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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-04204A-09-0206

Arizona Corporation Commission
DOCKETED
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NOTICE OF FILING SURREBUTTAL TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Surrebuttal Testimony of William A. Rigsby, CRRA, and Ben Johnson, Ph.D., in the above-referenced matter.

RESPECTFULLY SUBMITTED this 15th day of January, 2010.

Daniel W. Pozefsky
Chief Counsel

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UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 15, 2010

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INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office, located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to UNSE's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt and cost of common equity) for the Company's electric distribution operations located in Mohave and Santa Cruz Counties.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On October 30, 2009, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in UNSE's Application which was filed on April 30, 2009.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of UNSE's rebuttal testimony; a comparison of the cost of capital recommendations being made by the parties to the case; and a section on the cost of equity capital.

Q. Will you address the FVROR issues associated with the case?

A. No. RUCO consultant Ben Johnson, Ph.D. will discuss the FVROR aspects of the case.

SUMMARY OF UNSE ELECTRIC, INC.'S REBUTTAL TESTIMONY

Q. Have you reviewed UNSE'S rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimonies of Company witnesses Michael J. DeConcini, Kentton C. Grant and Martha B. Pritz which were filed on December 11, 2009.

Q. Please summarize Mr. DeConcini's rebuttal testimony.

A. Mr. DeConcini's rebuttal testimony provides an overview of the Company's rebuttal filing and addresses the various points of disagreement that UNSE has with the recommendations and positions of ACC Staff, RUCO, ASBA and AASBO. In regard to cost of capital, Mr. DeConcini expresses his displeasure with the FVROR recommendations of ACC Staff and RUCO.

Q. Please summarize Mr. Grant's rebuttal testimony.

A. Mr. Grant's rebuttal testimony focuses on the Company-proposed purchase of the Black Mountain Generating Station, changes to UNSE's PPFAC and the cost of capital recommendations made by ACC Staff and RUCO. Mr. Grant expresses his belief that the cost of equity recommendation presented in my direct testimony is too low and that UNSE will only earn an ROE of 6.00 percent if the Commission adopts it.

Q. Please summarize Ms. Pritz's rebuttal testimony.

A. Ms. Pritz's rebuttal testimony expresses her belief that the cost of equity recommendation presented in my direct testimony is too low and is critical of the inputs that I used in both my single stage DCF model and my CAPM model (which used both an arithmetic and geometric mean to arrive at the market risk premium component).

COMPARISON OF RECOMMENDATIONS

Q. Are the parties to the case in agreement on the issue of capital structure?

A. Yes, the parties to the case are in agreement on the issue of capital structure. Both ACC Staff and RUCO are recommending that the Commission adopt the Company-proposed capital structure comprised of 54.24 percent long-term debt and 45.76 percent common equity.

Q. Are ACC Staff and RUCO also in agreement with the Company-proposed 7.05 percent cost of long-term debt?

A. Yes. ACC Staff witness David C. Parcell and I have recommended that the Commission adopt the Company-proposed 7.05 percent cost of long-term debt.

Q. Are UNSE, ACC Staff and RUCO in agreement on a cost of equity capital for the Company?

A. No. As is typical in utility rate cases there is substantial disagreement on a cost of common equity.

Q. Please summarize the costs of common equity and the OCROR's that are being recommended by the parties to the case.

A. In regard to the cost of common equity, the parties to the case are presently recommending the following estimates:

UNSE	11.40%
ACC Staff	10.00%
RUCO	9.25%

As can be seen in the above comparison, the Company-proposed cost of equity capital is 215 basis points higher than my recommended cost of equity capital. The difference between my recommended cost of equity and Mr. Parcell's recommended cost of equity is 75 basis points. The OCROR (i.e. the weighted cost of capital based on the costs of debt and equity noted above) being recommended by the parties to the case are as follows:

UNSE	9.04%
ACC Staff	8.40%
RUCO	8.06%

As can be seen above, there is presently a 98 basis point difference between the Company-proposed 9.04 percent OCROR (before any FVROR adjustment) and RUCO's recommended weighted cost of capital of 8.06 percent. RUCO and ACC Staff's recommended OCROR are within 34 basis points of each other.

Q. What FVROR's are the parties to the case recommending?

A. The parties to the case are recommending the following FVROR's:

UNSE	6.88%
ACC Staff	5.49%
RUCO	5.96%

The above comparison shows a difference of 92 basis points between the Company and RUCO's recommended FVROR's and a difference of 47 basis points between the ACC Staff and RUCO recommendations.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On December 16, 2009, after a two-day meeting, the Federal Reserve made no changes to the Federal Funds rate which remains at 0.00- 0.25 percent.

Q. Please comment on Mr. Grant's position that UNSE will not be able to earn an appropriate return on common equity if the Commission adopts RUCO's recommendation.

A. Mr. Grant claims that the Company's net income and common equity projections for 2011 indicate that UNS will not be able to achieve its authorized rate of return if RUCO's cost of capital recommendation is adopted by the ACC. However, these are projections made by UNS that are mere speculation. In fact, both Mr. Grant and Ms. Pritz totally ignore RUCO's recommendation to allow UNSE to acquire the Black Mountain Generating Station which would certainly help UNSE's future financial position. RUCO believes that the rates it is recommending in this case will provide the Company with the opportunity to recover its operating expenses and provide a return on its invested capital. From that standpoint I believe that the capital attraction standards set forth in the Hope and Bluefield decisions have been satisfied. Ultimately it is up to the Company to manage its expenses and make prudent investments in order to achieve its authorized rate of return. This also means coming in for rate relief on a timely basis.

Capital Asset Pricing Model (CAPM)

Q. Please address Ms. Pritz's criticism that the 5-year Treasury rate that you used as the risk free rate of return in your CAPM models is not reflective of the "investment period" used by investors to value common stocks.

A. Ms. Pritz cites Dr. Roger Morin's broad assumption that the "relevant" period that the investment community relies on to value common stocks is "a very long period." But the fact is that utilities typically file for rates within a three to five-year period and the investment community is aware of that fact and understands the effect of rate case proceedings on earnings. Information on rate case proceedings is available to investors through SEC filings, investment research firms such as Value Line, and the mainstream financial press. One only has to look at UNSE as proof of this. The Company's prior rates were established on May 27, 2008 and UNSE filed for new rates in less than eleven months. Any investor who follows the Company's publicly traded parent would be aware of the impact that the Company's actions would have on future earnings and would base his or her investment decisions based on that information.

