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.36%	4.14%
1/18/1984	15.53%	11.38%	4.15%
1/26/1984	15.90%	11.41%	4.49%
2/14/1984	14.25%	11.50%	2.75%
2/28/1984	14.50%	11.58%	2.92%
3/20/1984	16.00%	11.69%	4.31%
3/23/1984	15.50%	11.72%	3.78%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.85%	4.35%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.03%	2.37%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.36%	3.64%
8/7/1984	16.69%	12.50%	4.19%
8/9/1984	15.33%	12.51%	2.82%
8/17/1984	14.82%	12.53%	2.29%
8/21/1984	14.64%	12.54%	2.10%
8/27/1984	14.52%	12.56%	1.96%
8/28/1984	14.75%	12.56%	2.19%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/30/1984	15.60%	12.57%	3.03%
9/12/1984	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%
9/25/1984	16.25%	12.61%	3.64%
10/2/1984	14.80%	12.62%	2.18%
10/9/1984	14.75%	12.63%	2.12%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.64%	2.36%
10/24/1984	15.50%	12.64%	2.86%
11/7/1984	15.00%	12.64%	2.36%
11/20/1984	15.92%	12.62%	3.30%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.53%	2.47%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.33%	2.52%
2/15/1985	15.00%	12.28%	2.72%
2/20/1985	14.50%	12.26%	2.24%
2/22/1985	14.86%	12.26%	2.60%
3/14/1985	15.50%	12.17%	3.33%
3/28/1985	14.80%	12.09%	2.71%
4/9/1985	15.50%	12.03%	3.47%
4/16/1985	15.70%	11.97%	3.73%
6/10/1985	15.75%	11.59%	4.16%
6/26/1985	14.82%	11.47%	3.35%
7/9/1985	15.00%	11.39%	3.61%
7/26/1985	14.50%	11.27%	3.23%
8/29/1985	14.50%	11.12%	3.38%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.04%	4.26%
9/25/1985	14.50%	11.03%	3.47%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.92%	4.33%
11/8/1985	12.94%	10.86%	2.08%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.72%	1.28%
12/11/1985	14.90%	10.69%	4.21%
12/20/1985	14.88%	10.60%	4.28%
12/20/1985	15.00%	10.60%	4.40%
12/20/1985	15.00%	10.60%	4.40%
12/30/1985	15.75%	10.53%	5.22%
12/31/1985	14.00%	10.52%	3.48%
12/31/1985	14.50%	10.52%	3.98%
1/17/1986	14.50%	10.38%	4.12%
2/11/1986	12.50%	10.21%	2.29%
2/12/1986	15.20%	10.20%	5.00%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.77%	3.13%
4/28/1986	13.01%	9.47%	3.54%
5/21/1986	13.25%	9.19%	4.06%
5/28/1986	14.00%	9.12%	4.88%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/29/1986	13.90%	9.11%	4.79%
6/2/1986	13.00%	9.08%	3.92%
6/11/1986	14.00%	8.98%	5.02%
6/13/1986	13.55%	8.95%	4.60%
6/27/1986	11.88%	8.78%	3.10%
7/14/1986	12.60%	8.60%	4.00%
7/30/1986	13.30%	8.39%	4.91%
8/14/1986	13.50%	8.23%	5.27%
9/5/1986	13.30%	8.03%	5.27%
9/23/1986	12.75%	7.91%	4.84%
10/30/1986	13.00%	7.68%	5.32%
10/31/1986	13.75%	7.67%	6.08%
11/10/1986	14.00%	7.62%	6.38%
11/19/1986	13.75%	7.57%	6.18%
11/25/1986	13.15%	7.54%	5.61%
12/22/1986	13.80%	7.48%	6.32%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.46%	5.54%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.72%	5.78%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.08%	3.32%
9/18/1987	13.00%	8.27%	4.73%
10/20/1987	12.60%	8.54%	4.06%
10/20/1987	12.98%	8.54%	4.44%
11/12/1987	12.75%	8.67%	4.08%
11/13/1987	12.75%	8.68%	4.07%
11/24/1987	12.50%	8.73%	3.77%
12/8/1987	12.50%	8.81%	3.69%
12/22/1987	12.00%	8.90%	3.10%
12/31/1987	12.85%	8.93%	3.92%
12/31/1987	13.25%	8.93%	4.32%
1/15/1988	13.15%	8.98%	4.17%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.94%	4.06%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.95%	3.80%
7/8/1988	12.00%	8.94%	3.06%
7/18/1988	12.00%	8.91%	3.09%
7/20/1988	13.40%	8.90%	4.50%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.93%	3.87%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%
10/28/1988	13.00%	8.94%	4.06%
11/15/1988	12.00%	8.97%	3.03%
11/29/1988	12.75%	9.01%	3.74%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.80%	4.20%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.73%	4.17%
9/21/1989	12.10%	8.63%	3.47%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	12.60%	8.46%	4.14%
11/9/1989	13.00%	8.46%	4.54%
11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.33%	4.92%
12/15/1989	13.00%	8.28%	4.72%
12/20/1989	12.90%	8.26%	4.64%
12/21/1989	12.80%	8.26%	4.54%
12/21/1989	12.90%	8.26%	4.64%
12/27/1989	12.50%	8.24%	4.26%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.17%	4.33%
1/26/1990	12.10%	8.15%	3.95%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.34%	4.91%
7/6/1990	12.10%	8.35%	3.75%
7/19/1990	11.70%	8.38%	3.32%
8/31/1990	12.50%	8.52%	3.98%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/31/1990	12.50%	8.52%	3.98%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%
9/20/1990	12.50%	8.61%	3.89%
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.10%	8.70%	3.40%
11/21/1990	12.50%	8.70%	3.80%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	13.60%	8.67%	4.93%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.64%	4.61%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.70%	8.56%	4.14%
2/15/1991	12.80%	8.56%	4.24%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.35%	3.35%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.31%	4.59%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.16%	3.59%
12/19/1991	12.60%	8.14%	4.46%
12/19/1991	12.80%	8.14%	4.66%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.99%	3.76%
3/18/1992	12.50%	7.95%	4.55%
5/15/1992	12.75%	7.87%	4.88%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%
10/29/1992	12.75%	7.71%	5.04%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	11.00%	7.68%	3.32%
11/25/1992	12.00%	7.68%	4.32%
12/3/1992	11.85%	7.67%	4.18%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.30%	7.63%	4.67%
12/22/1992	12.40%	7.63%	4.77%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.50%	7.25%	4.25%
5/3/1993	11.75%	7.25%	4.50%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.07%	4.71%
7/21/1993	11.90%	7.07%	4.83%
7/23/1993	11.50%	7.06%	4.44%
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.98%	3.77%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.25%	6.88%	4.37%
9/1/1993	11.47%	6.88%	4.59%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.73%	4.27%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.68%	4.82%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.65%	5.10%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	10.10%	6.58%	3.52%
10/29/1993	10.20%	6.58%	3.62%
10/29/1993	11.25%	6.58%	4.67%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	10.60%	6.46%	4.14%
12/16/1993	11.20%	6.46%	4.74%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/21/1993	11.30%	6.45%	4.85%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%
6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.83%	3.87%
9/29/1994	10.90%	7.20%	3.70%
9/29/1994	11.00%	7.20%	3.80%
10/7/1994	11.87%	7.25%	4.62%
10/18/1994	11.50%	7.31%	4.19%
10/18/1994	11.50%	7.31%	4.19%
10/24/1994	11.00%	7.35%	3.65%
11/22/1994	12.12%	7.52%	4.60%
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.71%	3.29%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.99%	3.77%
11/7/1995	12.50%	6.87%	5.63%
11/8/1995	11.10%	6.86%	4.24%
11/8/1995	11.30%	6.86%	4.44%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.65%	4.95%
1/31/1996	11.30%	6.46%	4.84%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.41%	4.36%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.41%	4.59%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.84%	4.46%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.85%	4.15%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.80%	4.90%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.49%	6.61%
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%
11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.01%	5.24%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.87%	6.23%
2/5/2001	11.50%	5.76%	5.74%
3/15/2001	11.25%	5.67%	5.58%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	10.30%	5.54%	4.76%
10/24/2001	11.00%	5.54%	5.46%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.47%	6.83%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.00%	5.30%	4.70%
11/20/2002	10.50%	5.30%	5.20%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.17%	6.08%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.97%	6.43%
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.93%	7.07%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.82%	5.38%
9/17/2003	9.90%	4.84%	5.06%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.20%	4.88%	5.32%
10/31/2003	10.75%	4.88%	5.87%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.54%	5.46%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	10.40%	4.53%	5.87%
12/21/2005	11.00%	4.53%	6.47%
12/22/2005	10.20%	4.53%	5.67%
12/22/2005	11.00%	4.53%	6.47%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	9.60%	4.86%	4.74%
7/24/2006	10.00%	4.86%	5.14%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.96%	4.75%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.85%	5.40%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.91%	4.79%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.47%	5.83%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.42%	6.08%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.90%	6.40%
3/25/2009	10.17%	3.84%	6.33%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.11%	6.04%
10/28/2009	10.15%	4.11%	6.04%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.25%	6.05%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.50%	4.26%	6.24%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.29%	6.09%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.23%	4.37%	5.86%
1/21/2010	10.33%	4.37%	5.96%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.45%	5.55%
6/18/2010	10.30%	4.45%	5.85%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.30%	4.31%	5.99%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.18%	5.57%
11/2/2010	9.75%	4.18%	5.57%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	9.56%	4.12%	5.44%
12/6/2010	10.09%	4.12%	5.97%
12/9/2010	10.25%	4.12%	6.13%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/14/2010	10.33%	4.12%	6.21%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.11%	5.81%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.09%	6.21%
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
5/26/2011	10.50%	4.31%	6.19%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.37%	4.46%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.93%	5.67%
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.06%	3.60%	5.46%
1/10/2012	9.45%	3.60%	5.85%
1/10/2012	9.45%	3.60%	5.85%
1/23/2012	10.20%	3.53%	6.67%
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.50%	3.16%	6.34%
4/24/2012	9.75%	3.16%	6.59%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	9.90%	2.92%	6.98%
10/31/2012	10.00%	2.92%	7.08%
11/1/2012	9.45%	2.92%	6.53%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.91%	7.39%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.00%	2.87%	7.13%
12/4/2012	10.50%	2.87%	7.63%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.50%	2.84%	7.66%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.91%	6.89%
4/23/2013	9.80%	2.95%	6.85%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.32%	6.28%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.52%	6.21%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.54%	6.18%
12/30/2013	10.00%	3.57%	6.43%
1/21/2014	9.65%	3.65%	6.00%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.71%	6.14%
2/28/2014	9.55%	3.72%	5.83%
3/16/2014	9.72%	3.73%	5.99%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.51%	5.59%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.45%	6.30%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.31%	6.89%
12/3/2014	10.00%	3.29%	6.71%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.83%	6.17%
10/30/2015	9.80%	2.86%	6.94%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%

Date of Natural Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.96%	6.54%
1/6/2016	9.50%	2.96%	6.54%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
		Average:	4.52%
		Count:	1,031

Flotation Cost Adjustment

From Southwest Gas Corporation 2015 SEC Form 10-K page 56.

Company	Date	Shares Issued	Agent Commissions	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
Southwest Gas Corporation	Shelf	645,225	$355,228	$35,522,812	$35,167,584	1.000%
Mean						

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield: Current	[5] Expected Dividend Yield: Adjusted for Flot. Costs	[6] Zacks Earnings Growth	[7] First Call Earnings Growth	[8] Value Line Earnings Growth	[9] Value Line Retention Growth	[10] Average Earnings Growth	[11] DCF k(e)	[12] Flotation Adjusted DCF k(e)
Atmos Energy Corporation	ATO	$1.68	$65.65	2.56%	2.65%	2.68%	6.60%	6.40%	7.00%	8.21%	7.05%	9.70%	9.73%
Laclede Group, Inc.	LG	$1.96	$61.14	3.21%	3.30%	3.34%	4.80%	4.78%	10.00%	4.90%	6.12%	9.42%	9.46%
New Jersey Resources Corporation	NJR	$0.96	$34.36	2.79%	2.87%	2.90%	6.50%	6.50%	4.00%	5.81%	5.70%	8.58%	8.61%
Northwest Natural Gas Company	NWN	$1.87	$51.25	3.65%	3.73%	3.77%	4.00%	4.00%	7.00%	3.73%	4.68%	8.42%	8.46%
South Jersey Industries, Inc.	SJI	$1.06	$24.21	4.36%	4.50%	4.55%	NA	6.00%	7.50%	6.56%	6.69%	11.19%	11.24%
WGL Holdings, Inc.	WGL	$1.95	$64.08	3.04%	3.14%	3.17%	7.30%	8.00%	5.50%	5.11%	6.48%	9.62%	9.65%
PROXY GROUP MEAN												9.49%	9.52%

DCF Result Adjusted For Flotation Costs:	9.52%	
DCF Result Unadjusted For Flotation Costs:	9.49%	
Difference (Flotation Cost Adjustment):	0.03%	[13]

Notes:

The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (1 - flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Equals [4] / (1 - 0%)
[6] Source: Zacks
[7] Source: Yahoo! Finance
[8] Source: Value Line
[9] Source: RBH-1, Value Line
[10] Equals Average([6], [7], [8], [9])
[11] Equals [4] + [10]
[12] Equals [5] + [10]
[13] Equals average [12] - average [11]

Review of Rate Mechanisms

Company	Ticker	Decoupling - Conservation/ Efficiency	Decoupling - Weather	Decoupling - Economic/ Other	Striaght-Fixed Variable	Infrastructure Cost Recovery
Atmos Energy	**ATO**	✓	✓			✓
Atmos Energy (Colorado)						✓
Atmos Energy (Kansas)			✓			✓
Atmos Energy (Kentucky)		✓	✓			✓
Atmos Energy (Louisiana)			✓			✓
Atmos Energy (Mississippi)			✓			✓
Atmos Energy (Tennessee)			✓			
Atmos Energy (Texas)			✓			✓
Atmos Energy (Virginia)			✓			✓
Laclede Group	**LG**	✓	✓	✓		✓
Laclede Gas Company (Missouri)			✓	✓	✓	✓
Missouri Gas Energy (Missouri)						✓
Alagasco (Alabama)			✓	✓		✓
New Jersey Resources	**NJR**	✓	✓	✓		✓
New Jersey Natural Gas		✓	✓	✓		✓
Northwest Natural Gas	**NWN**	✓	✓			✓
Northwest Natural Gas (Oregon)		✓	✓			✓
Northwest Natural Gas (Washington)						
South Jersey Industries	**SJI**	✓	✓	✓		✓
South Jersey Gas		✓	✓	✓		✓
WGL Holings, Inc	**WGL**	✓	✓	✓		✓
Washington Gas Light Company (Maryland)		✓		✓		✓
Washington Gas Light Company (Virginia)		✓	✓	✓		✓
Washington Gas Light Company (Washington, D.C.)						✓

Sources: American Gas Association: Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List as of November 2015. SEC Form 10-K.

Review of Decoupling Mechanisms

Company	Ticker	Disclosed in SEC Form 10-K Filing
Atmos Energy	ATO	
		Atmos Energy has WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 97 percent of our natural gas distribution gross margin. (pg 7) All subsidiaries have some form of infrastructure rider in place (pg. 8)
		Atmos Energy has weather-normalized rates for over 95 percent of our residential and commercial meters in our regulated distribution business, which substantially mitigates the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather-normalized rates could have an adverse effect on our operations and financial results (pg 15).
Laclede Group	LG	
		The Utilities' earnings are primarily generated by the sale of heating energy. The Missouri Utilities have weather mitigation rates designs and the Alabama Utility has a Temperature Adjustment Rider (TAR), eash of which is approved by the respective state regulatory body, which provide better assuamce of the recovery of fixed costs and margins during winter months despite variations in sales volumes due to the impacts of weather and other factors that affect customer usage. (pg 20)
		Furthermore, continuation of the weather mitigation rate design at Laclede Gas, the rate design where distribution costs are recovered predominatly through fixed monthly charges at MGE, or the Rate Stabilization and Equalization (RSE) at Alagasco are subject to regulatory discretion. (pg 20) Missouri Utilities have an Infrastructure System Replacement Surcharge for recovery of investments in between rate cases. (pg. 39)
New Jersey Resources	NJR	
		Conservation Incentive Program (CIP) - The CIP stabilizes New Jersey Natural Gas Company's (NJNG's) utility gross margin regardless of variations in weather. In addition, the CIP decouples the link between utility gross margin and customer usage, allowing NJNG to promote energy conservation measures. The NJ BPU approved the continuation of the CIP program with no expiration date; however, the program will be subject to review in a future tariff rate filing in 2017. (pg 8) NJR has a capital infrastructure plan named NJ RISE for storm hardening and mitigation projects (pg. 36)
Northwest Natural Gas	NWN	
		Decoupling is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers' efforts to conserve energy. The Oregon decoupling mechanism was reauthorized in the 2012 Oregon general rate case with the baseline determined in our 2012 general rate case being used in base rates. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. (pg 29-30)
		In Oregon, we have an approved weather normalization mechanism, which is applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through May of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. This weather normalization mechanism was reauthorized in the 2012 Oregon general rate case without an expiration date. (pg 30) In Oregon, NWN has a System Integrity Program (SIP), which provides cost recovery of pipeline system integrity programs. (pg. 3)
South Jersey Industries	SJI	
		Conservation Incentive Program (CIP) - The primary purpose of the CIP is to promote conservation efforts, without negatively impacting financial stability, and to base SJG's profit margin on the number of customers rather than the amount of natural gas distributed to customers. In October 2006, the BPU approved SJG's CIP as a three-year pilot program. In January 2010, the BPU approved an extension of this program through September 2013, with an automatic one year extension through September 2014 if a request for an extension was filed by March 2013. A petition was filed in March 2013 to extend the CIP program and in May 2014 the BPU approved the continuation of the CIP. Each CIP year begins October 1 and ends September 30 of the subsequent year. On a monthly basis during the CIP year, SJG records adjustments to earnings based on weather and customer usage factors, as incurred. Subsequent to each year, SJG makes filings with the BPU to review and approve amounts recorded under the CIP. BPU approved cash inflows or outflows generally will not begin until the next CIP year. (pg 71) SJI's infrastructure replacement program is known as SHARP (Storm Hardening and Reliability Program). (p.19)
WGL Holdings, Inc.	WGL	
		For each jurisdiction in which Washington Gas operates, changes in customer usage profiles are reflected in rate case proceedings and rates are adjusted accordingly. Changes in customer usage by existing customers that occur subsequent to rate case proceedings in Maryland generally will not change revenues because the RNA mechanism stabilizes the level of delivery charge revenues received from customers. In Virginia, decoupling rate mechanisms for residential, small commercial and industrial and group metered apartment customers permit Washington Gas to adjust revenues for non-weather related changes in customer usage. The WNA and the CRA are billing mechanisms that together eliminate the effects of both weather and other factors such as conservation. (pp 8-9). Infrastructure replacement programs in DC, MD, and VA are known as ACRP, STRIDE, and SAVE respectively (p. 50).

Source: 2014, 2015 SEC Form 10-K

CALCULATION OF THE FAIR VALUE RATE BASE

Rate Base Estimate		Amount	Weighting		Weighted Amount	
Original Cost Rate Base (OCRB)	$	1,336,049,260	50%	$	668,024,630	[1]
RCND Rate Base		2,288,780,072	50%	$	1,144,390,036	[2]
Fair Value Rate Base (FVRB)				$	1,812,414,665	[3]
Appreciation above OCRB				$	476,365,405	[4]
FV/OCRB Multiple		1.36				

CALCULATION OF THE FAIR VALUE RATE OF RETURN

Capital		Amount	Percent	Cost Rate		Weighted Cost Rate	
Authorized Capital Structure Original Cost Rate Base							
Long-Term Debt	$	645,445,398	48.31%	5.21%	[5]	2.52%	
Common Equity		690,603,862	51.69%	10.25%	[6]	5.30%	
Capital Financing OCRB	$	1,336,049,260	100.00%			7.82%	
Authorized Capital Structure Fair Value Rate Base							
Long-Term Debt	$	645,445,398	35.61%	5.21%		1.86%	
Common Equity		690,603,862	38.10%	10.25%		3.91%	
Appreciation above OCRB not recognized on utility's books	$	476,365,405	26.28%	0.93%	[7]	0.24%	
		1,812,414,665	100.00%			6.01%	[8]

Notes:
[1] Direct Testimony of Randi Cunningham
[2] Direct Testimony of Randi Cunningham
[3] Equals [1] + [2]
[4] Equals [3] - OCRB
[5] Schedule D-1
[6] Recommended ROE on OCRB
[7] 50 percent of long-term inflation rate derived on page 2 of this Exhibit
[8] FVRB Return equals OCRB Return - Inflation Rate

LONG-TERM INFLATION RATE ESTIMATE

Description (a)	Value (b)
Long-Term Nominal Treasury Rate [1]	4.00%
Real-Risk Free Rate of Return [2]	2.10%
Long-term Expected Inflation Rate [3]	1.86%

[1] Inflation Rate = [(1 + Nominal Rate) / (1 + Real Rate)] - 1

Sources:

[1] Average of the near term and long term projected Nominal 30-Year Treasury rate.
Blue Chip Financial Forecast, Vol 34, December, 1, 2015, p. 14 and Vol 35, February 1, 2015, p. 2.
[2] Average of the EIA Annual Energy Outlook Rate of Change in CPI from 2015-2040 and
Blue Chip Financial Forecast, Vol 34, December, 1, 2015, p. 14 and Vol 35, February 1, 2015, p. 2.
[3] Real Risk Free Rate = ((1+Nominal Treasury Rate/(Inflation+1) -1

Tab J

Direct Testimony

of

Christy M. Berger

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
CHRISTY M. BERGER

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 2, 2016

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of
Prepared Direct Testimony
of
CHRISTY M. BERGER

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Appendix A – Summary of Qualifications of Christy M. Berger

Exhibit No.__(CMB-1)

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
CHRISTY M. BERGER

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Christy M. Berger. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Rates and Regulatory Analysis Department. My title is Manager.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (Commission) and the Public Utilities Commission of Nevada.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's rate design proposals and the supporting H Schedules. Consistent with the settlement agreement in Decision No. 72723, an inclining block rate design is also presented. Additionally, I support tariff changes that encompass a variety of updates including: 1) a modification to Rule No. 6, Service and Main Extensions; 2) the addition of a Compression Services

Schedule; 3) modifying the definition of winter months to be inclusive of the four-month period of December through March and corresponding modification of the definition of summer months to be inclusive of the eight-month period of April through November; and 4) housekeeping changes that correct minor inconsistencies and conform the tariff to Southwest Gas' current business practices.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The Company's proposed rate design, including the Energy Efficiency Enabling Provision (EEP);
- A presentation of an inclining block rate design in compliance with Decision No. 72723;
- The proposed addition of a new methodology to Rule No. 6 when considering service and main extensions for multi-family projects;
- A proposal for a Compression Tariff (Rate Schedule G-50) to address compression services provided by utility ownership and operation of facilities on customer premises; and
- Minor tariff changes that correct inconsistencies and update the tariff to reflect current business practices.

II. RATE DESIGN

Q. 7 What considerations guided Southwest Gas' proposed rate design?

A. 7 The Company focused on the following key objectives in developing the rate design proposal presented in this application: 1) the fair and equitable recovery of costs; 2) rates that work well in concert with the EEP; 3) customer acceptance

and understandability; and 4) the effect of the rate design on the promotion of the Company's energy efficiency and conservation efforts.

Q. 8 Please explain how the concepts of fairness and equality affected Southwest Gas' rate design decisions.

A. 8 Nearly 100% of Southwest Gas' cost of providing service is fixed and does not increase or decrease with changes in customer consumption. These fixed costs are classified as customer- and demand-related. Customer costs are incurred as a result of connecting a customer to the distribution system, and are relatively equal for all residential customers. Demand costs are determined by how much gas customers need during the peak demands on the distribution system. When customer- and demand-related fixed costs are recovered through variable charges, Southwest Gas will not recover the full cost of providing service from its low-use customers, while recovering more than it cost to provide service from its high-use customers. If this shift of cost responsibility amongst similarly situated customers becomes too great, the fairness and equality of the rate design come into question. A true cost-based rate design would recover the entire customer and demand costs in monthly fixed charges. However, Southwest Gas' proposed rate design balances cost of service rate principles with the recognition of past Commission policy and decisions requiring that a certain portion of the fixed cost of service be collected in the variable charge.

Q. 9 Is the Company proposing an increase to monthly basic service charges as part of its rate design proposal?

A. 9 No. Southwest Gas is not proposing to increase the basic service charge associated with any rate schedule as part of its proposed rate design.

Q. 10 How does Southwest Gas' proposed rate design accomplish the objective of working in tandem with the EEP?

A. 10 Cost-based rates recognize the difference between fixed and variable costs associated with providing service and assign the costs to fixed and variable rate components accordingly. Under a cost-based rate design, fixed rates recover the fixed costs, and variable rates recover the variable costs. However, for various reasons, gas distribution rate design may deviate from cost-based factors, with some portion of the fixed cost of service being recovered through volumetric rates. The greater this deviation from cost-based rates, the greater the potential that actual cost recovery will vary from the authorized cost-of-service.

As previously stated, Southwest Gas is not proposing full cost-based fixed charges in this proceeding. The basic service charges are unchanged and the entire revenue deficiency will be recovered in the variable charge, which will facilitate providing customers an incentive to be more energy efficient. Although Southwest Gas' proposed rates do not recover all fixed costs in fixed monthly charges, a portion of fixed costs are recovered in fixed charges, and mitigate deferrals associated with the EEP.