Q. Can you cite another reason why you believe the 5-year treasury instrument used in your CAPM analysis is appropriate?

A. Yes. Professional analysts at investment services such as Value Line and Zacks Investment Research typically do not make projections beyond five years. In fact, the Federal Energy Regulatory Commission ("FERC") places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model that Ms. Pritz used to derive her cost of equity recommendation (a point that I will discuss later in my surrebuttal testimony).

Q. Please explain why Ms. Pritz's criticism regarding the use of a geometric mean in a CAPM analysis is unfounded.

A. The information on both the geometric and arithmetic means, published by Morningstar, is widely available to the investment community. For this reason alone I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2008 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the difference between arithmetic and geometric means?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the \$120 value of your original \$100 investment falls to \$96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

$$(\text{ year 1 return} + \text{year 2 return }) \div \text{number of periods} =$$

$$(20.0\% + -20.0\%) \div 2 =$$

$$(0.0\%) \div 2 = \underline{0.0\%}$$

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original \$100 investment is still worth \$100. But in reality, your original \$100 investment is only worth \$96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{ year 2 value} \div \text{original value })^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{-2.02\%}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original $100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's SBBI yearbook.

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms, that is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concluded that 4.00 percent to 5.50 percent is a reasonable forward looking market risk premium. Adding the current 5-year Treasury yield of 2.23 percent to these two estimates indicates a cost of equity range of 6.23 percent to 7.73 percent. Taking into consideration the fact that utilities generally exhibit less risk than industrials, a return in the low end of this range would be reasonable. In fact, my 9.25 percent cost of common equity estimate is 375 basis points more than the high end of the range exhibited above.

Q. Has the Commission authorized rates of return that were derived through the use of both arithmetic and geometric means in prior decisions?

A. Yes. A case that specifically comes to mind involved another UniSource Energy subsidiary, UNS Gas Inc., in which Decision No. 70011, dated November 27, 2007, stated the following:

> "We agree with the Staff and RUCO witnesses that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

In the UNS Gas, Inc. case, the ACC Staff witness was Mr. Parcell, who, as I do, consistently relies on both arithmetic and geometric means in our CAPM analyses.

Q. Can you provide further support for the reasonableness of the market risk premiums used in your CAPM models?

A. Yes. In his direct testimony in a prior Arizona Public Service Company ("APS") rate case proceeding, RUCO consultant Stephen G. Hill makes the argument for market risk premiums ranging from 4.0 percent to 6.0 percent[1] (Attachment A). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two

[1] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

scholarly articles on the subject published by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical market risk premiums (now published by Morningstar) have overstated investor expectations.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University in Washington D.C. on April 19 and 20, 2007, I had the opportunity to hear the views of Aswath Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model?

A. Using the 2.41 percent yield on a 5-year Treasury instrument (r_f) and the average beta of 0.73 used in my CAPM model, and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, produces the following results:

<u>Using a 4.0% Market Risk Premium</u>

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

$$k = 2.41\% + [\, 0.73\,(4.0\%)\,]$$

$$k = 2.41\% + 2.92\%$$

$$k = \underline{5.33\%}$$

<u>Using a 6.0% Market Risk Premium</u>

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

$$k = 2.41\% + [\, 0.73\,(6.0\%)\,]$$

$$k = 2.41\% + 4.38\%$$

$$k = \underline{6.79\%}$$

These results are lower than the 5.46 percent and 6.83 percent estimates that I relied on to arrive at my recommended 9.25 percent cost of common equity. When the market risk premium information noted above is taken into consideration, it is clear that Ms. Pritz's market risk premium inputs, as opposed to mine, appear to be out of line.

Q. Do you have any data that supports a 4.00 percent equity risk premium during the market crises which unfolded in September of 2008?

A. Yes. In September 2008 Dr. Damodaran, who I noted earlier in my testimony, presented a paper titled Equity Risk Premium (ERP): Determinants, Estimation and Implications, which contained an October update that presented data on the swings in implied equity risk premium that occurred between September 12, 2008 and October 16, 2008. During that time frame, implied equity risk premiums ranged from 4.20 percent to 6.39 percent. The 5.30 percent mean average of that range falls within the 4.20 percent to 6.10 percent range of my market risk premiums using geometric and arithmetic means respectively.

Q. On page 17 of her rebuttal testimony, Ms. Pritz acknowledges the fact that the spreads between 30-year U.S. Treasury instruments and Baa/BBB-rated debt has narrowed since her direct testimony was filed. What is the current spread between those two financial instruments?

A. As can be seen in the most recent Value Line Selection and Opinion publication (Attachment B), the current spread between the 30-year U.S. Treasury yield of 4.64 percent and the 6.53 percent yield on Baa/BBB-rated debt is 189 basis points. As Ms. Pritz points out, this is mainly due to the calming of the U.S financial markets since her direct testimony was filed. This clearly illustrates that periods of volatility in the financial markets eventually subside and things eventually return to normal. This only strengthens my rationale for relying on the historical market risk premium used in my CAPM model, which captures the effects of a number of events on the financial markets such as the Great Depression, numerous economic recessions (with varying degrees of severity), the U.S. involvement in five major armed conflicts (including World War II), and periods of domestic political and social strife.

Discounted Cash Flow (DCF)

Q. Please address Ms. Pritz's criticism of your DCF analysis, which takes into consideration the concept that a utility's market-to-book ratio will move toward a value of 1.0 if regulators set a utility's rate of return at a level that is equal to the cost of capital of firms with similar risk.

A. A utility's market price should equal its book price over the long run if regulators allow a rate of return that is equal to the utility's cost of capital. *That is assuming that the utility's rate of return ("ROR") is comparable to the rates of return of other firms in the same risk class.*[2] For example, if a hypothetical utility's book price is \$20.00 per share and regulators adopt a rate of return that is equal to the utility's cost of capital of 10.0%, the utility will earn \$2.00 per share ("EPS"). With earnings of \$2.00 per share, and a

[2] An in-depth discussion of market-to-book ratios can be found in Chapter 10 of Roger A. Morin's text Regulatory Finance, Utilities' Cost of Capital.

market required rate of return on equity of 10.00%, for firms in the utility's risk class, the market price of the utility's stock will set at $20.00 per share ($2.00 EPS ÷ 10.0% ROR = $20.00 per share price). If the utility records earnings that are higher than the earnings of other firms with similar risk, the market value of the utility's shares will increase accordingly, (e.g. $2.50 EPS ÷ 10.0% ROR = $25.00 per share). On the other hand, if the utility posts lower earnings, the stock's market price will fall below book value, (e.g. $1.50 EPS ÷ 10.0% ROR = $15.00 per share).