Q. 11 How does Southwest Gas' proposed rate design achieve the objective of customer acceptance and understandability?

A. 11 Southwest Gas is proposing to retain the existing monthly basic service charges and existing rate structures of its current rate design, and simply adjust the commodity rates to recover the proposed revenue deficiency. The Company's Arizona customers have had many years of experience with the current rate design, as it has been in place since the Company's 2007 general rate case. In

Southwest Gas' last general rate case (Docket No. G-01551A-10-0458), the EEP was added and customers have gained a level of experience, understandability, and acceptance in the intervening years since that component became part of the rate structure in January 2012.

Southwest Gas' customers are also accustomed to periodic adjustments between rate cases. For example, the gas cost rate is adjusted monthly, the gas cost surcharge is adjusted as necessary, and various other surcharges are adjusted annually.

Q. 12 Is the Company proposing any other changes that will have an impact on rate design?

A. 12 Yes. Southwest Gas is proposing to modify the definition of "winter season" to be inclusive of the four-month period of December through March, replacing the current definition of winter as the six-month period November through April. This modification also includes the corresponding definition of "summer season" to be inclusive of the eight-month period of April through November, which supplants the current summer definition of May through October. The relatively mild Arizona climate directly influences the consumption patterns of customers and the weather in the months of November and April is more characteristic of weather in the summer months of May through October. Additional information regarding this proposal can be found in the prepared direct testimonies of Company witnesses Carla Ayala and Edward Gieseking.

Q. 13 Which schedules illustrate the impact of the Company's rate design proposals on its customers?

A. 13 Statement H reflects the impact of Southwest Gas' proposed changes in revenue by rate schedule, bill comparisons at present and proposed rates by customer

class at various consumption levels, and the inputs used to develop Southwest Gas' proposed rates.

III. INCLINING BLOCK RATES

Q. 14 Does the Company's application include an inclining block rate design?

A. 14 Yes. In compliance with Decision No. 72723, Southwest Gas has included an inclining block rate design with its application. However, the Company believes the rate design described in Section II of my testimony is the more reasonable of the two approaches.

Q. 15 What is an inclining block rate design and why is it typically used?

A. 15 An inclining block rate design has two or more tiers or "blocks" where the rate per therm increases in each block, consistent with increased usage. Inclining block rate structures are typically used to encourage more conservation-minded customer behavior. However, the increase in the second block rate requires a decrease in the first block rate over current rate levels. Given Southwest Gas' customer usage characteristics, more than half of all usage falls within the first block. This type of change in the rate structure would likely have a negligible conservation effect, but would add a level of complication that does not currently exist.

In addition, as a commodity, natural gas tends to have a fairly inelastic demand especially as it relates to residential customer use, which was detailed in the testimony of Company witness James L. Cattanach (Docket No. G-01551A-04-0876). With the primary purpose of inclining block rate design to encourage conservation through changes in price, the relative insensitivity to changes in price are unlikely to yield the conservation effect that one would expect when compared with a commodity exhibiting a more elastic demand.

Q. 16 Which rate schedules are included in the Company's inclining block rate design presentation?

A. 16 Southwest Gas has included Single-Family Residential, Multi-Family Residential and Single-Family Low Income Residential and Multi-Family Low Income Residential rate schedules in its presentation.

Q. 17 Please summarize the elements of the inclining block rate design.

A. 17 The inclining block rate design includes an increase in the monthly basic service charge and variable charge for the second block as compared to the currently effective rates.

Q. 18 Why is an increase in the monthly basic service charge necessary under the inclining block rate design?

A. 18 Inclining block rate structures shift more cost recovery into higher levels of consumption making recovery of fixed costs more uncertain. In order to mitigate some of this uncertainty and maintain equity and fairness in rate design by alleviating potential increases in intra-class subsidies, more of the fixed costs that would otherwise be recovered through a flat volumetric rate are being recovered through the basic service charge.

Q. 19 Has the Company prepared schedules to illustrate the impact of an inclining block rate design on customers?

A. 19 Yes. Exhibit No.__(CMB-1) reflects the impact of Southwest Gas' proposed changes in revenue by rate schedule, bill comparisons at present and proposed rates by customer class at various consumption levels, and the inputs used to develop the inclining block rate design.

IV. SERVICE AND MAIN EXTENSIONS

Q. 20 Please provide a summary of the revisions the Company proposes to Rule No. 6, Service and Main Extensions.

A. 20 The Company proposes a change with respect to potential new-construction multi-family projects, which allows utility contributions to the customer/developer's beyond the meter gas facilities in cases where the design cost, as calculated using the incremental contribution method (ICM) prescribed in Rule No. 6, provides a rate of return on investment in excess of the overall rate of return authorized by the Commission in the Company's most recent general rate case.

Q. 21 What is the purpose of a utility contribution to the customer/developer?

A. 21 Any available contribution calculated under this method would be for the purpose of offsetting costs incurred for the installation of gas piping in the customer/developer premise, also known as "first costs".

Q. 22 Are "first costs" a significant barrier for developers of multi-family projects?

A. 22 Yes. The upfront costs associated with installing natural gas into a multi-family building can be considerable, ranging from several thousand to millions of dollars. These costs are attributable to the extensive additional piping and venting required throughout a multi-family building. Even if natural gas service can be brought to the building at no cost to the developer of a project, these additional costs within the building itself often economically preclude the installation of natural gas by the developer. These high upfront costs are the primary impediment for multi-family developers that may wish to provide natural gas to building occupants. For example, in 2015, only 12% of the multi-family

units constructed in the Phoenix and Tucson metropolitan areas used natural gas on an individual unit level.

Q. 23 How does this proposal complement the existing requirements of Rule No. 6?

A. 23 This proposal provides consideration to new-construction multi-family projects that are deemed economic as calculated using the ICM under the existing Rule No. 6 provisions. While this proposal adds new language to work in conjunction with the existing language, it does not alter the overall objective of assuring that new load does not place a burden on existing customers.

Q. 24 In practice, how will this proposal operate?

A. 24 When a project provides a rate of return in excess of that required, as calculated using the ICM, the dollar amount attributable to the excess rate of return may be provided as a utility contribution. Any contribution provided by the utility will not exceed the actual cost, nor will it cause the costs as calculated using the ICM to result in less than the authorized rate of return. Please refer to the Company's proposed revised tariff, filed concurrently herewith in Volume I of Southwest Gas' application, for additional detail.

V. COMPRESSION TARIFF

Q. 25 Please provide a summary of Southwest Gas' proposed Compression Tariff (Rate Schedule G-50).

A. 25 The Company has identified opportunities to provide high pressure compression service through facilities owned and operated by the Company, located on a customer's premises. Because each potential project would be unique, the proposed tariff describes the specific components of the rate structure which will be designed to recover the depreciation, return on capital investment, income

taxes, property taxes, and operating expenses associated with the high pressure equipment.

In addition to specifying applicable rates, the proposed Compression Tariff identifies both customer and Utility responsibilities, as well as definitions specific to the proposed Rate Schedule G-50.

Q. 26 Does the Company currently own and operate facilities located on the customer premise?

A. 26 Yes, it is normal practice to locate Company owned and operated facilities on the customer premise in order to provide utility service. A typical customer installation includes Company owned and operated service lines, pressure regulation equipment and meters, all located on the customer premise. Additionally, some of the Company's larger customers have Company owned and operated gas sampling and communications equipment.

Q. 27 What type of customer needs high pressure compression facilities?

A. 27 Typical customers are enterprises with large vehicle fleets that could use natural gas as a transportation fuel, and natural gas fueling stations. The Compression Tariff is not intended for residential applications. Please refer to the Company's proposed revised tariff, filed concurrently herewith in Volume I of Southwest Gas' application, for additional detail.

VI. MINOR AND CONFORMING TARIFF CHANGES

Q. 28 Is Southwest Gas proposing any other tariff changes in addition to those you previously discussed?

A. 28 Yes. Southwest Gas proposes the following minor and conforming changes to its tariff:

- The discontinuance of the Field Collection Fee as currently set forth in the Other Service Charges. For the safety of employees, no cash payments are accepted in the field; only checks are accepted. However, over the last several years, the Company has added numerous alternate and more convenient methods for customers to pay their bills; including the ability to pay with a check over the phone without being assessed a service fee. This provides customers who are needing to pay their bill with a check, but who have not previously submitted their payment through other means, the same option to pay their bill in order to avoid the termination of service, without incurring additional fees. It also provides customers the convenience to pay their bill after business hours and on weekends.
- A variety of housekeeping changes to clarify Southwest Gas' tariff and conform to current business practices. In addition, these proposed changes correct minor inconsistencies in references found throughout the tariff. Please refer to the Company's proposed revised tariff, filed concurrently herewith in Volume I of Southwest Gas' application, for additional detail.

Q. 29 Does this conclude your prepared direct testimony?

A. 29 Yes.

SUMMARY OF QUALIFICATIONS
CHRISTY M. BERGER

I received a Bachelor of Science degree in Accounting from the University of Nevada, Las Vegas in 1994, and later that year, I began my employment with Southwest Gas and have held a variety of positions of increasing responsibility.

From 1994 to 1997, I was a Corporate Accountant, and subsequently an Analyst, in the Company's Gas and Regulatory Accounting department, where my responsibilities included accounting and billing with respect to Southwest Gas' largest transportation customers, in addition to calculating and developing accounting entries for gas costs related to the Company's various rate jurisdictions.

In February 1998, I began a 15-month training program in Southwest Gas' Pricing and State Regulatory Affairs departments. As part of this program, I had a rotational assignment spending six months in the Pricing and Tariffs department, six months in the Revenue Requirements department, and three months in the State Regulatory Affairs department. At the conclusion of this training program, I was permanently assigned to the Pricing and Tariffs department in May 1999, where I held the positions of Specialist and Senior Specialist. My responsibilities included the development of Class Cost of Service Studies, as well as other rate case related duties, in addition to various pricing and tariff analyses.

In March 2007, I was promoted to Supervisor of the Company's Gas Scheduling department. My responsibilities included all gas scheduling activities for both the Company's sales customers, as well as confirmation of scheduled volumes for Southwest Gas' transportation customers on seven pipelines serving the Company's three-state jurisdiction.

In July 2009, I was promoted to Manager of State Regulatory Affairs, where I was responsible for all regulatory activity related to the three state regulatory commissions under which the Company operates.

In October 2014, I moved to my current position as Manager of Rates and Regulatory Analysis. I report to the Director of Regulation and Energy Efficiency. My primary responsibilities include all aspects of regulatory analysis related to Southwest Gas' various rate jurisdictions, including the calculation and implementation of customer rates, revenue requirement analyses, and tariff administration.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT RATES AND REVENUES WITH INCLINING BLOCK RATES
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills [1]	Billing Determinants: Sales (Therms) [1]	Revenue with Inclined Block Rates: Basic Service Charge	Revenue with Inclined Block Rates: Delivery Charge [2]	Revenue with Inclined Block Rates: Basic Service Charge	Revenue with Inclined Block Rates: Delivery Charge	Revenue with Inclined Block Rates: Total Margin	Revenue with Inclined Block Rates: Gas Cost [3]	Revenue with Inclined Block Rates: Total Revenue	Revenue at Present Rates [4]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Single-Family Residential Gas Service	G-5													
	Summer (April-November)														
1	Basic Service Charge per Month		5,471,571		$ 11.75		$ 64,290,959		$ 64,290,959		$ 64,290,959	$ 58,545,810	$ 5,745,149	9.8%	1
	Commodity Charge per Therm														
2	First 9 Therms			20,392,714		$ 0.51527		$ 10,507,754	10,507,754	$ 9,901,886	20,409,640	24,240,819	(3,831,179)	-15.8%	2
3	Over 9 Therms			73,901,819		0.76203		56,315,076	56,315,076	35,883,767	92,198,843	87,847,092	4,351,751	5.0%	3
	Winter (December-March)														
4	Basic Service Charge per Month		5,525,070		$ 11.75		64,919,573		64,919,573		64,919,573	59,118,249	5,801,324	9.8%	4
	Commodity Charge per Therm														
5	First 35 Therms			34,598,609		0.51527		17,827,625	17,827,625	16,799,701	34,627,326	41,127,367	(6,500,041)	-15.8%	5
6	Over 35 Therms			152,961,038		0.76203		116,560,222	116,560,222	74,271,762	190,831,984	181,824,786	9,007,198	5.0%	6
7	Total Single-Family Residential		10,996,641	281,854,180			$ 129,210,532	$ 201,210,677	$ 330,421,209	$ 136,857,116	$ 467,278,325	$ 452,704,123	$ 14,574,202	3.2%	7
	Multi-Family Residential Gas Service	G-6													
	Summer (April-November)														
8	Basic Service Charge per Month		208,043		$ 10.25		$ 2,132,441		$ 2,132,441		$ 2,132,441	$ 2,018,017	$ 114,424	5.7%	8
	Commodity Charge per Therm														
9	First 8 Therms			672,861		$ 0.51527		$ 346,705	346,705	$ 326,714	673,419	799,830	(126,411)	-15.8%	9
10	Over 8 Therms			2,080,651		0.76203		1,585,509	1,585,509	1,010,281	2,595,790	2,473,270	122,520	5.0%	10
	Winter (December-March)														
11	Basic Service Charge per Month		210,511		$ 10.25		2,157,738		2,157,738		2,157,738	2,041,957	115,781	5.7%	11
	Commodity Charge per Therm														
12	First 19 Therms			795,619		$ 0.51527		409,959	409,959	386,321	796,280	945,752	(149,472)	-15.8%	12
13	Over 19 Therms			2,705,920		0.76203		2,061,980	2,061,980	1,313,887	3,375,867	3,216,527	159,340	5.0%	13
14	Total Multi-Family Residential		418,554	6,255,051			$ 4,290,179	$ 4,404,153	$ 8,694,332	$ 3,037,203	$ 11,731,535	$ 11,495,353	$ 236,182	2.1%	14
	Single-Family Low Income Residential Gas Service	G-10													
	Summer (April-November)														
15	Basic Service Charge		230,881		$ 7.75		$ 1,789,328		$ 1,789,328		$ 1,789,328	$ 1,731,608	$ 57,720	3.3%	15
	Commodity Charge per Therm														
16	First 9 Therms			784,015		$ 0.51527		$ 403,979	403,979	$ 380,686	784,665	931,959	(147,294)	-15.8%	16
17	Over 9 Therms			3,152,320		0.76203		2,402,148	2,402,148	1,530,640	3,932,788	3,747,163	185,625	5.0%	17
	Winter (December-March)														
18	Basic Service Charge		233,375		$ 7.75		1,808,656		1,808,656		1,808,656	1,750,313	58,343	3.3%	18
	Commodity Charge per Therm														
19	First 35 Therms			1,453,104		0.51527		748,741	748,741	705,569	1,454,310	1,727,305	(272,995)	-15.8%	19
20	Over 35 Therms			6,043,034		0.76203		4,604,946	4,604,946	2,934,256	7,539,202	7,183,355	355,847	5.0%	20
21	Total Single-Family Low Income		464,256	11,432,473			$ 3,597,984	$ 8,159,814	$ 11,757,798	$ 5,551,151	$ 17,308,949	$ 17,071,702	$ 237,247	1.4%	21
	Multi-Family Low Income Residential Gas Service	G-11													
	Summer (April-November)														
22	Basic Service Charge per Month		20,185		$ 7.75		$ 156,434		$ 156,434		$ 156,434	$ 151,388	$ 5,046	3.3%	22
	Commodity Charge per Therm														
23	First 8 Therms			60,601		$ 0.51527		$ 31,226	31,226	$ 29,425	60,651	72,036	(11,385)	-15.8%	23
24	Over 8 Therms			245,079		0.76203		186,756	186,756	119,001	305,757	291,325	14,432	5.0%	24
	Winter (December-March)														
25	Basic Service Charge per Month		20,559		$ 7.75		159,332		159,332		159,332	154,193	5,139	3.3%	25
	Commodity Charge per Therm														
26	First 19 Therms			63,076		0.51527		32,501	32,501	30,627	63,128	74,978	(11,850)	-15.8%	26
27	Over 19 Therms			346,918		0.76203		264,360	264,360	168,450	432,810	412,381	20,429	5.0%	27
28	Total Multi-Family Low Income		40,744	715,674			$ 315,766	$ 514,843	$ 830,609	$ 347,503	$ 1,178,112	$ 1,156,303	$ 21,809	1.9%	28
29	Total Tariff Residential Sales		11,920,195	300,257,378			$ 137,414,461	$ 214,289,487	$ 351,703,948	$ 145,792,973	$ 497,496,921	$ 482,427,480	$ 15,069,441	3.1%	29
30	Total Revenue Requirement								351,703,004						30
31	Over/(Under)								$ 944						31

[1] Schedule H-6, Sheet 1-16.
[2] Calculated rates to recover proposed Margin with Inclining Block Rate Design per Schedule H-1, Sheet 2.
[3] Present Gas Cost rate effective November 30, 2015.
[4] Schedule H-2, Sheet 1-4.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND INCLINING BLOCK RATES
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

			Present Rates						Inclining Block Rates				
Line No.	Description	Schedule	Delivery Charge [1]	Rate Adjustment [2]	Gas Cost [2]	Currently Effective Tariff Rate	Description	Schedule	Delivery Charge [3]	Rate Adjustment [2]	Gas Cost [2]	Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Single-Family Residential Gas Service	G-5					Single-Family Residential Gas Service	G-5					
1	Basic Service Charge per Month		$ 10.70			$ 10.70	Summer (April-November)						1
2	Commodity Charge per Therm						Basic Service Charge per Month		$ 11.75			$ 11.75	2
3	All Usage		$ 0.70314	$ 0.00628	$ 0.48556	$ 1.19498	Commodity Charge per Therm						3
4							First 9 Therms		$ 0.51527	$ 0.00074	$ 0.48556	$ 1.00157	4
5							Over 9 Therms		0.76203	0.00074	0.48556	1.24833	5
							Winter (December-March)						
6							Basic Service Charge per Month		$ 11.75			$ 11.75	6
							Commodity Charge per Therm						
7							First 35 Therms		$ 0.51527	$ 0.00074	$ 0.48556	$ 1.00157	7
8							Over 35 Therms		0.76203	0.00074	0.48556	1.24833	8
	Multi-Family Residential Gas Service	G-6					Multi-Family Residential Gas Service	G-6					
9	Basic Service Charge per Month		$ 9.70			$ 9.70	Summer (April-November)						9
10	Commodity Charge per Therm						Basic Service Charge per Month		$ 10.25			$ 10.25	10
11	All Usage		$ 0.70314	$ 0.00628	$ 0.48556	$ 1.19498	Commodity Charge per Therm						11
12							First 8 Therms		$ 0.51527	$ 0.00074	$ 0.48556	$ 1.00157	12
13							Over 8 Therms		$ 0.76203	$ 0.00074	$ 0.48556	$ 1.24833	13
							Winter (December-March)						
14							Basic Service Charge per Month		$ 10.25			$ 10.25	14
							Commodity Charge per Therm						
15							First 19 Therms		$ 0.51527	$ 0.00074	$ 0.48556	$ 1.00157	15
16							Over 19 Therms		$ 0.76203	$ 0.00074	$ 0.48556	$ 1.24833	16
	Single-Family Low Income Residential Gas Service	G-10					Single-Family Low Income Residential Gas Service	G-10					
17	Basic Service Charge per Month		$ 7.50			$ 7.50	Summer (April-November)						17
18	Commodity Charge per Therm						Basic Service Charge per Month		$ 7.75			$ 7.75	18
	Summer (May - October)						Commodity Charge per Therm						
19	All Usage		$ 0.70314	$ (0.01879)	$ 0.48556	$ 1.16991	First 9 Therms		$ 0.51527	$ (0.02001)	$ 0.48556	$ 0.98082	19
20	Winter (November - April)						Over 9 Therms		$ 0.76203	$ (0.02001)	$ 0.48556	$ 1.22758	20
21	First 150 Therms		$ 0.35277	$ (0.01879)	$ 0.48556	$ 0.81954							21
22	Over 150 Therms		0.70314	$ (0.01879)	$ 0.48556	1.16991	Winter (December-March)						22
23							Basic Service Charge per Month		$ 7.75			$ 7.75	23
							Commodity Charge per Therm						
24							First 35 Therms		$ 0.22162	$ (0.02001)	$ 0.48556	$ 0.68717	24
25							Over 35 Therms		$ 0.76203	$ (0.02001)	$ 0.48556	$ 1.22758	25
	Multi-Family Low Income Residential Gas Service	G-11					Multi-Family Low Income Residential Gas Service	G-11					
26	Basic Service Charge per Month		$ 7.50			$ 7.50	Summer (April-November)						26
27	Commodity Charge per Therm						Basic Service Charge per Month		$ 7.75			$ 7.75	27
	Summer (May - October)						Commodity Charge per Therm						
28	All Usage		$ 0.70314	$ (0.01879)	$ 0.48556	$ 1.16991	First 8 Therms		$ 0.51527	$ (0.02001)	$ 0.48556	$ 0.98082	28
29	Winter (November - April)						Over 8 Therms		$ 0.76203	$ (0.02001)	$ 0.48556	$ 1.22758	29
30	First 150 Therms		$ 0.35277	$ (0.01879)	$ 0.48556	$ 0.81954							30
31	Over 150 Therms		0.70314	$ (0.01879)	$ 0.48556	1.16991	Winter (December-March)						31
32							Basic Service Charge per Month		$ 7.75			$ 7.75	32
							Commodity Charge per Therm						
33							First 19 Therms		$ 0.22162	(0.02001)	$ 0.48556	$ 0.68717	33
34							Over 19 Therms		$ 0.76203	(0.02001)	$ 0.48556	$ 1.22758	34
	Service Establishment Charge						Service Establishment Charge						
35	Normal					$ 35.00	Normal					$ 35.00	35
36	Expedited					$ 50.00	Expedited					$ 50.00	36

[1] Present Margin rates effective January 1, 2012.
[2] Present Rate Adjustment and Gas Cost rates effective November 30, 2015.
[3] Calculated rates to recover proposed Margin with Inclining Block Rate Design per Schedule H-1, Sheet 2.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - INCLINING RATES VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015
SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Inclining Block Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	$ 20.26	$ 19.76	$ (0.50)	-2.47%	1
2	Average Summer Use [1]	11	23.84	23.26	(0.58)	-2.43%	2
3	125 Percent Average Use	14	27.43	27.01	(0.42)	-1.53%	3
	Winter Season Bills						
4	75 Percent Average Use	30	$ 46.55	$ 41.80	$ (4.75)	-10.20%	4
5	Average Winter Use [1]	40	58.50	53.05	(5.45)	-9.32%	5
6	125 Percent Average Use	50	70.45	65.53	(4.92)	-6.98%	6
7	Annual Average Use	26	41.77	37.79	(3.98)	-9.53%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 10.70
Commodity Charge	
All Usage	$ 1.19498
Inclining Block Rates	
Basic Service Charge per Month	$ 11.75
Commodity Charge	
Summer (May-October)	
First 9 Therms	$ 1.00157
Over 9 Therms	1.24833
Winter (November-April)	
First 35 Therms	$ 1.00157
Over 35 Therms	1.24833

[1] Workpapers Schedule H-2, Sheets 50-54.
[2] Rates effective November 30, 2015 including all adjustments.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - INCLINING RATES VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015
MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Inclining Block Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	7	$ 18.06	$ 17.26	$ (0.80)	-4.43%	1
2	Average Summer Use [1]	9	20.45	19.51	(0.94)	-4.60%	2
3	125 Percent Average Use	11	22.84	22.01	(0.83)	-3.63%	3
	Winter Season Bills						
4	75 Percent Average Use	16	$ 28.82	$ 26.28	$ (2.54)	-8.81%	4
5	Average Winter Use [1]	21	34.79	31.78	(3.01)	-8.65%	5
6	125 Percent Average Use	26	40.77	38.02	(2.75)	-6.75%	6
7	Annual Average Use	15	27.56	25.22	(2.34)	-8.49%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 9.70
Commodity Charge	
All Usage	$ 1.19498
Inclining Block Rates	
Basic Service Charge per Month	$ 10.25
Commodity Charge	
Summer (May-October)	
First 9 Therms	$ 1.00157
Over 9 Therms	1.24833
Winter (November-April)	
First 35 Therms	$ 1.00157
Over 35 Therms	1.24833

[1] Workpapers Schedule H-2, Sheets 50-54.
[2] Rates effective November 30, 2015 including all adjustments.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - INCLINING RATES VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015
SINGLE-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Inclining Block Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	$ 16.86	$ 15.60	$ (1.26)	-7.47%	1
2	Average Summer Use [1]	11	20.37	19.03	(1.34)	-6.58%	2
3	125 Percent Average Use	14	23.88	22.72	(1.16)	-4.86%	3
	Winter Season Bills						
4	75 Percent Average Use	29	$ 31.27	$ 27.68	$ (3.59)	-11.48%	4
5	Average Winter Use [1]	38	38.64	35.48	(3.16)	-8.18%	5
6	125 Percent Average Use	48	46.84	47.76	0.92	1.96%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.50
Commodity Charge	
Summer (May-October)	
All Usage	$ 1.16991
Winter (November-April)	
First 150 Therms	$ 0.81954
Over 150 Therms	1.16991

Inclining Block Rates	
Basic Service Charge per Month	$ 7.75
Commodity Charge	
Summer (May-October)	
First 9 Therms	$ 0.98082
Over 9 Therms	1.22758
Winter (November-April)	
First 35 Therms	$ 0.68717
Over 35 Therms	1.22758

[1] Workpapers Schedule H-2, Sheets 50-54.
[2] Rates effective November 30, 2015 including all adjustments.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - INCLINING RATES VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015
MULTI-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Inclining Block Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	$ 16.86	$ 15.60	$ (1.26)	-7.47%	1
2	Average Summer Use [1]	10	19.20	18.05	(1.15)	-5.99%	2
3	125 Percent Average Use	13	22.71	21.73	(0.98)	-4.32%	3
	Winter Season Bills						
4	75 Percent Average Use	19	$ 23.07	$ 20.81	$ (2.26)	-9.80%	4
5	Average Winter Use [1]	25	27.99	28.17	0.18	0.64%	5
6	125 Percent Average Use	31	32.91	35.54	2.63	7.99%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.50
Commodity Charge	
Summer (May-October)	
All Usage	$ 1.16991
Winter (November-April)	
First 150 Therms	$ 0.81954
Over 150 Therms	1.16991

Inclining Block Rates	
Basic Service Charge per Month	$ 7.75
Commodity Charge	
Summer (May-October)	
First 9 Therms	$ 0.98082
Over 9 Therms	1.22758
Winter (November-April)	
First 35 Therms	$ 0.68717
Over 35 Therms	1.22758

[1] Workpapers Schedule H-2, Sheets 50-54.
[2] Rates effective November 30, 2015 including all adjustments.

Tab K

Direct Testimony

of

Edward Gieseking

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-16-0107

PREPARED DIRECT TESTIMONY
OF
EDWARD GIESEKING

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 2, 2016

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of
Prepared Direct Testimony
of
EDWARD GIESEKING

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Appendix A – Summary of Qualifications of Edward Gieseking

Exhibit No.__(EG-1)

Exhibit No.__(EG-2)

Exhibit No.__(EG-3)

Exhibit No.__(EG-4)

Exhibit No.__(EG-5)

Southwest Gas Corporation
Docket No. G-01551A-16-0107

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
Edward Gieseking

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Edward Gieseking. My business address is 5241 Spring Mountain Road, Las Vegas Nevada.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Regulation and Energy Efficiency department. My title is Director.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (Commission), the California Public Utilities Commission, the Public Utilities Commission of Nevada and the Federal Energy Regulatory Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I am sponsoring the Company's proposals to establish a regulatory mechanism to reflect changes in the property tax liability, and to expand the Company's infrastructure recovery mechanism. Additionally, I am sponsoring cost recovery treatment of the currently approved liquefied natural gas (LNG) storage facility

in southern Arizona, as well as subtle refinements to the Company's Energy Efficiency Enabling Provision (EEP).

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- Implementation of a Property Tax True-up Mechanism;
- Expansion of the currently authorized infrastructure recovery mechanism to both expand the Customer Owned Yard Line (COYL) program and to facilitate the replacement of other aging gas infrastructure and investment in gas infrastructure modernization;
- Cost recovery for the currently approved LNG facility; and
- Subtle enhancements to the EEP.

II. REGULATORY MECHANISMS

Q. 7 What is meant by the phrase "regulatory mechanism"?

A. 7 The phrase "regulatory mechanism" is intended to capture various types of cost recovery and rate design mechanisms that are commonly used in the utility industry, and that are departure from the traditional ratemaking methodologies. The American Gas Association (AGA) periodically publishes a report identifying the prevalence of various innovative regulatory mechanisms in the natural gas industry, among other topics. A copy of the AGA document is attached as Exhibit No.__(EG-1).

Q. 8 Why is it appropriate for the Commission to consider regulatory mechanisms?

A. 8 The rates established in the general rate case process are based on a level of cost that is expected to occur during the period that rates will be effective. Thus, there is an expectation that the Company will have a reasonable opportunity to recover those costs of providing utility service. Sometimes situations require a

departure from this traditional rate making process and merit being recovered outside of a general rate case through appropriate regulatory mechanisms. Typically, these costs have one or more of the following characteristics that make them eligible for recovery outside of general rates: 1) they are not included in the development of the authorized revenue requirement and are therefore not included in the development of general rates, 2) management has limited or no power or influence over the incurrence of these costs, and/or 3) the amount of these costs actually incurred can change significantly from year to year and could deviate significantly from an amount incurred within a general rate case test period.

Q. 9 What regulatory mechanisms does Southwest Gas currently utilize in Arizona?

A. 9 The Company currently utilizes three types of regulatory mechanisms. First, cost trackers are designed to track certain narrowly defined operating expenses and treat them as a pass through. The Company currently utilizes five different cost trackers to recover the following costs outside of general rates: 1) gas commodity and related costs, 2) energy efficiency expenditures, 3) low income discounts, 4) research and development (R&D) costs, and 5) federally mandated pipeline safety costs. The second type of regulatory mechanism is an infrastructure recovery mechanism. These mechanisms are utilized to provide a revenue stream for investments do not otherwise result in an increase in customers or throughput, and therefore do not result in any incremental increase in revenue to the Company. The Company's COYL program utilizes this type of regulatory mechanism by allowing the Company to recover the revenue requirement associated with non-revenue producing infrastructure replacement activity. The third type of regulatory mechanism is the EEP or decoupling

mechanism. The Company utilizes a margin per customer decoupling mechanism to ensure that the fixed costs that have been approved by the Commission are actually recovered from customers regardless of changes in consumption. In addition, because the Company is indifferent to its level of sales, it is better positioned to help customers use less natural gas through the promotion of energy efficiency programs.

Q. 10 How do the three criteria you listed above apply to the regulatory mechanisms used by Southwest Gas?

A. 10 The following table shows how each of those criteria apply to the specific programs that utilize a regulatory mechanism:

Rate Adjustment	Criteria 1	Criteria 2	Criteria 3
Gas Cost	X	X	X
EE	X	X	X
Low Income	X	X	X
R&D	X		
Safety	X	X	X
COYL	X		X
EEP	X	X	X

Q. 11 Is Southwest Gas proposing any changes to its currently approved regulatory mechanisms in this proceeding?

A. 11 Yes. Southwest Gas seeks to continue each of the three regulatory mechanisms, and proposes a few modifications to the various programs whose costs are recovered through the mechanisms. The Company proposes to implement a cost tracker for property tax expense and proposes to rebrand its infrastructure recovery mechanism to facilitate additional recovery of non-revenue producing investment from an expanded COYL program and a new pre-1970's vintage steep pipe (VSP) replacement program. Also, Southwest Gas proposes to discontinue the cost tracker for R&D costs. The Company's

proposal for the recovery of R&D costs is addressed by Company witness Randi L. Cunningham.

A. Property Tax True-Up

Q. 12 What qualifying criteria does the property tax expense possess that makes that cost eligible for tracking in a regulatory mechanism?

A. 12 By definition, incremental changes in the Company's property tax expense would not be included in general rates until the next general rate case. Also, property tax assessments are imposed by governmental agencies and are wholly outside the control of management. Finally, changes in property taxes can be significant between general rate cases and deviate significantly from amounts included in a general rate case test period. These points are more fully addressed in the prepared direct testimony of Company witness Byron C. Williams.

Q. 13 Please describe the Company's property tax true-up mechanism proposal.

A. 13 Each tax year, the difference between the property tax included in general rates and the change in the property tax expense would be calculated as explained below, and deferred into a tracking/balancing account. Annually, the Company will make a filing with the Commission to establish a surcharge or surcredit to recover or refund the balance in the account.

Q. 14 How will incremental changes in property taxes be calculated?

A. 14 The Company proposes that for each tax year, a calculation be performed that recognizes changes in the Company's taxable property, the current year statutory assessment ratio, the effective composite property tax rate and the capitalized property tax and therefore the Company's property tax expense. A hypothetical example of the calculation is shown below.

Current Year Taxable Property	$1,700,000,000	(A)
Current Year Statutory Assessment Ratio	18.0%	(B)
Assessed Value	$306,000,000	(C = A x B)
Current Year Composite Property Tax Rate	14.0%	(D)
Current Year Property Tax Liability	$42,840,000	(E = C x D)
Capitalized Property Tax	$1,831,351	(F)
Current Year Property Tax Expense	$41,008,649	(G = E – F))
Test Year Annualized Property Tax Expense	$41,584,263	(H)
Property Tax Deferral	($575,614)	(I = G - H)

Q. 15 How will the annual inputs be determined in the above calculation?

A. 15 The Current Year Taxable Property amount (or Full Cash Value) is determined annually by the Arizona Department of Revenue and reported to the Company on a Notice of Value. The Current Year Statutory Assessment Ratio is determined by the Arizona Legislature and is detailed in Ariz. Rev. Stat. § 42-15001. The Current Year Composite Property Tax Rate is based on rates as determined by the local governments in areas where Southwest Gas owns property. The Capitalized Property Tax is the amount recorded in the taxable property year. Finally, the Test Year Annualized Property Tax Expense is detailed in the instant proceeding per Adjustment No. 15.

Q. 16 How would these property tax deferrals be recovered from or returned to customers?

A. 16 Annually, similar to the other cost trackers utilized by the Company, Southwest Gas proposes to make a filing with the Commission to establish a rate to amortize the deferred balance over an anticipated 12-month rate effective period. The amounts recovered through the property tax amortization rate would

be recorded in the property tax true-up balancing account to offset the recorded incremental property tax change. Thus, the Company would only recover/refund the actual property tax expense - no more, no less.

B. Gas Infrastructure Modernization Mechanism

Q. 17 What is the GIM mechanism?

A. 17 The GIM mechanism is simply a rebranding of Southwest Gas' existing infrastructure recovery mechanism. The intent of rebranding this mechanism is to facilitate the inclusion of other non-revenue producing investment activity.

Q. 18 Are infrastructure recovery mechanisms prevalent for natural gas distribution companies?

A. 18 Yes. The issue of providing utilities the opportunity to more timely recover their investments from non-revenue producing work – namely replacing aging natural gas infrastructure, has been recognized throughout the country, and has been addressed by regulators in many states through the establishment of various cost recovery mechanisms. The recently published AGA assessment attached as Exhibit No.__(EG-1) shows that 99 utilities in 37 states have regulatory mechanisms that provide for the recovery of costs associated with gas infrastructure replacement.[1] This assessment also shows 7 additional gas utilities with pending mechanisms.

Q. 19 What non-revenue producing investment does Southwest Gas propose to include in the GIM mechanism?

A. 19 Southwest Gas proposes to include its COYL program and its proposed pre-1970's VSP replacement programs as part of the GIM mechanism.

[1] Exhibit No.__(EG-1), p. 2-4.

Q. 20 What qualifying criteria do COYL and pre-1970's VSP possess that make them eligible for regulatory mechanism treatment?

A. 20 These costs are not included in the development of the general rates requested in this proceeding. Further, the replacement of these facilities does not otherwise result in an increase in customers or throughput, and therefore does not result in any incremental increase in revenue to the Company. Accordingly, regulatory mechanisms are necessary to facilitate the replacement, or the accelerated replacement, of non-revenue producing facilities.

Q. 21 In addition to the criteria you have outlined, are there other reasons that support the Company's proposed GIM mechanism?

A. 21 Yes. The level of depreciation expense currently included in rates funds only a portion of infrastructure replacement related to normal business activity. Therefore none of the depreciation expense that the Company will incur as a result of the non-revenue investments contemplated with the GIM mechanism will be recovered in the Company's base rates. This situation will be further worsened with the reduction in depreciation rates proposed in this application. The Company will require a regulatory mechanism designed to recover the costs associated with a more robust infrastructure modernization effort between rate cases.

A proactive approach to replacing aging infrastructure will also mitigate the potential for rate shock in the future. As discussed by Southwest Gas witness Lang, the Company operates and maintains a substantial amount of natural gas infrastructure in Arizona. While these facilities are being operated in a safe and reliable manner, it is inevitable that all facilities will require replacement at some point, either due to normal wear and tear or due to regulatory directives. The

Company's proposed GIM mechanism will achieve the controlled replacement of these facilities over time, with gradual adjustments to rates, compared to a reactive and concentrated effort that would result in a much larger rate adjustment and potential rate shock.

Q. 22 Besides the COYL program and the proposed pre-1970's VSP program, what type of investments does the Company believe could be included in the GIM mechanism?

A. 22 The Company's proposed GIM mechanism would allow the Commission the flexibility to consider a wide range of activities, including unfunded government mandates and non-revenue producing investments in infrastructure that provide operational benefits. For example, as discussed by Company witness Lang, unfunded government mandates that may be imposed on natural gas distribution companies by the Pipeline and Hazardous Materials Safety Administration may require significant non-revenue producing investment and the use of regulatory mechanisms can help alleviate the financial burden associated with compliance.

Q. 23 What changes is Southwest Gas proposing with respect to the COYL program?

A. 23 As described in more detail in the testimony of Company witness Lang, Southwest Gas is proposing to expand the COYL program to include a targeted approach to identifying and replacing COYL.

Q. 24 What is the Company proposing with respect to establishing a pre-1970's VSP program?

A. 24 As described in more detail in the testimony of Company witness Lang, Southwest Gas is proposing to accelerate the replacement of pre-1970's vintage steel distribution and transmission pipe.

Q. 25 What is the Company's proposal for the GIM mechanism and the cost recovery of COYL and pre-1970's VSP?

A. 25 The proposed cost recovery for the GIM mechanism will function in a similar manner to the currently-authorized COYL program. Annually, the Company will file an application with the Commission seeking authority to establish a surcharge to recover the revenue requirement on the capital investment associated with the GIM mechanism – which would include COYL and pre-1970's VSP replacement activity. Similar to the existing COYL program, the amounts used to calculate the surcharge established under the GIM mechanism will be equal to the depreciation and authorized pre-tax rate of return associated with the actual GIM investment costs.

Q. 26 What consumer protections are included in the GIM mechanism?

A. 26 The current limitation on rate changes of $0.01 per therm per year will remain, except Southwest Gas proposes to expand the existing rate per therm limitation to $0.03 per therm per year to accommodate the proposed expansion of the COYL program and the new pre-1970's VSP program.

Q. 27 What is the expected bill impact of increasing the GIM mechanism rate limitation to $0.03 per therm?

A. 27 For a single family residential customer, the most rates could change would be approximately $0.77 per month for an average annual bill.

Q. 28 Would the GIM mechanism demonstrate the calculation of a fair value determination?

A. 28 Yes. The GIM mechanism revenue requirement development provides a demonstration of the fair value rate base and rate of return, applying the methodology used in the determination of fair value on the Company's plant

investment included in the general rate case test period. This is discussed more fully in the prepared direct testimony of Company witness Theodore Wood. Attached as Exhibit No.__(EG-2) is a demonstration of the revenue requirement and rate calculation that would be included in the GIM mechanism filing using the data that was included in the Company's most recent COYL mechanism filing.

Q. 29 What other information will the Company provide to allow for a complete review of the GIM mechanism activity?

A. 29 Similar to how COYL has operated over the last five years, concurrent with the annual GIM mechanism filing, the Company will include a report on the GIM activity – for both COYL and pre-1970's VSP. The GIM annual report will provide detailed information on the activities completed under the GIM mechanism and an accounting of the costs associated with the GIM-related activity. Attached as Exhibit No.__(EG-3) is the Plan of Administration for the GIM mechanism.

Q. 30 In addition to the operational benefits discussed by Southwest Gas witness Lang, can the Company quantify other benefits associated with the modernization of Arizona's natural gas infrastructure?

A. 30 Yes. The Company commissioned IHS Economics Consulting to perform an economic impact analysis to quantify the economic benefit associated with the Company's capital investment budget in Arizona. The study looked at the three year period 2016 through 2018, which included capital expenditure for gas infrastructure investments of $211 million in year 1, increasing to $313 million in year three. The study shows the increase in the Arizona sales activity, employment, labor income and gross state product associated with the modernization of Arizona's natural gas infrastructure by investment in

nonrevenue-producing natural gas facilities. The analysis quantified substantial economic benefits that Arizona will enjoy as a result of the Company's capital investment activity. These benefits will directly and/or indirectly benefit all citizens of Arizona, including the Company's natural gas customers.

For the purpose of visualizing the economic benefits associated with ongoing incremental infrastructure modernization investments, IHS also analyzed the economic benefit associated with an annual capital investment of $100 million. The economic benefits are scalable to the level of investment, so if the Company is able to invest in multiples or fractions of $100 million the economic benefits can be readily quantified. Some of the study's key findings are:

- Every million dollars of capex that Southwest Gas directly spends locally supports 11 jobs in Arizona.
- Every Southwest Gas FTE dedicated to these projects represents another 17 jobs supported across the state. In the case of the GIM Programs, this ratio jumps to 25 jobs.
- Every dollar of capex that Southwest Gas spends in Arizona leads to an additional dollar of contribution to Arizona's gross state product.
- The Company's local construction and maintenance capex will drive an estimated $13.4 million of state & local taxes in Arizona during 2018. About $5.7 million will be as a result of the GIM programs.

A copy of the economic impact analysis is attached as Exhibit No.__(EG-4).

C. Southern Arizona LNG Facility

Q. 31 What is the Company proposing with respect to cost recovery for the currently approved LNG facility?

A. 31 Southwest Gas proposes that following the completion of construction and after the facility is placed into service that it be permitted to include the LNG facility in the GIM mechanism for purposes of timely cost recovery. Alternatively, if the Commission does not approve the GIM mechanism, Southwest Gas requests the deferral account that was approved as part of the LNG facility pre-approval process be extended.

Q. 32 Please further explain the Company's proposal to include the LNG facility in the proposed GIM mechanism?

A. 32 As previously discussed with respect to the GIM mechanism and the need for regulatory mechanisms for non-revenue producing investment activity, the Company's LNG facility is an example of a gas system modernization effort that will require a significant capital investment, but will not result in any additional revenue to the Company. Since the LNG facility is a non-revenue producing investment activity it would qualify under the GIM mechanism.

Q. 33 Please further explain your alternative cost recovery proposal for the LNG facility?

A. 33 In its order approving the construction of the LNG facility, the Commission approved the Company's request to defer the revenue requirement associated with the LNG facility investment for consideration in a future rate case. The revenue requirement was defined as the depreciation expense, operations and maintenance expense, carrying costs, and property taxes associated with the LNG facility. If the LNG facility is not granted cost recovery approval through the GIM mechanism, Southwest Gas requests that it be allowed to defer the revenue requirement associated with the LNG facility until rates in a future general rate case proceeding are established. However, if the Company's Property Tax True-

up mechanism is approved, the Company proposes that the revenue requirement associated with the LNG facility investment be modified to include depreciation expense, operations and maintenance expense, and carrying costs.

D. Energy Efficiency Enabling Provision

Q. 34 What is the EEP?

A. 34 The EEP, authorized in the Company's last general rate case, is a mechanism that effectively decouples the recovery of the authorized delivery system revenue requirement from the amount of gas that is consumed. This is accomplished through a two part mechanism that includes a monthly weather normalization adjustment to customer bills during the winter months when the actual weather is warmer or colder than normal, and an annual true-up calculation that limits the amount recovered from customers to the authorized margin per customer established by the Commission in the general rate case. The annual true-up is accomplished through a per therm surcharge or credit.

Each quarter, the Company provides the Commission a status report on the customer impacts associated with the EEP. Additionally, the Company makes an annual filing to establish the annual true-up rate, which includes additional details on the mechanism. A copy the EEP Plan of Administration is attached as Exhibit No.__(EG-5).

Q. 35 What is the Company's recommendation regarding the EEP?

A. 35 Southwest Gas recommends continuing the mechanism, with minor enhancements. As acknowledged by the Commission in its Orders on each of

the EEP annual filings,[2] the mechanism has performed as intended and has benefited Arizona customers. During the winter months, bills have been adjusted upward during periods of warmer than normal weather and adjusted downward during periods of colder than normal weather. These adjustments ensure customers never overpay for the delivery charges associated with providing natural gas service. In addition, the Company has recorded credits for customers of $26,485,829 since the inception of the mechanism through November 2015, limiting the Company's recovery of margin to the authorized margin per customer approved by the Commission in the last general rate case - no more, no less.

Q. 36 What enhancements to the EEP is the Company recommending?

A. 36 The Company recommends refining the monthly weather adjustment mechanism in two ways, to ensure the mechanism only adjusts bills for weather sensitive usage. First, the Company recommends that the EEP monthly weather adjustment be applicable to the months December through March for each heating season. Next, the Company proposes that the "normal" heating degree days used in the calculation of the monthly weather adjustor be updated at the end of each heating season. Combined, the Company believes these two enhancements will continue to ensure that monthly weather adjustments are reflective of changes in customer's weather sensitive consumption.

Q. 37 Why is the Company seeking to modify the effective months for the weather adjustment from the current six-month period November through April to the four-month period December through March?

[2] Docket No. G-01551A-10-0458; Decision Nos. 74252, 74862, and 75356.

A. 37 Mild winter weather in the Company's Arizona service territories results in a very limited number of heating degree days in the months of November and April. The definition of "winter" was original based upon the commonly used definition in the industry of November to April. However, as the Company continues to closely monitor the EEP and its performance, as well as the unique climate in Arizona, the Company determined that changing the definition of "winter" in the tariff to the period December through March and synchronizing the monthly weather adjustment to that period will better align the adjustments with customers' experience of winter weather.

Q. 38 What is the benefit of updating the "normal" heating degree days used in the monthly weather adjustment at the end of each heating season?

A. 38 Updating the HDDs used in the monthly weather calculation will address trends in normal weather and will more closely model changes in weather sensitive customer use when there is a trending change in normal weather. In the Company's last general rate case, the Commission approved the implementation of the EEP monthly weather adjustment as proposed by Southwest Gas. The Company proposed the use of the normal heating degree days used in the development of rates to weather normalize its customer bills. While theoretically sound, using the heating degree days from the Company's last general rate case does not recognize trend changes in weather that may occur between general rate cases. In order to recognize trend changes in weather, the Company proposes that the normal heating degree days used in the weather normalization process be updated at the end of each winter season. This change will better recognize customers' weather sensitive consumption and limit weather adjustments to the customers' weather sensitive use.

Q. 39 How will the Company make the Commission and its customers aware of any change in the normal heating degree days used in the monthly weather adjustment?

A. 39 The Company would include the results of its normal weather updates in its annual report and would update the values on its website.

Q. 40 Does this conclude your prepared direct testimony?

A. 40 Yes.

SUMMARY OF QUALIFICATIONS
EDWARD GIESEKING

Mr. Gieseking is the Director of the Regulation and Energy Efficiency department at Southwest Gas Corporation. As Director of the Regulation and Energy Efficiency department, he contributes to the formulation of the Company's regulatory policies and is responsible for ensuring policy compliance. Additionally, he directs the development of revenue requirement, rate design and tariff proposals for Southwest Gas and Paiute Pipeline Company and the development and implementation of the Company's energy efficiency programs.

Mr. Gieseking graduated from Sonoma State University in 1985 with a Bachelor of Arts degree in Business Management with an emphasis in accounting. In 1993 he was awarded a Master of Arts degree in Economics from New Mexico State University.

From 1983 through 1993, he was employed by Pacific Gas and Electric Company in various capacities, including the position of Regulatory Analyst in the Revenue Requirement and Rate departments where his responsibilities primarily involved the development of pricing structures and supporting regulatory filings before the California Public Utilities Commission.

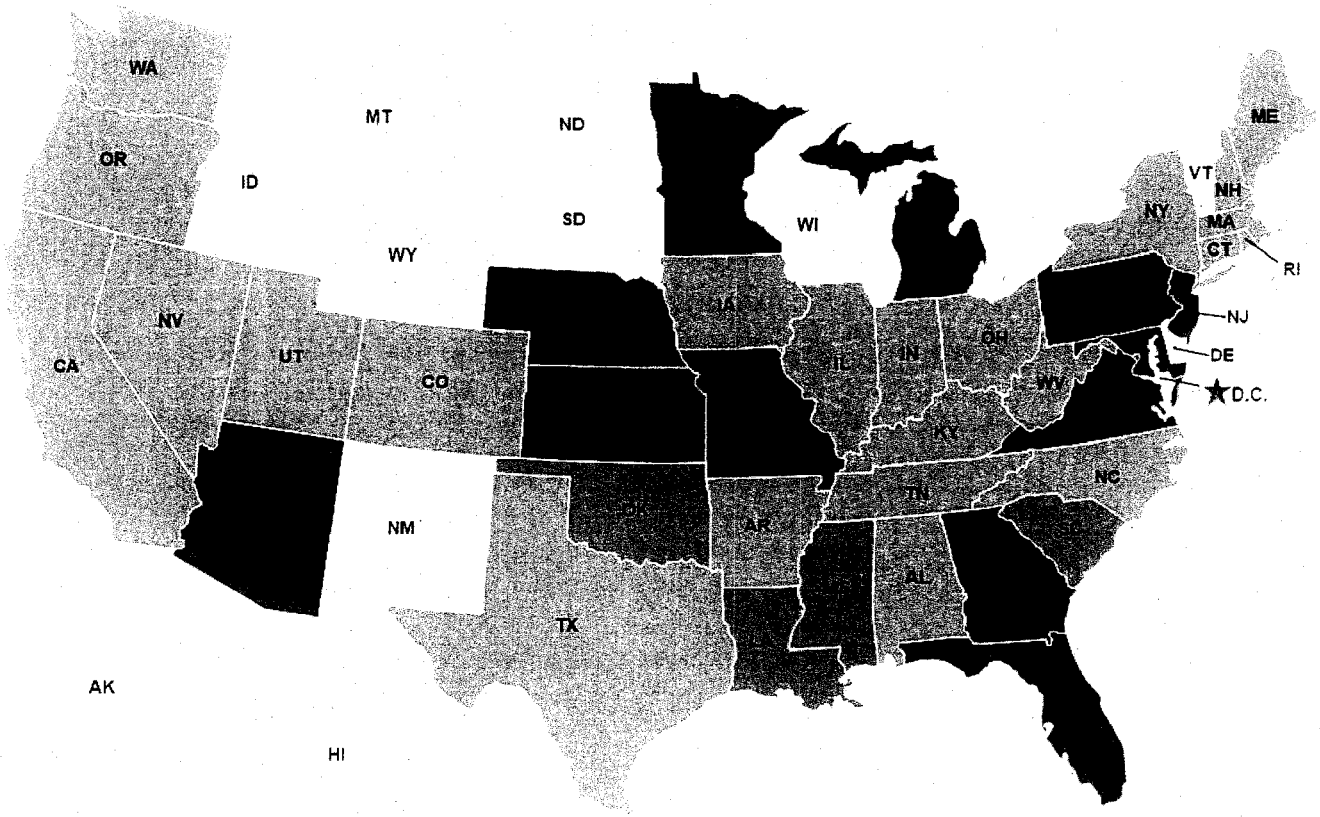
In 1993, he began his career with Southwest Gas Corporation as a Specialist in the Rate department. In 1995 he was promoted to Senior Specialist in the Regulatory Affairs department and subsequently promoted to Manager of the department in 1998. In addition to the day-to-day management of the department, his responsibilities included the supervision of regulatory filings to ensure timely and accurate submittals, and serving as the Company liaison with state regulatory agency and state consumer advocate professionals.