Because of economic forces beyond the control of regulators, it is not reasonable to assume that the utility will have earnings that match those of firms of similar risk in every year of operation. In some years, earnings may drop causing the market-to-book ratio to fall below 1.0, while in other years the utility may have earnings that exceed those of other firms in its risk classification. However, over the long run the utility's earnings should average out to the earnings that are expected based on its level of risk. These average earnings over time will result in a market-to-book ratio of 1.0. It has been suggested that regulators should set a utility's rate of return at a level that is slightly higher than that of firms in the same risk class of the hypothetical utility. In theory, this will send a message to investors that average long-term earnings will not be less than what is expected. A 1.0 ratio may never be achieved in practice and many investors may not even care what the market-to-book ratio is as long as they receive their required rate of return. In this respect, a utility stock is similar to a corporate bond whose value fluctuates as interest rates move above or below the stated yield on the bond. As long as the bond provides the level of income (i.e. the stated interest payment in the case of a bond or a dividend payment in the case of a utility stock) that the investor expects, the price of the instrument at any given point in time is immaterial (so long as the intent is to hold the bond until maturity or the utility stock over a long-term period).

Q. Does your recommended cost of equity take into consideration the theoretical concepts that you have just described?

A. Yes. As I just explained, in theory, a market-to-book ratio of 1.0 would be achieved if a utility's rate of return equaled the cost of capital that is close to the returns of firms with similar risk. The results of the CAPM analysis that I performed earlier in this testimony (using the yield on a 5-year U.S treasury instrument and average beta I presented in my direct testimony and the market risk premium inputs advocated by Mr. Hill) indicate that the rate of return for a firm with UNSE's level of risk is much lower than my recommended 9.25 percent cost of equity capital. This being the case, the adoption of my recommended 9.25 percent cost of capital would be consistent with the theory I have presented above.

Q. Are there any other reasons why your market-to-book ratio calculation is valid?

A. Yes. The utilities included in my samples, are engaged in unregulated activities to some degree. Because it is difficult to obtain a sample comprised only of "pure play" utilities, the calculation that I have employed in my DCF model helps to eliminate the impact that those unregulated operating segments would have on the market-to-book ratio of the utilities included in my sample.

Q. Do you agree with Ms. Pritz's assertion, on page 18 of her rebuttal testimony, that you ignored data in your workpapers to develop the growth estimate that you used in your DCF model?

A. No. In fact my growth estimate took all of that data (displayed in Schedules WAR-5 and WAR-6 of my direct testimony) into consideration. I also provided Ms. Pritz with an explanation of how I arrived at my growth estimates for each of the utilities in my sample.

Q. Please respond to Ms. Pritz's statement (on page 19 of her rebuttal testimony) that you failed to note that her multi-stage DCF growth estimate also took into consideration growth estimates for the electric utility industry and the U.S. Economy as a whole.

A. While I will admit that I did not note those facts in my direct testimony, Ms. Pritz's use of those growth rates raises several concerns.

Q. Please explain.

A. The argument for the use of an industry growth rate assumes that investors place their funds in individual electric stocks because they expect the individual electric's growth rates to converge with the long-term average of the electric utility industry. In other words, if you've seen one electric stock, you've seen them all because you are essentially investing in an industry as opposed to an individual utility. If this argument were true, then investors would be investing in the electric industry as a whole (i.e. through an investment vehicle such as a mutual fund) as opposed to investing in an individual electric utility. This argument totally ignores the premise that rational investors place their funds in individual stocks because they feel comfortable with the dividend yields and the growth potentials offered by the individual electric utility that they are investing in. I believe that rational investors also weigh other factors such as superior management, corporate culture and philosophy, and past records of performance when making their investment decisions. If you subscribe to the argument at hand, then it would not make any difference which electric utility you made an investment in since they will all eventually provide the same returns in growth. This begs the question as to why there is so much investor information available on individual companies or why the managements of publicly traded firms tout their ability to provide returns that will exceed industry averages.

Q. Please address the reliance on growth rates for the U.S. economy as a whole.

A. This argument assumes that every individual electric utility is going to have inflation-adjusted growth that mirrors the GDP of the entire U.S. economy into perpetuity. This in itself is a rather broad and unrealistic expectation. Professional analysts often have enough trouble making accurate projections of the near-term (i.e. one-year) earnings of the companies that they follow. It would be unrealistic to believe that projections that extend into perpetuity would be more accurate than the near-term projections. The growth estimates used in my DCF model are a balance of known historical 5-year growth figures and projected growth estimates over the next five-year period (i.e. 2009 through 2014). I believe that this is a reasonable horizon for future growth estimates, given the fact that utilities typically apply for rate relief within a three to five-year time frame.

Q. Are there any other reasons why you believe that the results obtained by Ms. Pritz's multi-stage model should be discounted?

A. Yes. As I noted earlier, the FERC places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model.

...

Q. Please explain how the FERC places more emphasis on short-term projections in the multi-stage DCF model.

A. The multi-stage DCF model required by the FERC weighs short-term estimates of growth, similar to the one to five-year projections that I relied on to develop the "g" component in my single stage DCF model, by a factor of two-thirds. The FERC's rationale is that short-term estimates of growth are more predictable and deserve more weight than long-term estimates such as the equally-weighted long-term estimates of growth used in the multi-stage DCF model that Ms. Pritz has relied on. This is explained in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment C):

> "**Return on Equity or Cost of Equity:** This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis of a proxy group of publicly held natural gas companies. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short-term growth estimates and the other long-term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long-term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk."

Although the FERC excerpt cited above is from the FERC's manual on natural gas utilities, there is no reason why it would not apply also to electric or water utilities.