On August 12 2002, Mr. Gieseking was promoted to the position of Senior Manager of the Pricing and Tariffs department and on July 14, 2003 was promoted to Director of the department. On October 6, 2014, Mr. Gieseking was promoted to his current position.

As of February 2016

AGA
American Gas
Association

States with Accelerated Infrastructure Cost Recovery



Cost Recovery Tracker | Surcharge | Rate Stabilization Mechanism | No Cost Recovery Tracker, Surcharge or Rate Stabilization Mechanism

Utilities with Full Infrastructure Cost Recovery Mechanisms

AL – Alabama Gas Company
AL – Mobile Gas Service
AR – Arkansas Oklahoma Gas
AR – SourceGas
AR – CenterPoint Energy
CA – San Diego Gas and Electric
CA – Southern California Gas
CA – Southwest Gas
CO – Public Service Co. of Colorado
CT – Connecticut Natural Gas
DC – Washington Gas
FL – Chesapeake Utilities
FL – Florida Public Utilities Company
FL – Florida City Gas
FL – TECO Peoples Gas
GA – Atlanta Gas Light
GA – Liberty Utilities
IL – Ameren Illinois
IL – NICOR Gas
IL – Peoples Gas
IN – Vectren North Indiana Gas
IN – Vectren South SIGECO
IN – NIPSCO
KS – Atmos Energy
KS – Black Hills
KS – Kansas Gas Service
KY – Atmos Energy
KY – Columbia Gas of Kentucky
KY – Delta Natural Gas
KY – Duke Energy Kentucky
LA – CenterPoint Energy
LA – Entergy Gulf States
MA—Berkshire Gas
MA – Columbia Gas of Massachusetts
MA – National Grid Massachusetts
MA – Eversource Energy
MA – Liberty Utilities
MA—Unitil
MD – Baltimore Gas and Electric
MD – Columbia Gas of Maryland
MD – Washington Gas
MI – Consumers Energy
MI – DTE
MI – SEMCO Energy
MN – Xcel Energy
MO – Ameren Missouri
MO – Liberty Utilities
MO – Laclede Gas
MO – Missouri Gas Energy
MS – Atmos Energy
MS – CenterPoint Energy
NC – Piedmont Natural Gas
NH – Liberty Utilities
NJ – New Jersey Natural
NJ – Elizabethtown Gas
NJ – Public Service Electric and Gas
NJ – South Jersey Gas
NV – Southwest Gas
OH – Columbia Gas of Ohio
OH – Dominion East Ohio
OH – Duke Energy
OH – Vectren Ohio
OK – CenterPoint Energy
OR – Avista Corp.
OR – NW Natural
PA – Columbia Gas of Pennsylvania
PA – Equitable Gas
PA – Peoples Gas Company
PA – Peoples TWP
PA – UGI Central Penn Gas
PA – UGI Penn Natural Gas
PA – PECO
PA – Philadelphia Gas Works
RI – National Grid Narragansett Gas
SC – Piedmont Natural Gas
SC – South Carolina Electric and Gas
TN – Atmos Energy
TN – Piedmont Natural Gas
TX – Atmos Energy
TX – CenterPoint Energy
TX – Texas Gas Service
UT – Questar Gas
VA – Atmos Energy
VA – Columbia Gas of Virginia
VA – Virginia Natural Gas
VA – Washington Gas
WA – Avista Corporation
WA – Puget Sound Energy, Inc.
WA – Cascade Natural Gas Company
WA – Northwest Natural Gas Company
WV – Mountaineer Gas Company

Limited and Pending Infrastructure Mechanisms

LIMITED – 3 States

AZ – Southwest Gas
ME – Northern Utilities
NY – Consolidated Edison
NY – Corning Natural Gas
NY – National Grid NYC
NY – National Grid Long Island
NY – National Grid Niagara Mohawk
NY – Orange and Rockland

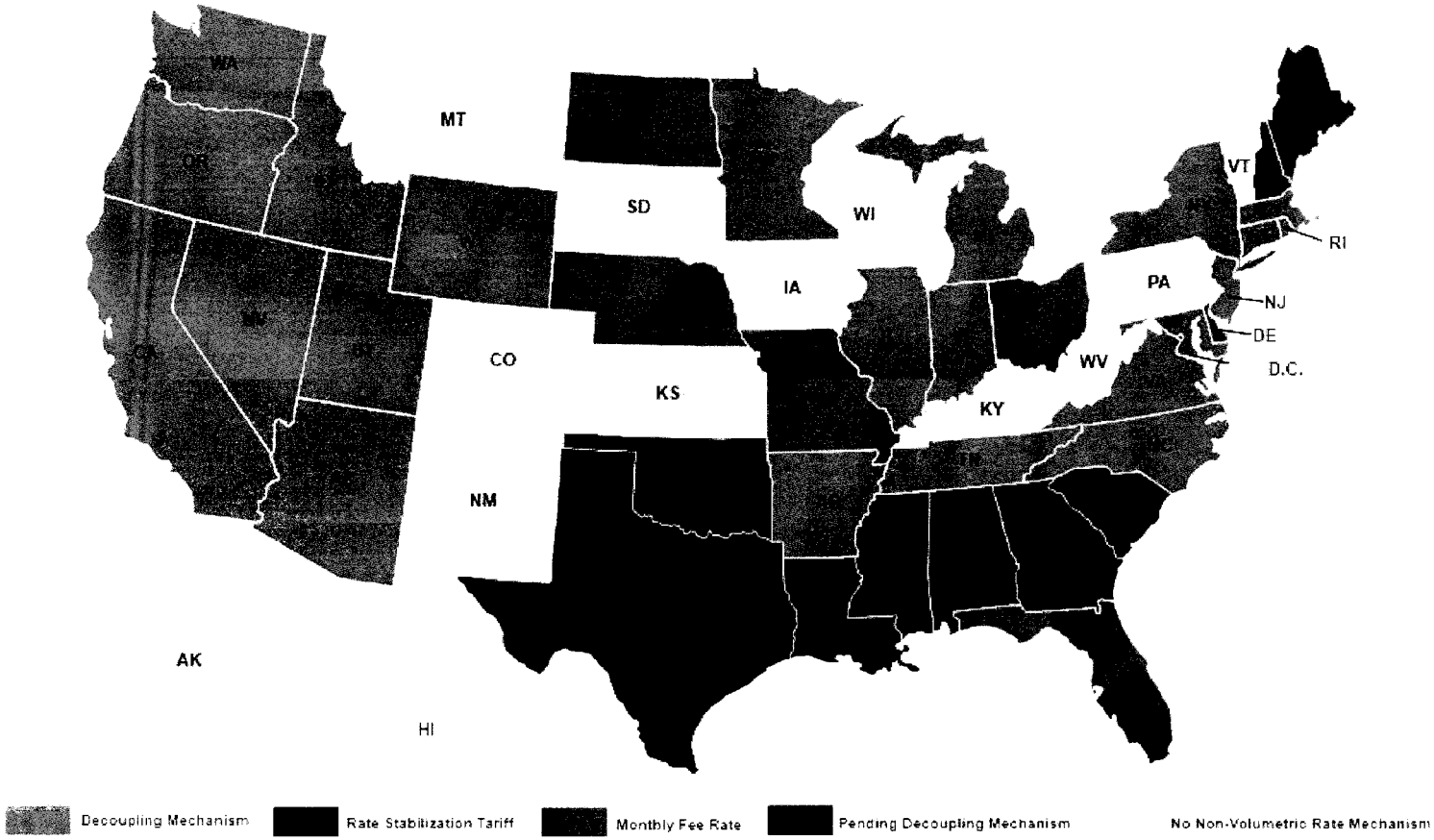
PENDING – 4 States

CO – Atmos Energy
NJ – Elizabethtown Gas
NY – Central Hudson Gas and Electric
NY – Consolidated Edison
NY – National Grid
NY – All utilities
WV – Mountaineer Gas

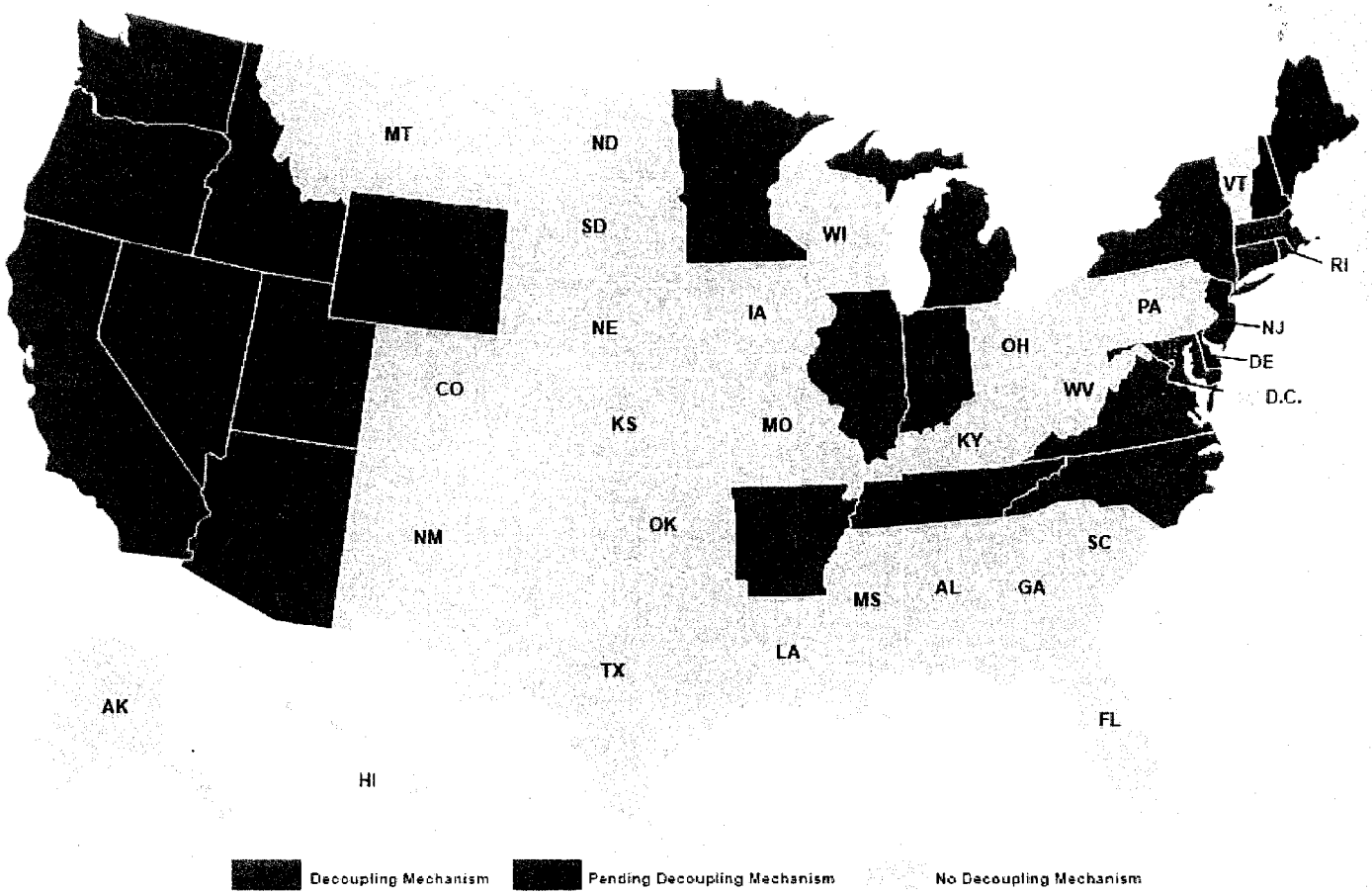
GENERIC RULINGS OR LEGISLATION – 3 States

Iowa – All utilities may apply
Nebraska – All utilities may apply
West Virginia – All utilities may apply

States with Non-Volumetric Rate Designs



Current Status of Decoupling Mechanisms



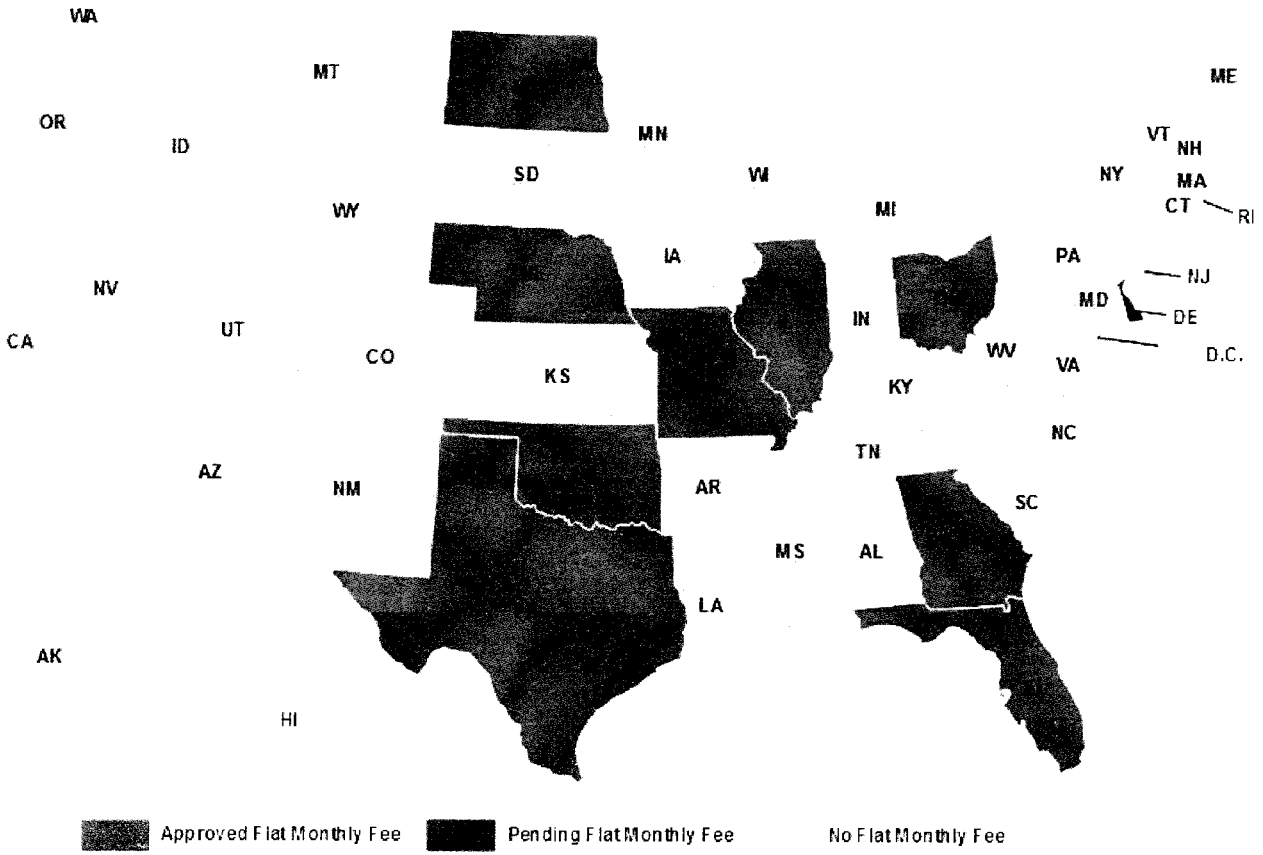
Utilities with Approved Decoupling Mechanisms

AR – Arkansas Oklahoma Gas
AR – SourceGas
AR – CenterPoint Energy
AZ – Southwest Gas
AZ – UNS Gas
CA – Pacific Gas and Electric
CA – San Diego Gas and Electric
CA – Southern California Gas
CA – Southwest Gas
CT – Connecticut Natural Gas
GA – Liberty Utilities
ID – Avista
IL – Ameren Illinois
IL – Peoples Gas
IL – North Shore Gas
IN- Citizens Energy Group
IN – Vectren North Indiana Gas
IN – Vectren South SIGECO
MA – Columbia Gas of Massachusetts
MA – Fitchburg Gas and Electric
MA – National Grid Massachusetts
MA – Eversource Energy
MA – Liberty Utilities
MD – Baltimore Gas and Electric
MD – Columbia Gas of Maryland
MD – Washington Gas
MI—Consumers Energy
MI – DTE
MN – CenterPoint Energy
MN – Minnesota Energy Resources
NC – Piedmont Natural Gas
NC – Public Service Company of North Carolina
NJ – New Jersey Natural Gas
NJ – South Jersey Gas
NV – Southwest Gas
NY – Corning Natural Gas
NY – National Grid NYC
NY – National Grid Long Island
NY – National Grid Niagara Mohawk
NY – National Fuel Distribution
NY – New York State Electric and Gas
NY – Orange and Rockland
NY – Rochester Gas and Electric
NY – Central Hudson Gas and Electric
OR – Cascade Natural Gas
OR – Northwest Natural Gas
RI – National Grid Narragansett
TN – Chattanooga Gas
UT – Questar Gas
VA – Columbia Gas of Virginia
VA – Virginia Natural Gas
VA – Washington Gas
WA – Avista Corp.
WA – Puget Sound Energy
WY – SourceGas
WY – Questar Gas

Pending Mechanisms

DE – Delmarva Power and Light
ME – Maine Natural Gas
NH – Passed Legislation
OR – Avista Corp.
WA – Cascade Natural Gas

Current Status of Flat Monthly Fee Rate Designs (SFV)



Utilities with Flat Monthly Fee Rate Designs (SFV)

Approved SFV

GA – Atlanta Gas Light – Individually determined monthly demand charge
MO – Missouri Gas Energy – Flat monthly fee
ND – Montana-Dakota Utilities
ND – Xcel Energy – Flat monthly fee
OH – Columbia Gas of Ohio – Flat monthly fee
OH – Dominion East Ohio – Flat monthly fee
OH – Duke Energy – Flat monthly fee
OH – Vectren Ohio – Flat monthly fee

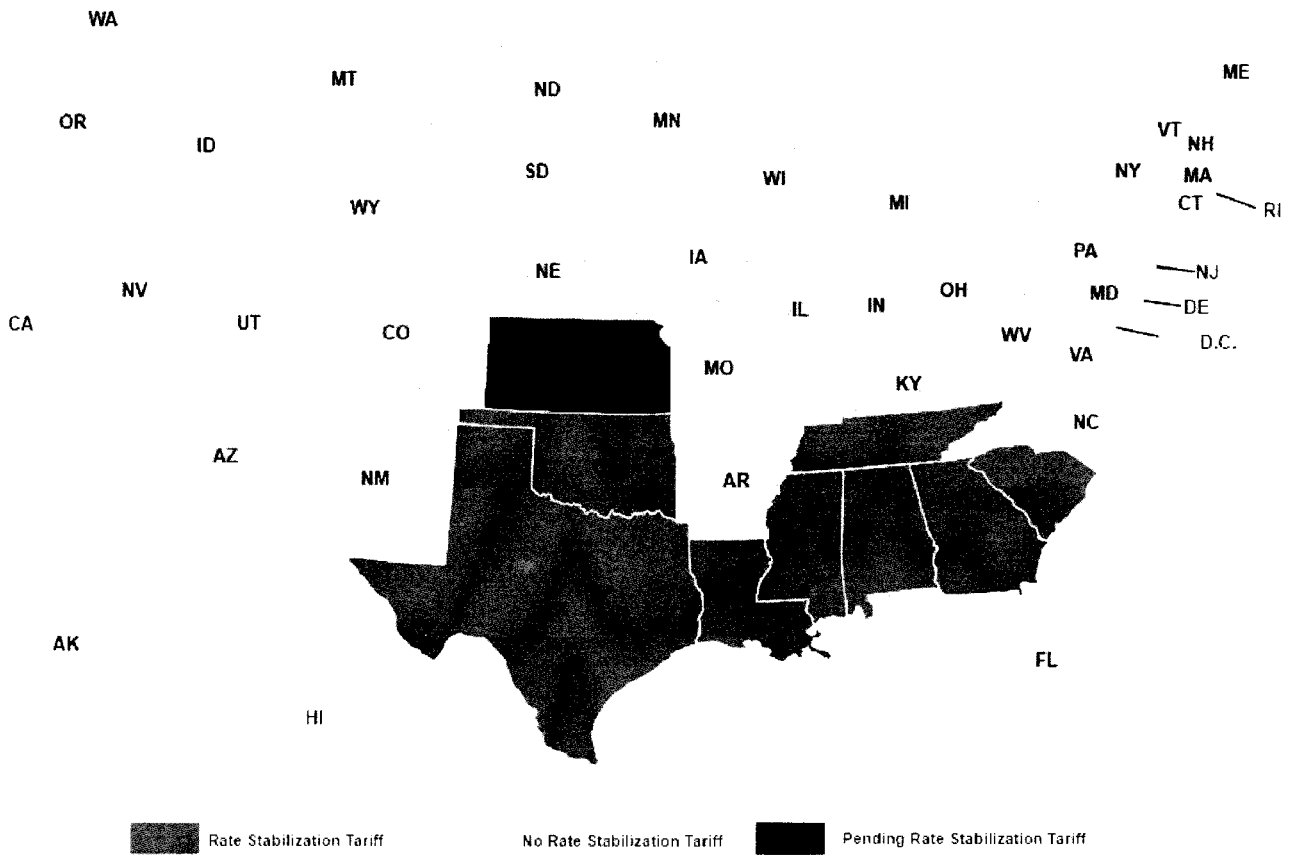
Similar to SFV

FL – TECO Peoples Gas – Three-tier monthly charge plus a small variable charge
IL - Ameren Illinois – 80% revenue for Residential and Small GS Customers per flat fee plus small variable charge
IL – Nicor Gas – Flat fee plus a small variable charge
MO – Ameren – Modified rate blocks for Residential Service customers
MO – Liberty Utilities – Flat fee plus a small variable charge
MO – Laclede Gas – Modified rate blocks
NE – Black Hills – Declining rate blocks
NE – SourceGas – Modified rate blocks
OK – Oklahoma Natural Gas – Two-tier plan – Offers customers a choice
TX – Texas Gas Service – Flat fee up to 200 ccf/month

Pending

DE – Delmarva Power and Light

Current Status of Rate Stabilization Tariffs



Current Status of Rate Stabilization Tariffs

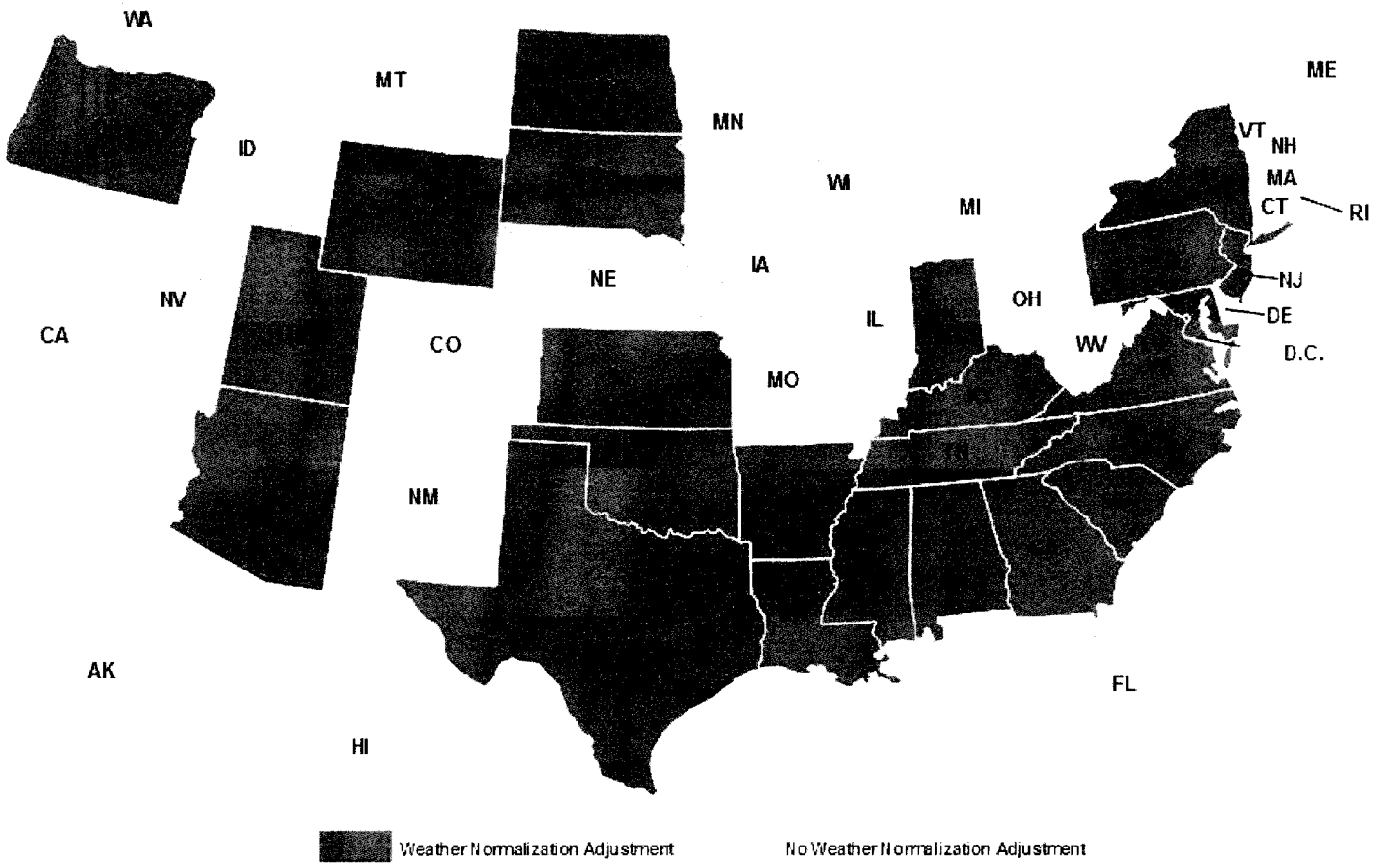
Approved

AL – Alabama Gas
AL – Mobile Gas
GA – Liberty Utilities
LA – Atmos Energy
LA – CenterPoint Energy
LA – Entergy
MS – Atmos Energy
MS – CenterPoint Energy
OK – CenterPoint Energy
OK – Oklahoma Natural Gas
SC – Piedmont Natural Gas
SC – South Carolina Electric and Gas
TN – Atmos Energy
TX – Atmos Energy