Q. Does Ms. Pritz give equal weight to the near-term and long-term growth estimates in her multi-stage model?

A. Yes. As I pointed out in my direct testimony, Ms. Pritz gives equal weight to both her near-term and long-term multi-stage inputs. As can be seen in the excerpt above, a good argument can be made that more emphasis should be placed on the near-term component of Ms. Pritz's 's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Has Ms. Pritz made any updates to the inputs of his models that were used to derive his recommended cost of common equity?

A. No. Ms. Pritz has not provided any such revisions in her rebuttal testimony.

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on UNSE?

A. Yes, it does.

ATTACHMENT A

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis. The average beta coefficients for the electric utility sample group was 0.83. Schedule 8 shows a CAPM cost of capital for the electric companies ranging from 9.23% to 10.56%.

Schedules 9 and 10 shows the theoretical basis and the data and calculations, respectively, for the Modified Earnings Price Ratio (MEPR) analysis. The MEPR analysis indicates a current cost of equity capital for electric companies in a narrow range from 8.79% to 9.13%. Finally, Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital for the electric utility companies of 9.31% (near-term) to 9.38% (long-term).

C. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC UTILITY COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table below.

METHOD	Electric Utility Companies
DCF	9.44%
CAPM	9.23%/10.56%
MEPR	9.13%/8.79%
MTB	9.31%/9.38%

For the electric utility sample group, the DCF result is 9.44%. In addition, the corroborating cost of equity indications (MEPR, MTB, and CAPM) indicate that DCF result is reasonable. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces and equity cost range of 9.11% to 9.69%, with a mid-point of 9.40%, only 4 basis points below the DCF result.

Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company like Arizona Public Service, facing similar risks as this group of electric utilities, ranges from 9.25% to 9.75%, with a mid-point of 9.50%.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED BEFORE DETERMINING A POINT-ESTIMATE FOR APS WITHIN A REASONABLE RAGE FOR SIMILAR-RISK FIRMS?

A. Yes. First, the electric sample group companies have similar operating risk to APS. The average S&P business risk score of my sample of electric utilities is 6—the same as that for APS. Therefore, on that basis there would be no reason to adjust the equity return from the mid-point of a reasonable range. However, because the capital structure I recommend for ratesetting purposes contains considerably more common equity and less debt than average for the sample group, APS, prospectively will have less financial risk than the sample group and should be awarded an equity return below the mid-point of a reasonable range.

Q. IS THERE A RECOGNIZED METHOD WITH WHICH DIFFERENCES IN FINANCIAL RISK CAN BE QUANTIFIED?

A. Yes. The cost of equity capital is affected by the capital structure a company employs. When a company increases the proportion of debt in its capital structure, it increases the riskiness of its equity. Financial risk (created by the use of debt in the capital structure) causes investors to demand a higher rate of return; that is, financial risk increases the cost of equity capital.

The impact of debt leverage on the cost of equity capital can be approximated through an examination of the changes in beta, which occur when leverage is increased or decreased. The Value Line betas for the sample companies used in my cost of capital analysis in this proceeding reflect the market's (investors') perception of both the business risks and the financial risks of a firm. That is, one portion of the beta of a firm is related to the *business* risk of the firm (the risk inherent in its operations) and one portion of the beta is related to the financial risk of that firm (the risk associated with the use of debt). Therefore, if a firm elects to finance its operations with debt as well as equity, the beta coefficient of that firm will reflect both the business and financial risk. When a firm uses debt to finance its operations, the beta can also be referred to as a "levered" beta (i.e., a beta coefficient that includes the impact of debt leverage).

The average beta coefficient of the sample group of utilities can be "unlevered." That is, the beta-risk related to the level of debt capital used by the firm can be removed. "Unlevering the betas" amounts to estimating what the average beta would be if the companies were financed entirely with equity capital. Equation (2) is used to estimate the unlevered beta for a firm or a group of similar-risk firms.[19]

$$\beta_U = \frac{\beta_{Measured}}{(1+(1-t)D/E)} \qquad (2)$$

Equation (2) indicates that an estimate of the unlevered beta (β_U) of a firm can be calculated by dividing the measured beta ($\beta_{Measured}$, e.g. the beta coefficient reported by investor services such as Value Line) by one plus the average debt-to-equity ratio, adjusted to account for taxes. The debt-to-equity ratio is measured using the average market value of the sample group's common equity capital. Once the unlevered beta for the firm (or, in this case, for the sample group of market-traded utility companies) is calculated, the beta coefficient is "re-levered" and adjusted to conform to the less leveraged capital structure of APS, which contains 50% common equity. The formula used to "re-lever" the utility betas is shown below.

$$\beta_{Relevered} = \beta_U\,(1+ (1-t)D/E) \qquad (3)$$

[19]Equation (1) is a version of the Hamada equation which combines the Miller-Modigliani theories regarding capital structure and the logic of the CAPM: Hamada, R.S., "Portfolio Analysis, Market equilibrium and Corporation Finance," *Journal of Finance*, March 1969, pp. 13-31.

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often said that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. That is not a correct statement because bonds have a fixed cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate a flotation cost reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 69% above book value. (Exhibit__(SGH-1), Schedule 4, p. 1) The difference between the market price of electric utility stock and book value dwarfs any issuance expense the companies might incur. Therefore, if common equity flotation costs were exactly like flotation costs with bonds, then, if an explicit adjustment to the cost of common equity were necessary, it should be downward, not upward.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses related to increases in stock outstanding is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[22]. There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market

[22] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs that lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's INTEGRATED UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.25%?

A. Schedule 13 attached to my testimony shows that an equity return of 9.25%, operating through an appropriate ratemaking capital structure of 50% equity and 50% debt, and the Company's requested embedded capital cost rates, produces an overall return of 7.33% for APS. Schedule 13 also shows that a 7.33% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times.