Pending

KS—Atmos Energy

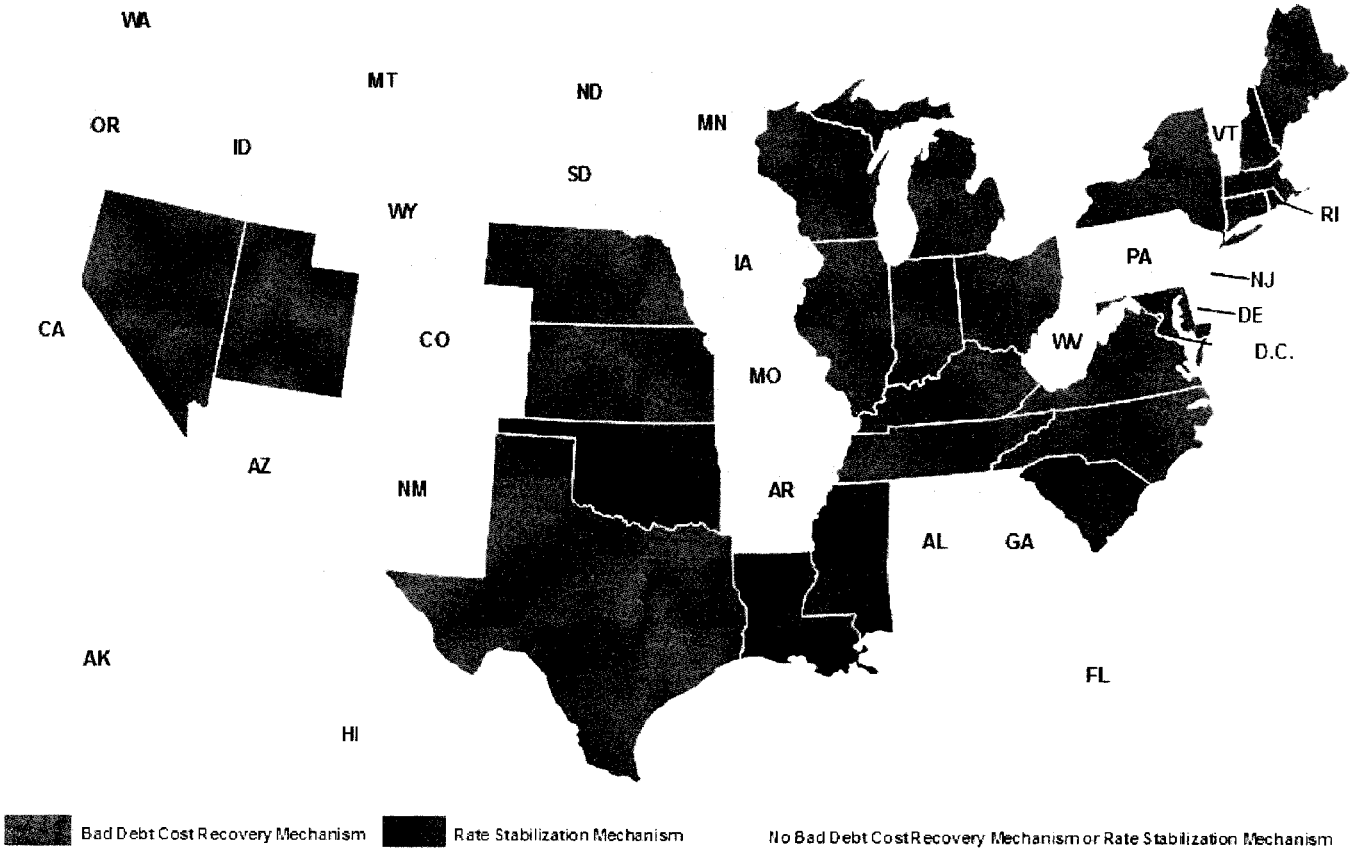
Current Status of Weather Normalization Adjustments



Utilities with Approved Weather Normalization Adjustments

AZ – Southwest Gas
AL – Alabama Gas
AL – Mobile Gas
AR – SourceGas
AR – CenterPoint Energy
GA – Liberty Utilities
IN – Citizens Energy Group
IN – Vectren North Indiana Gas
IN – Vectren South SIGECO
KS – Atmos Energy
KS – Black Hills
KS – Kansas Gas Service
KY – Atmos Energy
KY – Columbia Gas of Kentucky
KY – Delta Natural Gas
KY – Louisville Gas and Electric
LA – Atmos – Louisiana Gas Service
LA – Atmos – Trans Louisiana
LA – CenterPoint Energy
MD – Chesapeake Utilities
MD – Columbia Gas of Maryland
MS – Atmos Energy
MS – CenterPoint Energy
ND – Montana-Dakota Utilities
NJ – Elizabethtown Gas
NJ – New Jersey Natural Gas
NJ – Public Service Electric and Gas
NY – Central Hudson Gas and Electric
NY – Consolidated Edison
NY – National Fuel Gas Distribution
NY – National Grid Long Island
NY – National Grid Niagara Mohawk
NY – National Grid NYC
NY – New York State Electric and Gas
NY – Orange and Rockland Utilities
NY – Rochester Gas and Electric
OK – CenterPoint Energy
OK – Oklahoma Natural Gas
OR – Northwest Natural Gas
PA – Columbia Gas of Pennsylvania
PA – Philadelphia Gas Works
SC – Piedmont Natural Gas
SC – South Carolina Electric and Gas
SD – Montana-Dakota Utilities
TN – Atmos Energy
TN – Chattanooga Gas
TN – Piedmont Natural Gas
TX – Atmos Energy
TX – Texas Gas Service
UT – Questar Gas
VA – Atmos Energy
VA – City of Richmond Dept. of Public Utilities
VA – Columbia Gas of Virginia
VA – Roanoke Natural Gas
VA – Southwestern Virginia Natural Gas
VA – Virginia Natural Gas
VA – Washington Gas

Current Status of Bad Debt Cost Recovery



Utilities with Bad Debt Cost Recovery

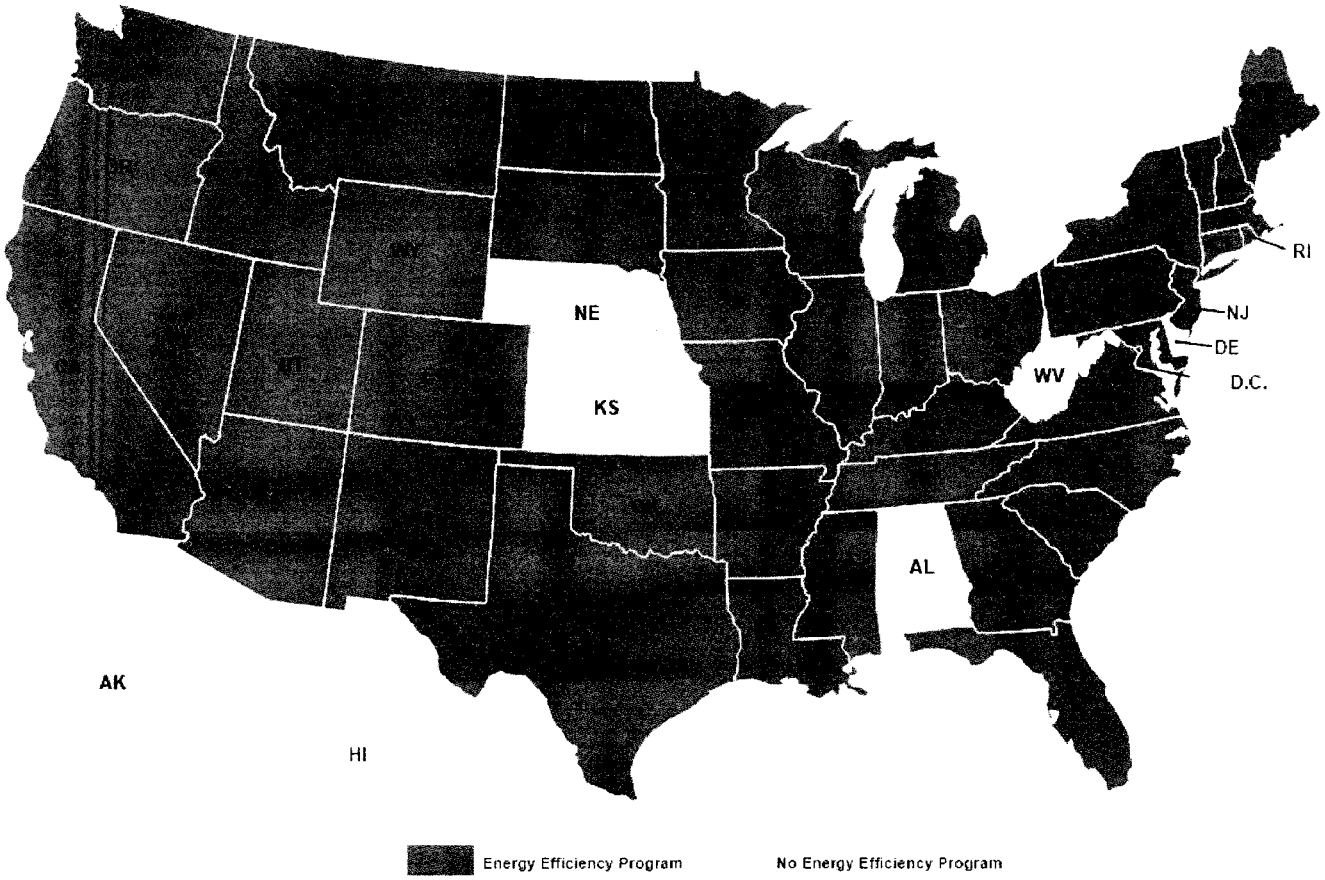
CT – Connecticut Natural Gas
CT – Southern Connecticut Natural Gas
CT – Yankee Gas
DC – Washington Gas
IL – Ameren Illinois
IL – Peoples Gas
IL – North Shore Gas
IL – Nicor Gas
IN – Citizens Energy Group
IN - NIPSCO
IN – Vectren North Indiana Gas
IN – Vectren South SIGECO
KS – Atmos Energy
KS – Black Hills
KS – Kansas Gas Service
KY – Atmos Energy
KY – Columbia Gas of Kentucky
KY – Delta Natural Gas
KY – Duke Energy
LA – CenterPoint Energy
MA – Columbia Gas of Massachusetts
MA – National Grid
MA – NSTAR Gas
MD – Baltimore Gas and Electric
MD – Washington Gas
ME – Northern Utilities
MI – DTE
MI – Michigan Gas Utilities
MS – CenterPoint Energy
NC – Piedmont Natural Gas
NE – Black Hills
NE – SourceGas
NH – Liberty Utilities
NH – Northern Utilities
NV – Southwest Gas
NY – Central Hudson Gas and Electric
NY – Consolidated Edison
NY – National Fuel Gas Distribution
NY – National Grid Long Island
NY – National Grid Niagara Mohawk
NY – National Grid NYC
NY – New York State Electric and Gas
NY – Orange and Rockland Utilities
OH – Columbia Gas of Ohio
OH – Dominion East Ohio
OH – Eastern Natural Gas
OH – Pike Natural Gas
OH – Vectren Energy Delivery of Ohio
OK – CenterPoint Energy
OK – Oklahoma Natural Gas
RI – National Grid
SC – Piedmont Natural Gas
SC – South Carolina Electric and Gas
TN – Atmos Energy
TN – Chattanooga Gas
TN – Piedmont Natural Gas
TX – Atmos Energy
TX – Texas Gas Service
UT – Questar Gas
VA – Washington Gas
VA – Atmos Energy
VA – Columbia Gas of Virginia
VA – Virginia Natural Gas
WI – Wisconsin Gas

Current Status of Pension and OPEB Cost Recovery

Utilities with Pension and OPEB Cost Recovery

CA – San Diego Gas and Electric
CA – Southern California Gas
DC – Washington Gas
KS – Atmos Energy
KS- Black Hills
KS – Kansas Gas Service
LA – Atmos Energy
LA – CenterPoint Energy
MA – Columbia Gas of Massachusetts
MA – Fitchburg Gas and Electric Light Co.
MA – National Grid
MA – NSTAR Gas Co.
MD – Baltimore Gas and Electric Co.
MI – DTE
MO – Ameren Missouri
MO – Laclede Gas
MO – Missouri Gas Energy
MS – Atmos Energy
MS – CenterPoint Energy
NY – Central Hudson Gas and Electric
NY – Consolidated Edison
NY – Orange and Rockland Utilities
NY – National Grid NYC
OH – Columbia Gas of Ohio
OK – CenterPoint Energy
OK – Oklahoma Natural Gas
PA – Philadelphia Gas Works
RI – National Grid
SC –Piedmont Natural Gas
SC – South Carolina Electric and Gas
TN – Piedmont Natural Gas
TX – Atmos Energy
TX – CenterPoint Energy
WI – Wisconsin Power and Light

Current Status of Natural Gas Energy Efficiency Programs



Utilities with Natural Gas Energy Efficiency Programs

AR – Arkansas Oklahoma Gas
AR – SourceGas
AR – CenterPoint Energy
AZ – Southwest Gas
CA – Pacific Gas and Electric
CA – San Diego Gas and Electric
CA – Southern California Gas
CA – Southwest Gas
CO – Atmos Energy
CO – Black Hills Energy
CO – Colorado Natural Gas
CO – SourceGas
CO – Public Service Co. of Colorado
CT – Connecticut Natural Gas
CT – Southern Connecticut Natural Gas
CT – Yankee Gas Service
FL – TECO Peoples Gas
GA – Atlanta Gas Light
IA – Liberty Utilities
IA – Black Hills Energy
IA – Interstate Power and Light
IA – MidAmerican Energy
IN – Citizens Energy Group
IN – NIPSCO
IN – Vectren North Indiana Gas
IN – Vectren South SIGECO
ID – Avista Utilities
ID – Intermountain Gas
IL – Ameren Illinois
IL – MidAmerican Energy
IL – Nicor Gas
IL – North Shore Gas
IL – Peoples Gas
KY – Atmos Energy
KY – Columbia Gas of Kentucky
KY – Delta Natural Gas
KY – Duke Energy Kentucky
KY – Louisville Gas and Electric
LA – Atmos Energy
LA – CenterPoint Energy
MA – Columbia Gas of Massachusetts
MA – Berkshire Gas
MA – Fitchburg Gas and Electric Light
MA – Liberty Utilities
MA – National Grid Massachusetts
MA – NSTAR Gas and Electric
MD – Baltimore Gas and Electric
MD – Columbia Gas of Maryland
MD – Washington Gas
ME – Northern Utilities
MI – Consumers Energy
MI – DTE
MI – Michigan Gas Utilities
MN – CenterPoint Energy
MN – Great Plains Natural Gas
MN – Interstate Power and Light
MN – Minnesota Energy Resources
MN – Xcel Energy
MO – Ameren
MO – Liberty Utilities
MO – Empire Natural Gas
MO – Laclede Gas
MO – Missouri Gas Energy
MS – Atmos Energy
MS – CenterPoint Energy
MT – Montana-Dakota Utilities
NC – Piedmont Natural Gas
NC – Public Service Co. of NC
ND – Montana-Dakota Utilities
NH – Liberty Utilities
NH – Northern Utilities
NJ – Elizabethtown Gas
NJ – New Jersey Natural Gas
NJ – Public Service Electric and Gas
NJ – South Jersey Gas
NM – New Mexico Gas
NV – NV Energy
NV – Southwest Gas
NY – Central Hudson Gas and Electric
NY – Consolidated Edison
NY – National Fuel Gas
NY – National Grid NY
NY – National Grid Long Island
NY – National Grid Niagara Mohawk
NY – Orange and Rockland Utilities
NY – St. Lawrence Gas
OH – Columbia Gas of Ohio
OH – Dominion East Ohio
OH – Duke Energy
OH – Vectren Energy Delivery of Ohio

Utilities with Natural Gas Energy Efficiency Programs (Cont.)

OK – CenterPoint Energy
OK – Oklahoma Natural Gas
OR – Avista Utilities
OR – Cascade Natural Gas
OR – Northwest Natural Gas
PA – Columbia Gas of Pennsylvania
PA – Equitable Gas
PA – PECO
PA – Peoples Natural Gas
PA – Philadelphia Gas Works
PA – UGI Central Penn Gas
PA – UGI Penn Natural Gas
PA – UGI Utilities
RI – National Grid
SC – Piedmont Natural Gas
SC – South Carolina Electric and Gas
SD – MidAmerican Energy
SD – Montana-Dakota Utilities
TN – Chattanooga Gas
TX – Atmos Energy
TX – Texas Gas Service
UT – Questar Gas
VA – Columbia Gas of Virginia
VA – Virginia Natural Gas
VA – Washington Gas
VT – Vermont Gas Systems
WA – Avista Utilities
WA – Cascade Natural Gas
WA – Northwest Natural Gas
WA – Puget Sound Energy
WI – City Gas
WI – Madison Gas And Electric
WI – Midwest Natural Gas
WI – St. Croix Valley Natural Gas
WI – Superior Water, Light and Power
WI – We Energies
WI – Wisconsin Light and Power
WI – Wisconsin Public Service
WI – Xcel Energy
WY – Montana-Dakota Utilities
WY – Questar Gas

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER OWNED YARD LINE (COYL) PROGRAM
ILLUSTRATIVE FAIR VALUE SURCHARGE CALCULATION
AS OF DECEMBER 31, 2015

Line No.	Description	Reference	Original Cost	RCN	FV	Line No.
	(a)	(b)	(c)	(d)		
1	Gross COYL Plant	Company Records	$ 23,102,623	$ 23,504,682		1
2	Accumulated Provision for Depreciation	Company Records	(1,510,441)	(1,555,818)		2
3	Net COYL Plant	Ln 1 + Ln 2	$ 21,592,182	$ 21,948,864		3
4	Accumulated Deferred Income Taxes	Company Records	(4,080,931)	(4,080,931)		4
5	COYL Rate Base	Ln 3 + Ln 4	$ 17,511,252	$ 17,867,933	$ 17,689,593	5
6	FV Return on COYL Rate Base	8.87% * Ln 5			1,568,334	6
7	Income Tax Factor	Settlement Agreement			0.6579	7
8	Income Taxes	Auth. Cost of Equity (9.5%) * Ln 5 * Ln 7			$ 1,105,608	8
9	Depreciation Expense	Company Records			1,002,866	9
10	Revenue Requirement	Ln 6 + Ln 8 + Ln 9			$ 3,676,809	10
11	2015 Full Margin Therms	Company Records			611,117,827	11
12	Surcharge	Ln 10 / Ln 11			$ 0.00602	12

SOUTHWEST GAS CORPORATION
Incremental COYL Investment
Fair Value Rate of Return

Line No.										Line No.
	Authorized Fair Value Rate Base	Authorized Rate Base								
1	Original Cost Rate Base (OCRB)	$ 17,511,252								1
2	Reconstruction Cost New Depreciated (RCND) rate base	17,867,933								2
3	Fair Value Rate Base (FVRB)	$ 17,689,592 [1]								3
4	FVRB/OCRB Multiple	1.01								4
	Authorized Capital Structure OCRB	Rate Base	Ratio	Cost	ROR	Pre-Tax FVROR	OCRB	ROR Revenue Requirement		
5	Common Equity	$ 9,158,385	52.30%	9.50%	4.97%	8.24%	$ 17,511,252	$ 1,442,450		5
6	Long-Term Debt	8,352,867	47.70%	8.34%	3.98%	3.98%	17,511,252	696,629		6
7	Total Capital	$ 17,511,252	100.00%		8.95%	12.22%		$ 2,139,079		7
	Authorized Fair Value Rate of Return (FVROR)	Rate Base	Ratio	Cost	FVROR	Pre-Tax FVROR	FVRB	FVROR Revenue Requirement		
8	Common Equity	$ 9,158,385	51.77%	9.50%	4.92%	8.15% [3]	$ 17,689,592	$ 1,442,450		8
9	Long-Term Debt	8,352,867	47.22%	8.34%	3.94%	3.94%	17,689,592	696,629		9
10	FVRB Increment Above OCRB	178,340	1.01%	0.93% [2]	0.01%	0.02% [3]	17,689,592	2,750		10
11	Total Capital	$ 17,689,592	100.00%		8.87%	12.11%		$ 2,141,829		11

Notes:
[1] FVRB = 0.5 X OCRB + 0.5 RCND
[2] 0.93% = 0.5 x Real Risk-Free Rate of Return of 1.86%
[3] Grossed up for taxes using the authorized gross-up factor of 1.6579

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COYL PROJECT
RCN COST OF GAS PLANT IN SERVICE AS OF DECEMBER 31, 2015

Account 380 - Services - Plastic

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	2010	0	440	1.11	0	1
2	2011	0	454	1.07	0	2
3	2012	4,148,620	469	1.04	4,314,565	3
4	2013	5,768,730	473	1.03	5,941,792	4
5	2014	6,305,185	481	1.01	6,368,237	5
6	2015	6,880,088	488	1.00	6,880,088	6
7	Total	$ 23,102,623			$ 23,504,682	7

RCN COST OF RESERVE AS OF DECEMBER 31, 2015

1	2010	0	440	1.11	0	1
2	2011	0	454	1.07	0	2
3	2012	(672,254)	469	1.04	(699,144)	3
4	2013	(525,485)	473	1.03	(541,250)	4
5	2014	(272,201)	481	1.01	(274,923)	5
6	2015	(40,501)	488	1.00	(40,501)	6
7	Total	$ (1,510,441)			$ (1,555,818)	7

Southwest Gas Corporation
Docket No. G-01551A-16-0107

Gas Infrastructure Modernization
Plan of Administration

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III. GIM RELATED FILINGS 2
IV. GIM ANNUAL CAP 3

Gas Infrastructure Modernization
Plan of Administration

I. GENERAL DESCRIPTION

This document describes the Plan of Administration (POA) for the Gas Infrastructure Modernization (GIM) mechanism. The GIM mechanism provides for the timely recovery of the capital costs (pre-tax return on investment and depreciation expense, net of associated retirements) associated with investments in the modernization of the natural gas delivery system infrastructure. To qualify for recovery under this mechanism, these costs must: (1) not be included in rate base for recovery in the Company's general rates, (2) have been approved for inclusion in the mechanism by order of the Commission, and (3) have been constructed and placed in service prior to the GIM Surcharge filing.

II. DEFINITIONS

A. GIM Cost or Revenue Requirement - An amount equal to the pre-tax return and depreciation expense, net of associated retirements, if any, associated with an investment in Commission authorized gas infrastructure modernization projects or programs.

B. GIM Surcharge - the rate necessary to recover the GIM revenue requirement. The GIM surcharge will be recovered from all tariff rate customer classes.

III. GIM RELATED FILINGS

A. Authorization for Inclusion in the GIM Mechanism - Prior to including a gas infrastructure modernization investment in the GIM mechanism, the Company must obtain authorization from the Commission. The Company can make this request in a general rate case, standalone filing, or in any other manner allowed by the Commission's regulations.

B. Surcharge Adjustment - The Company will make annual filings to establish and adjust the GIM surcharge. The Company will provide the following in each GIM surcharge adjustment filing:

1. A description of the project work authorized by the Commission for inclusion in the GIM mechanism;

2. Identification of the approved work that has been completed, placed in service, and included for cost recovery in the GIM mechanism; and

3. A schedule showing the calculation of the GIM revenue requirement and surcharge.

The GIM Surcharge Adjustment filing will be made on or about March 1 each year and will include calendar activity for the prior calendar year. The Arizona Corporation Commission Staff will endeavor to review the Company's filing and make its recommendation to the Commission within 45 days of the filing such

that the surcharge may go into effect by June 1 of each year.

IV. GIM ANNUAL CAP

The GIM Surcharge Adjustment will be subject to an annual year over year cap of $0.03 per therm. If the calculation of the GIM Surcharge Adjustment would result in an increase greater than the $0.03 per therm cap, any GIM mechanism cost not recovered in the $0.03 annual adjustment will be deferred for recovery in a subsequent GIM Surcharge Adjustment filing, however such subsequent filing(s) will be subject to the $0.03 per therm annual cap. Where the cap limits the recovery of deferrals in any year, and thus defers recovery of a portion of GIM costs to the following year, the surcharge in the following year will first recover any such carried over amounts, and then recover new amounts arising in that following year. Monthly, interest will be applied to the deferred balance equal to the one-year nominal Treasury constant maturities rate.