According to APS's 2005 S.E.C. Form 10-K (Exhibit 12), the pre-tax interest coverage over the past five years has averaged 2.94x and has ranged from 2.81x to 3.17x. The return I recommend would allow the Company the opportunity to improve its historical average interest coverage. Therefore, the equity return I recommend fulfills the legal requirement of Hope and Bluefield of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

V. COMPANY COST OF CAPITAL TESTIMONY

Q. HOW HAS COMPANY WITNESS AVERA ESTIMATED THE COST OF EQUITY CAPITAL IN THIS PROCEEDING?

Exhibit_(SGH-1)
Schedule 12

ARIZONA PUBLIC SERVICE COMPANY
LEVERAGE/BETA ADJUSTMENT TO THE COST OF EQUITY CAPITAL

COMPANY	COMMON EQUITY	FIXED INCOME CAPITAL	M/B RATIO	MKT. VALUE DEBT(1-t)/EQ.
Central Vermont P. S.	63.00%	37.00%	1.05	0.36
FirstEnergy Corp.	45.00%	55.00%	1.77	0.45
Green Mountain Power	56.00%	44.00%	1.30	0.39
Progress Energy	41.00%	59.00%	1.29	0.73
Ameren Corp.	50.00%	50.00%	1.58	0.41
Cleco Corporation	52.00%	48.00%	1.52	0.39
DPL, Inc.	35.00%	65.00%	4.51	0.27
Empire District Electric	46.00%	54.00%	1.37	0.56
Entergy Corp.	46.00%	54.00%	1.77	0.43
Hawaiian Electric	37.00%	63.00%	1.77	0.63
PNM Resources	38.00%	62.00%	1.31	0.81
Pinnacle West Capital	48.00%	52.00%	1.11	0.63
Unisource Energy	32.00%	68.00%	1.64	0.84
AVERAGES	45.31%	54.69%	1.69	0.53
TARGET CAP. STRUCTURE	50.00%	50.00%	1.69	**0.38**

AVERAGE (LEVERED) UTILITY BETA = 0.83

Beta (Unlevered) = Beta (Levered)/(1+D(1-t)/E)

Beta (Unlevered)= 0.83/(1+.53)= **0.54**

Beta (Relevered)= Beta (Unlevered)*(1+D(1-t)/E)

Beta (Relevered)= 0.54(1.38)= **0.75**

IMPACT ON COST OF EQUITY CAPITAL

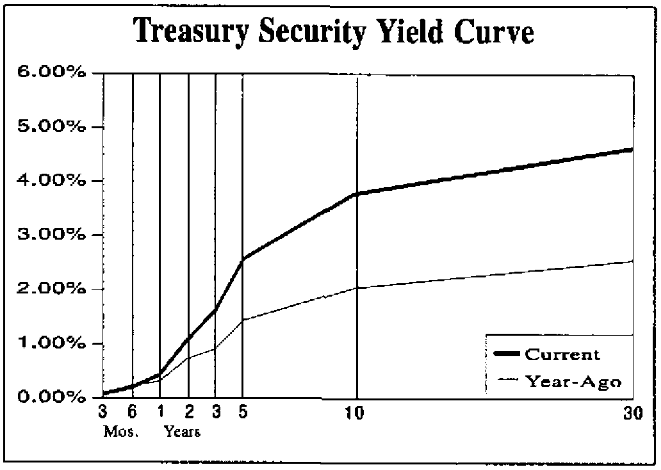
	Measured Beta	0.830
	Relevered Beta	0.751
[1]	Diff. in Beta	0.079
[2]	Market Risk Premium (rm-rf) =	4% to 6%

Average Cost of equity impact = [1] x [2] = **0.32% to 0.48%**

ATTACHMENT B

Selected Yields

	Recent (12/29/09)	3 Months Ago (9/30/09)	Year Ago (12/30/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.11	0.18	0.06
3-month LIBOR	0.25	0.29	1.44
Bank CDs			
6-month	0.29	0.40	1.16
1-year	0.54	0.64	1.43
5-year	1.97	2.27	2.51
U.S. Treasury Securities			
3-month	0.08	0.11	0.09
6-month	0.20	0.17	0.24
1-year	0.43	0.38	0.31
5-year	2.57	2.31	1.44
10-year	3.80	3.31	2.05
10-year (inflation-protected)	1.36	1.53	2.33
30-year	4.64	4.05	2.56
30-year Zero	4.81	4.13	2.42



	Recent (12/29/09)	3 Months Ago (9/30/09)	Year Ago (12/30/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.72	3.63	4.11
FHLMC 6.5% (Gold)	2.56	2.82	4.03
FNMA 6.5%	2.47	2.60	3.89
FNMA ARM	2.41	2.62	4.22
Corporate Bonds			
Financial (10-year) A	5.52	5.61	7.08
Industrial (25/30-year) A	5.80	5.31	5.90
Utility (25/30-year) A	5.98	5.40	5.85
Utility (25/30-year) Baa/BBB	6.53	5.73	6.58
Foreign Bonds (10-Year)			
Canada	3.62	3.31	2.66
Germany	3.37	3.22	2.95
Japan	1.31	1.30	1.17
United Kingdom	4.08	3.59	3.09
Preferred Stocks			
Utility A	5.98	5.77	6.00
Financial A	6.82	6.61	7.89
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.21	4.04	5.46
25-Bond Index (Revs)	4.94	4.86	6.22
General Obligation Bonds (GOs)			
1-year Aaa	0.28	0.37	0.85
1-year A	1.22	0.80	0.95
5-year Aaa	1.65	1.57	2.57
5-year A	2.77	2.00	2.87
10-year Aaa	3.25	2.57	3.70
10-year A	4.19	2.95	4.20
25/30-year Aaa	4.48	3.92	5.17
25/30-year A	5.42	4.45	6.15
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.77	4.70	6.15
Electric AA	4.72	4.75	6.20
Housing AA	5.81	5.10	6.50
Hospital AA	5.18	5.25	6.55
Toll Road Aaa	4.80	4.75	6.25

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	12/16/09	12/2/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1089691	1119560	-29869	1010650	882362	829643
Borrowed Reserves	171457	206509	-35052	243588	306498	438064
Net Free/Borrowed Reserves	918234	913051	5183	767063	575864	391580

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	12/14/09	12/7/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1683.0	1684.7	-1.7	2.6%	3.5%	5.2%
M2 (M1+savings+small time deposits)	8405.5	8402.0	3.5	3.9%	0.4%	3.2%

ATTACHMENT C

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

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$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

SURREBUTTAL TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 15, 2010

SURREBUTTAL TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-04204A-09-0206

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. Are you the same Ben Johnson that earlier filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the scope of your surrebuttal testimony?

A. I will respond to certain comments made by UNS Electric witnesses concerning my testimony on the following issues: the appropriate rate of return to be applied to a fair value rate base; various adjustments to operating income; and, residential rate design. Further, as alluded to in my direct testimony, I will provide some calculations that illustrate the potential impacts of my customer charge and inclining block rate recommendations.

Q. What does UNS have to say about calculating an appropriate rate of return to be applied to a fair value rate base?

A. UNS continues to argue that if the rate of return is reduced to reflect the impact of inflation, only half the actual rate of inflation should be subtracted from the rate of return, since half the FVRB (The OCRB portion) does not include inflation. UNS argues that such a methodology is required by the Commission's most recent decision in the Chaparral rate case.

> As recognized by the Commission in Decision No. 71308, RCND is impacted by inflation, whereas OCRB is stated in original nominal dollar terms. Since only 50% of FVRB is impacted by inflation, the Commission determined that the ROR on FVRB should be determined by subtracting only 50% of an inflation rate from the weighted average cost of capital. If the full rate of inflation were deducted from the weighted cost of capital, as advocated by Dr. Johnson, this method would result in an adjustment that overstates the impact of inflation on capital costs and would produce an unreasonably low ROR on FVRB. [Grant Rebuttal, pp. 16-17]

Q. Does the Commission's recent Chaparral decision require application of the same methodology in this case?

A. No. Nothing in that decision indicates that the Commission intended to adopt a specific methodology for application to all future cases. If the Commission were interested in doing that, it could easily have provided some indication of its intent in that case, and initiated a rulemaking proceeding – which would be the best way to go about investigating the pros and cons of adopting a uniform methodology to apply in all cases, regardless of the facts brought forward in each specific proceeding.

As well, I would note that while the Commission applied a methodology recommended by its Staff, the Commission did not discuss the pros and cons of that particular methodology at length in its final order. When describing Staff's methodology, the Commission stated:

> Because one half of the FVRB includes OCRB, which does not include inflation, Staff adjusted the 2.4 percent inflation factor by one-half, resulting in an inflation adjustment to the WACC of 1.2 percent. [Decision 71308, pp. 43-44]

However, this passage is merely descriptive of the Staff's rationale for using this particular methodology in this case, rather than one of the other methodologies that have been put forward by the Staff in various other proceedings. Importantly, when the Commission discussed it's own conclusions, *it did not discuss this line of reasoning* in detail, nor did it explicitly adopt this reasoning. The Commission simply concluded that FVRB includes an inflation component, it is appropriate to make a corresponding downward adjustment to the FVROR, and that adjustment should not be limited to the portion of the rate base that is funded with equity (as it had done in a prior proceeding). For example, the Commission states:

> Because there is an inflation component in the Company's FVRB, all inflation must be removed from the rate of return, whether in debt or equity. [Id., p. 49]

This conclusion is fully consistent with my recommended approach. Further, the Commission seems to realize that this issue is far from settled, given its controversial nature and recent history of litigation, and there is no indication in the order that it is unwilling to hear further evidence concerning the best approach to use. To the contrary, the Commission stated that further refinements to the inflation methodology are "possible" and were "encouraged" [Id.]

Q. Do you agree that because half the FVRB is comprised by the OCRB, that the WACC must be reduced by only half the rate of inflation?

A. No. As I explained in my direct testimony, the fact that OCRB is part of the fair value process does not provide an adequate justification for slashing the inflation rate in half. I will concede that OCRB is given half weight in developing the FVRB, and OCRB does not increase with inflation. However, half weight is being given to RCND, and reproduction costs tend to grow faster than the actual rate of inflation. RCND does not fully consider the favorable impact of technological changes, increasing economies of scale, the beneficial impact of making input substitutions to increase reliance on inputs that are decreasing in cost, have been more favorably affected by technological change, or have experienced relatively mild increases in price levels. These factors are taken into consideration in developing inflation statistics, and thus the rate of inflation that is reported for the Consumer Price Index, the GDP Deflator, and similar data series reflects the beneficial (ameliorating) impact of these phenomena – whereas RCND has a tendency to grow faster than the overall rate of inflation, because these ameliorating factors are not adequately reflected in the development of reproduction costs.

FVRB reflects the Commission's estimate of the current fair value of the utility's property and equipment; if the Commission were to rely exclusively on RCND, it would greatly overstate the current value, which would not be fair to consumers. In my opinion, while the Commission certainly has discretion in deciding on a fair return that is appropriate to apply to the fair value rate base, there is no logical reason to slash the inflation rate in half – much less adopt a rule that mandates this approach in all cases, regardless of the underlying factual circumstances (e.g. the manner in which the RCND estimates were developed, or the extent to which those estimates have been growing at a pace that is faster than the overall rate of inflation).

Q. Can you now discuss the Company's criticisms of your income and expense adjustments?

A. Given time and resource contraints, I will not respond to every point made by the Company; the absence of a comment in this surrebuttal should not be interpreted as agreement with the

Company's criticisms. One of the most significant, and fundamental points of disagreement relates to the appropriate application of the historical test year. The Company disagrees with many of my adjustments (or my decision to not adopt certain adjustments proposed by UNS), because it disagrees with my recommended cut-off date for the inclusion of changes to circumstances that were observed after the end of the test year. In my direct testimony, I recommended the Commission should continue to use an historical test year, and it should generally reject ad hoc adjustments for changes that occurred, or will occur, beyond the end of the test year. The Company disagrees with my use of a traditional historical test year approach, for two reasons. First, it argues that the Commission has sometimes allowed post test year adjustments in utility rate cases. Second, it contends that the Comission's rules and regulations do not specifically prohibit post test year adjustments. [See, Dukes Rebuttal, p. 6]