IHS ECONOMICS & COUNTRY RISK

Economic Impact of Southwest Gas' Capital Investment Projects in Arizona

April 2016

ihs.com

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Consulting | Applied Economics

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– Economic Contribution of All Arizona-based Projects 26
– Economic Contribution of Gas Infrastructure Modernization Projects 30

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CHAPTER 1

Executive Summary

Southwest Gas commissioned IHS to conduct an economic impact analysis to estimate the direct, indirect and induced economic benefits to Arizona's economy from its capital investment budget, including those resulting from the acceleration of certain pipe replacement activities under the company's proposed Gas Infrastructure Modernization (GIM) Mechanism. The primary goal of these capital expenditures is to enhance the safety and reliability of the company's natural gas distribution system.

Key Findings:

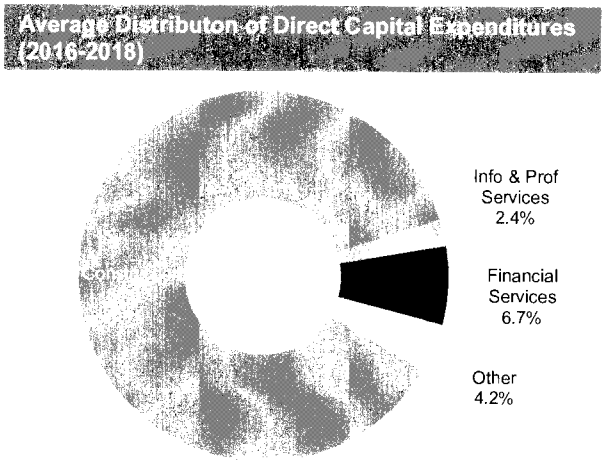
- Every million dollars of capex that Southwest Gas directly spends locally supports 11 jobs in Arizona.
- Every Southwest Gas FTE dedicated to these projects represents another 17 jobs supported across the state. In the case of the GIM Programs, this ratio jumps to 25 jobs.
- The average wage for jobs supported by Southwest Gas' capex will be about 20% higher than the statewide average in 2018.
- Every dollar of capex that Southwest Gas spends in Arizona leads to an additional dollar of contribution to Arizona's gross state product.
- IHS estimates that Southwest Gas' local construction and maintenance capex will drive $13.4 million of state & local taxes in Arizona during 2018. About $5.7 million will be as a result of the GIM programs.

In this study, IHS first quantified the economic contribution Southwest Gas' local spending on all Arizona-based projects for the period 2016 to 2018. By "local spending" we mean spending that directly enters the Arizona economy. Any spending on products or services sourced from outside Arizona was excluded from the main analysis. To illustrate: in 2016 Southwest Gas expects to spend $210.7 million, exclusive of wages paid to Southwest Gas employees, for construction and maintenance projects in Arizona. Of this, IHS estimated $172.9 million will enter the Arizona economy through spending directly with Arizona-based suppliers and service providers. The remaining $37.8 million, which will flow to goods and services (e.g., steel pipes) sourced outside of Arizona, is not included in the analysis. By 2018, total capex will rise to $313.4 million, with $243.9 million of local capex directly entering the Arizona economy.

Then, IHS isolated the combined economic contribution associated with three components under the Southwest Gas' GIM Mechanism including the Customer-owned Yard Line (COYL) Program, the building of a new Liquefied Natural Gas (LNG) facility and the replacement of Vintage Steel Pipe (VSP). The COYL Program is ongoing, with capital expenditures in each of the three years. Capex for the LNG Program will occur during 2017 and 2018 while the VSP Program will begin in 2018. IHS estimated that the combined non-labor spending on these three components will rise from $9.9 million (about 4.7% of total spending) in 2016 to $110.0 million (about 35.1% of total spending) in 2018, with the launch of the VSP Program.

IHS analyzed Southwest Gas' average direct local capital expenditures expected for the period 2016 to 2018. As shown in the graph, the analysis revealed that most of the capex will

directly enter the Arizona economy in three industries: Construction (86.6%); Financial Services (6.7%); and Information & Professional Services (2.4%). This direct spending initially triggers economic activity throughout Southwest Gas' local supply chain, followed by ripples of consumer spending activity as workers at Southwest Gas and its supply network spend portions of their wages in the Arizona economy.



The table below summarizes IHS' findings relative to the employment, value added, labor income, output and taxes accruing to Arizona due to Southwest Gas' capital projects within the state. IHS estimates that Southwest Gas will dedicate the equivalent of 155 full time workers (FTEs) from its existing employee base to these projects. Referring to the highlighted "SW Gas Direct Spending in AZ Supply Chain" row, the $243.9 million of capex that Southwest Gas plans to spend with local Arizona suppliers and service providers in 2018 will support another 2,616 local jobs. Thus, every Southwest Gas FTE represents another 17 jobs across the state. Viewed differently, every million dollars of capex that Southwest Gas spends locally will support 11 jobs in Arizona. These workers will bring home $161.0 million in wages or an average salary of $61.5K, which is about 11% above IHS's forecast for the statewide average of $55.7K in 2018.

Indicator	2016	2017	2018
Employment (Number of workers)	**2,089**	**2,036**	**2,771**
Southwest Gas FTEs	153	156	155
Direct Arizona Supply Chain	991	958	1,351
Indirect Arizona Supply Chain	318	310	436
Induced (Consumer Spending) Activity	627	613	828
Value Added Contribution to GSP (US$M)	**175.7**	**174.2**	**248.2**
Direct Arizona Supply Chain	93.1	92.1	133.2
Indirect Arizona Supply Chain	29.1	28.9	41.6
Induced (Consumer Spending) Activity	53.4	53.3	73.5
Labor Income (US$M)	**125.4**	**125.1**	**172.7**
Southwest Gas FTEs	11.0	11.4	11.7
Direct Arizona Supply Chain	65.5	65.1	92.8
Indirect Arizona Supply Chain	19.2	19.1	27.5
Induced (Consumer Spending) Activity	29.6	29.5	40.7
Output (US$M)	**306.4**	**302.5**	**430.5**
SW Gas Direct Spending in AZ Supply Chain	172.9	169.5	243.9
Indirect Arizona Supply Chain Activity	48.5	48.0	69.2
Induced (Consumer Spending) Activity	85.0	84.9	117.4
Taxes (US$M)	**26.7**	**26.5**	**38.5**
State & Local Taxes	9.1	9.1	13.4
Federal Taxes	17.6	17.5	25.0

* IHS assumed the capital expenditures would not effect SW Gas' expected sales revenue (output) and value added contribution to GSP). Also, while IHS does not anticipate SW Gas to hire additional employees specifically for these projects, the dedicated labor and corresponding wages are included in the employment and labor income effects (on an FTE basis) in this economic contribution summary.

At the time this study was conducted, Southwest Gas had yet to finalize capital investment schedules beyond 2018. Therefore, based on local 2018 capex spending patterns, IHS estimated the average economic contributions from $100 million of local spending through the GIM Mechanism. This provides a set of metrics that can be used to calibrate the expected economic contributions beyond 2018. For example, every $100 million that Southwest Gas directly spends with local suppliers and service providers (shown in the "SW Gas Direct Spending in AZ Supply Chain" row in the table below) will support 1,062 jobs above and beyond the 42 Southwest Gas FTEs working on GIM projects post-2018. This level of local spending will also generate $100.8 million of contribution to Arizona's gross state product and $5.7 million in state & local taxes.

Economic Contribution - Gas Infrastructure Modernization*

Indicator	2016	2017	2018	Post-2018**
Employment (Number of workers)	**114**	**356**	**1,215**	**1,104**
Southwest Gas FTEs	6	10	46	42
Direct Arizona Supply Chain	57	180	610	555
Indirect Arizona Supply Chain	18	58	198	180
Induced (Consumer Spending) Activity	34	108	361	328
Value Added Contribution to GSP (US$M)	**9.9**	**31.2**	**110.9**	**100.8**
Direct Arizona Supply Chain	5.3	16.6	60.2	54.7
Indirect Arizona Supply Chain	1.6	5.3	18.8	17.1
Induced (Consumer Spending) Activity	2.9	9.4	32.0	29.1
Labor Income (US$M)	**6.8**	**22.0**	**75.2**	**68.4**
Southwest Gas FTEs	0.4	0.7	3.3	3.0
Direct Arizona Supply Chain	3.7	12.7	41.8	38.0
Indirect Arizona Supply Chain	1.1	3.5	12.4	11.3
Induced (Consumer Spending) Activity	1.6	5.2	17.7	16.1
Output (US$M)	**17.3**	**53.6**	**192.4**	**174.9**
SW Gas Direct Spending in AZ Supply Chain	9.9	29.9	110.0	100.0
Indirect Arizona Supply Chain Activity	2.7	8.7	31.3	28.4
Induced (Consumer Spending) Activity	4.6	15.0	51.1	46.5
Taxes (US$M)	**1.5**	**4.9**	**17.5**	**15.9**
State & Local Taxes	0.5	1.6	6.2	5.7
Federal Taxes	1.0	3.3	11.3	10.3

* IHS assumed the capital expenditures would not effect SW Gas' expected sales revenue (output) and value added contribution to GSP). Also, while IHS does not anticipate SW Gas to hire additional employees specifically for these projects, the dedicated labor and corresponding wages are included in the employment and labor income effects (on an FTE basis) in this economic contribution summary.
** Assumes $100M in direct capital expenditures in Arizona each year.

Based on the research and analysis that was conducted for this study, IHS finds the construction and maintenance capital projects undertaken by Southwest Gas in Arizona have and will continue to make positive contributions to Arizona in terms of key economic indicators such as jobs, contribution to gross state product, wages and taxes.

CHAPTER 2

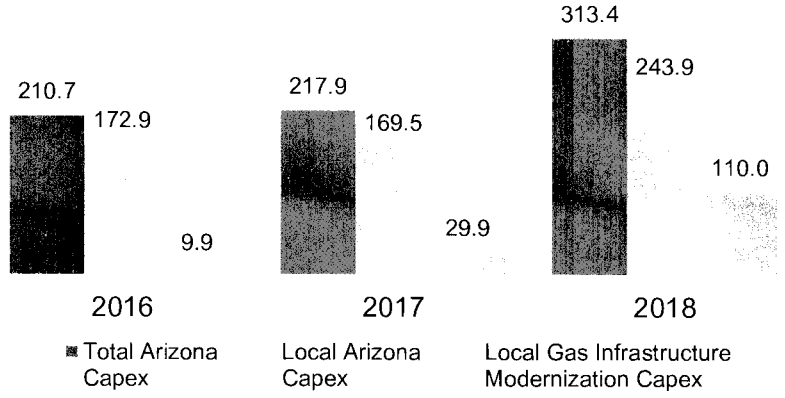
Introduction

Southwest Gas is the largest distributor of natural gas in Arizona – selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas.

Southwest Gas commissioned IHS to conduct an economic impact analysis to estimate the direct, indirect and induced economic benefits to Arizona's economy from its capital investment budget including those resulting from the acceleration of certain pipe replacement activities through the company's GIM Mechanism. The primary goal of these programs is to enhance the safety and reliability of the company's natural gas distribution.

In this study, IHS first quantified the economic contribution Southwest Gas' local spending on all Arizona-based projects for the period 2016 to 2018. By "local spending" we mean spending that directly enters the Arizona economy. Any spending on products or services sourced from outside Arizona was excluded from the main analysis. To illustrate: in 2016 Southwest Gas expects to spend $210.7 million, exclusive of wages paid to Southwest Gas employees, for construction and maintenance projects in Arizona. Of this, IHS estimated $172.9 million will enter the Arizona economy through direct spending with Arizona-based suppliers and service providers. The remaining $37.8 million will flow to goods and services sourced outside of Arizona, such as steel pipes. By 2018, total capex will rise to $313.4 million, with $243.9 million of local capex directly entering the Arizona economy.

Capital expenditures budgeted for Arizona-based Projects (millions of US dollars)



Source: IHS analysis of Southwest Gas data

Then, IHS isolated the combined economic contribution associated with three components of Southwest Gas' GIM Mechanism including the Customer-owned Yard Line (COYL) Program, the building of a new Liquefied Natural Gas (LNG) facility and the replacement of Vintage Steel Pipe (VSP). The VSP program is intended to be a proactive program in which older pipeline is updated and replaced at a controlled pace, rather than a series of a reactive response to system failures. The COYL Program is ongoing, with capital expenditures in each of the three years. Capex for the LNG Program will occur during 2017 and 2018 while

the VSP Program will begin in 2018. IHS estimated that the combined non-labor spending on these three components will rise from $9.9 million (about 4.7% of total spending) in 2016 to $110.0 million (about 35.1% of total spending) in 2018, with the launch of theVSP Program.

At the time this study was conducted, Southwest Gas had yet to finalize capital investment schedules beyond 2018. Therefore, based on local 2018 capex spending patterns, IHS estimated the average economic contributions from $100 million of local spending on their GIM Mechanism. This proves a set of metrics that can be used to calibrate the expected contributions beyond 2018. For example, every $100 million that Southwest Gas directly spends with local suppliers and service providers will support 1,062 jobs above and beyond the 42 Southwest Gas FTEs working on GIM projects post-2018. This level of local spending will also generate $100.8 million of contribution to Arizona's gross state product.

Economic Landscape of Arizona

Over the last decade, Arizona has begun to emerge as a center for high-tech electronics and telecommunications manufacturing, attracting growth from nearby California. The state is also home to many defense-oriented manufacturing companies, which have seen steady growth because of wartime contracts from the federal government and contracts with international buyers.

Labor force and demographics

In 2014, Arizona maintained its rank as the 15th-largest state in the nation, with a population of 6.7 million. From 2013 to 2014, the state population increased by 1.4%, the largest annual increase since 2008, but still pale in comparison to the boom years of the early 2000s. Net migration was also the highest it has been since 2007. Just over 62,000 people came to Arizona in 2014. More than 46,000 came from the United States, while nearly 15,000 came from abroad. An overwhelming majority of Arizona's population is located in its two largest metro areas: Phoenix and Tucson. Together, the two make up 82% of the state's total population and 83% of its labor force. In terms of age, the population distribution is larger at the extremes. Arizona has a large number of retirees and the share of the population 65 and over is 15.9%, compared with 14.5% nationwide. Conversely, it also has a considerably larger youth population, with 34.1% in the 24 and under category versus 32.9% for the United States.

Real estate and construction

The housing and credit crunch hit Arizona harder than many other places. The state continues to feel the effects of the market retreating from an unprecedented boom that brought significant price appreciation, along with a spate of new-home building, much of which was speculative. The enormous backlog of unsold or vacated homes has taken years to work off, but is at last approaching normality. Housing starts in Arizona fell to a low of less than 13,000 in 2010, down from a peak of more than 88,000 units in 2004: we expect over 40,000 starts in 2016 (up from a little over 30,000 in 2015) and almost 50,000 in 2017 as the market recovers. Meanwhile, home prices have bounced up sharply as the unsold inventory left from the bust has evaporated—prices are increasing at double-digit rates.

The outlook

The medium-term outlook for this Sun Belt state remains robust as the demographic center of the United States continues to push south and west. We expect that strong growth in population and households will be a driving force of economic expansion over the next five years. The state's population will rise at a 1.6% average annual pace through 2020. This is twice the rate of the United States, which will add people at a 0.8% rate. Significant increases in the resident population will be bolstered by further domestic and international in-migration. All of those new people will create strong demand for services and new housing. The healthcare sector will add jobs at a 2.6% pace. Construction will add jobs at a 6.1% pace as it recovers from abysmal recessionary lows. Business services will be crucial as well, expanding by an average of 3.9% each year.

CHAPTER 3

Methodology

Each component of the of Southwest Gas GIM Mechanism uses notable amounts of fixed capital (i.e., equipment) and variable inputs (i.e., labor) during their life cycle to deliver on the intended mission. The impact of the resulting economic activity can be measured by examining the transactions that occur between businesses, the wages paid to employees, and the headcount needed to realize each project's objective. There are also impacts that are generated through tax transfers to governments.

Input-output analysis was used in this study to quantify how these direct impacts flow through the economy. Further, the extent to which the ripple effect results from linkages to other businesses is measured by the indirect impacts while the spending that occurs by employees and owners of these businesses is captured through the induced impacts.

To accurately estimate the indirect economic impact of a given firm it is necessary to know the input requirements – the types, sources and quantities of goods and services needed in production – of the business. These flows between businesses are captured in input-output table for a regional economy. Induced impacts are estimated by applying wage and dividends generated by the firm to an average household expenditure pattern (i.e., destination and quantity of expenditure), and then by estimating the ways in which these expenditures produce further economic activity.

IHS sourced an IMPLAN model to serve as the initial foundation from which to quantify the economic impacts of Southwest Gas' service activity in Arizona and its modernization programs. The IMPLAN model closely follows the accounting conventions such as those used in the US Bureau of Economic Analysis's study, Input-Output Study of the US Economy, and is flexible enough to evaluate changes via the value of output or employment from the source industry. Using data from our World Industry Services, World Economic Services and other IHS-proprietary data assets, we customized and refined the modeling environment.

The direct, indirect, and induced job estimates in this report were quantified through input-output modeling and social accounting matrices using the customized IMPLAN model. Input-output accounting describes commodity flows from producers to intermediates and final consumers. The total industry purchases of commodities, services, employment compensation, value added, and imports are equal to the value of the commodities produced.

The notion of a multiplier rests upon the difference between the initial effect of a change in final demand and the total effects of that change. Total effects can be calculated either as direct and indirect effects or as direct, indirect, and induced effects. Direct effects are production changes associated with the immediate effects or final-demand changes. Indirect effects are production changes in backward-linked industries caused by the changing input needs of directly affected industries (for example, additional purchases to produce additional output). Induced effects are the changes in regional household spending patterns caused by changes in household income generated from the direct and indirect effects.

A Type I multiplier is the direct effect produced by a change in final demand plus the indirect effect, divided by the direct effect. Increased demands are assumed to lead to increased employment and population, with the average income level remaining constant. The Leontief

inverse (Type I multipliers matrix) is derived by inverting the direct coefficients matrix. The result is a matrix of total requirement coefficients, the amount each industry must produce for the purchasing industry to deliver one dollar's worth of output to final demand.

Type SAM multipliers incorporate "induced" effects resulting from the household expenditures from new labor income. The linear relationship between labor income and household expenditure can be customized in the IMPLAN software. The default relationship is PCE and total household expenditure. Each dollar of workplace- based income is spent based on the SAM relationship generated by IMPLAN.

The direct, indirect and induced impacts are reported via five measures, which are defined below. Each impact is calculated for each measure across 440 sectors in the economy and then aggregated to higher level industry totals. This bottom-up approach is inherent in the modeling system used for this economic impact study.

1. Output: The value of sales or revenue accrued to a company or industry from transactions with other businesses or consumers.

2. Employment (number of jobs): Includes all wage or salary jobs and those self-employed within an economy.

3. Total value added (contribution to GSP): The difference between the production cost of products or services and the sales price (i.e., total value added is revenue less outside purchases of material and services). The frequently cited Gross Domestic Product (GDP) or Gross State Product (GSP) is simply the sum of value added across all products and services produced within an economy. GDP is generally considered the broadest measure of the health of an economy.

4. Labor income (value of payments to workers through wages and benefits and owners)

5. Taxes (personal and corporate tax transfers to federal, state and local governments): Increased sales activity in will increase government revenues and taxes paid by Southwest Gas, its employees, its extensive supply chain, companies in ancillary industries, and so on.

CHAPTER 4

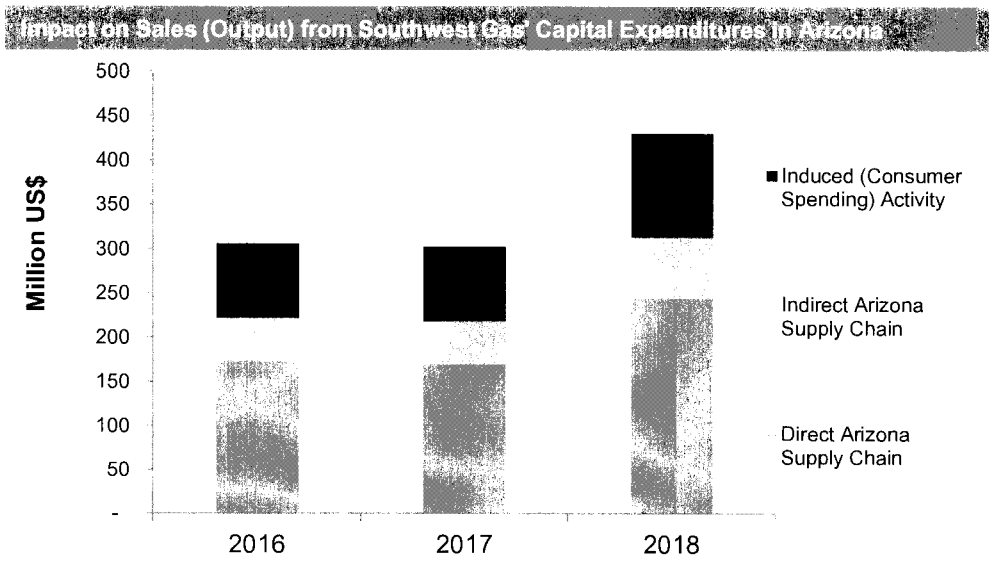
Economic Impact of Southwest Gas Capital Investment Projects in Arizona

The tables presented throughout the following section summarize IHS' findings relative to the output, employment, value added, labor income, and taxes accruing to Arizona due to Southwest Gas' construction and maintenance projects within the state. The results are consistent with IHS' analysis of Southwest Gas' average direct capital expenditures expected for the period 2016 to 2018, which revealed that most of the capex will directly enter the Arizona economy in three industries: Construction (86.6%); Financial Services (6.7%); and Information & Professional Services (2.4%). None of these industries have extensive supply chains, thus the indirect supply chain effects are muted relative to the direct supply chain effects. A similar pattern occurs for the GIM Programs as well.

Output (Value of Sales Transactions)

Referring to the "SW Gas Direct Spending in AZ Supply Chain" row under "Output by Type" in the table below, Southwest Gas is expecting to spend $172.9 million directly with Arizona-based suppliers and service providers for construction and maintenance projects in 2016. By 2018, this capex entering directly in the state's economy is expected to rise to $243.9 million. An additional $69.2 million in indirect spending will be supported through the supply chain and another $117.4 in consumer spending will be induced as workers use a portion of their income to make purchases during the year.

Economic Contribution - All Arizona-based Projects			
Output (millions of US $)	**2016**	**2017**	**2018**
Output by Type	**306.4**	**302.5**	**430.5**
SW Gas Direct Spending in AZ Supply Chain	172.9	169.5	243.9
Indirect Arizona Supply Chain	48.5	48.0	69.2
Induced (Consumer Spending) Activity	85.0	84.9	117.4
Output by Industry	**306.4**	**302.5**	**430.5**
Natural Resources	0.6	0.5	0.8
Transportation & Utilities	8.5	8.4	13.7
Construction	152.5	146.5	214.5
Manufacturing	8.5	8.4	12.0
Wholesale & Retail Trade	20.2	19.8	30.8
Information & Professional Services	58.6	60.5	79.4
Financial Services	40.3	41.0	56.2
Leisure & Other Services	12.8	12.8	17.8
Government	4.5	4.6	5.3

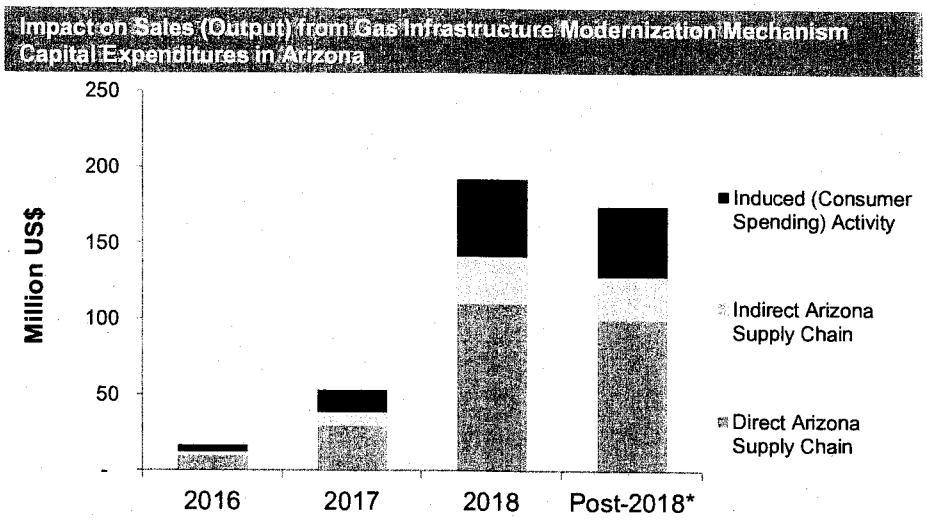


Within this budget is the combined spending on the three components of the GIM Mechanism. This will rise from $9.9 million in 2016 to $110.0 million in 2018, when the VSP Program begins. The proportional impact on the supply chain and consumer spending will be relative to Southwest Gas' overall spending in the state. At the time this study was conducted, Southwest Gas had yet to finalize capital investment schedules beyond 2018. Therefore, based on local 2018 capex spending patterns, IHS estimated the average economic contributions from $100 million of local spending through the GIM Mechanism (highlighted in the "SW Gas Direct Spending in AZ Supply Chain" row under "Output by Type" in the table below). This level of direct spending will drive an additional $74.9 million of sales activity in Arizona ($28.4 million of indirect and $46.5 million of induced activity)

Natural Gas Distribution - Gas Infrastructure Modernization

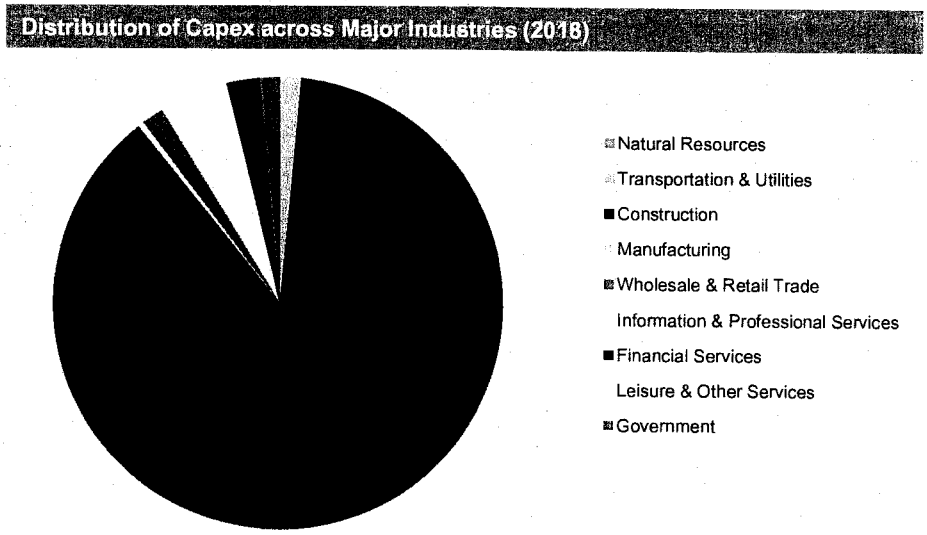
Output (millions of US $)	2016	2017	2018	Post-2018**
Output by Type	**17.3**	**53.6**	**192.4**	**174.9**
SW Gas Direct Spending in AZ Supply Chain	9.9	29.9	110.0	100.0
Indirect Arizona Supply Chain	2.7	8.7	31.3	28.4
Induced (Consumer Spending) Activity	4.6	15.0	51.1	46.5
Output by Industry	**17.3**	**53.6**	**192.4**	**174.9**
Natural Resources	0.0	0.1	0.3	0.3
Transportation & Utilities	0.4	1.3	7.0	6.4
Construction	9.5	22.3	96.5	87.7
Manufacturing	0.5	1.4	5.3	4.8
Wholesale & Retail Trade	1.1	3.2	15.3	13.9
Information & Professional Services	2.8	15.9	34.0	30.9
Financial Services	2.1	6.6	24.2	22.0
Leisure & Other Services	0.7	2.3	7.8	7.1
Government	0.3	0.5	2.0	1.9

** Assumes $100M in direct capital expenditures in Arizona each year



* Per $100 million of direct spending by Southwest Gas in the local Arizona Supply Chain

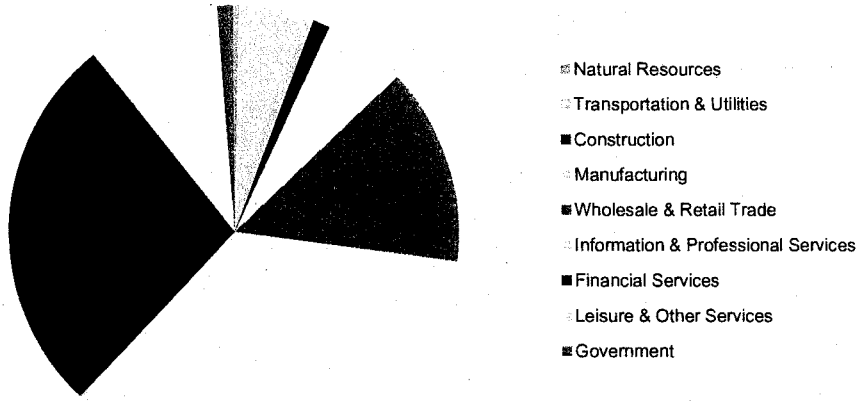
A pronounced share of the capital Southwest Gas is expected to deploy in 2018 will go to companies involved primarily in construction activities. This is a common allocation for capital projects within the scope of the utilities industry, as Southwest Gas is associated. A little over 40% of the company's spending directly in Arizona's economy will be allocated to the GIM Mechanism, where construction will be a major category for spending in the year.



However, looking at the impact further into the supply chain and down to the consumer level, the distribution of impact on industries is much more diverse. The chart below is an example of how Southwest Gas' spending will reach many sectors across the Arizona economy. Although there is a big share of the budget being spent directly in construction, it requires goods and services sourced from companies in mainly information/professional services, financial services and wholesale/retail trade to accommodate those orders. In addition, the

employees being paid to service the orders in any capacity are subsequently spending their money on goods and services with a decent share going towards leisure and other services. Typically consumers in higher income brackets tend to use a larger portion of their earnings on these types of services – an indication that the workers in Southwest Gas' extended supply chain are amongst the higher paid in the economy.

Distribution of Indirect and Induced Impacts across Major Industries (2018)



Employment

In order to complete a sale, a company must rely on its employees. Likewise, in order to produce the good or service being sold, a company needs inputs from other businesses that rely on their employees to facilitate, and so on. Lastly, when these employees purchase consumer goods and services, the businesses providing the goods and services require workers to fulfil those transactions. This cycle depicts how deep the impact of sales on employment in an economy reaches.

From 2016 to 2018, IHS estimates Southwest Gas will devote approximately 155 FTEs of labor to the company's Arizona-based capital investment projects. The number of workers needed in the company's entire supply chain is much higher. In 2016, 1,309 jobs will be supported in Southwest Gas' direct and indirect supply chains. This means for every Southwest Gas FTE devoted to Arizona-based capital investment projects, there are another 9 workers being supported in its supply chain. Put another way, for every $1 million spent directly with Southwest Gas' immediate suppliers, about 8 jobs are being supported throughout the entire supply chain. If the induced effects are factored in, by 2018 each Southwest Gas FTE will support another 17 jobs in the Arizona Economy.

Economic Contribution - All Arizona-based Projects			
Employment (number of workers)	**2016**	**2017**	**2018**
Employment by Type	**2,089**	**2,036**	**2,771**
Southwest Gas FTEs	153	156	155
Direct Arizona Supply Chain	991	958	1,351
Indirect Arizona Supply Chain	318	310	436
Induced (Consumer Spending) Activity	627	613	828
Employment by Industry	**2,089**	**2,036**	**2,771**
Southwest Gas FTEs	153	156	155
Natural Resources	3	3	3
Transportation & Utilities	42	41	70
Construction	871	826	1,195
Manufacturing	26	25	36
Wholesale & Retail Trade	166	161	235
Information & Professional Services	483	485	624
Financial Services	137	136	183
Leisure & Other Services	187	182	247
Government	21	21	23

IHS does not anticipate Southwest Gas will hire additional employees for its GIM Mechanism. Rather, the company will dedicate approximately 6 FTEs to these projects 2016, increasing to about 46 FTEs in 2018 as the VSP program ramps up. Meanwhile, transactions made through the direct and indirect supply chains to deliver on GIM projects will support almost 75 jobs in 2016 and over 800 jobs in 2018. Similar to the figures seen from overall spending in Arizona, for every $1 million spent with direct suppliers through the GIM Mechanism, about 8 jobs are supported in the direct and indirect supply chains, rising to 11 jobs when induced effects are included.

Economic Contribution - Gas Infrastructure Modernization				
Employment (number of workers)	**2016**	**2017**	**2018**	**Post-2018****
Employment by Type	**115**	**356**	**1,215**	**1,104**
Southwest Gas FTEs	6	10	46	42
Direct Arizona Supply Chain	57	180	610	555
Indirect Arizona Supply Chain	18	58	198	180
Induced (Consumer Spending) Activity	34	108	361	328
Employment by Industry	**115**	**356**	**1,215**	**1,104**
Southwest Gas FTEs	6	10	46	42
Natural Resources	0	0	1	1
Transportation & Utilities	2	6	38	35
Construction	54	126	537	488
Manufacturing	1	4	16	15
Wholesale & Retail Trade	9	27	111	101
Information & Professional Services	23	125	269	244
Financial Services	7	23	79	72
Leisure & Other Services	10	33	108	98
Government	1	2	9	8

** Assumes $100M in direct capital expenditures in Arizona each year

Value added

Production or output metrics such as sales revenues, while informative, have an inherent disadvantage of double-counting revenues for component goods and services (i.e., tires) that may be sold and resold during the creation of the final product (i.e., a car) that is purchased by a consumer. Measuring value added provides a means for removing these distortions.

Value added is the difference between the non-labor production costs of products or services (intermediate inputs) and their selling prices. As its name implies, value added measures how much more valuable a final product is relative to its component, non-labor inputs. Thus, it measures the ability of a firm to transform raw inputs into higher-value final products and services. Value added is often aggregated to measure the economic performance of a specific industry or region.

The ubiquitously cited GDP measure is simply the sum of value added across all products and services produced in an economy – it is generally considered the broadest measure of the health of an economy. Analogously, gross state product (GSP) is the sum of value added within a state.

Value added also corresponds to the pool of money a firm realizes after deducting the cost of intermediate inputs from its sales revenue. The firm draws from this pool to compensate employees, pay taxes and derive profits. As such, it provides insights into the ability of a firm or industry to attract and retain employees (through wages) as well as invest in capital projects (from profits) that can support future growth.

The table below summarizes the findings for value added by type (direct, indirect and induced) and industry sector. As previously noted, the direct effects were the most impactful, accounting for approximately $133.2 million (or 54%) of the $248.2 million of value added in 2018. On an industry level, $115.7 million (47%) of the value added will be generated by the construction sector. In 2018, IHS forecasts the GSP of Arizona will be $347.7 billion. Thus, Southwest Gas' contribution of $248.2 million will account for about 0.07% of Arizona's GSP.

Economic Contribution - All Arizona-based Projects

Value Added (millions of US $)	2016	2017	2018
Value Added by Type	**175.7**	**174.2**	**248.2**
Direct Arizona Supply Chain	93.1	92.1	133.2
Indirect Arizona Supply Chain	29.1	28.9	41.6
Induced (Consumer Spending) Activity	53.4	53.3	73.5
Value Added by Industry	**175.7**	**174.2**	**248.2**
Natural Resources	0.3	0.3	0.4
Transportation & Utilities	4.8	4.8	7.7
Construction	81.0	78.4	115.7
Manufacturing	2.2	2.2	3.2
Wholesale & Retail Trade	14.4	14.3	22.3
Information & Professional Services	36.8	37.7	49.3
Financial Services	26.2	26.6	36.4
Leisure & Other Services	7.6	7.6	10.5
Government	2.3	2.3	2.7

The table below presents the value added results for just the GIM Mechanism. Assuming Southwest Gas continues to annually devote $100 million to direct capital expenditures in Arizona beyond 2018, just over $100 million of value added will be generated. In other words, every dollar of capex that Southwest Gas spends in Arizona will grow the Arizona economy by one dollar.

Economic Contribution - Gas Infrastructure Modernization				
Value Added (millions of US $)	**2016**	**2017**	**2018**	**Post-2018****
Value Added by Type	**9.9**	**31.2**	**110.9**	**100.8**
Direct Arizona Supply Chain	5.3	16.6	60.2	54.7
Indirect Arizona Supply Chain	1.6	5.3	18.8	17.1
Induced (Consumer Spending) Activity	2.9	9.4	32.0	29.1
Value Added by Industry	**9.9**	**31.2**	**110.9**	**100.8**
Natural Resources	0.0	0.1	0.2	0.2
Transportation & Utilities	0.2	0.7	3.8	3.5
Construction	5.0	11.9	52.0	47.3
Manufacturing	0.1	0.4	1.4	1.3
Wholesale & Retail Trade	0.8	2.3	11.0	10.0
Information & Professional Services	1.7	9.9	21.1	19.2
Financial Services	1.4	4.3	15.6	14.2
Leisure & Other Services	0.4	1.4	4.6	4.2
Government	0.1	0.3	1.0	1.0

** Assumes $100M in direct capital expenditures on moderization in Arizona each year

Labor Income

As a subset of value added, the labor income results parallel the value added results. In general, labor income accounts for approximately 70% of value added. Thus, total employee and proprietor income supported by Southwest Gas capital investment projects in Arizona is expected to reach $172.7 million in 2018 from $125.4 million in 2016. About $84.7 million in 2016 and $120.3 million in 2018 will occur in the direct and indirect supply chains. On a per-employee basis, that represents an average income across the supply chain of almost $65,000 in 2016 and over $67,000 in 2018, approximately 20% higher than IHS' forecast of Arizona's average nonfarm annual wage in those years. Across all job classes (direct, indirect and induced) the average income will exceed $61,500 in 2018 or 11% above the state average.

Economic Contribution - All Arizona-based Projects			
Labor Income (millions of US $)	**2016**	**2017**	**2018**
Labor Income by Type	**125.4**	**125.1**	**172.7**
Southwest Gas FTEs	11.0	11.4	11.7
Direct Arizona Supply Chain	65.5	65.1	92.8
Indirect Arizona Supply Chain	19.2	19.1	27.5
Induced (Consumer Spending) Activity	29.6	29.5	40.7
Labor Income by Industry	**125.4**	**125.1**	**172.7**
Southwest Gas FTEs	11.0	11.4	11.7
Natural Resources	0.1	0.1	0.2
Transportation & Utilities	2.8	2.8	4.6
Construction	55.3	53.5	79.0
Manufacturing	1.6	1.6	2.3
Wholesale & Retail Trade	9.0	8.9	13.9
Information & Professional Services	30.6	31.5	40.6
Financial Services	7.2	7.4	10.0
Leisure & Other Services	6.1	6.1	8.5
Government	1.7	1.7	2.0

Looking beyond 2018, the GIM Mechanism will generate approximately $68.4 million of labor income annually in Arizona, assuming Southwest Gas maintains local capital expenditures of $100 million. Almost half of these wages ($32.3 million) will occur in the construction industry.

Economic Contribution - Gas Infrastructure Modernization				
Labor Income (millions of US $)	**2016**	**2017**	**2018**	**Post-2018****
Labor Income by Type	**6.8**	**22.0**	**75.2**	**68.4**
Southwest Gas FTEs	0.4	0.7	3.3	3.0
Direct Arizona Supply Chain	3.7	12.7	41.8	38.0
Indirect Arizona Supply Chain	1.1	3.5	12.4	11.3
Induced (Consumer Spending) Activity	1.6	5.2	17.7	16.1
Labor Income by Industry	**6.8**	**22.0**	**75.2**	**68.4**
Southwest Gas FTEs	0.4	0.7	3.3	3.0
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.1	0.4	2.4	2.2
Construction	3.4	8.1	35.5	32.3
Manufacturing	0.1	0.3	1.0	0.9
Wholesale & Retail Trade	0.5	1.4	6.8	6.2
Information & Professional Services	1.4	8.7	17.4	15.8
Financial Services	0.4	1.1	4.2	3.8
Leisure & Other Services	0.3	1.1	3.7	3.4
Government	0.1	0.2	0.8	0.7

** Assumes $100M in direct capital expenditures in Arizona each year

Taxes

Finally, the additional economic activity stimulated by Southwest Gas' construction and maintenance capital expenditures in Arizona will generate both federal and state & local tax revenues. These are summarized below.

Economic Contribution - All Arizona-based Projects			
Indicator	**2016**	**2017**	**2018**
Taxes (Million US$)	**26.7**	**26.5**	**38.5**
State & Local Taxes	9.1	9.1	13.4
Federal Taxes	17.6	17.5	25.0

Looking beyond 2018 – and once again assuming $100 in annual capital expenditures – the GIM Mechanism will generate $5.7 million in state & local taxes within Arizona.

Economic Contribution - Gas Infrastructure Modernization				
Indicator	**2016**	**2017**	**2018**	**Post-2018****
Taxes (Million US$)	**1.5**	**4.9**	**17.5**	**15.9**
State & Local Taxes	0.5	1.6	6.2	5.7
Federal Taxes	1.0	3.3	11.3	10.3

CHAPTER 5

Appendix

Economic Contribution Summary Tables

Economic Contribution - All Arizona-based Projects*

Indicator	2016	2017	2018
Employment (Number of workers)	**2,089**	**2,036**	**2,771**
Southwest Gas FTEs	153	156	155
Direct Arizona Supply Chain	991	958	1,351
Indirect Arizona Supply Chain	318	310	436
Induced (Consumer Spending) Activity	627	613	828
Value Added Contribution to GSP (US$M)	**175.7**	**174.2**	**248.2**
Direct Arizona Supply Chain	93.1	92.1	133.2
Indirect Arizona Supply Chain	29.1	28.9	41.6
Induced (Consumer Spending) Activity	53.4	53.3	73.5
Labor Income (US$M)	**125.4**	**125.1**	**172.7**
Southwest Gas FTEs	11.0	11.4	11.7
Direct Arizona Supply Chain	65.5	65.1	92.8
Indirect Arizona Supply Chain	19.2	19.1	27.5
Induced (Consumer Spending) Activity	29.6	29.5	40.7
Output (US$M)	**306.4**	**302.5**	**430.5**
SW Gas Direct Spending in AZ Supply Chain	172.9	169.5	243.9
Indirect Arizona Supply Chain Activity	48.5	48.0	69.2
Induced (Consumer Spending) Activity	85.0	84.9	117.4
Taxes (US$M)	**26.7**	**26.5**	**38.5**
State & Local Taxes	9.1	9.1	13.4
Federal Taxes	17.6	17.5	25.0

* IHS assumed the capital expenditures would not effect SW Gas' expected sales revenue (output) and value added contribution to GSP). Also, while IHS does not anticipate SW Gas to hire additional employees specifically for these projects, the dedicated labor and corresponding wages are included in the employment and labor income effects (on an FTE basis) in this economic contribution summary.

Economic Contribution - Gas Infrastructure Modernization*

Indicator	2016	2017	2018	Post-2018**
Employment (Number of workers)	**114**	**356**	**1,215**	**1,104**
Southwest Gas FTEs	6	10	46	42
Direct Arizona Supply Chain	57	180	610	555
Indirect Arizona Supply Chain	18	58	198	180
Induced (Consumer Spending) Activity	34	108	361	328
Value Added Contribution to GSP (US$M)	**9.9**	**31.2**	**110.9**	**100.8**
Direct Arizona Supply Chain	5.3	16.6	60.2	54.7
Indirect Arizona Supply Chain	1.6	5.3	18.8	17.1
Induced (Consumer Spending) Activity	2.9	9.4	32.0	29.1
Labor Income (US$M)	**6.8**	**22.0**	**75.2**	**68.4**
Southwest Gas FTEs	0.4	0.7	3.3	3.0
Direct Arizona Supply Chain	3.7	12.7	41.8	38.0
Indirect Arizona Supply Chain	1.1	3.5	12.4	11.3
Induced (Consumer Spending) Activity	1.6	5.2	17.7	16.1
Output (US$M)	**17.3**	**53.6**	**192.4**	**174.9**
SW Gas Direct Spending in AZ Supply Chain	9.9	29.9	110.0	100.0
Indirect Arizona Supply Chain Activity	2.7	8.7	31.3	28.4
Induced (Consumer Spending) Activity	4.6	15.0	51.1	46.5
Taxes (US$M)	**1.5**	**4.9**	**17.5**	**15.9**
State & Local Taxes	0.5	1.6	6.2	5.7
Federal Taxes	1.0	3.3	11.3	10.3

* IHS assumed the capital expenditures would not effect SW Gas' expected sales revenue (output) and value added contribution to GSP). Also, while IHS does not anticipate SW Gas to hire additional employees specifically for these projects, the dedicated labor and corresponding wages are included in the employment and labor income effects (on an FTE basis) in this economic contribution summary.
** Assumes $100M in direct capital expenditures in Arizona each year.

Economic Contribution of All Arizona-based Projects

Economic Contribution - All Arizona-based Projects			
Output (millions of US $)	**2016**	**2017**	**2018**
SW Gas Direct Spending in AZ Supply Chain	**172.9**	**169.5**	**243.9**
Natural Resources	0.0	0.0	0.0
Transportation & Utilities	1.3	1.3	3.5
Construction	150.8	144.8	212.3
Manufacturing	0.6	0.7	1.0
Wholesale & Retail Trade	1.0	1.0	4.6
Information & Professional Services	12.2	14.0	13.8
Financial Services	3.9	4.6	5.6
Leisure & Other Services	0.0	0.0	0.0
Government	3.0	3.1	3.2
Indirect Arizona Supply Chain Output	**48.5**	**48.0**	**69.2**
Natural Resources	0.2	0.2	0.3
Transportation & Utilities	2.8	2.8	4.3
Construction	0.9	0.9	1.2
Manufacturing	5.3	5.2	7.6
Wholesale & Retail Trade	6.0	5.8	8.4
Information & Professional Services	21.0	21.0	30.1
Financial Services	8.8	8.7	12.4
Leisure & Other Services	3.1	3.1	4.4
Government	0.4	0.4	0.5
Arizona Supply Chain (Direct + Indir) Output	**221.4**	**217.6**	**313.1**
Natural Resources	0.2	0.2	0.3
Transportation & Utilities	4.2	4.2	7.8
Construction	151.7	145.7	213.5
Manufacturing	6.0	5.9	8.6
Wholesale & Retail Trade	7.0	6.8	13.0
Information & Professional Services	33.2	34.9	43.9
Financial Services	12.7	13.3	18.0
Leisure & Other Services	3.1	3.1	4.3
Government	3.3	3.5	3.7
Induced Arizona Output	**85.0**	**84.9**	**117.4**
Natural Resources	0.4	0.3	0.5
Transportation & Utilities	4.3	4.3	5.9
Construction	0.8	0.8	1.1
Manufacturing	2.5	2.5	3.4
Wholesale & Retail Trade	13.1	13.0	17.8
Information & Professional Services	25.4	25.5	35.5
Financial Services	27.6	27.6	38.2
Leisure & Other Services	9.7	9.7	13.4
Government	1.2	1.2	1.6
Total Arizona Output Contribution	**306.4**	**302.5**	**430.5**
Natural Resources	0.6	0.5	0.8
Transportation & Utilities	8.5	8.4	13.7
Construction	152.5	146.5	214.5
Manufacturing	8.5	8.4	12.0
Wholesale & Retail Trade	20.2	19.8	30.8
Information & Professional Services	58.6	60.5	79.4
Financial Services	40.3	41.0	56.2
Leisure & Other Services	12.8	12.8	17.8
Government	4.5	4.6	5.3

Economic Contribution - All Arizona-based Projects			
Employment (number of workers)	**2016**	**2017**	**2018**
Southwest Gas FTEs	**153**	**156**	**155**
Direct Arizona Supply Chain Employment	**991**	**958**	**1,351**
Natural Resources	0	0	0
Transportation & Utilities	8	8	21
Construction	862	817	1,182
Manufacturing	2	2	3
Wholesale & Retail Trade	5	4	21
Information & Professional Services	89	100	96
Financial Services	11	12	14
Leisure & Other Services	1	0	0
Government	14	14	14
Indirect Arizona Supply Chain Employment	**318**	**310**	**436**
Natural Resources	1	1	1
Transportation & Utilities	15	15	23
Construction	5	5	7
Manufacturing	19	18	25
Wholesale & Retail Trade	28	27	39
Information & Professional Services	172	168	235
Financial Services	39	38	53
Leisure & Other Services	38	37	51
Government	1	1	2
Arizona Supply Chain (Direct + Indirect) Emp	**1,309**	**1,267**	**1,787**
Natural Resources	1	1	1
Transportation & Utilities	23	22	44
Construction	867	822	1,189
Manufacturing	20	20	29
Wholesale & Retail Trade	33	32	60
Information & Professional Services	262	268	331
Financial Services	49	50	67
Leisure & Other Services	38	37	51
Government	16	16	16
Induced Arizona Employment	**627**	**613**	**828**
Natural Resources	2	2	3
Transportation & Utilities	20	19	26
Construction	4	4	6
Manufacturing	5	5	7
Wholesale & Retail Trade	133	130	175
Information & Professional Services	222	217	293
Financial Services	88	86	116
Leisure & Other Services	149	145	196
Government	5	5	7
Total Arizona Employment Contribution	**2,089**	**2,036**	**2,771**
Southwest Gas FTEs	153	156	155
Natural Resources	3	3	3
Transportation & Utilities	42	41	70
Construction	871	826	1,195
Manufacturing	26	25	36
Wholesale & Retail Trade	166	161	235
Information & Professional Services	483	485	624
Financial Services	137	136	183
Leisure & Other Services	187	182	247
Government	21	21	23

Economic Contribution - All Arizona-based Projects			
Value Added (millions of US $)	**2016**	**2017**	**2018**
Direct Arizona Supply Chain Value Added	**93.1**	**92.1**	**133.2**
Natural Resources	0.0	0.0	0.0
Transportation & Utilities	0.7	0.7	1.7
Construction	80.1	77.5	114.5
Manufacturing	0.2	0.2	0.3
Wholesale & Retail Trade	0.7	0.7	3.2
Information & Professional Services	7.5	8.6	8.4
Financial Services	2.6	3.0	3.6
Leisure & Other Services	0.0	0.0	0.0
Government	1.4	1.5	1.5
Indirect Arizona Supply Chain Value Added	**29.1**	**28.9**	**41.6**
Natural Resources	0.1	0.1	0.2
Transportation & Utilities	1.6	1.6	2.5
Construction	0.5	0.5	0.6
Manufacturing	1.5	1.4	2.1
Wholesale & Retail Trade	4.1	4.0	5.9
Information & Professional Services	13.5	13.4	19.2
Financial Services	5.7	5.7	8.1
Leisure & Other Services	1.9	1.9	2.7
Government	0.2	0.2	0.3
Arizona Supply Chain (Direct + Indirect) VA	**122.3**	**121.0**	**174.7**
Natural Resources	0.1	0.1	0.2
Transportation & Utilities	2.3	2.3	4.2
Construction	80.6	78.0	115.1
Manufacturing	1.6	1.6	2.4
Wholesale & Retail Trade	4.8	4.7	9.1
Information & Professional Services	21.0	22.0	27.6
Financial Services	8.3	8.7	11.7
Leisure & Other Services	1.9	1.9	2.7
Government	1.6	1.7	1.8
Induced Arizona Value Added	**53.4**	**53.3**	**73.5**
Natural Resources	0.2	0.2	0.2
Transportation & Utilities	2.5	2.5	3.5
Construction	0.4	0.4	0.6
Manufacturing	0.6	0.6	0.8
Wholesale & Retail Trade	9.6	9.6	13.2
Information & Professional Services	15.8	15.7	21.7
Financial Services	18.0	17.9	24.7
Leisure & Other Services	5.7	5.7	7.9
Government	0.7	0.7	0.9
Total Arizona Value Added Contribution	**175.7**	**174.2**	**248.2**
Natural Resources	0.3	0.3	0.4
Transportation & Utilities	4.8	4.8	7.7
Construction	81.0	78.4	115.7
Manufacturing	2.2	2.2	3.2
Wholesale & Retail Trade	14.4	14.3	22.3
Information & Professional Services	36.8	37.7	49.3
Financial Services	26.2	26.6	36.4
Leisure & Other Services	7.6	7.6	10.5
Government	2.3	2.3	2.7