Q. Do you continue to believe that the Commission should generally follow a strict historical test year approach?

A. Yes. As I explained in my direct testimony, making adjustments for "known and measurable" cost increases is a popular method for dealing with the closely related problems of inflation and regulatory lag. However, despite its popularity, this approach tends to be arbitrary and controversial. Regardless of how well known or measurable a particular cost change may be, it is difficult to achieve internal consistency and an appropriate "matching" of revenues and costs when the adjustments go beyond the test year. If the Commission concludes that the financial situation of a particular utility calls for measures that go beyond a traditional historical test year approach, I don't believe the best response is to accept more and more adjustments for "known and measurable" changes, or to extend the cut off date for cost increases farther and farther beyond the end of the test year, while leaving revenues frozen at the level which occurred during, or at the end of, the test year. As adjustments stretch farther and farther beyond the test year, the computed revenue requirement tends to get larger and larger. While this makes it easy to justify higher and higher rates, this approach has little theoretical merit. To the contrary, the farther beyond the test year one ventures, the more difficult and arbitrary it becomes to select a cutoff date, and the less confidence one can have in the final result of the test year calculations. The farther one goes beyond the test year – particularly if expenses are adjusted more aggressively than revenues – the more severe the mismatch that occurs between revenues and expenses. As the misaligment of revenues and expenses becomes increasingly severe, it becomes harder to ensure that the adjustments are known and accurately measurable, and that the final result of the process is a realistic and representative snapshot of the Company's operations. For this reason, I would urge the Commission to adopt a strict application of the historical test year approach, and to the extent it decides to grant a larger rate increase than is justified by the historical test year data, in order to help maintain the Company's financial integrity or for some other valid reason, I recommend that it be explicit about that decision, the reasoning behind the decision, and the basis for determining the magnitude of the additional increase in rates beyond that which would be justified by the actual results of operations during the test year.

Q. Are there other issues related to specific adjustments that you would like to briefly address?

A. Yes. I would like to respond to the Company's discussion of my treatment of its pension and benefit (P&B) loading rate, and its property tax adjustment. In my direct testimony, I explained that the P&B adjustment includes pensions, the Company's share of contributions to the employees' 401(k) plan, and current medical costs. The adjustment essentially replaced actual 2008 expenses with anticipated 2009 expenses. I recommended against this adjustment, arguing that it is reasonable to rely on the actual pensions and benefits expenses during the test year, rather than estimating the level of costs that will be incurred during 2009. However, in its rebuttal, the Company explained that the P&B loading rate used by UNS in its rate filing went into effect on January 1, 2009, which is essentially equivalent to going into effect at the end of the 2008 test year. Accordingly, I would concede that this is a reasonable adjustment, which is consistent with the use of a historical test year, as well as my recommended treatment of the wage rate increase that went into effect on January 1, 2009. Hence, I am revising my position, to recommend that the Company's P&B adjustment be approved.

A somewhat similar situation applies to the Company's property tax adjustment. The Company proposed making an adjustment to property taxes to reflect the assessment ratio that will go into effect on January 1, 2010. I recommended making an adjustment based upon the assessment ratio that went into effect on January 1, 2009. In its surrebuttal testimony, UNS points out that the lien date for the 2009 property tax year is January 1, 2008, and that the lien date for the 2010 tax year is January 1, 2009. [See, Kissenger Rebuttal, p. 3] I continue to believe the approach I recommended in my direct testimony is a reasonable one, which is fully consistent with the strict application of a historical test year. However, in reviewing the Company's rebuttal testimony on this point, and thinking more about this issue, I can see that this is a grey area. Because there is such a long lag in the property taxation process, one can make a plausible argument that use of the assessment ratio that will go into effect on January 1, 2010 is consistent with a 2008 test year, since the assessment ratio is based on data that was gathered during 2008, and is being computed "as of" January 1, 2009 – essentially the end of the test year. Accordingly, while I still believe the approach I recommended in my direct testimony is the best approach, I will concede it is a close call, and that the Company's approach can also be fairly characterized as being somewhat consistent with a 2008 test year.

Q. Can you now discuss UNS' criticisms of your residential rate design recommendations?

A. Yes. In my direct testimony I recommended reducing Residential customer charges to $5.00 per month, rather than increasing them to $8.00 per month, as the Company proposes. I also recommended adding another block, or tier, to the Company's inclining block rate structure. More specifically, for residential customers I recommend applying the lowest rate to the first 400 kWh per month; charging a higher rate for the next 400 kWh per month, and charging a still higher rate for all additional kWh.

In response, UNS claims that I have proposed to "radically" shift cost recovery away from the customer charge to the energy charge.

> In doing so, he significantly understates the residential customer charge. This results in a mismatch between revenue collection and cost causation. Shifting customer-related costs to energy (per kWh) charges leads to the Company under-recovering when sales are relatively low, regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. Likewise, over-recoveries result when sales are relatively high. [Erdwurm Rebuttal, p. 6]

Mr. Erdwurm admits that my proposed rate design will provide customers a greater incentive to conserve engery. However, he believes that it will preclude the Company from having a reasonable opportunity to earn its allowed return, becasue certain costs "will go unrecovered if kWh sales levels are below the test-year levels used to design rates". [Id., p. 7]

Q. Do you agree with Mr. Erdwurm?

A. No, I do not. As I explained in my direct testimony, we have a fundamental disagreement about the most appropriate way to analyze costs; from my perspective, the Residential customer charges are already higher than appropriate (a similar problem probably exists with other rate schedules, but I have not studied those in as much depth). The Company's proposal is not based upon a valid analysis of economic costs. Rather it is based on an embedded cost allocation approach which allocates substantial portions of the Company's distribution investment and operating expenses on the basis of customers, regardless of whether or not these items directly vary in response to decisions by customers to join or leave the system. Most of the costs allocated to this rate are not focused on the variable costs that are directly attributable to the decision of customers to join or leave the system, and none of the computations are based on a forward looking, marginal cost analysis. The customer charge should primarily collect the variable costs of metering, billing, and collecting the monthly bill. Other so called "customer costs," including costs of the distribution system, which are largely determined by the configuration of the Company's service territory, the need to stand ready to provide service to all customers; and the need to be able to deliver energy to customers as and when they need it. These costs do not vary from month to month, with changes in the number of customers on the system, and it is reasonable to recover these costs through the service that is sold to consumers – just as the cost of a grocery store's parking lot is recovered through the price of groceries, rather than through a per-customer fee for the privilege of shopping at the store.

Furthermore, setting customer charges at relatively high levels (as the Company prefers) tends to encourage kWh consumption and discourage energy conservation – both of which are contrary to the public interest. Although the Company's inclining block rate structure ameliorates part of this problem, it does not completely eliminate it. As I explained in my direct testimony, the high customer charges proposed by the Company tend to result in customer bills that decrease on a per-total-kWh basis as usage increases, despite the inclining block structure. By proposing to further increase customer charges above levels which are already higher than necessary, the Company is proposing to place an even heavier burden on low use customers and losing an opportunity to encourage energy conservation.

Q. Does the Company have other complaints about your recommended reductions in the customer charge and increases in per kWh rates paid by high usage customers?

A. Yes. It complains that these changes will increase revenue and income volatility, and make it more difficult for it to achieve its approved rate of return, as explained by Company witness Erdwurm:

> The Company appreciates Dr. Johnson's acknowledgement that progress has been made in promoting conservation in rates. Dr. Johnson, however, has not adequately considered the adverse potential impact of his proposals on UNS Electric's financial condition.
>
> ...Dr. Johnson seeks to radically shift recovery away from the customer charge to the energy charge. ...This results in a mismatch between revenue collection and cost causation. Shifting customer-related costs to energy (per kWh) charges leads to the Company under-recovering when sales are relatively low, regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. ...a cost-based residential customer charge – like the one proposed by UNS Electric – helps mitigate periodic swings in revenue because of volatility in usage. In short, it is important that a rate design that promotes conservation also gives some measure of revenue stability for the Company. [Id., pp. 6-7]

Furthermore, setting customer charges at relatively high levels (as the Company prefers) tends to encourage kWh consumption and discourage energy conservation – both of which are contrary to the public interest. Although the Company's inclining block rate structure ameliorates part of this problem, it does not completely eliminate it. Mr. Erdwurm concedes that my suggested revisions to the Company's rate design will provide customers with a greater incentive to conserve, and he seems to realize that as a result of these stronger incentives, over time growth in kWh will gradually be slowed, as customers choose more energy-efficient light bulbs, come to accept higher thermostat settings, acquire more energy-efficient appliances, and so forth. However, he doesn't focus on the long term benefits of the gradual change in consumer behavior in response to these changed price signals, which will reduce the need to install costly new facilities, reducing the need for future rate increases in order to pass through the cost of these facilities, he instead focuses on potential adverse effects on the Company's earnings and revenue volatility in the short run:

> ...his rate design proposal will also preclude providing UNS Electric a reasonable opportunity to earn its approved return. UNS Electric's proposed residential rate design provides a balance between the conservation goal and providing the Company a fair opportunity to recover its costs. Dr. Johnson's residential rate design proposal, in contrast, ignores customer-related costs that the Company incurs for every customer that receives service from UNS Electric. I believe Dr. Johnson's rate design is confiscatory in its approach. [Id., p. 6]

Q. How do you respond?

A. It was certainly not my intent to be "radical" in any of my recommendations, nor do I think anything I proposed fits this characterization. Take the recommended reduction in customer charges, for example. I proposed reducing the customer charge for residential customers from the current level of $7.50, to $5.00 per month. Stated as a percentage, this reduction would be fairly dramatic – a decline of one-third. However, the reduction in revenue resulting from this reduction in the customer charge would be offset by an increase in revenue from higher per-kWh rates, so the net impact on a typical customer bill would be much less dramatic.

The following tables compare the Company's proposed rates with directly analogous rates that would result from retaining the existing $7.50 customer charge, reducing it to $6.50, or reducing it to $5.00 (as I recommend), while adjusting the per kWh rate in each case by an offsetting amount to provide the same total revenues. As shown, the impact on customer bills is relatively mild:

UNS Rate Proposal, including a $8.00 customer charge

	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$8.00	$8.00	$8.00	$8.00
Energy Charge	2.61	14.06	32.12	50.19
Base Charge	6.88	34.38	68.77	103.15
Total	$17.49	$56.44	$108.89	$161.34
Total per kWh	0.175	0.113	0.109	0.108

UNS Rate Proposal except using a $7.50 Customer Charge

	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$7.50	$7.50	$7.50	$7.50
Energy Charge	2.67	14.35	32.7	51.05
Base Charge	6.88	34.38	68.77	103.15
Total	$17.05	$56.23	$108.96	$161.70
Total per kWh	0.170	0.112	0.109	0.108

UNS Rate Proposal except using a $6.50 Customer Charge

	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$6.50	$6.50	$6.50	$6.50
Energy Charge	2.78	14.92	33.84	52.76
Base Charge	6.88	34.38	68.77	103.15
Total	$16.16	$55.80	$109.11	$162.41
Total per kWh	0.162	0.112	0.109	0.108

UNS Rate Proposal except using a $5.00 Customer Charge

	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$5.00	$5.00	$5.00	$5.00
Energy Charge	2.95	15.78	35.56	55.34
Base Charge	6.88	34.38	68.77	103.15
Total	$14.83	$55.16	$109.32	$163.49
Total per kWh	0.148	0.110	0.109	0.109

Similarly, the impact on the Company's revenues and net income will also be relatively mild. For instance, if the Residential customer charge is increased to $8.00, as the Company proposes, it will generate approximately $424,000 more per year than the current rate. Conversely, reducing the rate to $5.00 would generate $2,542,000 less than the current rate. In both cases, however, this change would be offset the an change in revenues from the per kWh rates of a similar total magnitude, initially leaving total revenues and net income largely unchanged. (Over time, revenues would grow more with the higher per kWh rates, and thus net income would also tend to grow more, over the long term). I find it hard to understand why the Company views this recommended shift in revenues from the fixed monthly rate category to the per kWh rate category "radical." To put these numbers into perspective, this recommended shift in revenues between categories of $2,542,000 per year is equivalent to just 8.5% of the Company's proposed revenues from Residential customers excluding revenues derived from Base Power Supply Charges, and just 3.1% of the analogous total including Base Power Supply Charges. Bearing in mind that this is merely a change in category – not an actual change in revenues – it is hard to see why the Company views such a modest change as too "radical."

In any event, the Commission can decide how far, and how fast, it wants to move toward encouraging energy conservation, and how quickly it wants to better align rates with marginal cost. If the Commission agrees with the approach I am recommending, but wants to move more gradually, it could adopt a more gradual change in rates, by reducing the customer charge to a lesser degree than I have recommended. A reduction in customer charges to $6.50 would represent a categorical shift in revenues of about 1.6%, yet it would still be a worthwhile step in the right direction.

Q. Does this conclude your surrebuttal testimony pre-filed on January 15, 2010?

A. Yes, it does.