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Economic Contribution - All Arizona-based Projects			
Labor Income (millions of US $)	**2016**	**2017**	**2018**
Southwest Gas FTEs	**11.0**	**11.4**	**11.7**
Direct Arizona Supply Chain Labor Income	**65.5**	**65.1**	**92.8**
Natural Resources	0.0	0.0	0.0
Transportation & Utilities	0.5	0.5	1.2
Construction	54.7	52.9	78.2
Manufacturing	0.1	0.2	0.2
Wholesale & Retail Trade	0.4	0.4	1.9
Information & Professional Services	7.3	8.4	8.2
Financial Services	1.4	1.6	2.0
Leisure & Other Services	0.0	0.0	0.0
Government	1.1	1.2	1.2
Indirect Arizona Supply Chain Labor Income	**19.2**	**19.1**	**27.5**
Natural Resources	0.0	0.0	0.1
Transportation & Utilities	1.0	1.0	1.5
Construction	0.3	0.3	0.4
Manufacturing	1.2	1.1	1.7
Wholesale & Retail Trade	2.5	2.4	3.6
Information & Professional Services	10.5	10.4	14.9
Financial Services	2.1	2.0	2.9
Leisure & Other Services	1.6	1.6	2.3
Government	0.1	0.1	0.2
Arizona Supply Chain (Direct + Indirect) LI	**84.8**	**84.2**	**120.3**
Natural Resources	0.0	0.0	0.1
Transportation & Utilities	1.4	1.4	2.8
Construction	55.0	53.2	78.6
Manufacturing	1.3	1.3	1.9
Wholesale & Retail Trade	2.9	2.8	5.5
Information & Professional Services	17.8	18.8	23.0
Financial Services	3.4	3.7	4.9
Leisure & Other Services	1.6	1.6	2.3
Government	1.2	1.3	1.4
Induced Arizona Labor Income	**29.6**	**29.5**	**40.7**
Natural Resources	0.1	0.1	0.1
Transportation & Utilities	1.4	1.4	1.9
Construction	0.3	0.3	0.4
Manufacturing	0.3	0.3	0.4
Wholesale & Retail Trade	6.1	6.1	8.4
Information & Professional Services	12.8	12.8	17.6
Financial Services	3.7	3.7	5.1
Leisure & Other Services	4.5	4.5	6.2
Government	0.4	0.4	0.6
Total Arizona Labor Income Contribution	**125.4**	**125.1**	**172.7**
Southwest Gas FTEs	11.0	11.4	11.7
Natural Resources	0.1	0.1	0.2
Transportation & Utilities	2.8	2.8	4.6
Construction	55.3	53.5	79.0
Manufacturing	1.6	1.6	2.3
Wholesale & Retail Trade	9.0	8.9	13.9
Information & Professional Services	30.6	31.5	40.6
Financial Services	7.2	7.4	10.0
Leisure & Other Services	6.1	6.1	8.5
Government	1.7	1.7	2.0

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Economic Contribution of Gas Infrastructure Modernization Projects

Economic Contribution - Gas Infrastructure Modernization				
Output (millions of US $)	**2016**	**2017**	**2018**	**Post-2018****
SW Gas Direct Spending in AZ Supply Chain	**9.9**	**29.9**	**110.0**	**100.0**
Natural Resources	0.0	0.0	0.0	0.0
Transportation & Utilities	0.0	0.1	2.4	2.1
Construction	9.4	22.0	95.5	86.9
Manufacturing	0.0	0.1	0.4	0.3
Wholesale & Retail Trade	0.0	0.0	3.7	3.4
Information & Professional Services	0.2	7.4	5.0	4.5
Financial Services	0.1	0.1	1.9	1.7
Leisure & Other Services	0.0	0.0	0.0	0.0
Government	0.2	0.2	1.1	1.0
Indirect Arizona Supply Chain Output	**2.7**	**8.7**	**31.3**	**28.4**
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.2	0.5	2.1	1.9
Construction	0.0	0.1	0.5	0.5
Manufacturing	0.3	0.8	3.4	3.1
Wholesale & Retail Trade	0.4	0.9	3.8	3.5
Information & Professional Services	1.2	4.0	13.5	12.3
Financial Services	0.5	1.6	5.6	5.1
Leisure & Other Services	0.2	0.6	1.9	1.8
Government	0.0	0.1	0.2	0.2
Arizona Supply Chain (Direct + Indir) Output	**12.7**	**38.6**	**141.3**	**128.4**
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.2	0.5	4.5	4.0
Construction	9.5	22.2	96.0	87.3
Manufacturing	0.3	0.9	3.8	3.5
Wholesale & Retail Trade	0.4	0.9	7.5	6.8
Information & Professional Services	1.4	11.4	18.5	16.9
Financial Services	0.6	1.8	7.5	6.8
Leisure & Other Services	0.2	0.6	1.9	1.8
Government	0.2	0.3	1.3	1.2
Induced Arizona Output	**4.6**	**15.0**	**51.1**	**46.5**
Natural Resources	0.0	0.1	0.2	0.2
Transportation & Utilities	0.2	0.8	2.6	2.3
Construction	0.0	0.1	0.5	0.4
Manufacturing	0.1	0.4	1.5	1.4
Wholesale & Retail Trade	0.7	2.3	7.8	7.0
Information & Professional Services	1.4	4.5	15.4	14.0
Financial Services	1.5	4.9	16.7	15.1
Leisure & Other Services	0.5	1.7	5.8	5.3
Government	0.1	0.2	0.7	0.6
Total Arizona Output Contribution	**17.3**	**53.6**	**192.4**	**174.9**
Natural Resources	0.0	0.1	0.3	0.3
Transportation & Utilities	0.4	1.3	7.0	6.4
Construction	9.5	22.3	96.5	87.7
Manufacturing	0.5	1.4	5.3	4.8
Wholesale & Retail Trade	1.1	3.2	15.3	13.9
Information & Professional Services	2.8	15.9	34.0	30.9
Financial Services	2.1	6.6	24.2	22.0
Leisure & Other Services	0.7	2.3	7.8	7.1
Government	0.3	0.5	2.0	1.9

Economic Contribution - Gas Infrastructure Modemization				
Employment (number of workers)	**2016**	**2017**	**2018**	**Post-2018****
Southwest Gas FTEs	**6**	**10**	**46**	**42**
Direct Arizona Supply Chain Employment	**57**	**180**	**610**	**555**
Natural Resources	0	0	0	0
Transportation & Utilities	0	0	15	14
Construction	54	124	532	484
Manufacturing	0	0	2	1
Wholesale & Retail Trade	0	0	17	15
Information & Professional Services	2	53	35	32
Financial Services	0	0	5	4
Leisure & Other Services	0	0	0	0
Government	1	1	5	5
Indirect Arizona Supply Chain Employment	**18**	**58**	**198**	**180**
Natural Resources	0	0	0	0
Transportation & Utilities	1	2	12	11
Construction	0	1	3	3
Manufacturing	1	3	11	10
Wholesale & Retail Trade	2	4	18	16
Information & Professional Services	9	33	106	96
Financial Services	2	7	24	22
Leisure & Other Services	2	8	23	21
Government	0	0	1	1
Arizona Supply Chain (Direct + Indirect) Emp	**74**	**238**	**808**	**735**
Natural Resources	0	0	0	0
Transportation & Utilities	1	3	27	24
Construction	54	125	535	486
Manufacturing	1	3	13	12
Wholesale & Retail Trade	2	4	35	31
Information & Professional Services	11	86	141	128
Financial Services	2	7	29	26
Leisure & Other Services	2	8	23	21
Government	1	1	6	5
Induced Arizona Employment	**34**	**108**	**361**	**328**
Natural Resources	0	0	1	1
Transportation & Utilities	1	3	11	10
Construction	0	1	2	2
Manufacturing	0	1	3	3
Wholesale & Retail Trade	7	23	76	69
Information & Professional Services	12	38	128	116
Financial Services	5	15	51	46
Leisure & Other Services	8	26	85	78
Government	0	1	3	3
Total Arizona Employment Contribution	**115**	**356**	**1,215**	**1,104**
Southwest Gas FTEs	6	10	46	42
Natural Resources	0	0	1	1
Transportation & Utilities	2	6	38	35
Construction	54	126	537	488
Manufacturing	1	4	16	15
Wholesale & Retail Trade	9	27	111	101
Information & Professional Services	23	125	269	244
Financial Services	7	23	79	72
Leisure & Other Services	10	33	108	98
Government	1	2	9	8

** Assumes $100M in direct capital expenditures in Arizona each year

Economic Contribution - Gas Infrastructure Modernization				
Value Added (millions of US $)	**2016**	**2017**	**2018**	**Post-2018****
Direct Arizona Supply Chain Value Added	**5.3**	**16.6**	**60.2**	**54.7**
Natural Resources	0.0	0.0	0.0	0.0
Transportation & Utilities	0.0	0.0	1.1	1.0
Construction	5.0	11.8	51.5	46.8
Manufacturing	0.0	0.0	0.1	0.1
Wholesale & Retail Trade	0.0	0.0	2.6	2.3
Information & Professional Services	0.1	4.5	3.0	2.8
Financial Services	0.1	0.1	1.3	1.1
Leisure & Other Services	0.0	0.0	0.0	0.0
Government	0.1	0.1	0.5	0.5
Indirect Arizona Supply Chain Value Added	**1.6**	**5.3**	**18.8**	**17.1**
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.1	0.3	1.2	1.1
Construction	0.0	0.1	0.3	0.2
Manufacturing	0.1	0.2	1.0	0.9
Wholesale & Retail Trade	0.2	0.6	2.7	2.4
Information & Professional Services	0.8	2.6	8.6	7.8
Financial Services	0.3	1.1	3.6	3.3
Leisure & Other Services	0.1	0.4	1.2	1.1
Government	0.0	0.0	0.1	0.1
Arizona Supply Chain (Direct + Indirect) VA	**6.9**	**21.8**	**78.9**	**71.8**
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.1	0.3	2.3	2.1
Construction	5.0	11.9	51.8	47.1
Manufacturing	0.1	0.3	1.1	1.0
Wholesale & Retail Trade	0.2	0.6	5.3	4.8
Information & Professional Services	0.9	7.1	11.7	10.6
Financial Services	0.4	1.2	4.9	4.4
Leisure & Other Services	0.1	0.4	1.2	1.1
Government	0.1	0.1	0.7	0.6
Induced Arizona Value Added	**2.9**	**9.4**	**32.0**	**29.1**
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.1	0.4	1.5	1.4
Construction	0.0	0.1	0.3	0.2
Manufacturing	0.0	0.1	0.3	0.3
Wholesale & Retail Trade	0.5	1.7	5.8	5.2
Information & Professional Services	0.9	2.8	9.5	8.6
Financial Services	1.0	3.1	10.7	9.8
Leisure & Other Services	0.3	1.0	3.4	3.1
Government	0.0	0.1	0.4	0.4
Total Arizona Value Added Contribution	**9.9**	**31.2**	**110.9**	**100.8**
Natural Resources	0.0	0.1	0.2	0.2
Transportation & Utilities	0.2	0.7	3.8	3.5
Construction	5.0	11.9	52.0	47.3
Manufacturing	0.1	0.4	1.4	1.3
Wholesale & Retail Trade	0.8	2.3	11.0	10.0
Information & Professional Services	1.7	9.9	21.1	19.2
Financial Services	1.4	4.3	15.6	14.2
Leisure & Other Services	0.4	1.4	4.6	4.2
Government	0.1	0.3	1.0	1.0

** Assumes $100M in direct capital expenditures in Arizona each year

Economic Contribution - Gas Infrastructure Modernization				
Labor Income (millions of US $)	**2016**	**2017**	**2018**	**Post-2018****
Southwest Gas FTEs	**0.4**	**0.7**	**3.3**	**3.0**
Direct Arizona Supply Chain Labor Income	**3.7**	**12.7**	**41.8**	**38.0**
Natural Resources	0.0	0.0	0.0	0.0
Transportation & Utilities	0.0	0.0	0.9	0.8
Construction	3.4	8.0	35.2	32.0
Manufacturing	0.0	0.0	0.1	0.1
Wholesale & Retail Trade	0.0	0.0	1.6	1.4
Information & Professional Services	0.1	4.5	3.0	2.7
Financial Services	0.0	0.0	0.7	0.6
Leisure & Other Services	0.0	0.0	0.0	0.0
Government	0.1	0.1	0.4	0.4
Indirect Arizona Supply Chain Labor Income	**1.1**	**3.5**	**12.4**	**11.3**
Natural Resources	0.0	0.0	0.0	0.0
Transportation & Utilities	0.1	0.2	0.8	0.7
Construction	0.0	0.1	0.2	0.2
Manufacturing	0.1	0.2	0.7	0.7
Wholesale & Retail Trade	0.1	0.4	1.6	1.5
Information & Professional Services	0.6	2.0	6.7	6.1
Financial Services	0.1	0.4	1.3	1.2
Leisure & Other Services	0.1	0.3	1.0	0.9
Government	0.0	0.0	0.1	0.1
Arizona Supply Chain (Direct + Indirect) LI	**4.7**	**16.2**	**54.2**	**49.3**
Natural Resources	0.0	0.0	0.0	0.0
Transportation & Utilities	0.1	0.2	1.6	1.5
Construction	3.4	8.1	35.4	32.1
Manufacturing	0.1	0.2	0.8	0.8
Wholesale & Retail Trade	0.1	0.4	3.2	2.9
Information & Professional Services	0.7	6.5	9.7	8.8
Financial Services	0.1	0.4	2.0	1.8
Leisure & Other Services	0.1	0.3	1.0	0.9
Government	0.1	0.1	0.5	0.4
Induced Arizona Labor Income	**1.6**	**5.2**	**17.7**	**16.1**
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.1	0.2	0.8	0.7
Construction	0.0	0.0	0.2	0.1
Manufacturing	0.0	0.1	0.2	0.2
Wholesale & Retail Trade	0.3	1.1	3.7	3.3
Information & Professional Services	0.7	2.2	7.7	7.0
Financial Services	0.2	0.7	2.2	2.0
Leisure & Other Services	0.2	0.8	2.7	2.4
Government	0.0	0.1	0.3	0.2
Total Arizona Labor Income Contribution	**6.8**	**22.0**	**75.2**	**68.4**
Southwest Gas FTEs	0.4	0.7	3.3	3.0
Natural Resources	0.0	0.0	0.1	0.1
Transportation & Utilities	0.1	0.4	2.4	2.2
Construction	3.4	8.1	35.5	32.3
Manufacturing	0.1	0.3	1.0	0.9
Wholesale & Retail Trade	0.5	1.4	6.8	6.2
Information & Professional Services	1.4	8.7	17.4	15.8
Financial Services	0.4	1.1	4.2	3.8
Leisure & Other Services	0.3	1.1	3.7	3.4
Government	0.1	0.2	0.8	0.7

** Assumes $100M in direct capital expenditures in Arizona each year

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Southwest Gas Corporation
Docket No. G-01551A-16-0107

Energy Efficiency Enabling Provision
Plan of Administration

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Energy Efficiency Enabling Provision
Plan of Administration

I. OVERVIEW

This document describes the plan of administration (POA) for the Southwest Gas Corporation (Southwest Gas or Company) Energy Efficiency Enabling Provision (EEP). The Arizona Corporation Commission (ACC or Commission) approved the EEP in Decision No. 72723 (Docket No. G-01551A-10-0458). The EEP is a revenue decoupling mechanism comprised of two components: (1) a monthly weather adjustment that provides "real-time" bill adjustments when actual weather during the winter months differs from the average weather, and (2) an annual non-weather component that ensures Southwest Gas recovers its Commission-authorized revenue per customer. The EEP POA specifies the accounting procedures and rate setting adjustments necessary to assure the Company neither over-recovers, nor under-recovers the margin-per-customer amounts authorized in its most recent general rate case proceeding.

The EEP Weather Adjustment accounts for variations between the actual temperatures and normal temperatures for each winter day in the customer's billing cycle. When actual temperatures are colder than normal, the delivery charge portion of customer bills will be adjusted downward to reflect what the customer would have used under normal temperature conditions. When actual temperatures are warmer than normal, the delivery charge portion of customer bills will be adjusted upward to reflect what the customer would have used under normal temperature conditions. Weather is quantified in Heating Degree Days (HDD). The EEP Weather Adjustment applies to consumption during the winter season months of December through March.

The EEP Annual Adjustment recovers or refunds any difference between the Company's billed margin and the margin amounts authorized in the Company's most recent general rate case proceeding.

II. DEFINITIONS

Decoupling: A rate design that separates the recovery of a utility's delivery costs from the amount of gas sold.

Delivery Charge: Per month and per therm charges that recover the costs incurred in the delivery of natural gas. Delivery charges do not include the cost of gas purchased for customer use.

Commodity Charge: The per therm charge applied to each unit of billed usage.

Heating Degree Days: A measurement used to reflect the demand for energy needed to heat a building. It is derived from measurements of outside air temperature and is calculated as the difference between 65 degrees Fahrenheit and the average daily temperature when the average daily temperature is below 65 degrees. When the average daily temperature is equal to or greater than 65 degrees, there are zero HDD.

Winter: The months of December through March.

III. APPLICABILITY

The EEP applies to residential Rate Schedule Nos. G-5, G-6, G-10 and G-11 and to General Service Schedule Nos. G-25(Small), G-25(Medium), G-25(Large-1) and G-25(Large-2) included in this Arizona Gas Tariff.

IV. EEP WEATHER ADJUSTMENT

The EEP Weather Adjustment accounts for variations between the actual temperatures and normal temperatures for each winter day in each customer's billing cycle. When actual temperatures are colder than normal, bills will be adjusted downward to reflect the delivery charge the customer would have incurred under normal temperature conditions. When actual temperatures are warmer than normal, bills will be adjusted upward to reflect the delivery charge the customer would have incurred under normal temperature conditions. Weather is quantified in Heating Degree Days (HDD). The EEP Weather Adjustment applies to consumption during the winter season. Three customer usage analyses are used in the determination of each customer's weather sensitive use: (1) an analysis of the customer's current billing cycle weather sensitivity, (2) an analysis of the customer's multi-season billing cycle weather sensitivity, and (3) the customer's current month metered use. Refer to Schedule 1 for an example of the current billing cycle analysis. Refer to Schedule 2 for an example of the multi-season analysis.

A. Billing Cycle Analysis - The billing cycle analysis uses the customer's current billing cycle HDD variance and billing cycle use per HDD to determine weather sensitive gas use and to calculate the billing cycle analysis volume adjustment.

1. Determine Billing Cycle HDD Variance

   Normal HDD = The sum of the ten-year average HDDs for each day in the customer's billing cycle
   Actual HDD = The sum of the actual HDDs for each day in the customer's billing cycle
   HDD Variance = Normal HDDs less the Actual HDDs

2. Determine Billing Cycle Use per HDD - Billing cycle use per HDD is calculated for each customer's bill by subtracting the customer's billing cycle base load volume from current monthly metered use and dividing the difference by the billing cycle actual HDDs.

   Billing cycle base load volume is equal to the customer's base load volume per day multiplied by the number of days in the customer's billing cycle. Base load volume per day for each customer is used to establish monthly non-temperature sensitive usage. The base load volume per day is equal to the customer's lowest average daily use for the May through October summer billing periods. Average daily use is the customer's total monthly use divided by the number of days in the

billing cycle. For new customers, base load volume per day will be the average base load volume per day in the customer's operating district.

3. Calculate Billing Cycle Analysis Volume Adjustment - The billing cycle analysis volume adjustment is calculated by multiplying the customer's billing cycle HDD variance by the billing cycle use per HDD.

B. Multi-Season Analysis - The multi-season analysis uses winter billing data from the previous 24 months to determine weather-sensitive gas use and to calculate the multi-season analysis volume adjustment. A linear regression is used to compare the customer's historical monthly metered use to the actual weather in each billing cycle to determine use per HDD. The multi-season analysis volume adjustment is calculated by multiplying the result of the linear regression by the billing cycle HDD variance for the customer's current billing cycle.

C. Bill Adjustment - The bill adjustment for the EEP weather adjustment is calculated by multiplying the applicable volume adjustment by the Commodity component of the customer's delivery charge. The applicable volume adjustment is whichever of the following three quantities is the closest to zero: (1) the billing cycle analysis volume adjustment, (2) the multi-season analysis volume adjustment, or (3) the customer's current monthly metered use.

However, in instances where the customer's billing cycle base load volume is greater than the customer's current monthly metered use or the sum of the actual HDDs in the customer's current billing cycle is equal to zero, the volume adjustment will be equal to zero and there will be no EEP Weather Adjustment to the customer's bill.

V. EEP ANNUAL ADJUSTMENT

The EEP Annual Adjustment recovers or refunds any differences between the Company's billed margin and the margin amounts authorized in its most recent general rate case proceeding. The process is set forth below.

A. EEP Balancing Account - Southwest Gas maintains accounting records that accumulate the difference between authorized and actual billed margin. Entries are recorded to the EEP Balancing Account (EEPBA) each month as follows:

1. A debit or credit entry equal to the difference between authorized margin and actual billed margin for each rate schedule subject to this provision. Authorized margin is the product of the monthly margin-per-customer authorized in Southwest Gas' last general rate case, and the actual number of customers billed during the month.

2. A debit or credit entry equal to the therms billed during the month under the schedules subject to this provision multiplied by the EEP Annual Adjustment Rate.

3. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the monthly one-year nominal Treasury Constant Maturities rate.

B. EEP Annual Adjustment Rate - The EEP Annual Adjustment Rate applicable to each schedule subject to this provision shall be revised annually to reflect the difference between the margin-per-customer authorized in the Company's last general rate case and the margin billed. The EEP Annual Adjustment Rate will be calculated by dividing the balance in the EEPBA by the most recent 12-month volume of natural gas for the customer class included in the EEP.

   The Company shall file its EEP Annual Adjustment Rate revisions with the Commission in accordance with all statutory and regulatory requirements following twelve (12) months of activity in the EEPBA. The EEP Annual Adjustment Rate shall be effective on the date of the first bill cycle in the month following the Commission's approval unless otherwise provided for by the Commission.

C. Amounts Recovered and Refunded - Southwest Gas is prohibited from recovering any under-collections in the EEPBA to the extent that recovery would increase earnings such that the Company would be earning more than its authorized return on common equity. In addition, the amount of deferred amounts to be recovered in any amortization period shall not exceed 5 percent of the test year average non-gas revenue per customer. Deferred amounts exceeding 5 percent of the test year average non-gas revenue per customer will be carried forward for recovery in the next year and subsequent years with no carrying charges. All over-collected balances in the EEPBA will be refunded, without limitation, over the next amortization period.

VI. EEP-RELATED COMPLIANCE FILINGS

The Company shall submit quarterly and annual compliance filings to the Commission pursuant to Decision No. 72723.

Schedule 1
Billing Cycle Calculation
(All numbers are used for illustrative purposes.)

Line No.	Description	Reference	Totals
1	Normal HDD	A	34
2	Actual HDD	B	60
3	Billing Cycle HDD Variance (A - B)	C	-26
4	Current Month Metered Use	D	129
5	Billing Cycle Base Load Volume	E	4
6	Line 4 - Line 5	F	125
7	Actual HDD	G	60
8	Billing Cycle Use Per HDD (F/G)	H	2.083333
9	Billing Cycle Analysis Volume Adjustment	C * H	-54

Schedule 2
Multi-Season Analysis – Linear Regression
(All numbers are used for illustrative purposes.)

Month	Billing Cycle Actual HDDs	Monthly Metered Use	Current Monthly Actual HDDs - Average Actual HDDs	Currently Month Metered Use - Average Metered Use	(c)*(d)	(c) * (c)
	(a)	(b)	(c)	(d)	(e)	(f)
April -16	5.0	8	-139.3000	-30.5000	4248.6500	19404.49
March-16	9.0	11	-135.3000	-27.5000	3720.7500	18306.09
February-16	87.0	31	-57.3000	-7.5000	429.7500	3283.29
January-16	243.0	60	98.7000	21.5000	2122.0500	9741.69
December-15	222.0	45	77.7000	6.5000	505.0500	6037.29
April-15	4.0	9	-140.3000	-29.5000	4138.8500	19684.09
March-15	139.0	37	-5.3000	-1.5000	7.9500	28.09
February-15	188.0	60	43.7000	21.5000	939.5500	1909.69
January-15	463.0	101	318.7000	62.5000	19918.7500	101569.69
December-14	83.0	23	-61.3000	-15.5000	950.1500	3757.69
Average	144.3000	38.5000		Total	36981.50	183722.10

Linear Regression Result = Total Column (e) / Total Column (f)	**0.2013**
Current Billing Cycle HDD Variance	**-26**
Multi-Season Analysis Volume Adjustment = Linear Regression Result x Billing Cycle HDD Variance	**-5**